UNITED STATE OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Niagara Mohawk Power Corporation

Amendments to the
New York Independent System Operator, Inc.
FERC Electric Tariff
Attachment H – Annual Transmission Revenue Requirement for
Point-to-Point Transmission Service and
Network Integration Transmission Service

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FEDERAL ENERGY REGULATORY COMMISSION

Niagara Mohawk Power Corporation) Docket No. ER12- __________

Direct Testimony
Of
James G. Holodak

I. Introduction and Qualifications:

Q. Please state your name and business address.

A. James Holodak, Jr., National Grid, 14th Floor, One Metrotech Center Brooklyn, NY 11201.

Q. By whom are you employed and in what capacity?

A. I am employed by National Grid USA Service Company as Vice President of Regulatory Strategy & Integrated Analytics. National Grid USA Service Company provides administrative, accounting, finance, IT, engineering, regulatory, and legal services for the National Grid operating companies, one of which is Niagara Mohawk Power Corporation ("NMPC"), d/b/a National Grid. In my current position, I oversee transmission and wholesale generation rates for the FERC regulated entities as well as regulatory strategy and analytical analysis for the state regulated entities within National Grid's US operations.

Q. Please describe your educational background and training.

A. I hold both a Bachelor Degree in Electrical Engineering and an MBA in Finance from Manhattan College. Effective April 2011, I was appointed Vice President of Regulatory Strategy & Integrated Analytics for National Grid's US operations. From August 2007 to March 2011, I was Director of Finance, Electric Distribution & Generation, where I was responsible for budgeting, financial analysis and support, financial reporting and strategic support for the Generation and Long Island Power Authority Finance segment of National Grid's Electric Distribution and Generation business functions in the United States. From September 2001 to August 2007, I was the Assistant Treasurer for the former KeySpan Company, which was acquired by National Grid USA in 2007. From 1998 to 2001, I was Director of Financial Planning and Analysis for KeySpan performing short-term and long-term financial forecasting and strategy. Prior to that, I was a manager in Financial Planning, Corporate Planning and M&A Economic Analysis, and held various engineering positions in Electric Operations, Marketing, and Engineering and Construction in LILCO, KeySpan's predecessor company, from 1980 to 1998.

Q. Have you submitted testimony in any prior rate proceedings?

A. Yes. I have previously provided testimony, as part of a joint panel, in National Grid Generation LLC's rate case reset filing in Docket No. ER09-628-000, before the Federal Energy Regulatory Commission ("Commission"). The panel was responsible for the development of forecasted data upon which the cost of service was prepared. I have also provided testimony and exhibits in National Grid Generation LLC's rate reset case filing in Docket No. ER04-112-000 before the Commission as the Company's cost of capital and capital structure witness. I have provided testimony and exhibits in LILCO's Electric Rate Case filing in Case No. 96-E-0132 before the New York Public Service Commission ("NYPSC") as the Company's revenue witness.

II. Purpose of Testimony:

Q. What is the purpose of your testimony?

A. The purpose of my testimony is three-fold. First, I support NMPC's filing of an amendment to its formula rates to update the depreciation rates in its wholesale Transmission Service Charge ("TSC") rate formula under the New York Independent System Operator's ("NYISO's") Open Access Transmission Tariff ("NYISO OATT"). NMPC proposes to amend its transmission depreciation rates in time for its Annual Update establishing TSC rates that will become effective on July 1, 2012 . NMPC's revenue requirement for calendar year 2011 will be used as the basis for determining its July 1, 2012 TSC rates. NMPC is proposing that the revised depreciation rates become effective as of January 24, 2011, the same date that identical depreciation rates were approved to become effective for NMPC by the NYPSC in Docket Number 10-E-0050.

Second, I support ministerial changes to Section 14.2 of Attachment H to the NYISO OATT, modifying Section headers so that they match the renumbering convention recently implemented by the NYISO as part of its e-tariff compliance filing. Specifically, the NYISO modified paragraph numbering in Attachment H of the NYISO OATT as part of its compliance with FERC Order 714, Electronic Tariff Filings. The NYISO OATT and Services Tariff were renumbered to facilitate section-based filings in e-Tariff. The NYISO filed its e-Tariff baseline on June 30, 2010 in Docket No. ER10-1657-000.

Third, I support a modification to the revenue requirement calculation in Section 14.2 of the NYISO OATT to incorporate the terms of a Stipulation and Agreement accepted by the Commission in Docket No. ER11-2228-000 as part of NMPC's 2010 Annual Update filing. Under the terms of the Stipulation and Agreement, NMPC agreed to exclude from any future Annual Update of the TSC rate the costs of a Temporary Assessment under section 18-a of the NY PSC. We have taken the opportunity in this filing to codify that change into NMPC's revenue requirement formula.

Q. Please provide a summary of the depreciation rate changes proposed in this proceeding.

A. NMPC is proposing to reflect updated depreciation rates in its TSC formula rates pursuant to new depreciation studies that were submitted to the NYPSC as part of state-jurisdictional rate case proceedings. The depreciation rates set forth in this docket were approved by the NYPSC on January 20, 2011 with an effective date of January 24, 2011 in NYPSC Docket Number 10-E-0050

Q. Are you sponsoring any statements as part of this proceeding?

A. Yes. Exhibit No. NMP-3 contains statements AA through BL required by the Commission's rate filing regulations. Period I is the twelve months ended December 31, 2010. I am sponsoring all of the statements.

Q. Are you sponsoring any other exhibits as part of this proceeding?

A. Yes. Exhibit No. NMP-4 contains the final formula rate spreadsheets filed as a Supplement to NMPC's 2011 Annual Update in Docket No. ER08-552-000. The supplement was filed with the Commission on December 9, 2011. Exhibit No. NMP-4 contains NMPC's final revenue requirement for calendar year 2010 and is used in this filing as the reference or starting point for NMPC's Period I revenue requirement under present rates. NMPC's revenue requirement under proposed rates is provided in Statement BJ/BK/BL of Exhibit No. NMP-3. I am also sponsoring Exhibit No. NMP-5, which is Exhibit No. NMP-4 modified to reflect the paragraph renumbering convention adopted by the NYISO as part of its e-Tariff compliance with the Commission's Order No. 714 The updated references are black-lined to show the changes. I am also sponsoring Exhibit No. NMP-6 and Exhibit No. NMP-7. NMP-6 is the testimony and exhibits prepared by NMPC's depreciation witness that were submitted to the NYPSC as part of state-jurisdictional rate case proceeding 10-E-0050. NMP-7 is the testimony and exhibits prepared by the NYPSC staff that was submitted in the same state-jurisdictional rate case proceeding.

III. Background

Q. Please provide a history of the TSC rates currently set forth in Attachment H.

A. On January 27, 1999, the Commission conditionally accepted in Docket No. ER97-1523-000 the proposal made by the Company and the other New York Transmission Owners ("NYTOs") to establish the NYISO. On November 17, 1999, the NYTOs filed a joint settlement agreement among all parties (the "NYISO Settlement"). The NYISO Settlement established in Attachment H of the NYISO OATT a "Settlement" Revenue Requirement and a Transmission Service Charge ("Settlement TSC") for wholesale transmission services provided under the NYISO OATT to all of the Company's customers. The NYISO Settlement was approved by the Commission by letter order dated July 31, 2000.

On February 11, 2008, as supplemented on May 30, 2008, NMPC submitted a filing under Section 205 of the Federal Power Act in Docket No. ER08-552-000 to replace the stated rates for its Transmission Service Charge ("National Grid TSC") in Attachment H to the NYISO OATT with formula rates to become effective May 1, 2008. On April 6, 2009, NMPC, on behalf of the Settling Parties, filed a settlement intended to resolve all issues set for hearing in that proceeding ("2009 Settlement"). Among other things, the 2009 Settlement set forth the terms of a formula rate for the calculation of NMPC's transmission service charge under the NYISO OATT (the "Settlement TSC Formula Rate"), as well as procedures for the annual adjustment of certain inputs to the formula rate. In a letter order issued June 22, 2009, the Commission approved the 2009 Settlement.

On November 30, 2009, NMPC filed to modify the manner of calculating the long-term debt cost of capital rate in its revenue requirement underlying the TSC rate in Docket Nos. ER10-328-000 and ER10-328-001. The filing sought to adjust the determination of the amount of long-term debt used in the calculation which was based on the average beginning of the year and year end long-term debt balances. On January 13, 2010 the filing was accepted by the Commission effective February 1, 2010.

In accordance with the 2009 Settlement, NMPC is directed to calculate each year new values for the Revenue Requirement(“RR”), Control Center Costs (“CCC”) and Billing Units (“BU”) components of the Settlement TSC Formula Rate based on updated Data Inputs. NMPC is further directed to prepare an Annual Update that reflects the revised Data Inputs, the resulting RR, CCC, and BU components, and certain supporting information. According to Section 14.1.9.4 of Attachment H to the NYISO OATT, NMPC is directed on or before June 14th of each year to (1) post the Annual Update on the NYISO’s Internet website, (2) submit its Annual Update to the Commission as an informational filing requiring no action by the Commission, and (3) serve the Annual Update electronically on all Interested Parties.

With respect to its 2010 Annual Update, on November 18, 2010 NMPC filed with the Commission a Stipulation and Agreement and a Supplemental Informational Filing (“2010 Stipulation”) in Docket No. ER11-2228-000 setting forth a modification to be made in NMPC’s future Annual Updates of certain components of the NMPC TSC rate based on adjusted inputs to the Settlement TSC Formula Rate. Specifically, NMPC agreed to exclude the costs of the section 18-a Temporary Assessment in any future Annual Update of the Settlement TSC Formula Rate. . The Commission accepted the 2010 Stipulation in a letter order issued January 7, 2011.

In accordance with the Annual Update procedures set forth in Section 14.1.9.4.1 of

Attachment H, NMPC filed its 2011 Annual Update with the Commission for informational purposes on June 14, 2011. On November 8, 2011 the New York Association of Public Power ("NYAPP") and the New York Municipal Power Agency ("NYMPA") submitted a list of Preliminary Challenges to NMPC. In accordance with Section 14.1.9.4.3 of Attachment H, NMPC notified the Interested Parties on November 18, 2011 of the successful resolution of the Preliminary Challenges, including the rate impact of that resolution. In accordance with Section 14.1.9.4.3.2 of Attachment H, NMPC submitted a Supplement on December 9, 2011 to reflect the impact of this resolution on the TSC rate that became effective as of January 1, 2012.

Q. Please describe NMPC's TSC formula rate.

A. The TSC is a formula rate. Attachment H to the NYISO OATT specifically provides for the Revenue Requirement ("RR") component, Control Center Costs ("CCC") component, and Annual Billing Units ("BU") component of a Transmission Owner's Wholesale TSC rate to be updated "based on Transmission Owner filings to FERC." Each Transmission Owner is entitled to amend these three components of Attachment H to the NYISO Tariff on its own initiative. As stated above, NMPC has filed and received approval via a settlement agreement accepted by the Commission in Docket No. ER08-552-000 to utilize a formula rate in accordance with the definitions set forth in Section 14.1.9.1, formerly Section 9.1, and the formula references in Section 14.1.9.2, formerly Section 9.2, of the NYISO Electric Tariff, Attachment H.

IV. <u>Proposed Amendments to the TSC Formula Rate</u>

Q. Please describe the depreciation rate changes being proposed to NMPC's TSC formula rate under Attachment H of the NYISO OATT.

A. On January 20, 2011, the New York State Public Service Commission issued an order establishing rates for NMPC's electric retail customers, including a change to NMPC's depreciation rates. NMPC is making this filing with the Commission so that the TSC formula rate will reflect the same depreciation rate changes approved by the NYPSC. This will permit NMPC to have a consistent set of depreciation rates on its books and ensure that both electric retail customers and transmission wholesale customers are consistently charged the same depreciation rates.

Q. Why are these changes being proposed at this time?

A. According to Section 14.1.9.4 of Attachment H to the NYISO OATT, NMPC recalculates its RR, CCC, and BU components as part of its Annual Update to become effective as of July 1 of each year. With the exception of forecasted information, the cost data used in the Annual Update is the cost data from NMPC's Annual FERC Form 1 or NMPC's official books of Record from the prior calendar year. The depreciation rate changes approved by the NYPSC to become effective as of January 24, 2011 will be reflected in NMPC's 2011 FERC Form 1. NMPC's 2012 Annual Update would be the first time the new depreciation rates would be utilized to calculate a TSC Formula Rate that will become effective as of July 1, 2012.

Q. Please describe the NYPSC proceeding in which these depreciation rates were approved.

A. In January 2010, NMPC submitted a general rate filing to the NYPSC to increase its electric delivery revenues in Case 10-E-0050. On November 17, 2010, the Administrative Law Judges assigned to the case provided their recommended decision, which addressed the contested issues and reported the stipulations the parties reached in this case. On January 20, 2011, The NYPSC issued an order establishing rates for Electric Service to be effective January 24, 2011. This order is included in Exhibit No. NMP-3, Statement AX.

NMPC provided a depreciation study with its rate filing. This depreciation study, along with expert testimony is provided in Exhibit No. NMP-6. As indicated on Page 19 of this exhibit, the Company proposed to keep the then effective depreciation rates in effect going forward.. However, NYPSC staff disagreed and proposed modifications to NMPC's depreciation rates. A copy of NYPSC Staff's testimony and exhibits is contained in Exhibit No. NMP-7. The NYPSC Staff proposed net salvage adjustments that, overall, decreased depreciation expenses by approximately $25.5 million. NYPSC Staff also proposed changes in average service lives that would similarly decrease depreciation expenses by another $10.5 million. Although the overall recommendation by the NYPSC staff resulted in a reduction to depreciation expenses, the NYPSC Staff's recommendation resulted in an increase in depreciation expenses for Transmission assets. The Administrative Law Judges recommended the NYPSC Staff's depreciation adjustments for NYPSC approval and NMPC filed exceptions to the recommendation. In its January 2011 Order, the NYPSC denied NMPC's exceptions and approved the depreciation rates recommended by NYPSC Staff.

Q. Please describe the changes to depreciation rates.

A. In this proceeding, NMPC is proposing to modify its depreciation rates to match those approved by the NYPSC. Exhibit No. NMP-3, Statement BJ/BK/BL pages 8 through 10 calculates the change in depreciation expense that results from the proposed depreciation rate changes, by FERC account, for the twelve months of depreciation expense reported in NMPC's 2010 FERC Form 1 (Period I). These pages also show the depreciation rates in effect in calendar year 2010 and the proposed depreciation rates ordered by the NYPSC to become effective as of January 24, 2011. The column labeled "Provision at New Rate" on these schedules calculates depreciation expense for calendar year 2010 under NMPC's proposed depreciation rates. Line 21 on page 8 of Statement BJ/BK/BL demonstrates that the proposed depreciation rate change results in an increase to NMPC's total Transmission Depreciation Expense of $3.5 million. The change in depreciation rates also impacts the calculation of depreciation reserves and deferred taxes in the RR calculation. In total, the depreciation rate changes result in a total increase of $2,735,595 to the RR calculation. The resulting increase to TSC customers would be 9% of that amount or $244,813.

Q. Why is it important to adopt the updated depreciation rates for NMPC that are identical to those approved by the NYPSC?

A. The goal of depreciation accounting is to charge to operations a reasonable estimate of the cost of the service potential of an asset or group of assets consumed during an accounting interval. Appropriate recovery of investor-supplied capital is dependent upon appropriate levels of depreciation expense. The NYPSC has already determined that the proposed depreciation rates are appropriate. However, it is also important to recognize that Commission approval is needed to ensure that NMPC's depreciation rates already approved by the NYPSC can be uniformly and consistently applied across the entire company. Consistently applied depreciations rates is administratively efficient for the Company and results in consistent reporting and cost recovery from all rate payers. Modified depreciation rates consistent with the rates approved for NMPC by the NYPSC are therefore proposed to be used in the TSC transmission formula rate.

Q. When are these depreciation rate changes proposed to become effective?

A. The depreciation rate changes are proposed to become effective as of January 24, 2011, the same date that they were permitted to become effective by the NYPSC. These depreciation rate changes to NMPC's calendar year 2011 revenue requirement will be reflected in NMPC's 2012 Annual Update that will become effective for TSC rates as of July 1, 2012.

Q. What parts of Attachment H is NMPC proposing to amend to reflect these depreciation rate changes?

A. As shown in Exhibit No. NMP-3, Statement BJ/BK/BL NMPC is proposing to change the depreciation rates in Section 14.1.9.1, Paragraph 14, Attachment H to coincide with the effective date of revisions to its retail electric rates approved by the New York Public Service Commission in Case 10-E-0050 .

V. <u>Updates to NMPC Formula Rate Spreadsheets:</u>

Q. Please describe the updates to NMPC's formula rate spreadsheets related to etariff compliance.

A. As a result of its compliance with FERC Order 714, Electronic Tariff Filings, the NYISO modified its paragraph numbering in Attachment H of the NYISO OATT. The NYISO OATT and Services Tariff were renumbered to facilitate section-based filings under the e-Tariff. The NYISO filed its e-Tariff baseline on June 30, 2010, in Docket No. ER10-1657-000. NMPC is taking this opportunity to update references to Attachment H in its formula rate spreadsheets so that they track the updated references in Attachment H.. Exhibit NMP-5 is the formula rate spreadsheets with the updated references black-lined to show changes. There is no revenue impact related to these changes.

Q. Please describe the updates to NMPC's formula rate spreadsheets related to reflect the 2010 Stipulation and Agreement.

A. As discussed above, in January 2011 FERC accepted in an unpublished letter order NMPC's negotiated settlement of the limited issues raised by the parties on the 2010 Annual Update filing, including removal from the formula rate a component reflecting the Temporary State Assessment under Section 18-a of the New York Public Service Law to prevent duplicate charging of that 18-a assessment to entities who are directly assessed or are otherwise exempt from such assessment. Schedule 1 and Schedule 9 of Attachment H is proposed to be updated to reflect the additional line item in the tariff illustrating the removal of 18a assessment from the formula rate. This is also reflected in the spreadsheet presented in Exhibit No. NMP-5.

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VI. Rate Impact:

Q. Please explain the customer rate impact of implementing the new depreciation rates for the formula TSC rate.

A. A comparison of the present TSC rate and the proposed TSC rate using the 2010 Period I test year yields a total revenue increase of $244,813 on an annual basis. This is shown in Exhibit NMP-3, Statement BG/BH. The estimated increase in the TSC rate of $.0738 per MWh is calculated in Exhibit NMP-3, Statement BJ/BK/BL. As shown in Statement BG/BH, this increase is a result of a change in total Transmission Revenue Requirement of $2,735,595 divided by Total Billing Units of 37,088,552MWh. Billing Units from TSC customers of 3,317,253MWh multiplied by the projected increase in the TSC rate yields a total increase of $244,813.

VII. Conclusion:

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit________ NMP-2
Clean and Black-lined Tariff Changes

14.1 Transmission Service Charge ("TSC")

14.1.1 Applicability of the Transmission Service Charge to Wholesale Customers

Each month, each wholesale Transmission Customer shall pay to the appropriate Transmission Owner the applicable Wholesale Transmission Service Charge ("Wholesale TSC") calculated in accordance with Section 14.1.2.2 of this Attachment for the first two months of LBMP implementation and in accordance with Section 14.1.2.1 of this Attachment thereafter. The TSC shall apply to Transmission Service:

14.1.1.1 from one or more Interconnection Points between the NYCA and another Control Area to one or more Interconnection Points between the NYCA and another Control Area ("Wheels Through");[1]

14.1.1.2 from the NYCA to one or more Interconnection Points between the NYCA and another Control Area, including transmission to deliver Energy purchased from the LBMP Market and delivered to such a Control Area Interconnection Point ("Exports");[1] or

14.1.1.3 to serve Load within the NYCA; except, the Wholesale TSC shall not apply to:

14.1.1.3.1 a Transmission Owner's use of its own system to provide bundled retail service to its Native Load Customers pursuant to a retail service tariff on file with the PSC or, in the case of LIPA, has been approved by the Long Island Power Authority's Board of Trustees;

[1] The TSC shall not apply to Wheels Through or Exports scheduled with the ISO to destinations within the New England Control Area provided that the conditions listed in Section 2.7.2.1.4 of this Tariff are satisfied.

14.1.1.3.2 Transmission Service pursuant to an Existing Transmission Agreement whereby the otherwise applicable TSC does not apply pursuant to Attachment K; or

14.1.1.3.3 retail Transmission Service pursuant to any tariff or rate schedule of a Transmission Owner that explicitly provides for other transmission charges in lieu of the Wholesale TSC, subject to any applicable provisions of the Federal Power Act.

Each Transmission Owner subject to FERC and/or PSC jurisdiction may file with FERC a separate TSC applicable to retail access in accordance with its retail access program filed with the PSC. To the extent that LIPA's rates for service are established by the Long Island Power Authority's Board of Trustees pursuant to Article 5, Title 1-A of the New York Public Authorities Law, Section 1020-f(u) and 1020-s and are not subject to FERC jurisdiction, this requirement will not apply to LIPA.

14.1.2 Wholesale TSC Calculation

Sections 14.1.2-14.1.6 do not apply to the development of the NYPA TSC, which is described in Section 14.1.7.

14.1.2.1 Wholesale TSC Formula

Beginning with the second month of the Capability Period corresponding to the initial auction for Long Term TCCs through the end of the LBMP Transition Period, each Transmission Owner, except NYPA shall calculate its TSC applicable to Transmission Service to serve Load within or exiting the NYCA at its Transmission District as follows:

WHOLESALE TSC = {(RR÷12) + (CCC÷12) + (LTPP÷12) - SR - ECR - CRR - WR - Reserved}/(BU÷12).

Where:

RR = The Annual Transmission Revenue Requirement, as stated in Table 1 of this Attachment. Gross Receipts Tax ("GRT") treatment by each individual company is described in Section 14.1.7. Revenues from grandfathered agreements listed on Attachment H-1 are treated as a revenue credit in the RR.

CCC = The annual Scheduling, System Control and Dispatch Costs of the individual Transmission Owner (*i.e.*, the transmission component of control center costs) as stated on Table 1 of this Attachment.

LTPP = The Transmission Owner's annual Net LBMP Transition Period Payment ("LTPP") (expressed as a positive value) or receipt (expressed as a negative value) as described in Attachment K, Section 17.6 (Note - The LTPP will be established once for the entire LBMP Transition Period after the Initial Auction, as defined in Attachment M, for Long Term TCCs). Prior to a 205 Filing under the FPA by the Transmission Owners, the LTPP will be set at zero.

$SR = SR_1 + SR_2$.

SR_1 will equal the revenues from the Direct Sale by the Transmission Owner of Original Residual TCCs, TCCs derived from Existing Transmission Capacity for Native Load, and Grandfathered TCCs associated with ETAs, the expenses for which are included in the Transmission Owner's Revenue Requirements where the Transmission Owner is the Primary Owner of said TCCs.

SR_2 will equal the Transmission Owner's revenues from the Centralized TCC Auction allocated pursuant to Attachments N. SR_2 includes revenues from: (a) TCCs associated with Residual Transmission Capacity that are sold in the Centralized TCC Auction; (b) the sale of

Grandfathered TCCs associated with ETAs, if the expenses for those ETAs are included in the Transmission Owner's Revenue Requirements; and (c) TCCs derived from Existing Transmission Capacity for Native Load that are sold in the Centralized TCC Auction.

Revenue from TCCs associated with Residual Transmission Capacity includes payments for Original Residual TCCs that the Transmission Owners sell through the Centralized TCC Auction and the allocation of revenue for other TCCs sold through the Centralized TCC Auction (per the Facility Flow-Based Methodology described in Attachment N).

SR_1 shall be updated prior to the start of each month based on actual data for the calendar month prior to the month in which the adjustment is made (*i.e.*, January actual data will be used in February to calculate the TSC effective in March). SR_1 for a month in which a Direct Sale is applicable shall equal the total nominal revenue that the Transmission Owner will receive under each applicable TCC sold in the Direct Sale divided by the duration of the TCC (in months). SR_2 shall equal the Transmission Owner's share of Net Auction Revenue for all rounds of a Centralized TCC Auction, as calculated pursuant to Attachment N, divided equally among the months covered by the Centralized TCC Auction. SR_2 shall be adjusted after each Centralized TCC Auction and the revised SR_2 shall be effective at the start of each Capability Period;

ECR = The Transmission Owner's share of Net Congestion Rents in a month, calculated pursuant to Attachment N;

CRR = The Transmission Owner's Congestion Payments received from Grandfathered TCCs and Imputed Revenues from Grandfathered Rights from ETA's, the expenses for which are included in the Transmission Owner's Revenue Requirement;

WR = The Transmission Owner's revenues from external sales (Wheels Through and Export Transactions) not associated with Existing Transmission Agreements included in Attachment L, Tables 18.1, 18.2 and 18.3 and wheeling revenue, associated with OATT reservations extending beyond the start-up of the ISO. (*i.e*., grandfathered OATT agreements)

14.1.2.1.1 Elements of the WR Component

The WR component will equal the sum of: (1) TSC revenues received from new external transactions (Wheels Through and Export Transactions); (2) transmission revenues received under grandfathered OATT agreements and actual revenues under Schedule 1 to the grandfathered OATT agreements, but not under Schedules 2 through 6 to the grandfathered OATT agreements; and (3) any revenues related to pre-OATT grandfathered arrangements if the transmission owner increased its OATT revenue requirement to derive its RR component to reflect the fact that revenues related to such transactions are at risk due to options available to the customers resulting from the current restructuring, and the customer retains its grandfathered arrangement.

In each subcomponent of the WR component above, the revenues will include the Gross Receipts Tax ("GRT") when the Transmission Owner has included the GRT in the RR.

14.1.2.1.2 Treatment of Schedule 1 Associated with Grandfathered OATT Service

All customers under grandfathered OATT service agreements must continue to pay the Schedule 1 charge applicable under the individual OATT, absent a settlement to the contrary. The revenues received from Schedule 1 charges paid by grandfathered OATT customers will be treated as revenue credit in the WR component as part of the wheeling revenue associated with OATT reservations extending beyond the start-up of the ISO.

Reserved = $\quad$ $Reserved_1 + Reserved_2 + Reserved_3 + Reserved_4$

$Reserved_1$ will equal the Transmission Owner's Congestion payments for a month received pursuant to Section 20.2.3 of Attachment N of this Tariff for the Transmission Owner’s ETCNL TCCs. $Reserved_2$ will equal the Transmission Owner's Congestion payments for a month received pursuant to Section 20.2.3 of Attachment N of this Tariff for the Transmission Owner’s RCRR TCCs. $Reserved_3$ will equal the value that a Transmission Owner receives for the sale of its ETCNL TCCs in a month, with the value for each ETCNL TCC sold divided equally over the months remaining until the expiration of that ETCNL TCC. $Reserved_4$ will equal the value that a Transmission Owner receives for the sale of its RCRR TCCs in a month, with the value for each RCRR TCC sold divided equally over the months remaining until the expiration of that ETCNL TCC.

BU = The Transmission Owner's Billing Units (annual MWh) for the Transmission District (see Table 1 of this Attachment) The Transmission Owner's BU has been adjusted upward to include subtransmission and distribution losses.

The RR, SR and CRR will not include expenses for the Transmission Owner's purchase of TCCs or revenues from the sale of said TCCs or from the collection of Congestion Rents for said TCCs. The ECR, CRR, WR, and Reserved shall be updated prior to the start of each month based on actual data for the calendar month prior to the month in which the adjustment is made (*e.g.*, January actual data will be used in February to calculate the TSC effective in March). The TSC shall not apply to the scheduled quantities physically Curtailed by the ISO.

Each Member System is responsible for calculating: (1) the RR component of its TSC charge; (2) the CCC component of its TSC charge; and (3) the BU component of its TSC charge.

The LTPP component of each Member System's TSC charge is initially set at zero. Any changes must be made by unanimous consent of the Transmission Owners (See ISO OATT Original Sheet No. 267). The Member Systems will make a Section 205 filing to propose any change to the LTPP.

The NYISO is responsible for calculating (1) the SR component of each Member System's TSC charge based on information provided by the Member System and information derived from ISO operation; (2) the ECR component of each Member System's TSC charge based on information derived from ISO operation; (3) the CRR component of each Member System's TSC charge based on information derived from ISO operation; (4) the Reserved component of each Member System's TSC charge based on information provided by the Member System and information derived from ISO operation; and (5) the WR component of each Member System's TSC charge based on information provided by the Member System and information derived from ISO operation. Any calculations that the ISO is responsible for are subject to review and comment by all affected parties.

The RR term will be updated based on Transmission Owner filings to FERC (or a NYISO filing to FERC on behalf of LIPA) under the FPA. These filings will be made when a Transmission Owner determines that a change to its RR is required under Section 205.

The CCC term will be updated based on Transmission Owner filings to FERC (or a NYISO filing to FERC on behalf of LIPA) under the FPA. These filings will be made when the Transmission Owner determines that a change to the CCC is required.

SR: The revenue from the Direct Sale of TCCs will be determined monthly and will enter the TSC formula through the SR term with a two-month lag (*e.g.*, January actual data will be used in February to calculate the SR term used in the TSC for March). The revenue that a Transmission Owner receives from a TCC sold in a Centralized Auction will be divided equally among the months for which the TCC is sold. The revenue from these TCCs will enter the TSC formula month-by-month through the SR term, beginning with the first month of the period covered by the Centralized Auction. The ISO is responsible for calculating the SR component of each Transmission Owner's TSC. The Transmission Owner will not adjust the ISO's calculation. The ECR revenue will be calculated monthly and will enter the TSC formula with a two-month lag (e.g., January actual data will be used in February to calculate the ECR term used in the TSC for March). The ISO is responsible for calculating the ECR component of each Transmission Owner's TSC. The Transmission Owner will not adjust the ISO's calculation.

The CRR revenue will be calculated monthly and will enter the TSC formula with a two-month lag (*e.g.*, January actual data will be used in February to calculate the CRR term used in the TSC for March). Each Transmission Owner will identify for the ISO each ETA ("Identified ETA"), under which the Transmission Owner is a customer, the expenses for which are included in the Transmission Owner's RR. The ISO shall calculate that Transmission Owner's Congestion Payments received from Grandfathered TCCs and Imputed Revenues from Grandfathered Rights from the Transmission Owner's Identified ETAs. If the inclusion of the costs under an Identified ETA in the Transmission Owner's RR is subject to refund, then the CRR shall be subject to adjustment. If the costs under one or more of the Identified ETAs are removed from the RR and the Transmission Owner is required to recalculate its TSC with the adjusted RR, then in recalculating the TSC, the Transmission Owner shall reverse the portion of the CRR that was attributed to each such ETA. The Transmission Owner shall rebill the customers based on the recalculated TSC. To the extent the Transmission Owner owes a refund to the customer, it shall comply with any applicable refund obligations, including payment of interest to the extent due pursuant to 18 C.F.R. § 35.19a(a)(2)(iii), or its successor. If the reversal of the CRR results in a higher TSC than was charged, the customer shall pay in the time prescribed for payment of TSCs the Transmission Owner the difference between the TSC payments it made and the rebilled amounts, with interest thereon from the dates payments were made to the date that the rebilled amounts are due. Said interest will be calculated in the same manner as interest on over-payments as specified in 18 C.F.R. § 35.19a(a)(2)(iii), or its successor.

The Reserved will be calculated monthly and will enter the TSC formula with a two-month lag (*e.g.*, January actual data will be used in February to calculate the ETCNL TCC term used in the TSC for March). The ISO shall calculate a Transmission Owner's Reserved.

WR: The revenue that a Transmission Owner collects for new external sales will be calculated monthly and will enter the WR term in the TSC formula with a two-month lag (i.e., January actual data will be used in February to calculate the WR term used in the TSC for March). The ISO is responsible for calculating new external sales subcomponent of the WR component of each Transmission Owner's TSC. The Transmission Owner will not adjust the ISO's calculation. The actual revenue that a Transmission Owner collects for grandfathered OATT service that extends beyond ISO start-up, and revenues related to pre-OATT grandfathered arrangements as provided for under numbers (2) and (3) of Original Sheet No. 214A, will also be calculated monthly and will enter the WR term in the TSC formula based upon the prior month's information. For the first month the credit will be equal to the actual revenues received under those-grandfathered agreements to be included in the WR component.

The BU term will be updated based on Transmission Owner filings to FERC (or a NYISO filing to FERC on behalf of LIPA) under the FPA. These filings will be made when the Transmission Owner determines that a change to its BU is required.

14.1.2.2 Implementation of TSC

At the start of LBMP implementation, certain variables of the TSC equation will not be available. For the first and second month of LBMP implementation, the only terms in the TSC equation that will be known by each Transmission Owner are its Annual Transmission Revenue Requirement (RR), Scheduling, System Control and Dispatch Costs (CCC), Revenues from the Sale of TCCs in the Transitional Auction (SR_2), Wheeling Revenues Associated with continuing OATT reservations (WR) and Billing Units (BU), which have been approved by or filed with FERC or, in the case of LIPA, approved by the Long Island Power Authority's Board of Trustees. (Billing Units for "metered" retail customers are based on manual meter readings). For these two months each Transmission Owner shall calculate its TSC using the following equation:

WHOLESALE TSC = [(RR÷12) +(CCC÷12) - SR-WR]/BU÷12)

LTPP will not be available until after the Initial Auction as defined in Attachment M for Long Term TCCs. For the third month of LBMP implementation until the second month of the Capability Period corresponding to the initial auction for Long Term TCCs, each Transmission Owner shall calculate its TSC using the following equation:

WHOLESALE TSC = {(RR÷12) + (CCC÷12) - SR - ECR -CRR-WR}/(BU÷12)

From the second month of the Capability Period corresponding to the initial auction for Long Term TCCs , until the conclusion of the LBMP Transition Period, the TSC shall be calculated using the equation in Section 14.1.2.1.

After the conclusion of the LBMP Transition Period, the LTPP component will no longer be applicable and each Transmission Owner shall calculate its Wholesale TSC using the following equation:

WHOLESALE TSC = {(RR÷12) + (CCC÷12) - SR - ECR - CRR - WR - Reserved}/(BU÷12)

14.1.3 Filing and Posting of Wholesale TSCs

The Transmission Owners shall coordinate with the ISO to update certain components of the Wholesale TSC formula on a monthly basis or Capability Period basis. Each Transmission Owner may update its Wholesale TSC calculation to change its RR, CCC, or BU component value(s). Such updates, however, shall be subject to necessary FERC filings under the FPA. Each Transmission Owner will calculate its monthly Wholesale TSC and provide the ISO with the Wholesale TSC by no later than the fourteenth of each month, for posting on the OASIS to become effective on the first of the next calendar month. Beginning with the implementation of LBMP, the monthly Wholesale TSCs for each of the Transmission Districts shall be posted on the OASIS by the ISO no later than the fifteenth of each month to become effective on the first of the next calendar month.

14.1.4 TSC Calculation Information

The Annual Transmission Revenue Requirements (“RR”); Scheduling, System Control and Dispatch Costs (“CCC”), Billing Units (“BU”) and Rates of the Transmission Owners, except NYPA, for the purpose of calculating the respective Transmission District-based Wholesale TSC are shown in Table 1 below.

TABLE 1 - WHOLESALE TSC CALCULATION INFORMATION

Transmission Owner	Revenue Requirement (RR)	Scheduling System Control and Dispatch Costs (CCC)	Annual Billing Units (BU) MWh	Rate $/MWh[1]
Central Hudson Gas & Electric Corp.	$16,375,919	$1,309,980	4,723,659	$3.7441
Consolidated Edison Co. of NY, Inc.	$385,900,000	$21,000,000	49,984,628	$8.1405
LIPA	$105,602,083	$3,453,343	20,618,939	$5.2891
New York Electric & Gas Corporation[2]	$94,143,899	$1,633,000	14,817,111	$6.4639
Niagara Mohawk Power Corporation	See Attachment H, Section 14.1.9	See Attachment H, Section 14.1.9	See Attachment H, Section 14.1.9	See Attachment H, Section 14.1.9
Orange and Rockland Utilities, Inc.	$21,034,831	$942,579	3,595,947	$6.1117
Rochester Gas and Electric Corporation	$25,795,509	$583,577	6,967,556	$3.7860

[1]The rate column represents the unit rate prior to crediting; the actual rate will be determined pursuant to the applicable TSC formula rate.

[2]NYSEG's RR, BU and unit Rate prior to adjustment pursuant to Attachment H, are subject to retroactive modification pursuant to the provisions of the Settlement Agreement approved by the Commission in its March 26, 2004 order issued in Docket No. EL04-56-000. For any Transmission Customer that "opts out" of the Settlement Agreement as described in paragraph 1.E thereof, the applicable NYSEG "RR" shall be $100,541,739; the "BU" shall be 13,741,901 MWh; and, the "Rate" prior to adjustment pursuant to Attachment H, shall be $7.4235 effective as of March 1, 2004.

14.1.5 Treatment of Gross Receipts Tax

14.1.5.1 Central Hudson Gas & Electric Corporation

Central Hudson's TSC shall be increased by dividing the following surcharge factors into the total of all applicable rates and charges to reflect the New York State GRT (0.94922 in the MTA regions and 0.95750 in the non-MTA regions), which is not specifically provided for in the transmission rate, to the extent such tax is imposed on Central Hudson as a result of the transmission service provided to such Customer. Central Hudson shall make an appropriate filing pursuant to Section 205 of the Federal Power Act to implement any change in the specified tax rate prior to altering the tax rate under this provision.

14.1.5.2 Consolidated Edison Company of New York, Inc.

The GRT is included in Con Edison's TSC rate. Con Edison will not charge separately for GRT.

14.1.5.3 LIPA

The GRT is included in LIPA's TSC rate. LIPA will not charge separately for GRT.

14.1.5.4 New York State Electric & Gas Corporation

The Transmission Customer shall pay an amount sufficient to reimburse NYSEG for any amounts payable by NYSEG as sales, excise, value-added, gross receipts or other applicable taxes with respect to the total amount payable to NYSEG pursuant to the Tariff. The total of all rates and charges will be divided by the appropriate tax factor listed below, depending upon the geographic location of the Transmission Customer's Point(s) of Delivery

Within the Metropolitan Commuter Transportation District:	0.984583
Not within the Metropolitan Commuter Transportation District:	0.986823

These tax factors incorporate the taxes imposed on the Transmission Provider's electric revenues pursuant to New York law and represents the Franchise Tax on Gross Earnings, the Gross Income Tax, and where applicable the Metropolitan Commuter Transportation District Surcharge.

This Provision shall be effective upon commencement of services under the ISO OATT.

14.1.5.5 Niagara Mohawk Power Corporation

For the settled Niagara Mohawk TSC rate, the GRT is included in the RR and there will be no separate GRT tax assessed; For the filed Niagara Mohawk TSC rate, GRT initially is included in the RR and there will be no separate GRT assessed; however, this issue with regard to GRT is subject to final Commission action in Docket No. OA96-194-000, including all stipulations executed in connection therewith.

14.1.5.6 Orange and Rockland Utilities, Inc.

The Transmission Customer's rate will be increased to reflect the gross receipts tax ("GRT") which is not specifically provided for in the transmission rate and ancillary service rates, that a governmental authority may impose on Orange and Rockland as a result of the Transmission Service provided to such Transmission Customer pursuant to Sections 186 and 186-a of the New York Tax Law. The current effective GRT rate for the Section 186-a tax is 3.25% from October 1, 1998 through October 31, 1999 and 2.5% on and after January 1, 2000. The maximum locality rate allowable under state law for each locality is specified below. However, if the actual locality rate is less than the maximum locality rate permitted under state law, O&R shall charge the actual tax rate levied by the locality. The currently effective GRT rate for the Section 186 tax is .75%.

Airmont	1.0%
Bloomingburg	1.0%
Chestnut Ridge	1.0%
Goshen	1.0%
Grandview on Hudson	1.0%
Greenwood Lake	1.0%
Harriman	1.0%
Haverstraw	1.0%
Highland Falls	1.0%
Hillburn	1.0%
Kaser	1.0%
Kiryas Joel	1.0%

Middletown	1.0%
Monroe	1.0%
Montebello	1.0%
New Hempstead	1.0%
New Square	1.0%
Nyack	1.0%
Otisville	1.0%
Piermont	1.0%
Pomona	1.0%
Port Jervis	1.0%
Sloatsburg	1.0%
South Nyack	1.0%
Spring Valley	1.0%
Suffern	1.0%
Unionville	1.0%
Upper Nyack	1.0%
Warwick	1.0%
Washingtonville	1.0%
Wesley Hills	1.0%
West Haverstraw	1.0%
Wurtsboro	1.0%

14.1.5.7 Rochester Gas & Electric Corporation

The Transmission Customer's rate will be increased to reflect the gross receipts tax which is not specifically provided for in the transmission rate and ancillary service rates, that a governmental authority may impose on RG&E as a result of the Transmission Service provided to such Transmission Customer pursuant to Sections 186 and 186-a of the New York Tax Law. The currently effective GRT rate for the Section 186-a tax is 3.5% and each locality rate is specified below. The currently effective GRT rate for the Section 186 tax is .75%.

City of Rochester	3.0%
Leroy	1.0%
Manchester	1.0%
Perry	1.0%
Shortsville	1.0%
Warsaw	1.0%
Hilton	1.0%
Pittsford	1.0%
Caledonia	1.0%
Wolcott	1.0%
Avon	1.0%

Leicester	1.0%
Nunda	1.0%
Genesco	1.0%
Mt. Morris	1.0%
Sodus Point	1.0%
Livonia	1.0%
Meridian	1.0%
City of Canandaigua	1.0%
Fairport	1.0%
Brockport	1.0%
Scottsville	1.0%
East Rochester	1.0%

14.1.6 TSC For Retail Access Customers ("RTSC")

Customers who apply for unbundled Transmission Service in accordance with the provisions of a Transmission Owner's retail access program filed with the PSC or, in the case of LIPA, approved by the Long Island Power Authority's Board of Trustees, will be responsible for paying a retail transmission service charge as detailed in Section 5 of this Tariff.

14.1.7 NYPA Transmission Service Charge

The NYPA TSC for service to its directly connected Loads (Reynolds Metals, GM-Massena, Town of Massena and the City of Plattsburgh) shall, at the Eligible Customer's option, be (a) $1.30 per kilowatt-month or (b) no more than $3.75 per MWh; not to exceed $60.00 per MW Day applied to peak MWh scheduled any hour each day; not to exceed $300.00 per MW-Week applied to the peak MWh scheduled any hour each week. The TSC applicable to service over the Vermont intertie[2] and the Ontario-Hydro intertie shall be the same as (b). The TSC applicable to service over the Hydro-Quebec intertie shall be no more than $4.62 per MWh; not to exceed $73.85 per MW-Day applied to peak MWh scheduled each day; not to exceed $369.23 per MW-Week applied to the peak MWh scheduled any hour each week. NYPA shall coordinate

[2] The NYPA TSC shall not apply to service over the Vermont intertie provided that the conditions listed in Section 2.7.2.1.4 of this Tariff are satisfied.

with the ISO to update its TSC. Such updates shall be subject to FERC filings.

14.1.8 Discounting

Each Transmission Owner may advise the ISO of discounts to its TSC applicable during a specified period to all deliveries to a particular Interconnection between the NYCA and another Control Area. The ISO shall post the discounts on the OASIS for the specified period.

Three principal requirements apply to discounts for Transmission Service as follows: (1) any offer of a discount made by a Transmission Owner must be announced to all Eligible Customers solely by posting on the OASIS; (2) any customer-initiated requests for discounts (including requests for use by a Transmission Owner's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS; and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount that the Transmission Owner agrees to and advises the ISO of, the same discounted Transmission Service rate will be offered to all Transmission Customers for the same period for all deliveries to a particular Interconnection between the NYCA and another Control Area. The ISO will post the discounts on the OASIS for the specified period.

TABLE 2

Applicable Wholesale TSC for Exports from New York State, by Transmission Circuit

Ckt.Id	From/To	kV	From Co./To Ext.	Wholesale TSC Paid
5018	Ramapo / Branchburg	500	O&R/PJM	Con Ed/O&R
398	Pleasant Valley/ Long Mtn	345	CHG&E / NE	Con Ed
B3402	Farragut / Hudson	345	Con Ed / PJM	Con Ed
C3403	Farragut / Hudson	345	Con Ed / PJM	Con Ed
A2253	Goethals / Linden	230	Con Ed / PJM	Con Ed
FE	Smithfield / Falls Village	69	CHG&E/NE	CHG&E
1385	Northport / Norwalk [1]	138	LIPA / NE	LIPA
393	Alps / Berkshire	345	NMPC / NE	NMPC
69	So. Ripley / Erie East	230	NMPC / PJM	NMPC
E205W	Rotterdam / Bear Swamp	230	NMPC / NE	NMPC
BP76	Packard / Beck	230	NMPC / OH	NMPC
171	Falconer / Warren	115	NMPC / PJM	NMPC
6	Hoosick / Bennington	115	NMPC /NE	NMPC
7	Whitehall / Blissville	115	NMPC / NE	NMPC
1	Dennison / Rosemont	115	NMPC / HQ	NMPC
2	Dennison / Rosemont	115	NMPC / HQ	NMPC
37-HS	Stolle Road / Homer City	345	NYSEG / PJM	NYSEG
30-HW	Watercure / Homer City	345	NYSEG / PJM	NYSEG
70-EH	Hillside / East Towanda	230	NYSEG / PJM	NYSEG
952	Goudey / Laurel Lake	115	NYSEG / PJM	NYSEG
956	No. Waverly / East Sayre	115	NYSEG / PJM	NYSEG
J	So. Mahwah / Waldwick	345	O&R / PJM	Con Ed/O&R
K	So. Mahwah / Walkwick	345	O&R / PJM	Con Ed/O&R
7040	Massena / Chateaugay	765	NYPA / HQ NYPA	NYPA
PA302	Niagara / Beck A	345	NYPA / OH	NYPA
PA301	Niagara / Beck B	345	NYPA / OH	NYPA
L34P	Moses / St. Lawrence	230	NYPA / OH	NYPA
L33P	Moses / St. Lawrence	230	NYPA / OH	NYPA
PA27	Niagara / Beck	230	NYPA / OH	NYPA
PV-20	Plattsburgh / Grand Isle	115	NYPA / NE	NYPA

[1] All scheduling over the Northport - Norwalk Intertie is conducted by LIPA pursuant to Section 5.7 of this Tariff.

TABLE 3
Applicable Wholesale TSC for Municipal Utilities,
Electric Cooperatives and Loads

Except for those municipal utilities and electric cooperatives that continue to take transmission service under an Existing Transmission Agreement, the following Loads shall be obligated to pay the noted Transmission District - based TSC as applicable in accordance with Section 2.7 of this Tariff.

Load	**TSC Paid**	**Load**	**TSC Paid**	**Load**	**TSC Paid**
		Greene	NYSEG	Sherrill	NMPC
		Green Island	NMPC	Silver Springs	NYSEG
		Greenport	LIPA	Skaneateles	NMPC
		Groton	NYSEG	Solvay	NMPC
		Hamilton	NYSEG	Spencerport	RG&E
		Holley	NMPC	Springville	NMPC
		Ilion	NMPC	Steuben	NYSEG
Akron	NMPC	Lake Placid	NMPC	Theresa	NMPC
Andover	NMPC	Little Valley	NMPC	Tupper Lake	NMPC
Angelica	RG&E	Marathon	NYSEG	Watkins Glen	NYSEG
Arcade	NMPC	Mayville	NMPC	Wellsville	NMPC
Bath	NYSEG	Mohawk	NMPC	Westfield	NMPC
Bergen	NMPC	Oneida -Madison	NMPC/ NYSEG	Massena	NYPA
Boonville	NMPC	Otsego	NYSEG	Freeport	LIPA
Brolton	NMPC	Penn Yan	NYSEG	Jamestown	NMPC
Castile	NYSEG	Philadelphia	NMPC	Rockville Ctr.	LIPA
Churchville	NMPC	Plattsburgh	NYPA	Alcoa	(1)
Delaware	NYSEG	Richmondville	NMPC	Reynolds	NYPA
Endicott	NYSEG	Rouses Point	NYSEG	Gen. Motors (Massena, NY)	NYPA
Fairport	NMPC	Salamanca	NMPC	Cornwall	NMPC
Frankfort	NMPC	Sherburne	NYSEG		

Notes: (1) - Load is treated as an entity external to the NYCA.

14.1.9 Niagara Mohawk Power Corporation Wholesale TSC Formula Components RR, CCC and BU and Sources of Data Inputs

Niagara Mohawk Power Corporation ("NMPC") will calculate and update each of its RR, CCC, and BU components annually using the formulas for each component contained in

Attachment 1 and in accordance with the update procedures set forth in Section 14.1.9.4. With the exception of forecasted information, the cost data used in the Formula Rate will be cost data from NMPC's annual FERC Form 1, NMPC's Annual Report to the New York State Public Service Commission, or NMPC's official books of record.

14.1.9.1 Definitions

Capitalized terms used in this calculation will have the following definitions:

Allocation Factors

14.1.9.1.1 Electric Wages and Salaries Allocation Factor shall be fixed at 0.835.

14.1.9.1.2 Gross Transmission Plant Allocation Factor shall equal the total investment in Transmission Plant in Service, Transmission Related Electric General Plant, Transmission Related Common Plant and Transmission Related Intangible Plant divided by Gross Electric Plant.

14.1.9.1.3 Transmission Wages and Salaries Allocation Factor shall be fixed at 0.13.

14.1.9.1.4 Gross Electric Plant Allocation Factor shall equal Gross Electric Plant divided by the sum of Total Gas Plant, Total Electric Plant, and total Common Plant.

Ratebase and Expense Items

14.1.9.1.5 Administrative and General Expense shall equal expenses as recorded in FERC Account Nos. 920-935. FERC Account No. 926 shall be adjusted by reversing the adjustment to the deferred pension costs booked per the NYPSC Statement of Policy for Accounting and Ratemaking Treatment for Pension and Post-Retirement Benefits Other than Pensions. In addition, Administrative and

General Expenses shall exclude the actual Post-Employment Benefits Other than Pensions ("PBOP") expenses included in FERC Account No. 926, and shall add back the FERC accepted Post Employment Benefit Other than Pensions of $88,644,000 annually or $7,387,000 per month or any other amount subsequently approved by FERC under Section 205 or 206 of the Federal Power Act.

14.1.9.1.6 Amortization of Investment Tax Credits shall equal credits as recorded in FERC Account No. 420, per 18 C.F.R. Parts 101 (Electric) and 201 (Gas).

14.1.9.1.7 Amortization of Debt Discount Expense shall equal expenses as recorded in FERC Account No. 428.

14.1.9.1.8 Amortization of Loss on Reacquired Debt shall equal expenses as recorded in FERC Account No. 428.1.

14.1.9.1.9 Amortization of Premium on Debt –Credit shall equal the expenses as recorded in FERC Account 429.

14.1.9.1.10 Amortization of Gain on Reacquired Debt--Credit shall equal the expenses as recorded in FERC Account No. 429.1.

14.1.9.1.11 Common Plant shall equal the balance of plant recorded in FERC Account Nos. 389-399. Common Plant shall be defined as the plant common to NMPC's gas and electric functions per 18 C.F.R. Parts 101 (Electric) and 201 (Gas).

14.1.9.1.12 Common Plant Depreciation Expense shall equal the common plant depreciation expenses as recorded in FERC Account No. 403 associated with Common Plant per 18 C.F.R. Parts 101 (Electric) and 201 (Gas).

14.1.9.1.13 Common Plant Depreciation Reserve shall equal the common plant depreciation reserve balance as recorded in FERC Account No. 108 associated with Common Plant per 18 C.F.R. Parts 101 (Electric) and 201 (Gas).

14.1.9.1.14 Depreciation Expense for Transmission Plant in Service shall equal depreciation expenses as recorded in FERC Account No. 403 calculated using the depreciation rates set forth in the following table:

Depreciation Rates

FERC Account/NMPC Internal Account No.		Annual Rate
350	Land –Rights of Way and Easements	1.32
352	Structures and Improvements	2.08
353	Station Equipment	2.44
353.55	Station Equipment – EMS	3.40
354	Towers and Fixtures	1.71
355	Poles and Fixtures	2.00
356	Overhead Conductors and Devices	1.60
357	Underground Conduit	1.33
358	Underground Conductors and Devices	1.48
359	Roads and Trails	1.33
370	Meters	
	Meters	5.05
	Installation	5.05

14.1.9.1.15 Distribution Plant shall equal the plant balance as recorded in FERC Account Nos. 360 – 374.

14.1.9.1.16 Equity AFUDC Component of Depreciation Expense shall equal the activity recorded in FERC Account No. 419.1.

14.1.9.1.17 Electric Environmental Remediation Expense shall be the environmental remediation expense as recorded in NMPC's internal Account 930.200.

14.1.9.1.18 Electric General Plant shall equal the plant balance recorded in FERC Account Nos. 389-399. Electric General Plant shall be defined as the general plant associated with NMPC's electric function.

14.1.9.1.19 Electric General Plant Depreciation Expense shall equal general plant depreciation expenses as recorded in FERC Account No. 403 associated with Electric General Plant.

14.1.9.1.20 Electric General Plant Depreciation Reserve shall equal the general plant depreciation reserve balance as recorded in FERC Account No. 108 associated with Electric General Plant.

14.1.9.1.21 Electric Property Insurance shall equal property insurance recorded in FERC Account No. 924.

14.1.9.1.22 Electric Research and Development Expense shall equal research and development expenses as recorded in NMPC internal Account No. 930.210.

14.1.9.1.23 Gain on Reacquired Debt shall equal the balance as recorded in FERC Account No. 257.

14.1.9.1.24 Gross Electric Plant shall equal Total Electric Plant plus an allocation of Common Plant determined by multiplying Common Plant by the Electric Wages and Salaries Allocation Factor.

14.1.9.1.25 Gross Plant (Gas & Electric) shall equal Total Gas Plant plus Total Electric Plant plus Total Common Plant.

14.1.9.1.26 Gross Transmission Investment shall equal the total of Transmission Plant in Service, Transmission Related Electric General Plant, Transmission Related Common Plant and Transmission Related Intangible Plant.

14.1.9.1.27 Intangible Electric Plant shall equal the balance of plant recorded in FERC Account Nos. 301-303. Intangible Electric Plant shall be defined as the intangible plant associated with NMPC's electric functions.

14.1.9.1.28 Intangible Electric Plant Depreciation Expense shall equal the intangible electric plant depreciation expenses as recorded in FERC Account No. 403 associated with Intangible Electric Plant.

14.1.9.1.29 Intangible Electric Plant Depreciation Reserve shall equal the intangible plant depreciation reserve balance as recorded in FERC Account No. 108 associated with Intangible Electric Plant.

14.1.9.1.30 Loss on Reacquired Debt shall equal the loss on reacquired debt as recorded in FERC Account No. 189.

14.1.9.1.31 Materials and Supplies shall equal materials and supplies balance as recorded in FERC Account No. 154 per 18 C.F.R. Parts 101 (Electric) and 201 (Gas).

14.1.9.1.32 Payroll Taxes shall equal the electric payroll tax expenses related to FICA and federal and state unemployment as recorded in NMPC's internal Account Nos. 408.100, 408.110 and 408.130.

14.1.9.1.33 Plant Held for Future Use shall equal the balance as recorded in FERC Account No. 105 for transmission uses within 5 years.

14.1.9.1.34 Prepayments shall equal prepayment balance as recorded in FERC Account No. 165 per 18 C.F.R. Parts 101 (Electric) and 201 (Gas) less prepaid state and Federal income taxes.

14.1.9.1.35 Real Estate Tax Expenses shall equal electric real estate tax expense as recorded in NMPC's internal Account No. 408.140 and 408.180.

14.1.9.1.36 Regulatory Assets and Liabilities shall equal state and federal regulatory asset balances in FERC Account Nos. 182.3 and 254, assets and liabilities solely related to FAS109, and excess AFUDC.

14.1.9.1.37 Total Accumulated Deferred Income Taxes shall equal the sum of deferred tax balances recorded in FERC Account Nos. 281 - 283 plus accumulated deferred investment tax credits as reflected in FERC Account No. 255, minus the deferred tax balance in FERC Account No. 190. Total Accumulated Deferred Income Taxes shall exclude the specifically identified generation-related stranded cost deferred taxes.

14.1.9.1.38 Total Electric Plant shall equal the sum of Transmission Plant, Distribution Plant, Electric General Plant and Intangible Electric Plant.

14.1.9.1.39 Total Gas Plant shall equal the plant balance recorded in 18 C.F.R. Part 201, FERC Account Nos. 301-399. Total Gas Plant shall exclude Common Plant.

14.1.9.1.40 Transmission Depreciation Reserve shall equal electric transmission plant related depreciation reserve balance as recorded in FERC Account No. 108, plus Transmission Related General Plant Accumulated Depreciation, Transmission Related Amortization of Other Utility Plant, and Common Plant Accumulated Depreciation associated with Gross Electric Plant.

14.1.9.1.41 Transmission Operation and Maintenance Expense shall equal the sum of electric expenses as recorded in FERC Account Nos. 560, 562-574.

14.1.9.1.42 Transmission Plant shall equal the gross plant balance as recorded in FERC Account Nos. 350-359.

14.1.9.1.43 Transmission Related Bad Debt Expense shall equal Bad Debt Expense as reported in Account 904 related to NMPC's wholesale transmission billing.

14.1.9.1.44 Unamortized Discount on Long-Term Debt shall equal the balance in FERC Account No. 226.

14.1.9.1.45 Wholesale Metering Investment shall equal the gross plant investment associated with any Revenue or Remote Terminal Unit ("RTU") meters and associated equipment connected to an internal or external tie at voltages equal to or greater than 23 kV. The gross plant investment shall be determined by multiplying the number of such existing wholesale meters recorded in FERC Account No. 370.3 and in blanket metering accounts by the average cost of the meters plus the average costs of installation. To the extent future gross plant investment for Wholesale Metering can be specifically identified, actual gross meter costs will be used.

Forecast and True-up Related Terms

14.1.9.1.46 Forecast Period shall mean the calendar year immediately following the calendar year for which the most recent FERC Form 1 data is available, as of the beginning of the Update Year.

14.1.9.1.47 Forecasted Transmission Plant Additions ("FTPA") shall mean the sum of:

14.1.9.1.47.1 NMPC's actual Transmission Plant additions during the first quarter (January 1 through March 31) of the Forecast Period; and

14.1.9.1.47.2 NMPC's forecasted transmission investment for the Forecast Period less the amount (i), divided by 2.

14.1.9.1.48 Interest on refunds, surcharges, or adjustments, as applicable, shall mean interest calculated in accordance with the methodology specified in the Commission's regulations at 18 C.F.R. § 35.19a (a) (2) (iii) (or as such provision may be renumbered in the future).

14.1.9.1.49 Actual Transmission Revenue Requirement shall mean the current Historical Transmission Revenue Requirement (as defined in Attachment 1).

14.1.9.1.50 Actual Scheduling, System Control and Dispatch cost shall mean the most recently established CCC (as defined in Attachment 1).

14.1.9.1.51 Actual Billing Units shall mean the most recently established BU (as defined in Attachment 1).

14.1.9.1.52 Prior Year Transmission Revenue Requirement shall equal RR less Annual True-Up ("ATU"), as defined in Attachment 1, for the most recently ended calendar year as of the beginning of the Update Year.

14.1.9.1.53 Prior Year Scheduling, System Control and Dispatch shall equal the CCC, as defined in Attachment 1, for the prior calendar year.

14.1.9.1.54 Prior Year Billing Units shall equal the BU, as defined in Attachment 1, for the prior calendar year.

14.1.9.1.55 Prior Year Unit Rate shall equal the sum of RR, as defined in Attachment 1, for the most recently ended Prior Year Revenue Requirement and the Prior Year Scheduling, System Control and Dispatch divided by the Prior Year Billing Units.

14.1.9.1.56 Annual Update shall mean the calculation of the RR, CCC, and BU components with Data Inputs for an Update Year in accordance with Section 14.1.9.4.

14.1.9.1.57 Data Input shall mean any data required for the calculation of RR, CCC and BU, in accordance with the Formula Rate.

14.1.9.1.58 Formal Challenge shall mean a challenge presented in accordance with Section 14.1.9.4.3.2.

14.1.9.1.59 Informational Filing shall mean the filing that NMPC makes in accordance with Section 14.1.9.4 to establish the Annual Update for an Update Year.

14.1.9.1.60 Interested Party shall mean a person that is (i) a party to FERC Docket No. ER08-552, (ii) the New York State Public Service Commission; (iii) a transmission customer under this Tariff that pays charges based on the Formula Rate during the calendar year prior to the submission of the Informational Filing; or (iv) a state regulatory authority having jurisdiction over the retail electric rates of such a transmission customer, provided that such regulatory authority or such customer notifies NMPC of that fact no later than 30 days prior to the Publication Date. An Interested Person includes employees of or consultants to such person.

14.1.9.1.61 Material Accounting Change shall mean an accounting policy or practice, including, but not limited to, a policy or practice affecting the allocation of costs or revenues, employed by NMPC during an Update Year that differs from the corresponding policy or practice in effect during any of the three previous calendar years which change affects any Data Input for the Update Year by $1.0 million or more, as compared to the previous calendar year.

14.1.9.1.62 Preliminary Challenge shall mean a challenge presented by an Interested Party in accordance with Section 14.1.9.4.2.1.

14.1.9.1.63 Publication Date shall be the date of an Informational Filing for an Update Year.

14.1.9.1.64 Review Period shall be the period ending one-hundred and fifty (150) days after the Publication Date, unless extended in accordance with Section 14.1.9.4.2.1.

14.1.9.1.65 Formula Rate shall be the formulas set forth in Attachment 1.

14.1.9.1.66 Update Year shall be the period from July 1 of a given calendar year through June 30 of the subsequent calendar year for a particular Annual Update.

All references to FERC accounts in the above definitions are references to 18 C.F.R. Part 101, unless specifically noted otherwise. In the event that the above-referenced FERC accounts are renumbered, renamed, or otherwise modified, the above sections shall be deemed amended to incorporate such renumbered, renamed, modified or additional accounts.

14.1.9.2 Calculation of RR

The RR component shall equal the (a) Historical Transmission Revenue Requirement plus (b) the Forecasted Transmission Revenue Requirement plus (c) the Annual True-Up, determined in accordance with the Formula Rate.

14.1.9.3 Fixed Formula Inputs

Formula Rate inputs for (i) the authorized return on common equity (“ROE”), (ii) any cap on the common equity component of the capital structure, (iii) amount and amortization period of extraordinary property losses, (iv) depreciation and/or amortization rates, (v) PBOP expenses, and (vi) the electric wages and salaries allocation factor and transmission wages and salaries allocation factor shall be stated values until changed by the FERC pursuant to Section 205 or Section 206 of the Federal Power Act. An application under Section 205 or 206 or a proceeding initiated by FERC *sua sponte* under Section 206 to modify any of these stated values under the Formula Rate other than the ROE, the cap on the common equity component of the capital structure or the allocation factors in (vi) shall not be deemed to open for review other components of the Formula Rate.

14.1.9.4 Annual Update Process

14.1.9.4.1 Annual Updates

14.1.9.4.1.1 On or before June 14th of each year, NMPC shall recalculate its RR, CCC, and BU components, applying the Data Inputs called for in the Formula Rate to produce the Annual Update for the upcoming Update Year, and:

14.1.9.4.1.1.1 shall post such Annual Update and a "workable" excel file containing that year's Annual Update on the NYISO's Internet website;

14.1.9.4.1.1.2 shall file such Annual Update with the FERC as the Informational Filing. The submission of such Informational Filing with FERC shall not require any action by the agency; and

14.1.9.4.1.1.3 shall serve the Annual Update electronically on all Interested Parties.

14.1.9.4.1.2 If the date for making the Informational Filing should fall on a weekend or a holiday recognized by the FERC, then the posting/filing shall coincide with the NYISO posting requirement for July rates.

14.1.9.4.1.3 The Annual Update for the Update Year:

14.1.9.4.1.3.1 shall use the Data Inputs specified in NMPC's Formula Rate, and therefore, to the extent specified in NMPC's Formula Rate, be based upon NMPC's FERC Form No. 1 data for the most recent calendar year; to the extent specified in NMPC's Formula Rate, be based upon the books and records of NMPC consistent with FERC accounting policies, and, to the extent specified in NMPC's Formula Rate, be based on projections for the upcoming calendar year;

14.1.9.4.1.3.2 shall provide supporting documentation for Data Inputs in the form of the data provided in Attachment C to the Offer of Settlement dated April 6, 2009, in Docket No. ER08-552; and, with respect to Billing Units, shall include monthly documents in PDF format with redacted names and revised reference numbers for each entity to protect confidentiality, showing the Billing Units for each month of the most recently completed calendar billing year (the six-month updated BUs), including NMPC's Transmission Owner Load ("TOL"), consisting of metered loads for the December through November timeframe showing the calendar billing year BUs reported to the NYISO by NMPC. The total MWh of generation (including load modifiers) and net interchange for each NMPC transmission zone will be displayed. National Grid will also provide a document as a "workable" Excel file summarizing the TOL for disputed station service, High Load Factor Fitzpatrick and any other entity excluded from the Billing Units calculation in Attachment 1, Schedule 6.12, of the Formula Rate. The summary will be labeled to show the reason for exclusion, consistent with the definition of

Billing Units and will reconcile to the totals shown on Attachment 1, Schedule 6.12.

14.1.9.4.1.3.3 shall provide notice of and describe all Material Accounting Changes, which description shall include an explanation of the purpose for and the circumstances giving rise to the Material Accounting Change, including references to any relevant orders, policies or notices of the Securities and Exchange Commission, the FERC or a retail regulator, which explanation may incorporate by reference any applicable disclosure statements filed with any such agency;

14.1.9.4.1.3.4 shall provide notice of the date and location of the meeting to be held in accordance with Section 14.1.9.4.2.2;

14.1.9.4.1.3.5 shall be subject to challenge and review only in accordance with the procedures set forth in this Section 14.1.9.4, provided that such procedures shall not preclude investigation of the Annual Update by FERC, including through hearing procedures;

14.1.9.4.1.3.6 shall not seek to modify NMPC's Formula Rate and shall not be subject to challenge by an Interested Party seeking to modify NMPC's Formula Rate (*i.e.*, all such modifications to the Formula Rate will require, as applicable, a Federal Power Act Section 205 or Section 206 proceeding), provided that an Interested Party may propose for consideration a change to the Formula Rate, as provided in Section 14.1.9.4.3.5;

14.1.9.4.1.3.7 shall include a list of the email addresses of Interested Parties upon which the Annual Update was served; and

14.1.9.4.1.3.8 shall provide a description of, and workpapers for, any correction of an error discovered by NMPC that affects the calculation of any charges under the Formula Rate during a prior year within the period applicable under Section 14.1.9.4.4.

14.1.9.4.1.4 The fixed Formula Rate inputs set forth in Section 14.1.9.3 shall not be subject to adjustment in an Annual Update.

14.1.9.4.2 Annual Review Procedures

Each Annual Update shall be subject to the following review procedures:

14.1.9.4.2.1 Any Interested Party shall have up to one hundred fifty (150) days after the Publication Date (unless such period is extended with the written consent of NMPC) to review the calculations and to notify NMPC in writing of any specific challenges to the accuracy of any Data Input in the Annual Update or the conformance of any such Data Input with the requirements of the Formula Rate ("Preliminary Challenge"); provided, however, that each Interested Party shall make a good faith effort to submit Preliminary Challenges at the earliest practicable date so that they may be resolved as soon as possible, and provide NMPC with a non-binding list of potential Preliminary Challenges it may present, based on its review of the Annual Update and on responses to information requests provided to that point, within ninety (90) days of the Publication Date. Any Preliminary Challenge shall be posted on the NYISO's internet website and served by electronic service on all Interested Parties by the next business day following the date it is provided to NMPC.

14.1.9.4.2.2 Within thirty (30) days of the Publication Date, NMPC shall hold a meeting open to all Interested Parties, at which meeting: (a) NMPC shall present and explain the Annual Update; (b) NMPC shall respond to questions from Interested Parties, to the extent such questions can be answered immediately; and (c) Interested Parties shall identify any areas of potential Preliminary Challenges, to the extent they have identified them at the time of the meeting.

14.1.9.4.2.3 Interested Parties shall have up to one hundred thirty (130) days after each annual Publication Date (unless such period is extended with the written consent of NMPC) to serve reasonable information requests on NMPC; provided, however, that the Interested Parties shall make a good faith effort to submit consolidated sets of information requests that limit the number and overlap of questions to the extent practicable. Such information requests may be directed to matters relevant to the accuracy of the Data Inputs included in the Annual Update and the conformance of those Data Inputs with the requirements of the corresponding provisions of the Formula Rate, including: (a) the reasons for any change in a Data Input from the corresponding Data Input in an earlier Annual Update; (b) the reasons for any change in a Data Input based on actual costs from the corresponding Data Input based on a cost projection in an earlier Annual Update; (c) any reports or other materials provided to fulfill the requirements of a state or federal regulatory agency that explain the basis for projected or actual costs reflected in a Data Input; and (d) the impact of any Material Accounting Change identified in the Annual Update on the charges produced by the Formula Rate.

14.1.9.4.2.4 NMPC shall make a good faith effort to respond to information requests pertaining to the Annual Update within ten (10) business days of receipt of such requests. NMPC may give reasonable priority to responding to requests that satisfy the practicable coordination and consolidation provision of Section 14.1.9.4.2.3, above. NMPC's responses to information requests shall not be entitled to protection as privileged settlement communications; provided, however, that: (a) any communications between NMPC and any Interested Party in connection with efforts to negotiate a resolution of a Preliminary Challenge or Formal Challenge shall be entitled to such protection; (b) if NMPC's response to an information request contains proprietary or trade secret information or critical energy infrastructure information, NMPC and the Interested Party or Parties receiving such information shall enter into a confidentiality agreement materially similar to the model protective order used by the FERC to protect the confidentiality of such information; and (c) nothing herein shall require NMPC to provide information that is protected by the attorney-client privilege, the attorney work product doctrine, or any other legally recognized privilege.

14.1.9.4.3 Resolution of Challenges

14.1.9.4.3.1 NMPC and the Interested Parties shall negotiate in good faith throughout the Review Period to attempt to resolve any Preliminary Challenges.

14.1.9.4.3.2 If NMPC and any Interested Party or Parties have not resolved any Preliminary Challenge to the Annual Update within the Review Period, an Interested Party shall have an additional twenty-one (21) days (unless such period is extended with the written consent of NMPC to continue efforts to resolve a

Preliminary Challenge) to present the subject matter of the Preliminary Challenge to the FERC as a Formal Challenge, which shall be served on NMPC and all other Interested Parties by electronic service on the date of such filing and posted on the NYISO's internet website, however, there shall be no need to make a Formal Challenge or to await conclusion of the time periods in Section 14.1.9.4.2 if the FERC already has initiated a proceeding to investigate the Annual Update. By no later than five (5) business days after the end of the Review Period, NMPC shall apprise Interested Parties of the resolution of all Preliminary Challenges that have been resolved and of the impact of the resolution of all such Preliminary Challenges on the Annual Update. Within an additional fifteen (15) business days, NMPC shall submit a supplement to its Informational Filing to the FERC, with electronic service upon the Interested Parties, reflecting the impact of all successfully resolved Preliminary Challenges.

14.1.9.4.3.3 Any response by NMPC to a Formal Challenge must be submitted to the FERC within twenty-one (21) days of the date of the filing of the Formal Challenge, and shall be posted on the NYISO's Internet website and served on all Interested Parties by electronic service on the date of such filing.

14.1.9.4.3.4 In any proceeding initiated by the FERC concerning the Annual Update or in response to a Formal Challenge, NMPC shall bear the burden of proving that the Data Inputs in that year's Annual Update are correct and conform to the terms of the Formula Rate and refunds or adjustments may be made, in either case with interest, to charges collected under the Formula Rate if the FERC concludes that the Data Inputs are incorrect or do not conform to the terms of the Formula Rate.

In all other respects, any such proceeding shall be governed by the rules and requirements applicable to proceedings under Section 206 of the Federal Power Act.

14.1.9.4.3.5 An Interested Party may propose that resolution of a Preliminary Challenge or Formal Challenge concerning a Material Accounting Change necessitates changes to the Formula Rate to ensure that the resulting charges, including the effect of the Material Accounting Change, are just and reasonable. If NMPC agrees to such a proposed change to the Formula Rate to resolve a Preliminary Challenge, NMPC shall file the change to the Formula Rate with the FERC for approval pursuant to Section 205 of the Federal Power Act. If NMPC does not agree to such a proposed change, the Interested Party may file the proposed change with the FERC for approval pursuant to Section 206 of the Federal Power Act concurrent with its submission of a Formal Challenge; provided that if FERC approves the proposed change, the change to the Formula Rate shall take effect as of the beginning of the Update Year during which the Section 206 filing is made, and refunds or surcharges shall be made, in either case with interest, to charges under the Formula Rate after the beginning of such Update Year to reflect the proposed change.

14.1.9.4.3.6 Nothing herein shall be deemed to limit in any way the right of NMPC to file unilaterally, pursuant to Section 205 of the Federal Power Act and the regulations thereunder, changes to NMPC’s Formula Rate (including changes in connection with any incentive mechanism) or any of its Data Inputs (including, but not limited to, any fixed Data Inputs) or the right of any other party to file for such changes pursuant to Section 206 of the Federal Power Act and the regulations thereunder. All parties reserve all rights to challenge, or take any position in response to, any such filing by any other party.

14.1.9.4.4 Changes to Data Inputs

14.1.9.4.4.1 Any changes to the Data Inputs for an Annual Update, including but not limited to revisions resulting from any FERC proceeding to consider the Annual Update, or as a result of the procedures set forth herein, shall take effect as of the beginning of the Update Year and the impact of such changes shall be incorporated into the charges produced by the Formula Rate (with interest determined in accordance with 18 C.F.R. § 35.19(a)) in the Annual Update for the next effective Update Year. This mechanism shall apply in lieu of mid-Update Year adjustments and any refunds or surcharges, except that, if an error in a Data Input is discovered and agreed upon within the Review Period, the impact of such change shall be incorporated prospectively into the charges produced by the Formula Rate during the remainder of the year preceding the next effective Update Year, in which case the impact reflected in subsequent charges shall be reduced accordingly.

14.1.9.4.4.2 The impact of an error affecting a Data Input on charges collected during the Formula Rate during the five (5) years prior to the Update Year in which the error was first discovered shall be corrected by incorporating the impact of the error on the charges produced by the Formula Rate during the five-year period into the charges produced by the Formula Rate (with interest determined in accordance with 18 C.F.R. § 35.19(a)) in the Annual Update for the next effective

Update Year. Charges collected before the five-year period shall not be subject to correction.

14.2 Attachment 1 to Attachment H

14.2.1 Schedules

Table of Contents

<u>Calculation of RR</u>

14.1.9.2 The RR component shall equal the (a) Historical Transmission Revenue Requirement plus (b) the Forecasted Transmission Revenue Requirement plus (c) the Annual True-Up, determined in accordance with the formula below.

Historical Transmission Revenue Requirement (Historical TRR)

Line No.					
1		**<u>Historical Transmission Revenue Requirement (Historical TRR)</u>**			
2					
3	14.1.9.2 (a)	Historical TRR shall equal the sum of NMPC's (A) Return and Associated Income Taxes, (B) Transmission Related Depreciation Expense, (C)			
4		Transmission Related Real Estate Tax Expense, (D) Transmission Related Amortization of Investment Tax Credits,			
5		(E) Transmission Operation and Maintenance Expense, (F) Transmission Related Administrative and General Expenses, (G) Transmission			
6		Related Payroll Tax Expense, (H) Billing Adjustments, and (I) Transmission Related Bad Debt Expense less			
7		(J) Revenue Credits, and (K) Transmission Rents, all determined for the most recently ended calendar year as of the beginning of the update year.			
8			Reference		
9			*Section:*	**0**	
10		Return and Associated Income Taxes	(A)	#DIV/0!	Schedule 8, line 64
11		Transmission-Related Depreciation Expense	(B)	#DIV/0!	Schedule 9, Line 6, column 5
12		Transmission-Related Real Estate Taxes	(C)	#DIV/0!	Schedule 9, Line 12, column 5
13		Transmission - Related Investment Tax Credit	(D)	#DIV/0!	Schedule 9, Line 16, column 5
14		Transmission Operation & Maintenance Expense	(E)	$0	Schedule 9, Line 23, column 5
15		Transmission Related Administrative & General Expense	(F)	#DIV/0!	Schedule 9, Line 38, column 5
16		Transmission Related Payroll Tax Expense	(G)	$0	Schedule 9, Line 44, column 5
17		Sub-Total (sum of Lines 10 - Line 16)		#DIV/0!	
18					
19		Plus: Billing Adjustments	(H)	$0	Schedule 10, Line 1
20		Plus : Bad Debt Expenses	(I)	$0	Schedule 10, Line 4
21		Less: Revenue Credits	(J)	$0	Schedule 10, Line 7
22		Less: Transmission Rents	(K)	$0	Schedule 10, Line 14
23					
24		Total Historical Transmission Revenue Requirement (Sum of Line 17 - Line 22)		#DIV/0!	
25					

Niagara Mohawk Power Corporation **Attachment 1**
Forecasted Transmission Revenue Requirement **Schedule 2**
Attachment H, Section 14.1.9.2

0

Shading denotes an input

Line No.			Period	Reference		Source
	14.1.9.2	**FORECASTED TRANSMISSION REVENUE**				
1	(b)	**REQUIREMENTS**				
2		Forecasted TRR shall equal (1) the Forecasted Transmission Plant Additions (FTPA) multiplied by the Annual FTRRF, plus (2) the Mid-Year Trend				
3		Adjustment (MYTA), plus (3) the Tax Rate Adjustment (TRA), as shown in the following formula:				
4						
5		Forecasted TRR = (FTPA * FTRRF) + MYTA + TRA				
6						
7			Period	Reference		Source
8						
9						
10	(1)	Forecasted Transmission Plant Additions (FTPA)			$0	Workpaper 8, Section I, Line 16
11		Annual Transmission Revenue Requirement Factor (FTRRF)			#DIV/0!	Line 35
12		Sub-Total (Lines 10*11)			#DIV/0!	
13		Plus Mid-Year Trend Adjustment (2) (MYTA)			$0	Workpaper 9, line 31, variance column
14		Forecasted Transmission Revenue Requirement (Line 12 + Line 13)			**#DIV/0!**	
15						
16	(2)	**MID YEAR TREND ADJUSTMENT (MYTA)**				
17		The Mid-Year Trend Adjustment shall be the difference, whether positive or negative, between				
18		(i) the Historical TRR Component (E) based on actual data for the first three months of the Forecast Period,				
19		and (ii) the Historical TRR Component (E) based on data for the first three months of the year prior to the Forecast Period.				Workpaper 9
20						
21	(3)	**The Tax Rate Adjustment (TRA)**				
22		The Tax Rate Adjustment shall be the amount, if any, required to adjust Historical TRR Component (A) for any change in the Federal Income Tax Rate				
23		and/or the State Income Tax Rate that takes effect during the first five months of the Forecast Period.				
24						
25	14.1.9.2(c)	**ANNUAL FORECAST TRANSMISSION REVENUE REQUIREMENT FACTOR**				
26		The Annual Forecast Transmission Revenue Requirement Factor (Annual FTRRF) shall equal the sum of Historical TRR components (A) through (C),				
27		divided by the year-end balance of Transmission Plant in Service determined in accordance with Section 14.1.9.2 (a), component (A)1(a).				
28						
29						
30		Investment Return and Income Taxes		(A)	#DIV/0!	Schedule 1, Line 10
31		Depreciation Expense		(B)	#DIV/0!	Schedule 1, Line 11
32		Property Tax Expense		(C)	#DIV/0!	Schedule 1, Line 12
33		Total Expenses (Lines 30 thru 32)			#DIV/0!	
34		Transmission Plant		(a)	#DIV/0!	Schedule 6, Page 1, Line 12
35		Annual Forecast Transmission Revenue Requirement Factor (Lines 33/ Line 34)			#DIV/0!	

Niagara Mohawk Power Corporation **Attachment 1**
Annual True-up (ATU) **Schedule 3**

Attachment H Section 14.1.9.2 (c)

Line No.				0	Year	Source:
1						
2	14.1.9.2(d)		The Annual True-Up (ATU) shall equal (1) the difference between the Actual Transmission Revenue Requirement and the Prior Year			
3			Transmission Revenue Requirement, plus (2) the difference between the Actual Scheduling, System Control and Dispatch costs			
4			and Prior Year Scheduling, System Control and Dispatch costs, plus (3) the difference between the Prior Year Billing Units and the Actual Year			
5			Billing Units multiplied by the Prior Year Unit Rate, plus (4) Interest on the net differences.			
6						
7		(1)	Revenue Requirement (RR) of rate effective July 1 of prior year	$0		Schedule 4, Line 1, Col (d)
8			Less: Annual True-up (ATU) from rate effective July 1 of prior year	$0		Schedule 4, Line 1, Col (c)
9			Prior Year Transmission Revenue Requirement	$0		Line 7 - Line 8
10						
11			Actual Transmission Revenue Requirement	#DIV/0!		Schedule 4, Line 2, Col (a)
12			Difference	#DIV/0!		Line 11 - Line 9
13						
14		(2)	Prior Year Scheduling, System Control and Dispatch costs (CCC)	$0		Schedule 4, Line 1, Col (e)
15			Actual Scheduling, System Control and Dispatch costs (CCC)	$0		Schedule 4, Line 2, Col (e)
16			Difference	$0		Line 15 - Line 14
17						
18		(3)	Prior Year Billing Units (MWH)	$0		Schedule 4, Line 1, Col (f)
19			Actual Billing Units	-		Schedule 4, Line 2, Col (f)
20			Difference	-		Line 18 - Line 19
21			Prior Year Indicative Rate	#DIV/0!		Schedule 4, Line 1, Col (g)
22			Billing Unit True-Up	#DIV/0!		Line 20 * Line 21
23						
24			Total Annual True-Up before Interest	#DIV/0!		(Line 12 + Line 16 + Line 22)
25						
26		(4)	Interest	#DIV/0!		Line 57
27						
28			Annual True-up RR Component	#DIV/0!		(Line 24 + Line 26)
29						

30 Interest Calculation per 18 CFR § 35.19a

Line No.	(1) Quarters	(2) Annual Interest Rate (a)	(3) Accrued Prin & Int. @ Beg Of Period	(4) Monthly (Over)/Under Recovery	(5) Days in Period	(6) Period Days	(7) Multiplier	(8) Accrued Prin & Int. @ End Of Period	(9) Accrued Int. @ End Of Period
35									
36	3rd QTR '07		0		92	92	1.0000	$0	$0
37	July	0.00%		#DIV/0!	31	92	1.0000	#DIV/0!	#DIV/0!
38	August	0.00%		#DIV/0!	31	61	1.0000	#DIV/0!	#DIV/0!
39	September	0.00%		#DIV/0!	30	30	1.0000	#DIV/0!	#DIV/0!
40									
41	4th QTR '07		#DIV/0!		92	92	1.0000	#DIV/0!	#DIV/0!
42	October	0.00%		#DIV/0!	31	92	1.0000	#DIV/0!	#DIV/0!
43	November	0.00%		#DIV/0!	30	61	1.0000	#DIV/0!	#DIV/0!
44	December	0.00%		#DIV/0!	31	31	1.0000	#DIV/0!	#DIV/0!
45									
46	1st QTR		#DIV/0!		91	91	1.0000	#DIV/0!	#DIV/0!

	'08								
47	January	0.00%		#DIV/0!	31	91	1.0000	#DIV/0!	#DIV/0!
48	February	0.00%		#DIV/0!	29	60	1.0000	#DIV/0!	#DIV/0!
49	March	0.00%		#DIV/0!	31	31	1.0000	#DIV/0!	#DIV/0!
50									
51	2nd QTR '08		#DIV/0!		91	91	1.0000	#DIV/0!	#DIV/0!
52	April	0.00%		#DIV/0!	30	91	1.0000	#DIV/0!	#DIV/0!
53	May	0.00%		#DIV/0!	31	61	1.0000	#DIV/0!	#DIV/0!
54	June	0.00%		#DIV/0!	30	30	1.0000	#DIV/0!	#DIV/0!
55									
56									
57	Total (over)/under Recovery			#DIV/0!	(line 24)	#DIV/0!			#DIV/0!

(a) Interest rates shall be the interest rates as reported on the FERC Website http://www.ferc.gov/legal/acct-matts/interest-rates.asp

Attachment 1
Schedule 4

Niagara Mohawk Power Corporation Wholesale TSC Calculation Information
2008 Forecast using 2007 Historical Data and 2008 Forecast

		(a)	(b)	See Note (**) below. (c)	(d)	(e)	(f)	(g)
		Historical Transmission Revenue Requirement (Historical TRR)	Forecasted Transmission Revenue Requirement	Annual True Up (**)	Revenue Requirement (RR)	Scheduling System Control and Dispatch Costs (CCC)	Annual Billing Units (BU) MWh	Rate $/MWh (*)
1	Prior Year Rates Effective ________	-	-	-	-	-	-	#DIV/0!
2	Current Year Rates Effective July 1, 2008	#DIV/0!	#DIV/0!		#DIV/0!	-	-	#DIV/0!
3	Increase/(Decrease)							#DIV/0!
4	Percentage Increase/(Decrease)							#DIV/0!

1.) Information directly from Niagara Mohawk Prior Year Informational Filing
2.)
(a) Schedule 1, Line 24
(b) Schedule 2, Line 14
(c) Schedule 3, Line 28
(d) Attachment H, Section 14.1.9.2 The RR Component shall equal Col (a) Historical Transmission Revenue Requirement plus Col (b) the Forecasted Transmission Revenue Requirement plus Col (c) the Annual True-Up
(e) Schedule 11 - Annual Scheduling, System Control and Dispatch Costs. (i.e. the Transmission Component of control center costs) as recorded in FERC Account 561 and its associated sub-accounts from the prior calendar year excluding any NY Independent System Operating (NYISO) system control and load dispatch expenses already recovered under Schedule 1 of the NYISO Tariff.
(f) Schedule 12 - Billing Units shall be the total Niagara Mohawk load as reported to the NYISO for the calendar year prior to the Forecast Period, including the load for customers taking service under Niagara Mohawk's TSC rate. The total Niagara Mohawk load will be adjusted to exclude (i) load associated with wholesale transactions being revenue credited through the WR, CRR, SR, ECR, and Reserved components of Attachment H of the NYISO TSC rate including Niagara Mohawk's external sales, load associated with grandfathered OATT agreements, and any load related to pre-OATT grandfathered agreements; (ii) load associated with transactions being revenue credited under Historical TRR Component J; and (iii) load associated with netted station service.
(g) (Col (d) + Col (e)) / Col (f)

(*) The rate column represents the unit rate prior to adjustments; the actual rate will be determined pursuant to the applicable TSC formula rate.
(**) There was no true-up for this period. This is illustrative only.

Niagara Mohawk Power Corporation
Allocation Factors - As calculated pursuant to Section 14.1.9.1

Attachment 1
Schedule 5

0

Shading denotes an input

Line No.

Source

Definition

1	14.1.9.1 1.	**Electric Wages and Salaries Factor**	**83.5000%**		Fixed per settlement
2					
3	14.1.9.1 3.	**Transmission Wages and Salaries Allocation Factor**	**13.0000%**		Fixed per settlement
4					
5					
6					
7					
8	14.1.9.1 2.	**Gross Transmission Plant Allocation Factor**			
9		Transmission Plant in Service	#DIV/0!	Schedule 6, Page 2, Line 3, Col 5	Gross Transmission Plant Allocation Factor shall equal the total investment in
10		Plus: Transmission Related General	$0	Schedule 6, Page 2, Line 5, Col 5	Transmission Plant in Service, Transmission Related Electric General Plant,
11		Plus: Transmission Related Common	$0	Schedule 6, Page 2, Line 10, Col 5	Transmission Related Common Plant and Transmission Related Intangible Plant
12		Plus: Transmission Related Intangible Plant	$0	Schedule 6, Page 2, Line 15, Col 5	divided by Gross Electric Plant.
13		Gross Transmission Investment	#DIV/0!	Sum of Lines 9 - 13	
14					
15		Total Electric Plant		FF1 207.104	
16		Plus: Electric Common	$0	Schedule 6, Page 2, Line 10, Col 3	
17		Gross Electric Plant in Service	$0	Line 15 + Line 16	
18					
19		**Percent Allocation**	**#DIV/0!**	Line 13 / Line 17	
20					
21	14.1.9.1 4.	**Gross Electric Plant Allocation Factor**			
22					
23		Total Electric Plant in Service	$0	Line 15	Gross Electric Plant Allocation Factor shall equal
24		Plus: Electric Common Plant	$0	Schedule 6, Page 2, Line 10, Col 3	Gross Electric Plant divided by the sum of Total Gas Plant,
25		Gross Electric Plant in Service	$0	Line 23 + Line 24	Total Electric Plant, and Total Common Plant
26					
27		Total Gas Plant in Service		FF1 201.8d	
28		Total Electric Plant in Service	$0	Line 15	
29		Total Common Plant in Service	$0	Schedule 6, Page 2, Line 10, Col 1	
30		Gross Plant in Service (Gas & Electric)	-	Sum of Lines 27-Lines 29	
31					
32		**Percent Allocation**	**#DIV/0!**	Line 25 / Line 30	

Attachment 1
Schedule 6
Page 1 of 2

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Transmission Investment Base (Part 1 of 2)
Attachment H, section 14.1.9.2

Line No.

1 14.1.9.2 (a) Transmission Investment Base
2
3 A.1. Transmission Investment Base shall be defined as (a) Transmission Plant in Service, plus (b) Transmission Related Electric General Plant, plus
4 (c) Transmission Related Common Plant, plus (d) Transmission Related Intangible Plant, plus (e) Transmission Related Plant Held for Future Use, less
5 (f) Transmission Related Depreciation Reserve, less (g) Transmission Related Accumulated Deferred Taxes, plus (h) Transmission Related
6 Regulatory Assets net of Regulatory Liabilities, plus (i) Transmission Related Prepayments, plus (j) Transmission Related Materials and Supplies,
7 plus (k) Transmission Related Cash Working Capital.
8
9

Line No.		Reference	2007	Reference
10		Reference	**2007**	Reference
11		*Section:*		
12	Transmission Plant in Service	(a)	#DIV/0!	Schedule 6, page 2, line 3, column 5
13	General Plant	(b)	$0	Schedule 6, page 2, line 5, column 5
14	Common Plant	(c)	$0	Schedule 6, page 2, line 10, column 5
15	Intangible Plant	(d)	$0	Schedule 6, page 2, line 15, column 5
16	Plant Held For Future Use	(e)	$0	Schedule 6, page 2, line 19, column 5
17	Total Plant (Sum of Line 12 - Line 16)		#DIV/0!	
18				
19	Accumulated Depreciation	(f)	#DIV/0!	Schedule 6, page 2, line 29, column 5
20	Accumulated Deferred Income Taxes	(g)	#DIV/0!	Schedule 7, line 6, column 5
21	Other Regulatory Assets	(h)	#DIV/0!	Schedule 7, line 11, column 5
22	Net Investment (Sum of Line 17 -Line 21)		#DIV/0!	
23				
24	Prepayments	(i)	#DIV/0!	Schedule 7, line 15, column 5
25	Materials & Supplies	(j)	#DIV/0!	Schedule 7, line 21, column 5
26	Cash Working Capital	(k)	$0	Schedule 7, line 28, column 5
27				
28	Total Investment Base (Sum of Line 22 - Line 26)		#DIV/0!	

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Transmission Investment Base (Part 1 of 2)
Attachment H Section 14.1. 9.2 (a) A. 1.

Attachment 1
Schedule 6
Page 2 of 2

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Shading denotes an input

Line No.		(1) Total	(2) Allocation Factor		(3) = (1)*(2) Electric Allocated	(4) Allocation Factor		(5) = (3)*(4) Transmission Allocated	FERC Form 1/PSC Report Reference for col (1)		Definition
1	Transmission Plant								FF1 207.58g	14.1.9.2(a)A.1.(a)	Transmission Plant in Service s balance of total investment in T Plant
2	Wholesale Meter Plant							#DIV/0!	Workpaper 1, Line 45		
3	Total Transmission Plant in Service (Line 1+ Line 2)							#DIV/0!			plus Wholesale Metering Invest
4											
5	General Plant		100.00%		$0	13.00%	(c)	$0	FF1 207.99g	14.1.9.2(a)A.1.(b)	Transmission Related Electric G Plant shall
6											equal the balance of investment General
7											Plant mulitplied by the Transmi Wages and
8											Salaries Allocation Factor
9											
10	Common Plant		83.50%	(a)	$0	13.00%	(c)	$0	FF1 201. 8h	14.1.9.2(a)A.1.(c)	Transmission Related Common equal Common
11											Plant multiplied by the Electric Salaries
12											Allocation Factor and further m the
13											Transmission Wages and Salari Allocation Factor.
14											
15	Intangible Plant		100.00%		-	13.00%	(c)	$0	FF1 205.5g	14.1.9.2(a)A.1.(d)	Transmission Related Intangibl equal Intangible
16											Electric Plant multiplied by the Transmission Wages and
17											Salaries Allocation Factor.
18											
19	Transmission Plant Held for Future Use	$0						$0	Workpaper 10, Line 1	14.1.9.2(a)A.1.(e)	Transmission Related Plant Hel Use shall equal
20											the balance in Plant Held for Fu associated with
21											property planned to be used for transmission service within
22											five years
23	Transmission Accumulated Depreciation										
24	Transmission Accum. Depreciation							$0	FF1 219.25b	14.1.9.2(a)A.1.(f)	Transmission Related Deprecia Reserve shall equal the balance of: (i) Transmission De
25	General Plant Accum.Depreciation		100.00%		$0	13.00%	(c)	$0	FF1 219.28b		Reserve, plus (ii)
26	Common Plant Accum Depreciation		83.50%	(a)	$0	13.00%	(c)	$0	FF1 356.1 end of year balance		the product of Electric General

27	Amortization of Other Utility Plant		100.00%	$0	13.00%	(c)	$0	FF1 200.21c		Depreciation Reserve multiplied by the Transmission Salaries
28	Wholesale Meters	#DIV/0!					#DIV/0!	Workpaper 1, Line 46		Allocation Factor, plus (iii) the Common Plant
29	Total Depreciation (Sum of line 24 - Line 28)						#DIV/0!			Depreciation Reserve multiplie Electric Wages and
30										Salaries Allocation Factor and t multiplied by the
31										Transmission Wages and Salari Allocation Factor plus (iv)
32										the product of Intangible Electr Depreciation Reserve
33										multiplied by the Transmission Salaries
34										Allocation Factor plus (v) depre reserve associated with
35										the Wholesale Metering Investr
36										

Allocation Factor Reference
(a) Schedule 5, line 1
(b) Schedule 5, line 32 - not used on this Schedule
(c) Schedule 5, line 3
(d) Schedule 5, line 19 - not used on this Schedule

Niagara Mohawk Power Corporation **Attachment 1**
Annual Revenue Requirements of Transmission Facilities **Schedule 7**
Transmission Investment Base (Part 2 of 2)

Attachment H Section 14.1.9.2 (a) A. 1.
Shading denotes an input **0**

Line No.		(1) Total	(2) Allocation Factor	(3) = (1)*(2) Electric Allocated	(4) Allocation Factor		(5) = (3)*(4) Transmission Allocated	FERC Form 1/PSC Report Reference for col (1)		Definition
1	Transmission Accumulated Deferred Taxes									
2	Accumulated Deferred Taxes (281-282)		100.00%	$0	#DIV/0!	(d)	#DIV/0!	FF1 275.2k	14.1.9.2(a)A.1.(g)	Transmission Related Accumulated Deferred Income Taxes
3	Accumulated Deferred Taxes (283)	$0	100.00%	$0	#DIV/0!	(d)	#DIV/0!	Workpaper 2, Line 5 (link)		shall equal the electric balance of Total Accumulated Deferred
4	Accumulated Deferred Taxes (190)		100.00%	$0	#DIV/0!	(d)	#DIV/0!	FF1 234.8c		Income Taxes (FERC Accounts 190, 55,281, 282, and 283 net of
5	Accumulated Deferred Inv. Tax Cr (255)		100.00%	$0	#DIV/0!	(d)	#DIV/0!	FF1 267.8h		stranded costs), multiplied by the Gross Transmission Plant
6	Total (Sum of line 2 - Line 5)			$0			#DIV/0!			Allocation Factor.
7										
8	Other Regulatory Assets									
9	FAS 109 (Asset Account 182.3)		100.00%	$0	#DIV/0!	(d)	#DIV/0!	FF1 232 lines	14.1.9.2(a)A.1.(h)	Transmission Related Regulatory Assets shall be Regulatory

10	FAS 109 (Liability Account 254)		100.00%	$0	#DIV/0!	(d)	#DIV/0!	2,4,9,17 FF1 278.1 lines 4&21(f)		Assets net of Regulatory Liabilities multiplied by the Gross
11	Total (line 9 + Line 10)	$0		$0			#DIV/0!			Transmission Plant Allocation Factor.
12										
13	<u>Transmission Prepayments</u>							FF1 111.57c	14.1.9.2(a)A.1.(i)	Transmission Related Prepayments shall be the product of
14	Less: Prepaid State and Federal Income Tax							FF1 263 lines 2 & 9 (h)		Prepayments excluding Federal and State taxes multiplied by
15	Total Prepayments	$0	#DIV/0! (b)	#DIV/0!	#DIV/0!	(d)	#DIV/0!			the Gross Electric Plant Allocation Factor and further
16										multiplied by the Gross Transmission Plant Allocation Factor.
17										
18	<u>Transmission Material and Supplies</u>								14.1.9.2(a)A.1.(j)	Transmission Related Materials and Supplies shall equal: (i)
19	Trans. Specific O&M Materials and Supplies						$0	FF1 227.8		the balance of Materials and Supplies assigned to
20	Construction Materials and Supplies		#DIV/0! (b)	#DIV/0!	#DIV/0!	(d)	#DIV/0!	FF1 227.5		Transmission plus (ii) the product of Material and Supplies
21	Total (Line 19 + Line 20)						#DIV/0!			assigned to Construction multiplied by the Gross Electric
22										Plant Allocation Factor and further multiplied by Gross
23										Transmission Plant Allocation Factor.
24										
25	<u>Cash Working Capital</u>								14.1.9.2(a)A.1.(k)	Transmission Related Cash Working Capital shall be an
26	Operation & Maintenance Expense						$0	Schedule 9, Line 23		allowance equal to the product of: (i) 12.5% (45 days/ 360 days = 12.5%)
27							0.1250	x 45 / 360		multiplied by (ii) Transmission Operation and Maintenance Expense.
28	Total (line 26 * line 27)						$0			
29										
30										

Allocation Factor Reference
(a) Schedule 5, line 1 - not used on this Schedule
(b) Schedule 5, line 32
(c) Schedule 5, line 3 - not used on this Schedule
(d) Schedule 5, line 19

Shading denotes an input | 0

Line No.

1 **The Cost of Capital Rate shall equal the proposed Weighted Costs of Capital plus Federal Income Taxes and State Income Taxes.**

2 The Weighted Costs of Capital will be calculated for the Transmission Investment Base using NMPC's actual capital structure and will equal the sum of (i), (ii), and (iii) below:

3

4 (i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of NMPC's long-term debt outstanding during the year and the sum of (a) the ratio of actual long-term debt to total capital at year-end; and

5 (b) the extent, if any, by which the ratio of NMPC's actual common equity to total capital at year-end exceeds fifty percent (50%). Long term debt shall be defined as the average of the beginning of the year and end of year balances of the following: long term debt less the unamortized

6 Discounts on Long-Term Debt less the unamortized Loss on Reacquired Debt plus unamortized Gain on Reacquired Debt. Cost to maturity of NMPC's long-term debt shall be defined as the cost of long term debt included in the debt discount expense and

7 any loss or gain on reacquired debt.

8 (ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of NMPC's preferred stock then outstanding and the ratio of actual preferred stock to total capital at year-end;

9

10 (iii) the return on equity component shall be the product of the allowed return on equity of 11.5% and the ratio of NMPC's actual common equity to total capital at year-end, provided that such ratio

11 shall not exceed fifty percent (50%).

12

Line			CAPITALIZATION	Source:	CAPITALIZATION RATIOS	COST OF CAPITAL	Source:	WEIGHTED COST OF CAPITAL	EQUITY PORTION
13									
14									
15									
16									
17	(i)	Long-Term Debt	$0	Workpaper. 6, Line 16b	#DIV/0!	#DIV/0!	Workpaper 6, Line 17c	#DIV/0!	
18	(ii)	Preferred Stock		FF1 112.3c	#DIV/0!	#DIV/0!	Workpaper 6, Line 24d	#DIV/0!	#DIV/0!
19	(iii)	Common Equity		FF1 112.16c - FF1 112.3,12,15c	#DIV/0!	11.50%		#DIV/0!	#DIV/0!
20									
21		Total Investment Return	$0		#DIV/0!			#DIV/0!	#DIV/0!

22

23

24

25

26 14.1.9.2.2.(b) Federal Income Tax shall equal

$$= \frac{(\text{A.} + [\text{B} / \text{C}] \times \text{Federal Income Tax Rate})}{(1 - \text{Federal Income Tax Rate})}$$

27

28

29 where A is the sum of the preferred stock component and the return on equity component, each as determined in Sections (a)(ii) and for the ROE set forth in (a)(iii) above, B is the Equity AFUDC component of Depreciation Expense for

30 Transmission Plant in Service as defined at Section 14.1.9.1.16 (FF1 117.38c), and C is the Transmission Investment Base as shown at Schedule 6, Page 1 of 2, Line 28.

31

32 =

(#DIV/0! +($0) / #DIV/0! X)

33 (1 - 0)

34

35 = #DIV/0!

36

37

38 14.1.9.2.2.(c) State Income Tax shall equal = (A. + [B / C] + Federal Income Tax Rate) X State Income Tax Rate

39 (1 - State Income Tax Rate)

40

41 where A is the sum of the preferred stock component and the return on equity component as determined in (a)(ii) and (a)(iii) above , B is the Equity AFUDC component of Depreciation Expense for Transmission Plant in

42 Service as defined at Section 14.1.9.1.16 above, and C is the Transmission Investment Base as shown at Schedule 6, Page 1 of 2, Line 28.

43

44

45

46 = (#DIV/0! +($ 0) / #DIV/0! + #DIV/0!) X

47 (1 - 0)

48

49 = #DIV/0!

50

51

52

53 (a)+(b)+(c) Cost of Capital Rate = #DIV/0!

54

55

56 **14.1.9.2(a) A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate**

57

58

59

60	Transmission Investment Base	#DIV/0!	Schedule 6, page 1 of 2, Line 28
61			
62	Cost of Capital Rate	#DIV/0!	Line 53
63			
64	= Investment Return and Income Taxes	#DIV/0!	Line 60 X Line 62

Niagara Mohawk Power Corporation | **Attachment 1**
Annual Revenue Requirements of Transmission Facilities | **Schedule 9**
Transmission Expenses

Attachment H Section 14.1.9.2 | **0**

Shading denotes an input

Line No.		(1) Total	(2) Allocation Factor	(3) = (1)*(2) Electric Allocated	(4) Allocation Factor	(5) = (3)*(4) Transmission Allocated	FERC Form 1/ PSC Report Reference for col (1)		Definition
	Depreciation Expense								
1	Transmission Depreciation					$0	FF1 336.7f	14.1.9.2.B.	Transmission Related Depreciation Expense shall equal the sum of:
2	General Depreciation		100.0000%	$0	13.0000% (c)	$0	FF1 336.10f		(i) Depreciation Expense for Transmission Plant in Service, plus (ii)
3	Common Depreciation		83.5000% (a)	$0	13.0000% (c)	$0	FF1 356.1		the product of Electric General Plant Depreciation Expense multiplied
4	Intangible Depreciation		100.0000%	$0	13.0000% (c)	$0	FF1 336.1f		by the Transmission Wages and Salaries Allocation Factor plus (iii)
5	Wholesale Meters					#DIV/0!	Workpaper 1, Line 47		Common Plant Depreciation Expense multiplied by the Electric
6	Total (line 1+2+3+4+5)					#DIV/0!			Wages and Salaries Allocation Factor, further multiplied by the
7									Transmission Wages and Salaries Allocation Factor plus (iv)
8									Intangible Electric Plant Depreciation Expense multiplied by the
9									Transmission Wages and Salaries Factor plus (v) depreciation
10									expense associated with the Wholesale Metering Investment.
11									
12	Real Estate Taxes		100.0000%	$0	#DIV/0! (d)	#DIV/0!	FF1 263.25i	14.1.9.2.C.	Transmission Related Real Estate Tax Expense shall equal the
13									electric Real Estate Tax Expenses multiplied by the Gross
14									Transmission Plant Allocation Factor.
15									
16	Amortization of Investment Tax Credits		#DIV/0! (b)	#DIV/0!	#DIV/0! (d)	#DIV/0!	FF1 117.58c	14.1.9.2.D.	Transmission Related Amortization of Investment Tax Credits shall
17									equal the product of Amortization of Investment Tax Credits multiplied
18									by the Gross Electric Plant Allocation Factor and further multiplied by
19									the Gross Transmission Plant Allocation Factor.
20	Transmission Operation and Maintenance								
21	Operation and Maintenance					$0	FF1 321.112b	14.1.9.2.E.	Transmission Operation and Maintenance Expense shall equal
22	less Load Dispatching - #561					$0	FF1 321.84-92b		the sum of electric expenses as recorded in
23	O&M (Line 21 - Line 22)	$0				$0			FERC Account Nos. 560, 562-574.
24									
25	Transmission Administrative and General							14.1.9.2.F.	Transmission Related Administrative and General Expenses shall
26	Total Administrative and General						FF1 323.197b		equal the product of electric Administrative and General Expenses,
27	less Property Insurance (#924)						FF1 323.185b		excluding the sum of Electric Property Insurance, Electric Research and
28	less Pensions and Benefits (#926)						FF1 323.187b		Development Expense and Electric Environmental Remediation Expense,
29	less: Research and Development Expenses (#930)	$0					Workpaper 12, Line 3		and 50% of the NYPSC Regulatory Expense
30	Less: 50% of NY PSC Regulatory Expense						FF1 351.4h		multiplied by the Transmission Wages and Salaries Allocation Factor,

31	Less: 18a Charges (Temporary Assessment						FF1 351.1.h, Workpaper 16, Line 15, Column f
32	less: Environmental Remediation Expense	$0					Workpaper 11, Line 3
33	Subtotal (Line 26-27-28-29-30-31-32)	$0	100.0000%	$0	13.0000% (c)	$0	
34	PLUS Property Insurance alloc. using Plant Allocation	$0	100.0000%	$0	#DIV/0! (d)	#DIV/0!	Line 27
35	PLUS Pensions and Benefits	$88,644,000	100.0000%	$88,644,000	13.0000% (c)	$11,523,720	Workpaper 3
36	PLUS Transmission-related research and development	$0				$0	Workpaper 12
37	PLUS Transmission-related Environmental Expense	$0				$0	Workpaper 11
38	Total A&G (Line 33+34+35+36+37)	$88,644,000		$88,644,000		#DIV/0!	
39							
40	<u>Payroll Tax Expense</u>						
41	Federal Unemployment						FF1 263.4i
42	FICA						FF1 263.3i
43	State Unemployment						FF1 263.17i
44	Total (Line 41+42+43)	$0	100.0000%	$0	13.0000% (b)	$0	

Allocation Factor Reference
(a) Schedule 5, line 1
(b) Schedule 5, line 32
(c) Schedule 5, line 3
(d) Schedule 5, line 19

plus the sum of Electric Property Insurance multiplied by the Gross Transmission Plant Allocation Factor, plus transmission-specific Electric Research and Development Expense, and transmission-specific Electric Environmental Remediation Expense. In addition, Administrative and General Expenses shall exclude the actual Post-Employment Benefits Other than Pensions ("PBOP") included in FERC Account 926, and shall add back in the amounts shown on Workpaper 3, page 1, or other amount subsequently approved by FERC under Section 205 or 206.

14.1.9.2.G. Transmission Related Payroll Tax Expense shall equal the product of electric Payroll Taxes multiplied by the Transmission Wages and Salaries Allocation Factor.

Niagara Mohawk Power Corporation **Attachment 1**
Annual Revenue Requirements of Transmission Facilities **Schedule 10**
Billing Adjustments, Revenue Credits, Rental Income

0

Attachment H Section
14.1.9.2 (a)

Shading denotes an input

Line No.		(1) Total	Source		Definition
1	Billing Adjustments			14.1.9.2.H.	Billing Adjustments shall be any adjustments made in accordance with Section 14.1.9.4.4 below.
2					
3					
4	Bad Debt Expense	$0	Workpaper 4, Line 4	14.1.9.2.I.	Transmission Related Bad Debt Expense shall equal
5					Bad Debt Expense as reported in Account 904 related to NMPC's wholesale transmission billing.
6					
7	Revenue Credits	$0	Workpaper 5, Line 11	14.1.9.2.J.	Revenue Credits shall equal all Transmission revenue recorded in FERC account 456
8					excluding (a) any NMPC revenues already reflected in the WR, CRR, SR, ECR and Reserved
9					components in Attachment H of the NYISO TSC rate; (b) any revenues associated
10					with expenses that have been excluded from NMPC's revenue requirement; and (c) any
11					revenues associated with transmission service provided under this TSC rate, for which the
12					load is reflected in the calculation of BU.
13					
14	Transmission Rents	$0	Workpaper 7	14.1.9.2.K.	Transmission Rents shall equal all Transmission-related rental income recorded in FERC
15					account 454.615
16					
17				14.1.9.4(d)	
18				1	Any changes to the Data Inputs for an Annual Update, including but not limited to
19					revisions resulting from any FERC proceeding to consider the Annual Update, or
20					as a result of the procedures set forth herein, shall take effect as of the beginning
21					of the Update Year and the impact of such changes shall be incorporated into the
22					charges produced by the Formula Rate (with interest determined in accordance
23					with 18 C.F.R. § 38.19(a)) in the Annual Update for the next effective Update
24					Year. This mechanism shall apply in lieu of mid-Update Year adjustments and
25					any refunds or surcharges, except that, if an error in a Data Input is discovered
26					and agreed upon within the Review Period, the impact of such change shall be
27					incorporated prospectively into the charges produced by the Formula Rate during
28					the remainder of the year preceding the next effective Update Year, in which case
29					the impact reflected in subsequent charges shall be reduced accordingly.
30				2	The impact of an error affecting a Data Input on charges collected during the
31					Formula Rate during the five (5) years prior to the Update Year in which the error
32					was first discovered shall be corrected by incorporating the impact of the error on
33					the charges produced by the Formula Rate during the five-year period into the
34					charges produced by the Formula Rate (with interest determined in accordance
35					with 18 C.F.R. § 38.19(a)) in the Annual Update for the next effective Update
36					Year. Charges collected before the five-year period shall not be subject to correction.
(b)	List of Items excluded from the Revenue Requirement		Reason		

Niagara Mohawk Power Corporation
System, Control, and Load Dispatch Expenses (CCC)
Attachment H, Section 14.1.9.5

The CCC shall equal the annual Scheduling, System Control and Dispatch Costs (i.e., the transmission component of control center costs) as recorded in FERC Account 561 and its associated sub-accounts using information from the prior calendar year, excluding NYISO system control and load dispatch expense already recovered under Schedule 1 of the NYISO Tariff.

1	**Scheduling and Dispatch Expenses**			**0**	**Source**
2					
3	Accounts	561	Load Dispatching		FF1 321.84b
4	Accounts	561.1	Reliability		FF1 321.85b
5	Accounts	561.2	Monitor and Operate Transmission System		FF1 321.86b
6	Accounts	561.3	Transmission Service and Schedule		FF1 321.87b
7	Accounts	561.4	Scheduling System Control and Dispatch		FF1 321.88b
8	Accounts	561.5	Reliability, Planning and Standards Development		FF1 321.89b
9	Accounts	561.6	Transmission Service Studies		FF1 321.90b
10	Accounts	561.7	Generation Interconnection Studies		FF1 321.91b
11	Accounts	561.8	Reliability, Planning and Standards Dev. Services		FF1 321.92b
12					
13		Total Load Dispatch Expenses (sum of Lines 3 - 11)			sum lines 3 - 11
14					
15	Less Account 561 directly recovered under Schedule 1 of the NY ISO Tariff				
16					
17	Accounts	561.4	Scheduling System Control and Dispatch		line 7
18	Accounts	561.8	Reliability, Planning and Standards Dev. Services		line 11
19		Total NYISO Schedule 1			line 17 + line 18
20					
21	Total CCC Component				line 13 - line 19

Niagara Mohawk Power Corporation

Attachment 1
Schedule 12

Billing Units - MWH
Attachment H, Section 14.1.9.6

BU shall be the total Niagara Mohawk load as reported to the NYISO for the calendar billing year prior to the Forecast Period, including the load for customers taking service under Niagara Mohawk's TSC Rate. The total Niagara Mohawk load will be adjusted to exclude (i) load associated with wholesale transactions being revenue credited through the WR, CRR, SR, ECR and Reserved components of Workpaper H of the NYISO TSC rate including Niagara Mohawk's external sales, load associated with grandfathered OATT agreements, and any load related to pre-OATT grandfathered agreements; (ii) load associated with transactions being revenue credited under Historical TRR Component J; and (iii) load associated with netted station service.

Line No.		Dec 06- Nov 07	SOURCE
1	Subzone 1		NIMO TOL (transmission owner load)
2	Subzone 2		NIMO TOL (transmission owner load)
3	Subzone 3		NIMO TOL (transmission owner load)
4	Subzone 4		NIMO TOL (transmission owner load)
5	Subzone 29		NIMO TOL (transmission owner load)
6	Subzone 31		NIMO TOL (transmission owner load)
7	Total NIMO Load report to NYISO	**0.000**	sum lines 1-6
8	LESS: All non-retail transactions		
9	Watertown		FF1 page 329.11.j
10	High Load Factor Fitzpatrick		NIMO TOL (transmission owner load)
11	Disputed Station Service		NIMO TOL (transmission owner load)
12	Other non-retail transactions		All other non-retail transactions (Sum of 300,000 series PTID's from TOL)
13	Total Deductions	**0.000**	sum lines 9 - 12
14	PLUS: TSC Load		
15	NYMPA Muni's, Misc. Villages, Jamestown (X1)**		FF1 page 329.19.j ****
16	NYPA Niagara Muni's (X2)		FF1 page 329.1.j ****
17	Total additions	**0.000**	sum lines 15 -17
18	Total Billing Units	**0.000**	line 7 - line 13 + line 18

**** In 2007, the volumes were not detailed in FERC Form 1 as shown. Detail for 2007 will be provided as requested.
On 8/31/07, the contracts for Jamestown and the NYPA Niagara Municipal expired. The previous contract was billed at demand.
The 2007 energy values for the NYPA Niagara Municipals and Jamestown are proxy numbers representing a full year of metered load for December 2006 - November 2007 as billed in January - December. These entities transitioned to the TSC rate on September 1, 2007 for billing effective October 2007. However, the full year billing load was included above.

** One of the Misc Villages at Line 15 is reported on the TOL file with one of the NYPA Niagara Muni's labeled X2.

14.2.2 NYPA Transmission Adjustment Charge ("NTAC")

14.2.2.1 Applicability of the NYPA Transmission Adjustment Charge

Each Billing Period, the ISO shall charge, and each Transmission Customer shall pay, the applicable NYPA Transmission Adjustment Charge ("NTAC") calculated in accordance with Section 14.2.2.2 of this Attachment for the first two (2) months of LBMP and in accordance with Section 14.2.2.1 of this Attachment thereafter. The NTAC shall apply to Transmission Service:

14.2.2.1.1 from one or more Interconnection Points between the NYCA and another Control Area to one or more Interconnection Points between the NYCA and another Control Area ("Wheels Through");[1] or

14.2.2.1.2 from the NYCA to one or more Interconnection Points between the NYCA and another Control Area, including transmission to deliver Energy purchased from the LBMP Market and delivered to such a Control Area Interconnection ("Exports");[1] or

14.2.2.1.3 to serve Load within the NYCA.

In summary the NTAC will be applied to all Energy Transactions, including internal New York State Loads and Wheels Through and Exports out of the NYCA at a uniform, non-discountable rate.

14.2.2.2 NTAC Calculation

14.2.2.2.1 NTAC Formula

Beginning with January 2001, NYPA shall calculate the NTAC applicable to Transmission Service to serve New York State Load, Wheels Through and Exports as follows:

NTAC = {(RR÷12) - (EA) - (IR÷12) - SR - CRN - WR - ECR - NR - NT}/(BU÷12)

Where:

RR = NYPA's Annual Transmission Revenue Requirement, which includes the Scheduling, System Control and Dispatch Costs of NYPA's control center, as approved by FERC;

EA = Monthly Net Revenues from Modified Wheeling Agreements, Facility Agreements and Third Party TWAs, and Deliveries to directly connected Transmission Customers;

SR = $SR_1 + SR_2$

SR_1 will equal the revenues from the Direct Sale by NYPA of Original Residual TCCs, and Grandfathered TCCs associated with ETAs, the expenses for which are included in NYPA's Revenue Requirement where NYPA is the Primary Owner of said TCCs.

SR_2 will equal NYPA's revenues from the Centralized TCC Auction allocated pursuant to Attachment M; this includes revenues from: (a) TCCs associated with Residual Transmission Capacity that are sold in the Centralized TCC Auction; and (b) the sale of Grandfathered TCCs associated with ETAs, if the expenses for these ETAs are included in NYPA's Revenue Requirement.

Revenue from TCCs associated with Residual Transmission Capacity includes payments for Original Residual TCCs that the Transmission Providers sell through the Centralized TCC Auction and the allocation of revenue for other TCCs sold through the Centralized TCC Auction (per the Facility Flow-Based Methodology described in Attachment N).

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[1] The NTAC shall not apply to Wheels Through or Exports scheduled with the ISO to destinations within the New

SR_1 shall be updated prior to the start of each month based on actual data for the calendar month prior to the month in which the adjustment is made (*i.e.*, January actual data will be used in February to calculate the NTAC effective in March). SR_1 for a month in which a Direct Sale is applicable shall equal the total nominal revenue that NYPA will receive under each applicable TCC sold in a Direct Sale divided by the duration of the TCC (in months).

SR_2 shall equal the Transmission Owner's share of Net Auction Revenue for all rounds of a Centralized TCC Auction, as calculated pursuant to Attachment N, divided equally among the months covered by the Centralized TCC Auction. SR_2 shall be adjusted after each Centralized TCC Auction, and the revised SR_2 shall be effective at the start of each Capability Period;

ECR = NYPA's share of Net Congestion Rents in a month, calculated pursuant to Attachment N. The computation of ECR is exclusive of any Congestion payments or Rents included in the CRN term;

CRN = Monthly Day-Ahead Congestion Rents in excess of those required to offset Congestion paid by NYPA's SENY governmental customers associated with the NYPA OATT Niagara/St. Lawrence Service reservations, net of the Initial Cost.

IR = A. The amount that NYPA will credit to its RR assessed to the SENY Load on account of the foregoing NYPA Niagara/St. Lawrence OATT reservations for SENY governmental customers. Such annual revenues will be computed as the product ("Initial Cost") of NYPA's current OATT system rate of $2.23 per kilowatt per month and the 600 MW of TCCs (or the amount of TCCs reduced by Paragraph C below). In the event NYPA sells these TCCs (or any part thereof), all revenues from these sales will offset the NTAC and the Initial Cost will be

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England Control Area provided that the conditions listed in Section 2.7.2.1.4 of this Tariff are satisfied.

concomitantly reduced to reflect the net amount of Niagara/St. Lawrence OATT Reservations, if any, retained by NYPA for the SENY Load. The parties hereby agree that the revenue offset to NTAC will be the greater of the actual sale price obtained by NYPA for the TCCs sold or that computed at the applicable system rate in accordance with Paragraph B below;

B. The system rate of $2.23 per kilowatt per month will be benchmarked to the RR for NYPA transmission initially accepted by FERC ("Base Period RR") for the purposes of computing the Initial Cost. Whenever an amendment to the RR is accepted by FERC ("Amended RR"), the system rate for the purpose of computing the Initial Cost will be increased (or decreased) by the ratio of the Amended RR to the Base Period RR and the effect of Paragraph A on NTAC will be amended accordingly.

C. If prior to the Centralized TCC Auction all Grandfathered Transmission Service including NYPA's 600 MW Niagara/St. Lawrence OATT reservations held on behalf of its SENY governmental customers are found not to be feasible, then such OATT reservations will be reduced until feasibility is assured. A reduction, subject to a 200 MW cap on the total reduction as described in Attachment M, will be applied to the NYPA Niagara/St. Lawrence OATT reservations held on behalf of its SENY governmental customers.

WR = NYPA's revenues from external sales (Wheels Through and Exports) not associated with Existing Transmission Agreements in Attachment L, Tables 1 and 2 and Wheeling revenues from OATT reservations extending beyond the start-up of the ISO;

NR = NYPA Reserved_1 + NYPA Reserved_2

NYPA Reserved_1 will equal NYPA's Congestion payments for a month received pursuant to Section 20.2.3 of Attachment N of this Tariff for NYPA's RCRR TCCs. NYPA Reserved_2 will equal the value that NYPA receives for the sale of RCRR TCCs in a month, with the value for each RCRR TCC sold divided equally over the months remaining until the expiration of that RCRR TCC.

NT = The amount of actual NYPA transmission revenues minus NYPA's monthly revenue requirement.

BU = Annual Billing Units are New York State Loads and Loads associated with Wheels Through and Exports in megawatt-hours ("MWh").

The RR and SR will not include expenses for NYPA's purchase of TCCs or revenues from the sale of such purchased TCCs or from the collection of Congestion Rents for such TCCs.

The ECR, EA, CRN, WR, NR, and NT shall be updated prior to the start of each month based on actual data for the calendar month prior to the month in which the adjustment is made (*i.e.*, January actual data will be used in February to calculate the NTAC effective in March).

The NTAC shall be calculated as a $/MWh charge and shall be applied to Actual Energy Withdrawals, except for Wheels Through and Exports in which case the NTAC shall be applied to scheduled Energy quantities. The NTAC shall not apply to scheduled quantities that are Curtailed by the ISO.

14.2.2.2.2 Implementation of NTAC

At the start of LBMP implementation certain variables of the NTAC equation will not be available. For the first and second months of LBMP implementation, the only terms in the NTAC equation that will be known by NYPA are its historical Annual Transmission Revenue

Requirement (RR) and the historical Billing Units (BU), which have been approved by or filed with FERC. For these two months NYPA shall calculate the NTAC using the following equation:

$$\mathbf{NTAC = \{(RR \div 12) - (EA) - (IR \div 12)\}/(BU \div 12)}$$

SR_2 shall not be available until after the first Centralized TCC Auction. For the third month of LBMP implementation until the second month of the Capability Period corresponding to the first Centralized TCC Auction, NYPA shall recalculate the NTAC using the following equation:

$$\mathbf{NTAC = \{(RR \div 12) - (EA) - (IR \div 12) - WR - CRN - SR_1 - ECR\}/(BU \div 12)}$$

Prior to and during implementation of LBMP those current NYPA transmission customers wishing to terminate their Third Party TWAs shall notify the ISO. The ISO shall duly inform NYPA of such conversion so that NYPA can calculate revenues (EA) to be derived from Existing Transmission Wheeling Agreements.

14.2.2.2.2.1 NYPA's recovery pursuant to NTAC initially is limited to expenses and return associated with its transmission system as that system exists at the time of FERC approval of the NTAC ("base period revenue requirement"). Additions to its system may be included in the computation of NTAC only if: a) upgrades or expansions do not exceed $5 million on an annual basis; or b) such upgrades or expansions have been unanimously approved by the Transmission Owners. Notwithstanding the above, NYPA may invest in transmission facilities in excess of $5 million annually without unanimous Transmission Owners' authorization outside the NTAC recovery mechanism. In that case, NYPA cannot recover any expenses or return associated with such additions under NTAC and any TCC or other revenues associated with such additions will not be considered NYPA transmission revenue for purposes of developing the NTAC nor be used as a credit in the allocation of NTAC to transmission system users.

14.2.2.2.3 Filing and Posting of NTAC

NYPA shall coordinate with the ISO to update certain components of the NTAC formula on a monthly or Capability Period basis. NYPA may update the NTAC calculation to change the RR, initially approved by FERC, and such updates shall be submitted to FERC. An integral part of the agreement between the other Transmission Owners and NYPA is NYPA's consent to the submission of its RR for FERC review and approval on the same basis and subject to the same standards as the Revenue Requirements of the Investor-Owned Transmission Owners. Each January, beginning with January 2001, the ISO shall inform NYPA of the prior year's actual New York internal Load requirements and the actual Wheels Through and Exports and shall post this information on the OASIS. NYPA shall change the BU component of the NTAC formula to reflect the prior calendar year's information, with such change to take effect beginning with the March NTAC of the current year. NYPA will calculate the monthly NTAC and provide this information to the ISO by no later than the fourteenth day of each month, for posting on the OASIS to become effective on the first day of the next calendar month. Beginning with LBMP implementation, the monthly NTAC shall be posted on the OASIS by the ISO no later than the fifteenth day of each month to become effective on the first day of the next calendar month.

14.2.2.3 NTAC Calculation Information

NYPA's Annual Transmission Revenue Requirement (RR), for facilities owned as of January 31, 1997, and Annual Billing Units (BU) of the NTAC are:

RR = $165,449,297

BU = 133,386,541MWh

NYPA's Annual Transmission Revenue Requirement is subject to Commission approval in accordance with Section 14.2.3 of this Attachment.

14.2.2.4 Billing

The New York State Loads, Wheels Through, and Exports will be billed based on the product of: (i) the NTAC; and (ii) the Customer's billing units for the Billing Period. The billing units will be based on the metered energy for all Transactions to supply Load in the NYCA during the Billing Period, and hourly Energy schedules for the Billing Period for all Wheels Through and Exports.

14.1 Transmission Service Charge ("TSC")

14.1.1 Applicability of the Transmission Service Charge to Wholesale Customers

Each month, each wholesale Transmission Customer shall pay to the appropriate Transmission Owner the applicable Wholesale Transmission Service Charge ("Wholesale TSC") calculated in accordance with Section 14.1.2.2 of this Attachment for the first two months of LBMP implementation and in accordance with Section 14.1.2.1 of this Attachment thereafter. The TSC shall apply to Transmission Service:

14.1.1.1 from one or more Interconnection Points between the NYCA and another Control Area to one or more Interconnection Points between the NYCA and another Control Area ("Wheels Through");[1]

14.1.1.2 from the NYCA to one or more Interconnection Points between the NYCA and another Control Area, including transmission to deliver Energy purchased from the LBMP Market and delivered to such a Control Area Interconnection Point ("Exports");[1] or

14.1.1.3 to serve Load within the NYCA; except, the Wholesale TSC shall not apply to:

14.1.1.3.1 a Transmission Owner's use of its own system to provide bundled retail service to its Native Load Customers pursuant to a retail service tariff on file with the PSC or, in the case of LIPA, has been approved by the Long Island Power Authority's Board of Trustees;

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[1] The TSC shall not apply to Wheels Through or Exports scheduled with the ISO to destinations within the New England Control Area provided that the conditions listed in Section 2.7.2.1.4 of this Tariff are satisfied.

14.1.1.3.2 Transmission Service pursuant to an Existing Transmission Agreement whereby the otherwise applicable TSC does not apply pursuant to Attachment K; or

14.1.1.3.3 retail Transmission Service pursuant to any tariff or rate schedule of a Transmission Owner that explicitly provides for other transmission charges in lieu of the Wholesale TSC, subject to any applicable provisions of the Federal Power Act.

Each Transmission Owner subject to FERC and/or PSC jurisdiction may file with FERC a separate TSC applicable to retail access in accordance with its retail access program filed with the PSC. To the extent that LIPA's rates for service are established by the Long Island Power Authority's Board of Trustees pursuant to Article 5, Title 1-A of the New York Public Authorities Law, Section 1020-f(u) and 1020-s and are not subject to FERC jurisdiction, this requirement will not apply to LIPA.

14.1.2 Wholesale TSC Calculation

Sections 14.1.2-14.1.6 do not apply to the development of the NYPA TSC, which is described in Section 14.1.7.

14.1.2.1 Wholesale TSC Formula

Beginning with the second month of the Capability Period corresponding to the initial auction for Long Term TCCs through the end of the LBMP Transition Period, each Transmission Owner, except NYPA shall calculate its TSC applicable to Transmission Service to serve Load within or exiting the NYCA at its Transmission District as follows:

WHOLESALE TSC = {(RR÷12) + (CCC÷12) + (LTPP÷12) - SR - ECR - CRR - WR - Reserved}/(BU÷12).

Where:

RR = The Annual Transmission Revenue Requirement, as stated in Table 1 of this Attachment. Gross Receipts Tax ("GRT") treatment by each individual company is described in Section 14.1.7. Revenues from grandfathered agreements listed on Attachment H-1 are treated as a revenue credit in the RR.

CCC = The annual Scheduling, System Control and Dispatch Costs of the individual Transmission Owner (*i.e.*, the transmission component of control center costs) as stated on Table 1 of this Attachment.

LTPP = The Transmission Owner's annual Net LBMP Transition Period Payment ("LTPP") (expressed as a positive value) or receipt (expressed as a negative value) as described in Attachment K, Section 17.6 (Note - The LTPP will be established once for the entire LBMP Transition Period after the Initial Auction, as defined in Attachment M, for Long Term TCCs). Prior to a 205 Filing under the FPA by the Transmission Owners, the LTPP will be set at zero.

$SR = SR_1 + SR_2$.

SR_1 will equal the revenues from the Direct Sale by the Transmission Owner of Original Residual TCCs, TCCs derived from Existing Transmission Capacity for Native Load, and Grandfathered TCCs associated with ETAs, the expenses for which are included in the Transmission Owner's Revenue Requirements where the Transmission Owner is the Primary Owner of said TCCs.

SR_2 will equal the Transmission Owner's revenues from the Centralized TCC Auction allocated pursuant to Attachments N. SR_2 includes revenues from: (a) TCCs associated with Residual Transmission Capacity that are sold in the Centralized TCC Auction; (b) the sale of

Grandfathered TCCs associated with ETAs, if the expenses for those ETAs are included in the Transmission Owner's Revenue Requirements; and (c) TCCs derived from Existing Transmission Capacity for Native Load that are sold in the Centralized TCC Auction.

Revenue from TCCs associated with Residual Transmission Capacity includes payments for Original Residual TCCs that the Transmission Owners sell through the Centralized TCC Auction and the allocation of revenue for other TCCs sold through the Centralized TCC Auction (per the Facility Flow-Based Methodology described in Attachment N).

SR_1 shall be updated prior to the start of each month based on actual data for the calendar month prior to the month in which the adjustment is made (*i.e.*, January actual data will be used in February to calculate the TSC effective in March). SR_1 for a month in which a Direct Sale is applicable shall equal the total nominal revenue that the Transmission Owner will receive under each applicable TCC sold in the Direct Sale divided by the duration of the TCC (in months). SR_2 shall equal the Transmission Owner's share of Net Auction Revenue for all rounds of a Centralized TCC Auction, as calculated pursuant to Attachment N, divided equally among the months covered by the Centralized TCC Auction. SR_2 shall be adjusted after each Centralized TCC Auction and the revised SR_2 shall be effective at the start of each Capability Period;

ECR = The Transmission Owner's share of Net Congestion Rents in a month, calculated pursuant to Attachment N;

CRR = The Transmission Owner's Congestion Payments received from Grandfathered TCCs and Imputed Revenues from Grandfathered Rights from ETA's, the expenses for which are included in the Transmission Owner's Revenue Requirement;

WR = The Transmission Owner's revenues from external sales (Wheels Through and Export Transactions) not associated with Existing Transmission Agreements included in Attachment L, Tables 18.1, 18.2 and 18.3 and wheeling revenue, associated with OATT reservations extending beyond the start-up of the ISO. (*i.e*., grandfathered OATT agreements)

14.1.2.1.1 Elements of the WR Component

The WR component will equal the sum of: (1) TSC revenues received from new external transactions (Wheels Through and Export Transactions); (2) transmission revenues received under grandfathered OATT agreements and actual revenues under Schedule 1 to the grandfathered OATT agreements, but not under Schedules 2 through 6 to the grandfathered OATT agreements; and (3) any revenues related to pre-OATT grandfathered arrangements if the transmission owner increased its OATT revenue requirement to derive its RR component to reflect the fact that revenues related to such transactions are at risk due to options available to the customers resulting from the current restructuring, and the customer retains its grandfathered arrangement.

In each subcomponent of the WR component above, the revenues will include the Gross Receipts Tax ("GRT") when the Transmission Owner has included the GRT in the RR.

14.1.2.1.2 Treatment of Schedule 1 Associated with Grandfathered OATT Service

All customers under grandfathered OATT service agreements must continue to pay the Schedule 1 charge applicable under the individual OATT, absent a settlement to the contrary. The revenues received from Schedule 1 charges paid by grandfathered OATT customers will be treated as revenue credit in the WR component as part of the wheeling revenue associated with OATT reservations extending beyond the start-up of the ISO.

Reserved = $\text{Reserved}_1 + \text{Reserved}_2 + \text{Reserved}_3 + \text{Reserved}_4$

Reserved_1 will equal the Transmission Owner's Congestion payments for a month received pursuant to Section 20.2.3 of Attachment N of this Tariff for the Transmission Owner's ETCNL TCCs. Reserved_2 will equal the Transmission Owner's Congestion payments for a month received pursuant to Section 20.2.3 of Attachment N of this Tariff for the Transmission Owner's RCRR TCCs. Reserved_3 will equal the value that a Transmission Owner receives for the sale of its ETCNL TCCs in a month, with the value for each ETCNL TCC sold divided equally over the months remaining until the expiration of that ETCNL TCC. Reserved_4 will equal the value that a Transmission Owner receives for the sale of its RCRR TCCs in a month, with the value for each RCRR TCC sold divided equally over the months remaining until the expiration of that ETCNL TCC.

BU = The Transmission Owner's Billing Units (annual MWh) for the Transmission District (see Table 1 of this Attachment) The Transmission Owner's BU has been adjusted upward to include subtransmission and distribution losses.

The RR, SR and CRR will not include expenses for the Transmission Owner's purchase of TCCs or revenues from the sale of said TCCs or from the collection of Congestion Rents for said TCCs. The ECR, CRR, WR, and Reserved shall be updated prior to the start of each month based on actual data for the calendar month prior to the month in which the adjustment is made (*e.g.*, January actual data will be used in February to calculate the TSC effective in March). The TSC shall not apply to the scheduled quantities physically Curtailed by the ISO.

Each Member System is responsible for calculating: (1) the RR component of its TSC charge; (2) the CCC component of its TSC charge; and (3) the BU component of its TSC charge.

The LTPP component of each Member System's TSC charge is initially set at zero. Any changes must be made by unanimous consent of the Transmission Owners (See ISO OATT Original Sheet No. 267). The Member Systems will make a Section 205 filing to propose any change to the LTPP.

The NYISO is responsible for calculating (1) the SR component of each Member System's TSC charge based on information provided by the Member System and information derived from ISO operation; (2) the ECR component of each Member System's TSC charge based on information derived from ISO operation; (3) the CRR component of each Member System's TSC charge based on information derived from ISO operation; (4) the Reserved component of each Member System’s TSC charge based on information provided by the Member System and information derived from ISO operation; and (5) the WR component of each Member System’s TSC charge based on information provided by the Member System and information derived from ISO operation. Any calculations that the ISO is responsible for are subject to review and comment by all affected parties.

The RR term will be updated based on Transmission Owner filings to FERC (or a NYISO filing to FERC on behalf of LIPA) under the FPA. These filings will be made when a Transmission Owner determines that a change to its RR is required under Section 205.

The CCC term will be updated based on Transmission Owner filings to FERC (or a NYISO filing to FERC on behalf of LIPA) under the FPA. These filings will be made when the Transmission Owner determines that a change to the CCC is required.

SR: The revenue from the Direct Sale of TCCs will be determined monthly and will enter the TSC formula through the SR term with a two-month lag (*e.g.*, January actual data will be used in February to calculate the SR term used in the TSC for March). The revenue that a Transmission Owner receives from a TCC sold in a Centralized Auction will be divided equally among the months for which the TCC is sold. The revenue from these TCCs will enter the TSC formula month-by-month through the SR term, beginning with the first month of the period covered by the Centralized Auction. The ISO is responsible for calculating the SR component of each Transmission Owner's TSC. The Transmission Owner will not adjust the ISO's calculation. The ECR revenue will be calculated monthly and will enter the TSC formula with a two-month lag (e.g., January actual data will be used in February to calculate the ECR term used in the TSC for March). The ISO is responsible for calculating the ECR component of each Transmission Owner's TSC. The Transmission Owner will not adjust the ISO's calculation.

The CRR revenue will be calculated monthly and will enter the TSC formula with a two-month lag (*e.g.*, January actual data will be used in February to calculate the CRR term used in the TSC for March). Each Transmission Owner will identify for the ISO each ETA ("Identified ETA"), under which the Transmission Owner is a customer, the expenses for which are included in the Transmission Owner's RR. The ISO shall calculate that Transmission Owner's Congestion Payments received from Grandfathered TCCs and Imputed Revenues from Grandfathered Rights from the Transmission Owner's Identified ETAs. If the inclusion of the costs under an Identified ETA in the Transmission Owner's RR is subject to refund, then the CRR shall be subject to adjustment. If the costs under one or more of the Identified ETAs are removed from the RR and the Transmission Owner is required to recalculate its TSC with the adjusted RR, then in recalculating the TSC, the Transmission Owner shall reverse the portion of the CRR that was attributed to each such ETA. The Transmission Owner shall rebill the customers based on the recalculated TSC. To the extent the Transmission Owner owes a refund to the customer, it shall comply with any applicable refund obligations, including payment of interest to the extent due pursuant to 18 C.F.R. § 35.19a(a)(2)(iii), or its successor. If the reversal of the CRR results in a higher TSC than was charged, the customer shall pay in the time prescribed for payment of TSCs the Transmission Owner the difference between the TSC payments it made and the rebilled amounts, with interest thereon from the dates payments were made to the date that the rebilled amounts are due. Said interest will be calculated in the same manner as interest on over-payments as specified in 18 C.F.R. § 35.19a(a)(2)(iii), or its successor.

The Reserved will be calculated monthly and will enter the TSC formula with a two-month lag (*e.g.*, January actual data will be used in February to calculate the ETCNL TCC term used in the TSC for March). The ISO shall calculate a Transmission Owner’s Reserved.

WR: The revenue that a Transmission Owner collects for new external sales will be calculated monthly and will enter the WR term in the TSC formula with a two-month lag (i.e., January actual data will be used in February to calculate the WR term used in the TSC for March). The ISO is responsible for calculating new external sales subcomponent of the WR component of each Transmission Owner’s TSC. The Transmission Owner will not adjust the ISO's calculation. The actual revenue that a Transmission Owner collects for grandfathered OATT service that extends beyond ISO start-up, and revenues related to pre-OATT grandfathered arrangements as provided for under numbers (2) and (3) of Original Sheet No. 214A, will also be calculated monthly and will enter the WR term in the TSC formula based upon the prior month's information. For the first month the credit will be equal to the actual revenues received under those-grandfathered agreements to be included in the WR component.

The BU term will be updated based on Transmission Owner filings to FERC (or a NYISO filing to FERC on behalf of LIPA) under the FPA. These filings will be made when the Transmission Owner determines that a change to its BU is required.

14.1.2.2 Implementation of TSC

At the start of LBMP implementation, certain variables of the TSC equation will not be available. For the first and second month of LBMP implementation, the only terms in the TSC equation that will be known by each Transmission Owner are its Annual Transmission Revenue Requirement (RR), Scheduling, System Control and Dispatch Costs (CCC), Revenues from the Sale of TCCs in the Transitional Auction (SR_2), Wheeling Revenues Associated with continuing OATT reservations (WR) and Billing Units (BU), which have been approved by or filed with FERC or, in the case of LIPA, approved by the Long Island Power Authority's Board of Trustees. (Billing Units for “metered” retail customers are based on manual meter readings). For these two months each Transmission Owner shall calculate its TSC using the following equation:

WHOLESALE TSC = [(RR÷12) +(CCC÷12) - SR-WR]/BU÷12)

LTPP will not be available until after the Initial Auction as defined in Attachment M for Long Term TCCs. For the third month of LBMP implementation until the second month of the Capability Period corresponding to the initial auction for Long Term TCCs, each Transmission Owner shall calculate its TSC using the following equation:

WHOLESALE TSC = {(RR÷12) + (CCC÷12) - SR - ECR -CRR-WR}/(BU÷12)

From the second month of the Capability Period corresponding to the initial auction for Long Term TCCs , until the conclusion of the LBMP Transition Period, the TSC shall be calculated using the equation in Section 14.1.2.1.

After the conclusion of the LBMP Transition Period, the LTPP component will no longer be applicable and each Transmission Owner shall calculate its Wholesale TSC using the following equation:

WHOLESALE TSC = {(RR÷12) + (CCC÷12) - SR - ECR - CRR - WR - Reserved}/(BU÷12)

14.1.3 Filing and Posting of Wholesale TSCs

The Transmission Owners shall coordinate with the ISO to update certain components of the Wholesale TSC formula on a monthly basis or Capability Period basis. Each Transmission Owner may update its Wholesale TSC calculation to change its RR, CCC, or BU component value(s). Such updates, however, shall be subject to necessary FERC filings under the FPA. Each Transmission Owner will calculate its monthly Wholesale TSC and provide the ISO with the Wholesale TSC by no later than the fourteenth of each month, for posting on the OASIS to become effective on the first of the next calendar month. Beginning with the implementation of LBMP, the monthly Wholesale TSCs for each of the Transmission Districts shall be posted on the OASIS by the ISO no later than the fifteenth of each month to become effective on the first of the next calendar month.

14.1.4 TSC Calculation Information

The Annual Transmission Revenue Requirements ("RR"); Scheduling, System Control and Dispatch Costs ("CCC"), Billing Units ("BU") and Rates of the Transmission Owners, except NYPA, for the purpose of calculating the respective Transmission District-based Wholesale TSC are shown in Table 1 below.

TABLE 1 - WHOLESALE TSC CALCULATION INFORMATION

Transmission Owner	Revenue Requirement (RR)	Scheduling System Control and Dispatch Costs (CCC)	Annual Billing Units (BU) MWh	Rate $/MWh[1]
Central Hudson Gas & Electric Corp.	$16,375,919	$1,309,980	4,723,659	$3.7441
Consolidated Edison Co. of NY, Inc.	$385,900,000	$21,000,000	49,984,628	$8.1405
LIPA	$105,602,083	$3,453,343	20,618,939	$5.2891
New York Electric & Gas Corporation[2]	$94,143,899	$1,633,000	14,817,111	$6.4639
Niagara Mohawk Power Corporation	See Attachment H, Section 14.1.9	See Attachment H, Section 14.1.9	See Attachment H, Section 14.1.9	See Attachment H, Section 14.1.9
Orange and Rockland Utilities, Inc.	$21,034,831	$942,579	3,595,947	$6.1117
Rochester Gas and Electric Corporation	$25,795,509	$583,577	6,967,556	$3.7860

[1]The rate column represents the unit rate prior to crediting; the actual rate will be determined pursuant to the applicable TSC formula rate.

[2]NYSEG's RR, BU and unit Rate prior to adjustment pursuant to Attachment H, are subject to retroactive modification pursuant to the provisions of the Settlement Agreement approved by the Commission in its March 26, 2004 order issued in Docket No. EL04-56-000. For any Transmission Customer that "opts out" of the Settlement Agreement as described in paragraph 1.E thereof, the applicable NYSEG "RR" shall be $100,541,739; the "BU" shall be 13,741,901 MWh; and, the "Rate" prior to adjustment pursuant to Attachment H, shall be $7.4235 effective as of March 1, 2004.

14.1.5 Treatment of Gross Receipts Tax

14.1.5.1 Central Hudson Gas & Electric Corporation

Central Hudson's TSC shall be increased by dividing the following surcharge factors into the total of all applicable rates and charges to reflect the New York State GRT (0.94922 in the MTA regions and 0.95750 in the non-MTA regions), which is not specifically provided for in the transmission rate, to the extent such tax is imposed on Central Hudson as a result of the transmission service provided to such Customer. Central Hudson shall make an appropriate filing pursuant to Section 205 of the Federal Power Act to implement any change in the specified tax rate prior to altering the tax rate under this provision.

14.1.5.2 Consolidated Edison Company of New York, Inc.

The GRT is included in Con Edison's TSC rate. Con Edison will not charge separately for GRT.

14.1.5.3 LIPA

The GRT is included in LIPA's TSC rate. LIPA will not charge separately for GRT.

14.1.5.4 New York State Electric & Gas Corporation

The Transmission Customer shall pay an amount sufficient to reimburse NYSEG for any amounts payable by NYSEG as sales, excise, value-added, gross receipts or other applicable taxes with respect to the total amount payable to NYSEG pursuant to the Tariff. The total of all rates and charges will be divided by the appropriate tax factor listed below, depending upon the geographic location of the Transmission Customer’s Point(s) of Delivery

Within the Metropolitan Commuter Transportation District:	0.984583
Not within the Metropolitan Commuter Transportation District:	0.986823

These tax factors incorporate the taxes imposed on the Transmission Provider’s electric revenues pursuant to New York law and represents the Franchise Tax on Gross Earnings, the Gross Income Tax, and where applicable the Metropolitan Commuter Transportation District Surcharge.

This Provision shall be effective upon commencement of services under the ISO OATT.

14.1.5.5 Niagara Mohawk Power Corporation

For the settled Niagara Mohawk TSC rate, the GRT is included in the RR and there will be no separate GRT tax assessed; For the filed Niagara Mohawk TSC rate, GRT initially is included in the RR and there will be no separate GRT assessed; however, this issue with regard to GRT is subject to final Commission action in Docket No. OA96-194-000, including all stipulations executed in connection therewith.

14.1.5.6 Orange and Rockland Utilities, Inc.

The Transmission Customer's rate will be increased to reflect the gross receipts tax ("GRT") which is not specifically provided for in the transmission rate and ancillary service rates, that a governmental authority may impose on Orange and Rockland as a result of the Transmission Service provided to such Transmission Customer pursuant to Sections 186 and 186-a of the New York Tax Law. The current effective GRT rate for the Section 186-a tax is 3.25% from October 1, 1998 through October 31, 1999 and 2.5% on and after January 1, 2000. The maximum locality rate allowable under state law for each locality is specified below. However, if the actual locality rate is less than the maximum locality rate permitted under state law, O&R shall charge the actual tax rate levied by the locality. The currently effective GRT rate for the Section 186 tax is .75%.

Airmont	1.0%
Bloomingburg	1.0%
Chestnut Ridge	1.0%
Goshen	1.0%
Grandview on Hudson	1.0%
Greenwood Lake	1.0%
Harriman	1.0%
Haverstraw	1.0%
Highland Falls	1.0%
Hillburn	1.0%
Kaser	1.0%
Kiryas Joel	1.0%

Middletown	1.0%
Monroe	1.0%
Montebello	1.0%
New Hempstead	1.0%
New Square	1.0%
Nyack	1.0%
Otisville	1.0%
Piermont	1.0%
Pomona	1.0%
Port Jervis	1.0%
Sloatsburg	1.0%
South Nyack	1.0%
Spring Valley	1.0%
Suffern	1.0%
Unionville	1.0%
Upper Nyack	1.0%
Warwick	1.0%
Washingtonville	1.0%
Wesley Hills	1.0%
West Haverstraw	1.0%
Wurtsboro	1.0%

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14.1.5.7 Rochester Gas & Electric Corporation

The Transmission Customer's rate will be increased to reflect the gross receipts tax which is not specifically provided for in the transmission rate and ancillary service rates, that a governmental authority may impose on RG&E as a result of the Transmission Service provided to such Transmission Customer pursuant to Sections 186 and 186-a of the New York Tax Law. The currently effective GRT rate for the Section 186-a tax is 3.5% and each locality rate is specified below. The currently effective GRT rate for the Section 186 tax is .75%.

City of Rochester	3.0%
Leroy	1.0%
Manchester	1.0%
Perry	1.0%
Shortsville	1.0%
Warsaw	1.0%
Hilton	1.0%
Pittsford	1.0%
Caledonia	1.0%
Wolcott	1.0%
Avon	1.0%

Leicester	1.0%
Nunda	1.0%
Genesco	1.0%
Mt. Morris	1.0%
Sodus Point	1.0%
Livonia	1.0%
Meridian	1.0%
City of Canandaigua	1.0%
Fairport	1.0%
Brockport	1.0%
Scottsville	1.0%
East Rochester	1.0%

14.1.6 TSC For Retail Access Customers ("RTSC")

Customers who apply for unbundled Transmission Service in accordance with the provisions of a Transmission Owner's retail access program filed with the PSC or, in the case of LIPA, approved by the Long Island Power Authority's Board of Trustees, will be responsible for paying a retail transmission service charge as detailed in Section 5 of this Tariff.

14.1.7 NYPA Transmission Service Charge

The NYPA TSC for service to its directly connected Loads (Reynolds Metals, GM-Massena, Town of Massena and the City of Plattsburgh) shall, at the Eligible Customer's option, be (a) $1.30 per kilowatt-month or (b) no more than $3.75 per MWh; not to exceed $60.00 per MW Day applied to peak MWh scheduled any hour each day; not to exceed $300.00 per MW-Week applied to the peak MWh scheduled any hour each week. The TSC applicable to service over the Vermont intertie[2] and the Ontario-Hydro intertie shall be the same as (b). The TSC applicable to service over the Hydro-Quebec intertie shall be no more than $4.62 per MWh; not to exceed $73.85 per MW-Day applied to peak MWh scheduled each day; not to exceed $369.23 per MW-Week applied to the peak MWh scheduled any hour each week. NYPA shall coordinate

[2] The NYPA TSC shall not apply to service over the Vermont intertie provided that the conditions listed in Section 2.7.2.1.4 of this Tariff are satisfied.

with the ISO to update its TSC. Such updates shall be subject to FERC filings.

14.1.8 Discounting

Each Transmission Owner may advise the ISO of discounts to its TSC applicable during a specified period to all deliveries to a particular Interconnection between the NYCA and another Control Area. The ISO shall post the discounts on the OASIS for the specified period.

Three principal requirements apply to discounts for Transmission Service as follows: (1) any offer of a discount made by a Transmission Owner must be announced to all Eligible Customers solely by posting on the OASIS; (2) any customer-initiated requests for discounts (including requests for use by a Transmission Owner's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS; and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount that the Transmission Owner agrees to and advises the ISO of, the same discounted Transmission Service rate will be offered to all Transmission Customers for the same period for all deliveries to a particular Interconnection between the NYCA and another Control Area. The ISO will post the discounts on the OASIS for the specified period.

TABLE 2

Applicable Wholesale TSC for Exports from
New York State, by Transmission Circuit

Ckt.Id	From/To	kV	From Co./To Ext.	Wholesale TSC Paid
5018	Ramapo / Branchburg	500	O&R/PJM	Con Ed/O&R
398	Pleasant Valley/ Long Mtn	345	CHG&E / NE	Con Ed
B3402	Farragut / Hudson	345	Con Ed / PJM	Con Ed
C3403	Farragut / Hudson	345	Con Ed / PJM	Con Ed
A2253	Goethals / Linden	230	Con Ed / PJM	Con Ed
FE	Smithfield / Falls Village	69	CHG&E/NE	CHG&E
1385	Northport / Norwalk [1]	138	LIPA / NE	LIPA
393	Alps / Berkshire	345	NMPC / NE	NMPC
69	So. Ripley / Erie East	230	NMPC / PJM	NMPC
E205W	Rotterdam / Bear Swamp	230	NMPC / NE	NMPC
BP76	Packard / Beck	230	NMPC / OH	NMPC
171	Falconer / Warren	115	NMPC / PJM	NMPC
6	Hoosick / Bennington	115	NMPC /NE	NMPC
7	Whitehall / Blissville	115	NMPC / NE	NMPC
1	Dennison / Rosemont	115	NMPC / HQ	NMPC
2	Dennison / Rosemont	115	NMPC / HQ	NMPC
37-HS	Stolle Road / Homer City	345	NYSEG / PJM	NYSEG
30-HW	Watercure / Homer City	345	NYSEG / PJM	NYSEG
70-EH	Hillside / East Towanda	230	NYSEG / PJM	NYSEG
952	Goudey / Laurel Lake	115	NYSEG / PJM	NYSEG
956	No. Waverly / East Sayre	115	NYSEG / PJM	NYSEG
J	So. Mahwah / Waldwick	345	O&R / PJM	Con Ed/O&R
K	So. Mahwah / Walkwick	345	O&R / PJM	Con Ed/O&R
7040	Massena / Chateaugay	765	NYPA / HQ NYPA	NYPA
PA302	Niagara / Beck A	345	NYPA / OH	NYPA
PA301	Niagara / Beck B	345	NYPA / OH	NYPA
L34P	Moses / St. Lawrence	230	NYPA / OH	NYPA
L33P	Moses / St. Lawrence	230	NYPA / OH	NYPA
PA27	Niagara / Beck	230	NYPA / OH	NYPA
PV-20	Plattsburgh / Grand Isle	115	NYPA / NE	NYPA

[1] All scheduling over the Northport - Norwalk Intertie is conducted by LIPA pursuant to Section 5.7 of this Tariff.

TABLE 3
Applicable Wholesale TSC for Municipal Utilities,
Electric Cooperatives and Loads

Except for those municipal utilities and electric cooperatives that continue to take transmission service under an Existing Transmission Agreement, the following Loads shall be obligated to pay the noted Transmission District **-** based TSC as applicable in accordance with Section 2.7 of this Tariff.

Load	TSC Paid	Load	TSC Paid	Load	TSC Paid
		Greene	NYSEG	Sherrill	NMPC
		Green Island	NMPC	Silver Springs	NYSEG
		Greenport	LIPA	Skaneateles	NMPC
		Groton	NYSEG	Solvay	NMPC
		Hamilton	NYSEG	Spencerport	RG&E
		Holley	NMPC	Springville	NMPC
		Ilion	NMPC	Steuben	NYSEG
Akron	NMPC	Lake Placid	NMPC	Theresa	NMPC
Andover	NMPC	Little Valley	NMPC	Tupper Lake	NMPC
Angelica	RG&E	Marathon	NYSEG	Watkins Glen	NYSEG
Arcade	NMPC	Mayville	NMPC	Wellsville	NMPC
Bath	NYSEG	Mohawk	NMPC	Westfield	NMPC
Bergen	NMPC	Oneida -Madison	NMPC/ NYSEG	Massena	NYPA
Boonville	NMPC	Otsego	NYSEG	Freeport	LIPA
Brolton	NMPC	Penn Yan	NYSEG	Jamestown	NMPC
Castile	NYSEG	Philadelphia	NMPC	Rockville Ctr.	LIPA
Churchville	NMPC	Plattsburgh	NYPA	Alcoa	(1)
Delaware	NYSEG	Richmondville	NMPC	Reynolds	NYPA
Endicott	NYSEG	Rouses Point	NYSEG	Gen. Motors (Massena, NY)	NYPA
Fairport	NMPC	Salamanca	NMPC	Cornwall	NMPC
Frankfort	NMPC	Sherburne	NYSEG		

Notes: (1) - Load is treated as an entity external to the NYCA.

14.1.9 Niagara Mohawk Power Corporation Wholesale TSC Formula Components RR, CCC and BU and Sources of Data Inputs

Niagara Mohawk Power Corporation ("NMPC") will calculate and update each of its RR, CCC, and BU components annually using the formulas for each component contained in

Attachment 1 and in accordance with the update procedures set forth in Section 14.1.9.4. With the exception of forecasted information, the cost data used in the Formula Rate will be cost data from NMPC's annual FERC Form 1, NMPC's Annual Report to the New York State Public Service Commission, or NMPC's official books of record.

14.1.9.1 Definitions

Capitalized terms used in this calculation will have the following definitions:

Allocation Factors

14.1.9.1.1 Electric Wages and Salaries Allocation Factor shall be fixed at 0.835.

14.1.9.1.2 Gross Transmission Plant Allocation Factor shall equal the total investment in Transmission Plant in Service, Transmission Related Electric General Plant, Transmission Related Common Plant and Transmission Related Intangible Plant divided by Gross Electric Plant.

14.1.9.1.3 Transmission Wages and Salaries Allocation Factor shall be fixed at 0.13.

14.1.9.1.4 Gross Electric Plant Allocation Factor shall equal Gross Electric Plant divided by the sum of Total Gas Plant, Total Electric Plant, and total Common Plant.

Ratebase and Expense Items

14.1.9.1.5 Administrative and General Expense shall equal expenses as recorded in FERC Account Nos. 920-935. FERC Account No. 926 shall be adjusted by reversing the adjustment to the deferred pension costs booked per the NYPSC Statement of Policy for Accounting and Ratemaking Treatment for Pension and Post-Retirement Benefits Other than Pensions. In addition, Administrative and

General Expenses shall exclude the actual Post-Employment Benefits Other than Pensions ("PBOP") expenses included in FERC Account No. 926, and shall add back the FERC accepted Post Employment Benefit Other than Pensions of $88,644,000 annually or $7,387,000 per month or any other amount subsequently approved by FERC under Section 205 or 206 of the Federal Power Act.

14.1.9.1.6 Amortization of Investment Tax Credits shall equal credits as recorded in FERC Account No. 420, per 18 C.F.R. Parts 101 (Electric) and 201 (Gas).

14.1.9.1.7 Amortization of Debt Discount Expense shall equal expenses as recorded in FERC Account No. 428.

14.1.9.1.8 Amortization of Loss on Reacquired Debt shall equal expenses as recorded in FERC Account No. 428.1.

14.1.9.1.9 Amortization of Premium on Debt –Credit shall equal the expenses as recorded in FERC Account 429.

14.1.9.1.10 Amortization of Gain on Reacquired Debt--Credit shall equal the expenses as recorded in FERC Account No. 429.1.

14.1.9.1.11 Common Plant shall equal the balance of plant recorded in FERC Account Nos. 389-399. Common Plant shall be defined as the plant common to NMPC's gas and electric functions per 18 C.F.R. Parts 101 (Electric) and 201 (Gas).

14.1.9.1.12 Common Plant Depreciation Expense shall equal the common plant depreciation expenses as recorded in FERC Account No. 403 associated with Common Plant per 18 C.F.R. Parts 101 (Electric) and 201 (Gas).

14.1.9.1.13 Common Plant Depreciation Reserve shall equal the common plant depreciation reserve balance as recorded in FERC Account No. 108 associated with Common Plant per 18 C.F.R. Parts 101 (Electric) and 201 (Gas).

14.1.9.1.14 Depreciation Expense for Transmission Plant in Service shall equal depreciation expenses as recorded in FERC Account No. 403 calculated using the depreciation rates set forth in the following table:

Depreciation Rates

FERC Account/NMPC Internal Account No.		Annual Rate
350	Land –Rights of Way and Easements	1.32
352	Structures and Improvements	2.08
353	Station Equipment	2.44
353.55	Station Equipment – EMS	3.40
354	Towers and Fixtures	1.71
355	Poles and Fixtures	2.00
356	Overhead Conductors and Devices	1.60
357	Underground Conduit	1.33
358	Underground Conductors and Devices	1.48
359	Roads and Trails	1.33
370	Meters	
	Meters	5.05
	Installation	5.05

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Wood Pole Lines 1.58¶

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14.1.9.1.15 Distribution Plant shall equal the plant balance as recorded in FERC Account Nos. 360 – 374.

14.1.9.1.16 Equity AFUDC Component of Depreciation Expense shall equal the activity recorded in FERC Account No. 419.1.

14.1.9.1.17 Electric Environmental Remediation Expense shall be the environmental remediation expense as recorded in NMPC's internal Account 930.200.

14.1.9.1.18 Electric General Plant shall equal the plant balance recorded in FERC Account Nos. 389-399. Electric General Plant shall be defined as the general plant associated with NMPC's electric function.

14.1.9.1.19 Electric General Plant Depreciation Expense shall equal general plant depreciation expenses as recorded in FERC Account No. 403 associated with Electric General Plant.

14.1.9.1.20 Electric General Plant Depreciation Reserve shall equal the general plant depreciation reserve balance as recorded in FERC Account No. 108 associated with Electric General Plant.

14.1.9.1.21 Electric Property Insurance shall equal property insurance recorded in FERC Account No. 924.

14.1.9.1.22 Electric Research and Development Expense shall equal research and development expenses as recorded in NMPC internal Account No. 930.210.

14.1.9.1.23 Gain on Reacquired Debt shall equal the balance as recorded in FERC Account No. 257.

14.1.9.1.24 Gross Electric Plant shall equal Total Electric Plant plus an allocation of Common Plant determined by multiplying Common Plant by the Electric Wages and Salaries Allocation Factor.

14.1.9.1.25 Gross Plant (Gas & Electric) shall equal Total Gas Plant plus Total Electric Plant plus Total Common Plant.

14.1.9.1.26 Gross Transmission Investment shall equal the total of Transmission Plant in Service, Transmission Related Electric General Plant, Transmission Related Common Plant and Transmission Related Intangible Plant.

14.1.9.1.27 Intangible Electric Plant shall equal the balance of plant recorded in FERC Account Nos. 301-303. Intangible Electric Plant shall be defined as the intangible plant associated with NMPC's electric functions.

14.1.9.1.28 Intangible Electric Plant Depreciation Expense shall equal the intangible electric plant depreciation expenses as recorded in FERC Account No. 403 associated with Intangible Electric Plant.

14.1.9.1.29 Intangible Electric Plant Depreciation Reserve shall equal the intangible plant depreciation reserve balance as recorded in FERC Account No. 108 associated with Intangible Electric Plant.

14.1.9.1.30 Loss on Reacquired Debt shall equal the loss on reacquired debt as recorded in FERC Account No. 189.

14.1.9.1.31 Materials and Supplies shall equal materials and supplies balance as recorded in FERC Account No. 154 per 18 C.F.R. Parts 101 (Electric) and 201 (Gas).

14.1.9.1.32 Payroll Taxes shall equal the electric payroll tax expenses related to FICA and federal and state unemployment as recorded in NMPC's internal Account Nos. 408.100, 408.110 and 408.130.

14.1.9.1.33 Plant Held for Future Use shall equal the balance as recorded in FERC Account No. 105 for transmission uses within 5 years.

14.1.9.1.34 Prepayments shall equal prepayment balance as recorded in FERC Account No. 165 per 18 C.F.R. Parts 101 (Electric) and 201 (Gas) less prepaid state and Federal income taxes.

14.1.9.1.35 Real Estate Tax Expenses shall equal electric real estate tax expense as recorded in NMPC's internal Account No. 408.140 and 408.180.

14.1.9.1.36 Regulatory Assets and Liabilities shall equal state and federal regulatory asset balances in FERC Account Nos. 182.3 and 254, assets and liabilities solely related to FAS109, and excess AFUDC.

14.1.9.1.37 Total Accumulated Deferred Income Taxes shall equal the sum of deferred tax balances recorded in FERC Account Nos. 281 - 283 plus accumulated deferred investment tax credits as reflected in FERC Account No. 255, minus the deferred tax balance in FERC Account No. 190. Total Accumulated Deferred Income Taxes shall exclude the specifically identified generation-related stranded cost deferred taxes.

14.1.9.1.38 Total Electric Plant shall equal the sum of Transmission Plant, Distribution Plant, Electric General Plant and Intangible Electric Plant.

14.1.9.1.39 Total Gas Plant shall equal the plant balance recorded in 18 C.F.R. Part 201, FERC Account Nos. 301-399. Total Gas Plant shall exclude Common Plant.

14.1.9.1.40 Transmission Depreciation Reserve shall equal electric transmission plant related depreciation reserve balance as recorded in FERC Account No. 108, plus Transmission Related General Plant Accumulated Depreciation, Transmission Related Amortization of Other Utility Plant, and Common Plant Accumulated Depreciation associated with Gross Electric Plant.

14.1.9.1.41 Transmission Operation and Maintenance Expense shall equal the sum of electric expenses as recorded in FERC Account Nos. 560, 562-574.

14.1.9.1.42 Transmission Plant shall equal the gross plant balance as recorded in FERC Account Nos. 350-359.

14.1.9.1.43 Transmission Related Bad Debt Expense shall equal Bad Debt Expense as reported in Account 904 related to NMPC's wholesale transmission billing.

14.1.9.1.44 Unamortized Discount on Long-Term Debt shall equal the balance in FERC Account No. 226.

14.1.9.1.45 Wholesale Metering Investment shall equal the gross plant investment associated with any Revenue or Remote Terminal Unit ("RTU") meters and associated equipment connected to an internal or external tie at voltages equal to or greater than 23 kV. The gross plant investment shall be determined by multiplying the number of such existing wholesale meters recorded in FERC Account No. 370.3 and in blanket metering accounts by the average cost of the meters plus the average costs of installation. To the extent future gross plant investment for Wholesale Metering can be specifically identified, actual gross meter costs will be used.

Forecast and True-up Related Terms

14.1.9.1.46 Forecast Period shall mean the calendar year immediately following the calendar year for which the most recent FERC Form 1 data is available, as of the beginning of the Update Year.

14.1.9.1.47 Forecasted Transmission Plant Additions ("FTPA") shall mean the sum of:

14.1.9.1.47.1 NMPC's actual Transmission Plant additions during the first quarter (January 1 through March 31) of the Forecast Period; and

14.1.9.1.47.2 NMPC's forecasted transmission investment for the Forecast Period less the amount (i), divided by 2.

14.1.9.1.48 Interest on refunds, surcharges, or adjustments, as applicable, shall mean interest calculated in accordance with the methodology specified in the Commission's regulations at 18 C.F.R. § 35.19a (a) (2) (iii) (or as such provision may be renumbered in the future).

14.1.9.1.49 Actual Transmission Revenue Requirement shall mean the current Historical Transmission Revenue Requirement (as defined in Attachment 1).

14.1.9.1.50 Actual Scheduling, System Control and Dispatch cost shall mean the most recently established CCC (as defined in Attachment 1).

14.1.9.1.51 Actual Billing Units shall mean the most recently established BU (as defined in Attachment 1).

14.1.9.1.52 Prior Year Transmission Revenue Requirement shall equal RR less Annual True-Up ("ATU"), as defined in Attachment 1, for the most recently ended calendar year as of the beginning of the Update Year.

14.1.9.1.53 Prior Year Scheduling, System Control and Dispatch shall equal the CCC, as defined in Attachment 1, for the prior calendar year.

14.1.9.1.54 Prior Year Billing Units shall equal the BU, as defined in Attachment 1, for the prior calendar year.

14.1.9.1.55 Prior Year Unit Rate shall equal the sum of RR, as defined in Attachment 1, for the most recently ended Prior Year Revenue Requirement and the Prior Year Scheduling, System Control and Dispatch divided by the Prior Year Billing Units.

14.1.9.1.56 Annual Update shall mean the calculation of the RR, CCC, and BU components with Data Inputs for an Update Year in accordance with Section 14.1.9.4.

14.1.9.1.57 Data Input shall mean any data required for the calculation of RR, CCC and BU, in accordance with the Formula Rate.

14.1.9.1.58 Formal Challenge shall mean a challenge presented in accordance with Section 14.1.9.4.3.2.

14.1.9.1.59 Informational Filing shall mean the filing that NMPC makes in accordance with Section 14.1.9.4 to establish the Annual Update for an Update Year.

14.1.9.1.60 Interested Party shall mean a person that is (i) a party to FERC Docket No. ER08-552, (ii) the New York State Public Service Commission; (iii) a transmission customer under this Tariff that pays charges based on the Formula Rate during the calendar year prior to the submission of the Informational Filing; or (iv) a state regulatory authority having jurisdiction over the retail electric rates of such a transmission customer, provided that such regulatory authority or such customer notifies NMPC of that fact no later than 30 days prior to the Publication Date. An Interested Person includes employees of or consultants to such person.

14.1.9.1.61 Material Accounting Change shall mean an accounting policy or practice, including, but not limited to, a policy or practice affecting the allocation of costs or revenues, employed by NMPC during an Update Year that differs from the corresponding policy or practice in effect during any of the three previous calendar years which change affects any Data Input for the Update Year by $1.0 million or more, as compared to the previous calendar year.

14.1.9.1.62 Preliminary Challenge shall mean a challenge presented by an Interested Party in accordance with Section 14.1.9.4.2.1.

14.1.9.1.63 Publication Date shall be the date of an Informational Filing for an Update Year.

14.1.9.1.64 Review Period shall be the period ending one-hundred and fifty (150) days after the Publication Date, unless extended in accordance with Section 14.1.9.4.2.1.

14.1.9.1.65 Formula Rate shall be the formulas set forth in Attachment 1.

14.1.9.1.66 Update Year shall be the period from July 1 of a given calendar year through June 30 of the subsequent calendar year for a particular Annual Update.

All references to FERC accounts in the above definitions are references to 18 C.F.R. Part 101, unless specifically noted otherwise. In the event that the above-referenced FERC accounts are renumbered, renamed, or otherwise modified, the above sections shall be deemed amended to incorporate such renumbered, renamed, modified or additional accounts.

14.1.9.2 Calculation of RR

The RR component shall equal the (a) Historical Transmission Revenue Requirement plus (b) the Forecasted Transmission Revenue Requirement plus (c) the Annual True-Up, determined in accordance with the Formula Rate.

14.1.9.3 Fixed Formula Inputs

Formula Rate inputs for (i) the authorized return on common equity (“ROE”), (ii) any cap on the common equity component of the capital structure, (iii) amount and amortization period of extraordinary property losses, (iv) depreciation and/or amortization rates, (v) PBOP expenses, and (vi) the electric wages and salaries allocation factor and transmission wages and salaries allocation factor shall be stated values until changed by the FERC pursuant to Section 205 or Section 206 of the Federal Power Act. An application under Section 205 or 206 or a proceeding initiated by FERC *sua sponte* under Section 206 to modify any of these stated values under the Formula Rate other than the ROE, the cap on the common equity component of the capital structure or the allocation factors in (vi) shall not be deemed to open for review other components of the Formula Rate.

14.1.9.4 Annual Update Process

14.1.9.4.1 Annual Updates

14.1.9.4.1.1 On or before June 14th of each year, NMPC shall recalculate its RR, CCC, and BU components, applying the Data Inputs called for in the Formula Rate to produce the Annual Update for the upcoming Update Year, and:

14.1.9.4.1.1.1 shall post such Annual Update and a “workable” excel file containing that year’s Annual Update on the NYISO’s Internet website;

14.1.9.4.1.1.2 shall file such Annual Update with the FERC as the Informational Filing. The submission of such Informational Filing with FERC shall not require any action by the agency; and

14.1.9.4.1.1.3 shall serve the Annual Update electronically on all Interested Parties.

14.1.9.4.1.2 If the date for making the Informational Filing should fall on a weekend or a holiday recognized by the FERC, then the posting/filing shall coincide with the NYISO posting requirement for July rates.

14.1.9.4.1.3 The Annual Update for the Update Year:

14.1.9.4.1.3.1 shall use the Data Inputs specified in NMPC's Formula Rate, and therefore, to the extent specified in NMPC's Formula Rate, be based upon NMPC's FERC Form No. 1 data for the most recent calendar year; to the extent specified in NMPC's Formula Rate, be based upon the books and records of NMPC consistent with FERC accounting policies, and, to the extent specified in NMPC's Formula Rate, be based on projections for the upcoming calendar year;

14.1.9.4.1.3.2 shall provide supporting documentation for Data Inputs in the form of the data provided in Attachment C to the Offer of Settlement dated April 6, 2009, in Docket No. ER08-552; and, with respect to Billing Units, shall include monthly documents in PDF format with redacted names and revised reference numbers for each entity to protect confidentiality, showing the Billing Units for each month of the most recently completed calendar billing year (the six-month updated BUs), including NMPC's Transmission Owner Load ("TOL"), consisting of metered loads for the December through November timeframe showing the calendar billing year BUs reported to the NYISO by NMPC. The total MWh of generation (including load modifiers) and net interchange for each NMPC transmission zone will be displayed. National Grid will also provide a document as a "workable" Excel file summarizing the TOL for disputed station service, High Load Factor Fitzpatrick and any other entity excluded from the Billing Units calculation in Attachment 1, Schedule 6.12, of the Formula Rate. The summary will be labeled to show the reason for exclusion, consistent with the definition of

Billing Units and will reconcile to the totals shown on Attachment 1, Schedule 6.12.

14.1.9.4.1.3.3 shall provide notice of and describe all Material Accounting Changes, which description shall include an explanation of the purpose for and the circumstances giving rise to the Material Accounting Change, including references to any relevant orders, policies or notices of the Securities and Exchange Commission, the FERC or a retail regulator, which explanation may incorporate by reference any applicable disclosure statements filed with any such agency;

14.1.9.4.1.3.4 shall provide notice of the date and location of the meeting to be held in accordance with Section 14.1.9.4.2.2;

14.1.9.4.1.3.5 shall be subject to challenge and review only in accordance with the procedures set forth in this Section 14.1.9.4, provided that such procedures shall not preclude investigation of the Annual Update by FERC, including through hearing procedures;

14.1.9.4.1.3.6 shall not seek to modify NMPC's Formula Rate and shall not be subject to challenge by an Interested Party seeking to modify NMPC's Formula Rate (*i.e*., all such modifications to the Formula Rate will require, as applicable, a Federal Power Act Section 205 or Section 206 proceeding), provided that an Interested Party may propose for consideration a change to the Formula Rate, as provided in Section 14.1.9.4.3.5;

14.1.9.4.1.3.7 shall include a list of the email addresses of Interested Parties upon which the Annual Update was served; and

14.1.9.4.1.3.8 shall provide a description of, and workpapers for, any correction of an error discovered by NMPC that affects the calculation of any charges under the Formula Rate during a prior year within the period applicable under Section 14.1.9.4.4.

14.1.9.4.1.4 The fixed Formula Rate inputs set forth in Section 14.1.9.3 shall not be subject to adjustment in an Annual Update.

14.1.9.4.2 Annual Review Procedures

Each Annual Update shall be subject to the following review procedures:

14.1.9.4.2.1 Any Interested Party shall have up to one hundred fifty (150) days after the Publication Date (unless such period is extended with the written consent of NMPC) to review the calculations and to notify NMPC in writing of any specific challenges to the accuracy of any Data Input in the Annual Update or the conformance of any such Data Input with the requirements of the Formula Rate ("Preliminary Challenge"); provided, however, that each Interested Party shall make a good faith effort to submit Preliminary Challenges at the earliest practicable date so that they may be resolved as soon as possible, and provide NMPC with a non-binding list of potential Preliminary Challenges it may present, based on its review of the Annual Update and on responses to information requests provided to that point, within ninety (90) days of the Publication Date. Any Preliminary Challenge shall be posted on the NYISO's internet website and served by electronic service on all Interested Parties by the next business day following the date it is provided to NMPC.

14.1.9.4.2.2 Within thirty (30) days of the Publication Date, NMPC shall hold a meeting open to all Interested Parties, at which meeting: (a) NMPC shall present and explain the Annual Update; (b) NMPC shall respond to questions from Interested Parties, to the extent such questions can be answered immediately; and (c) Interested Parties shall identify any areas of potential Preliminary Challenges, to the extent they have identified them at the time of the meeting.

14.1.9.4.2.3 Interested Parties shall have up to one hundred thirty (130) days after each annual Publication Date (unless such period is extended with the written consent of NMPC) to serve reasonable information requests on NMPC; provided, however, that the Interested Parties shall make a good faith effort to submit consolidated sets of information requests that limit the number and overlap of questions to the extent practicable. Such information requests may be directed to matters relevant to the accuracy of the Data Inputs included in the Annual Update and the conformance of those Data Inputs with the requirements of the corresponding provisions of the Formula Rate, including: (a) the reasons for any change in a Data Input from the corresponding Data Input in an earlier Annual Update; (b) the reasons for any change in a Data Input based on actual costs from the corresponding Data Input based on a cost projection in an earlier Annual Update; (c) any reports or other materials provided to fulfill the requirements of a state or federal regulatory agency that explain the basis for projected or actual costs reflected in a Data Input; and (d) the impact of any Material Accounting Change identified in the Annual Update on the charges produced by the Formula Rate.

14.1.9.4.2.4 NMPC shall make a good faith effort to respond to information requests pertaining to the Annual Update within ten (10) business days of receipt of such requests. NMPC may give reasonable priority to responding to requests that satisfy the practicable coordination and consolidation provision of Section 14.1.9.4.2.3, above. NMPC's responses to information requests shall not be entitled to protection as privileged settlement communications; provided, however, that: (a) any communications between NMPC and any Interested Party in connection with efforts to negotiate a resolution of a Preliminary Challenge or Formal Challenge shall be entitled to such protection; (b) if NMPC's response to an information request contains proprietary or trade secret information or critical energy infrastructure information, NMPC and the Interested Party or Parties receiving such information shall enter into a confidentiality agreement materially similar to the model protective order used by the FERC to protect the confidentiality of such information; and (c) nothing herein shall require NMPC to provide information that is protected by the attorney-client privilege, the attorney work product doctrine, or any other legally recognized privilege.

14.1.9.4.3 Resolution of Challenges

14.1.9.4.3.1 NMPC and the Interested Parties shall negotiate in good faith throughout the Review Period to attempt to resolve any Preliminary Challenges.

14.1.9.4.3.2 If NMPC and any Interested Party or Parties have not resolved any Preliminary Challenge to the Annual Update within the Review Period, an Interested Party shall have an additional twenty-one (21) days (unless such period is extended with the written consent of NMPC to continue efforts to resolve a

Preliminary Challenge) to present the subject matter of the Preliminary Challenge to the FERC as a Formal Challenge, which shall be served on NMPC and all other Interested Parties by electronic service on the date of such filing and posted on the NYISO's internet website, however, there shall be no need to make a Formal Challenge or to await conclusion of the time periods in Section 14.1.9.4.2 if the FERC already has initiated a proceeding to investigate the Annual Update. By no later than five (5) business days after the end of the Review Period, NMPC shall apprise Interested Parties of the resolution of all Preliminary Challenges that have been resolved and of the impact of the resolution of all such Preliminary Challenges on the Annual Update. Within an additional fifteen (15) business days, NMPC shall submit a supplement to its Informational Filing to the FERC, with electronic service upon the Interested Parties, reflecting the impact of all successfully resolved Preliminary Challenges.

14.1.9.4.3.3 Any response by NMPC to a Formal Challenge must be submitted to the FERC within twenty-one (21) days of the date of the filing of the Formal Challenge, and shall be posted on the NYISO's Internet website and served on all Interested Parties by electronic service on the date of such filing.

14.1.9.4.3.4 In any proceeding initiated by the FERC concerning the Annual Update or in response to a Formal Challenge, NMPC shall bear the burden of proving that the Data Inputs in that year's Annual Update are correct and conform to the terms of the Formula Rate and refunds or adjustments may be made, in either case with interest, to charges collected under the Formula Rate if the FERC concludes that the Data Inputs are incorrect or do not conform to the terms of the Formula Rate.

In all other respects, any such proceeding shall be governed by the rules and requirements applicable to proceedings under Section 206 of the Federal Power Act.

14.1.9.4.3.5 An Interested Party may propose that resolution of a Preliminary Challenge or Formal Challenge concerning a Material Accounting Change necessitates changes to the Formula Rate to ensure that the resulting charges, including the effect of the Material Accounting Change, are just and reasonable. If NMPC agrees to such a proposed change to the Formula Rate to resolve a Preliminary Challenge, NMPC shall file the change to the Formula Rate with the FERC for approval pursuant to Section 205 of the Federal Power Act. If NMPC does not agree to such a proposed change, the Interested Party may file the proposed change with the FERC for approval pursuant to Section 206 of the Federal Power Act concurrent with its submission of a Formal Challenge; provided that if FERC approves the proposed change, the change to the Formula Rate shall take effect as of the beginning of the Update Year during which the Section 206 filing is made, and refunds or surcharges shall be made, in either case with interest, to charges under the Formula Rate after the beginning of such Update Year to reflect the proposed change.

14.1.9.4.3.6 Nothing herein shall be deemed to limit in any way the right of NMPC to file unilaterally, pursuant to Section 205 of the Federal Power Act and the regulations thereunder, changes to NMPC's Formula Rate (including changes in connection with any incentive mechanism) or any of its Data Inputs (including, but not limited to, any fixed Data Inputs) or the right of any other party to file for such changes pursuant to Section 206 of the Federal Power Act and the regulations thereunder. All parties reserve all rights to challenge, or take any position in response to, any such filing by any other party.

14.1.9.4.4 Changes to Data Inputs

14.1.9.4.4.1 Any changes to the Data Inputs for an Annual Update, including but not limited to revisions resulting from any FERC proceeding to consider the Annual Update, or as a result of the procedures set forth herein, shall take effect as of the beginning of the Update Year and the impact of such changes shall be incorporated into the charges produced by the Formula Rate (with interest determined in accordance with 18 C.F.R. § 35.19(a)) in the Annual Update for the next effective Update Year. This mechanism shall apply in lieu of mid-Update Year adjustments and any refunds or surcharges, except that, if an error in a Data Input is discovered and agreed upon within the Review Period, the impact of such change shall be incorporated prospectively into the charges produced by the Formula Rate during the remainder of the year preceding the next effective Update Year, in which case the impact reflected in subsequent charges shall be reduced accordingly.

14.1.9.4.4.2 The impact of an error affecting a Data Input on charges collected during the Formula Rate during the five (5) years prior to the Update Year in which the error was first discovered shall be corrected by incorporating the impact of the error on the charges produced by the Formula Rate during the five-year period into the charges produced by the Formula Rate (with interest determined in accordance with 18 C.F.R. § 35.19(a)) in the Annual Update for the next effective

Update Year. Charges collected before the five-year period shall not be subject to correction.

14.2 Attachment 1 to Attachment H

14.2.1 Schedules

Table of Contents

Niagara Mohawk Power Corporation | Year | **Attachment 1**

Calculation of RR Pursuant to Attachment H, Section 14.1.9.2 | **Schedule 1**

Calculation of RR

14.1.9.2 The RR component shall equal the (a) Historical Transmission Revenue Requirement plus (b) the Forecasted Transmission Revenue Requirement plus (c) the Annual True-Up, determined in accordance with the formula below.

Historical Transmission Revenue Requirement (Historical TRR)

Line No.					
1		**Historical Transmission Revenue Requirement (Historical TRR)**			
2					
3	14.1.9.2 (a)	Historical TRR shall equal the sum of NMPC's (A) Return and Associated Income Taxes, (B) Transmission Related Depreciation Expense, (C)			
4		Transmission Related Real Estate Tax Expense, (D) Transmission Related Amortization of Investment Tax Credits,			
5		(E) Transmission Operation and Maintenance Expense, (F) Transmission Related Administrative and General Expenses, (G) Transmission			
6		Related Payroll Tax Expense, (H) Billing Adjustments, and (I) Transmission Related Bad Debt Expense less			
7		(J) Revenue Credits, and (K) Transmission Rents, all determined for the most recently ended calendar year as of the beginning of the update year.			
8			Reference		
9			*Section:*	**0**	
10		Return and Associated Income Taxes	(A)	#DIV/0!	Schedule 8, line 64
11		Transmission-Related Depreciation Expense	(B)	#DIV/0!	Schedule 9, Line 6, column 5
12		Transmission-Related Real Estate Taxes	(C)	#DIV/0!	Schedule 9, Line 12, column 5
13		Transmission - Related Investment Tax Credit	(D)	#DIV/0!	Schedule 9, Line 16, column 5
14		Transmission Operation & Maintenance Expense	(E)	$0	Schedule 9, Line 23, column 5
15		Transmission Related Administrative & General Expense	(F)	#DIV/0!	Schedule 9, Line 38, column 5
16		Transmission Related Payroll Tax Expense	(G)	$0	Schedule 9, Line 44, column 5
17		Sub-Total (sum of Lines 10 - Line 16)		#DIV/0!	
18					
19		Plus: Billing Adjustments	(H)	$0	Schedule 10, Line 1
20		Plus : Bad Debt Expenses	(I)	$0	Schedule 10, Line 4
21		Less: Revenue Credits	(J)	$0	Schedule 10, Line 7
22		Less: Transmission Rents	(K)	$0	Schedule 10, Line 14
23					
24		Total Historical Transmission Revenue Requirement (Sum of Line 17 - Line 22)		#DIV/0!	
25					

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Niagara Mohawk Power Corporation **Attachment 1**
Forecasted Transmission Revenue Requirement **Schedule 2**
Attachment H, Section 14.1.9.2

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Shading denotes an input

Line No.			Period	Reference		Source
	14.1.9.2	**FORECASTED TRANSMISSION REVENUE**				
1	(b)	**REQUIREMENTS**				
2		Forecasted TRR shall equal (1) the Forecasted Transmission Plant Additions (FTPA) multiplied by the Annual FTRRF, plus (2) the Mid-Year Trend				
3		Adjustment (MYTA), plus (3) the Tax Rate Adjustment (TRA), as shown in the following formula:				
4						
5		Forecasted TRR = (FTPA * FTRRF) + MYTA + TRA				
6						
7			Period	Reference		Source
8						
9						
10	(1)	Forecasted Transmission Plant Additions (FTPA)			$0	Workpaper 8, Section I, Line 16
11		Annual Transmission Revenue Requirement Factor (FTRRF)			#DIV/0!	Line 35
12		Sub-Total (Lines 10*11)			#DIV/0!	
13		Plus Mid-Year Trend Adjustment (2) (MYTA)			$0	Workpaper 9, line 31, variance column
14		Forecasted Transmission Revenue Requirement (Line 12 + Line 13)			**#DIV/0!**	
15						
16	(2)	**MID YEAR TREND ADJUSTMENT (MYTA)**				
17		The Mid-Year Trend Adjustment shall be the difference, whether positive or negative, between				
18		(i) the Historical TRR Component (E) based on actual data for the first three months of the Forecast Period,				
19		and (ii) the Historical TRR Component (E) based on data for the first three months of the year prior to the Forecast Period.				Workpaper 9
20						
21	(3)	**The Tax Rate Adjustment (TRA)**				
22		The Tax Rate Adjustment shall be the amount, if any, required to adjust Historical TRR Component (A) for any change in the Federal Income Tax Rate				
23		and/or the State Income Tax Rate that takes effect during the first five months of the Forecast Period.				
24						
25	14.1.9.2(c)	**ANNUAL FORECAST TRANSMISSION REVENUE REQUIREMENT FACTOR**				
26		The Annual Forecast Transmission Revenue Requirement Factor (Annual FTRRF) shall equal the sum of Historical TRR components (A) through (C),				
27		divided by the year-end balance of Transmission Plant in Service determined in accordance with Section 14.1.9.2 (a), component (A)1(a).				
28						
29						
30		Investment Return and Income Taxes		(A)	#DIV/0!	Schedule 1, Line 10
31		Depreciation Expense		(B)	#DIV/0!	Schedule 1, Line 11
32		Property Tax Expense		(C)	#DIV/0!	Schedule 1, Line 12
33		Total Expenses (Lines 30 thru 32)			#DIV/0!	
34		Transmission Plant		(a)	#DIV/0!	Schedule 6, Page 1, Line 12
35		Annual Forecast Transmission Revenue Requirement Factor (Lines 33/ Line 34)			#DIV/0!	

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Niagara Mohawk Power Corporation **Attachment 1**
Annual True-up (ATU) **Schedule 3**
Attachment H Section 14.1.9.2 (c)

Line No.			0 Year	Source:
1				
2	14.1.9.2(d)	The Annual True-Up (ATU) shall equal (1) the difference between the Actual Transmission Revenue Requirement and the Prior Year		
3		Transmission Revenue Requirement, plus (2) the difference between the Actual Scheduling, System Control and Dispatch costs		
4		and Prior Year Scheduling, System Control and Dispatch costs, plus (3) the difference between the Prior Year Billing Units and the Actual Year		
5		Billing Units multiplied by the Prior Year Unit Rate, plus (4) Interest on the net differences.		
6				
7	(1)	Revenue Requirement (RR) of rate effective July 1 of prior year	$0	Schedule 4, Line 1, Col (d)
8		Less: Annual True-up (ATU) from rate effective July 1 of prior year	$0	Schedule 4, Line 1, Col (c)
9		Prior Year Transmission Revenue Requirement	$0	Line 7 - Line 8
10				
11		Actual Transmission Revenue Requirement	#DIV/0!	Schedule 4, Line 2, Col (a)
12		Difference	#DIV/0!	Line 11 - Line 9
13				
14	(2)	Prior Year Scheduling, System Control and Dispatch costs (CCC)	$0	Schedule 4, Line 1, Col (e)
15		Actual Scheduling, System Control and Dispatch costs (CCC)	$0	Schedule 4, Line 2, Col (e)
16		Difference	$0	Line 15 - Line 14
17				
18	(3)	Prior Year Billing Units (MWH)	$0	Schedule 4, Line 1, Col (f)
19		Actual Billing Units	-	Schedule 4, Line 2, Col (f)
20		Difference	-	Line 18 - Line 19
21		Prior Year Indicative Rate	#DIV/0!	Schedule 4, Line 1, Col (g)
22		Billing Unit True-Up	#DIV/0!	Line 20 * Line 21
23				
24		Total Annual True-Up before Interest	#DIV/0!	(Line 12 + Line 16 + Line 22)
25				
26	(4)	Interest	#DIV/0!	Line 57
27				
28		Annual True-up RR Component	#DIV/0!	(Line 24 + Line 26)
29				

30 Interest Calculation per 18 CFR § 35.19a

Line No.	(1) Quarters	(2) Annual Interest Rate (a)	(3) Accrued Prin & Int. @ Beg Of Period	(4) Monthly (Over)/Under Recovery	(5) Days in Period	(6) Period Days	(7) Multiplier	(8) Accrued Prin & Int. @ End Of Period	(9) Accrued Int. @ End Of Period
35									
36	3rd QTR '07		0		92	92	1.0000	$0	$0
37	July	0.00%		#DIV/0!	31	92	1.0000	#DIV/0!	#DIV/0!
38	August	0.00%		#DIV/0!	31	61	1.0000	#DIV/0!	#DIV/0!
39	September	0.00%		#DIV/0!	30	30	1.0000	#DIV/0!	#DIV/0!
40									
41	4th QTR '07		#DIV/0!		92	92	1.0000	#DIV/0!	#DIV/0!
42	October	0.00%		#DIV/0!	31	92	1.0000	#DIV/0!	#DIV/0!
43	November	0.00%		#DIV/0!	30	61	1.0000	#DIV/0!	#DIV/0!
44	December	0.00%		#DIV/0!	31	31	1.0000	#DIV/0!	#DIV/0!
45									
46	1st QTR		#DIV/0!		91	91	1.0000	#DIV/0!	#DIV/0!

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	'08								
47	January	0.00%		#DIV/0!	31	91	1.0000	#DIV/0!	#DIV/0!
48	February	0.00%		#DIV/0!	29	60	1.0000	#DIV/0!	#DIV/0!
49	March	0.00%		#DIV/0!	31	31	1.0000	#DIV/0!	#DIV/0!
50									
51	2nd QTR '08		#DIV/0!		91	91	1.0000	#DIV/0!	#DIV/0!
52	April	0.00%		#DIV/0!	30	91	1.0000	#DIV/0!	#DIV/0!
53	May	0.00%		#DIV/0!	31	61	1.0000	#DIV/0!	#DIV/0!
54	June	0.00%		#DIV/0!	30	30	1.0000	#DIV/0!	#DIV/0!
55									
56									
57	Total (over)/under Recovery			#DIV/0!	(line 24)	#DIV/0!			#DIV/0!

(a) Interest rates shall be the interest rates as reported on the FERC Website http://www.ferc.gov/legal/acct-matts/interest-rates.asp

Attachment 1
Schedule 4

Niagara Mohawk Power Corporation Wholesale TSC Calculation Information
2008 Forecast using 2007 Historical Data and 2008 Forecast

		(a)	(b)	See Note (**) below. (c)	(d)	(e)	(f)	(g)
		Historical Transmission Revenue Requirement (Historical TRR)	Forecasted Transmission Revenue Requirement	Annual True Up (**)	Revenue Requirement (RR)	Scheduling System Control and Dispatch Costs (CCC)	Annual Billing Units (BU) MWh	Rate $/MWh (*)
1	Prior Year Rates Effective ________	-	-	-	-	-	-	#DIV/0!
2	Current Year Rates Effective July 1, 2008	#DIV/0!	#DIV/0!		#DIV/0!	-	-	#DIV/0!
3	Increase/(Decrease)							#DIV/0!
4	Percentage Increase/(Decrease)							#DIV/0!

1.) Information directly from Niagara Mohawk Prior Year Informational Filing
2.)
(a) Schedule 1, Line 24
(b) Schedule 2, Line 14
(c) Schedule 3, Line 28
(d) Attachment H, Section 14.1.9.2 The RR Component shall equal Col (a) Historical Transmission Revenue Requirement plus Col (b) the Forecasted Transmission Revenue Requirement plus Col (c) the Annual True-Up
(e) Schedule 11 - Annual Scheduling, System Control and Dispatch Costs. (i.e. the Transmission Component of control center costs) as recorded in FERC Account 561 and its associated sub-accounts from the prior calendar year excluding any NY Independent System Operating (NYISO) system control and load dispatch expenses already recovered under Schedule 1 of the NYISO Tariff.
(f) Schedule 12 - Billing Units shall be the total Niagara Mohawk load as reported to the NYISO for the calendar year prior to the Forecast Period, including the load for customers taking service under Niagara Mohawk's TSC rate. The total Niagara Mohawk load will be adjusted to exclude (i) load associated with wholesale transactions being revenue credited through the WR, CRR, SR, ECR, and Reserved components of Attachment H of the NYISO TSC rate including Niagara Mohawk's external sales, load associated with grandfathered OATT agreements, and any load related to pre-OATT grandfathered agreements; (ii) load associated with transactions being revenue credited under Historical TRR Component J; and (iii) load associated with netted station service.
(g) (Col (d) + Col (e)) / Col (f)

(*) The rate column represents the unit rate prior to adjustments; the actual rate will be determined pursuant to the applicable TSC formula rate.
(**) There was no true-up for this period. This is illustrative only.

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Niagara Mohawk Power Corporation
Allocation Factors - As calculated pursuant to Section 14.1.9.1

Attachment 1
Schedule 5

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Shading denotes an input

Line No.

Source

Definition

Line	Section	Description	Amount	Source	Notes
1	14.1.9.1 1.	**Electric Wages and Salaries Factor**	**83.5000%**		Fixed per settlement
2					
3	14.1.9.1 3.	**Transmission Wages and Salaries Allocation Factor**	**13.0000%**		Fixed per settlement
4					
5					
6					
7					
8	14.1.9.1 2.	**Gross Transmission Plant Allocation Factor**			
9		Transmission Plant in Service	#DIV/0!	Schedule 6, Page 2, Line 3, Col 5	Gross Transmission Plant Allocation Factor shall equal the total investment in
10		Plus: Transmission Related General	$0	Schedule 6, Page 2, Line 5, Col 5	Transmission Plant in Service, Transmission Related Electric General Plant,
11		Plus: Transmission Related Common	$0	Schedule 6, Page 2, Line 10, Col 5	Transmission Related Common Plant and Transmission Related Intangible Plant
12		Plus: Transmission Related Intangible Plant	$0	Schedule 6, Page 2, Line 15, Col 5	divided by Gross Electric Plant.
13		Gross Transmission Investment	#DIV/0!	Sum of Lines 9 - 13	
14					
15		Total Electric Plant		FF1 207.104	
16		Plus: Electric Common	$0	Schedule 6, Page 2, Line 10, Col 3	
17		Gross Electric Plant in Service	$0	Line 15 + Line 16	
18					
19		**Percent Allocation**	**#DIV/0!**	Line 13 / Line 17	
20					
21	14.1.9.1 4.	**Gross Electric Plant Allocation Factor**			
22					
23		Total Electric Plant in Service	$0	Line 15	Gross Electric Plant Allocation Factor shall equal
24		Plus: Electric Common Plant	$0	Schedule 6, Page 2, Line 10, Col 3	Gross Electric Plant divided by the sum of Total Gas Plant,
25		Gross Electric Plant in Service	$0	Line 23 + Line 24	Total Electric Plant, and Total Common Plant
26					
27		Total Gas Plant in Service		FF1 201.8d	
28		Total Electric Plant in Service	$0	Line 15	
29		Total Common Plant in Service	$0	Schedule 6, Page 2, Line 10, Col 1	
30		Gross Plant in Service (Gas & Electric)	-	Sum of Lines 27-Lines 29	
31					
32		**Percent Allocation**	**#DIV/0!**	Line 25 / Line 30	

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Transmission Investment Base (Part 1 of 2)
Attachment H, section 14.1.9.2

Line No.

1 14.1.9.2 (a) Transmission Investment Base
2
3 A.1. Transmission Investment Base shall be defined as (a) Transmission Plant in Service, plus (b) Transmission Related Electric General Plant, plus
4 (c) Transmission Related Common Plant, plus (d) Transmission Related Intangible Plant, plus (e) Transmission Related Plant Held for Future Use, less
5 (f) Transmission Related Depreciation Reserve, less (g) Transmission Related Accumulated Deferred Taxes, plus (h) Transmission Related
6 Regulatory Assets net of Regulatory Liabilities, plus (i) Transmission Related Prepayments, plus (j) Transmission Related Materials and Supplies,
7 plus (k) Transmission Related Cash Working Capital.
8
9

Line No.		Reference	**2007**	Reference
10		Reference	**2007**	Reference
11		*Section:*		
12	Transmission Plant in Service	(a)	#DIV/0!	Schedule 6, page 2, line 3, column 5
13	General Plant	(b)	$0	Schedule 6, page 2, line 5, column 5
14	Common Plant	(c)	$0	Schedule 6, page 2, line 10, column 5
15	Intangible Plant	(d)	$0	Schedule 6, page 2, line 15, column 5
16	Plant Held For Future Use	(e)	$0	Schedule 6, page 2, line 19, column 5
17	Total Plant (Sum of Line 12 - Line 16)		#DIV/0!	
18				
19	Accumulated Depreciation	(f)	#DIV/0!	Schedule 6, page 2, line 29, column 5
20	Accumulated Deferred Income Taxes	(g)	#DIV/0!	Schedule 7, line 6, column 5
21	Other Regulatory Assets	(h)	#DIV/0!	Schedule 7, line 11, column 5
22	Net Investment (Sum of Line 17 -Line 21)		#DIV/0!	
23				
24	Prepayments	(i)	#DIV/0!	Schedule 7, line 15, column 5
25	Materials & Supplies	(j)	#DIV/0!	Schedule 7, line 21, column 5
26	Cash Working Capital	(k)	$0	Schedule 7, line 28, column 5
27				
28	Total Investment Base (Sum of Line 22 - Line 26)		#DIV/0!	

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Transmission Investment Base (Part 1 of 2)
Attachment H Section 14.1. 9.2 (a) A. 1.

Attachment 1
Schedule 6
Page 2 of 2

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Line No.		(1) Total	(2) Allocation Factor		(3) = (1)*(2) Electric Allocated	(4) Allocation Factor		(5) = (3)*(4) Transmission Allocated	FERC Form 1/PSC Report Reference for col (1)		Definition
1	Transmission Plant								FF1 207.58g	14.1.9.2(a)A.1.(a)	Transmission Plant in Service s
									Workpaper 1,		balance of total investment in T
2	Wholesale Meter Plant							#DIV/0!	Line 45		Plant
3	Total Transmission Plant in Service (Line 1+ Line 2)							#DIV/0!			plus Wholesale Metering Invest
4											Transmission Related Electric C
5	General Plant		100.00%		$0	13.00%	(c)	$0	FF1 207.99g	14.1.9.2(a)A.1.(b)	Plant shall
6											equal the balance of investment General
7											Plant mulitplied by the Transmi Wages and
8											Salaries Allocation Factor
9											Transmission Related Common
10	Common Plant		83.50%	(a)	$0	13.00%	(c)	$0	FF1 201. 8h	14.1.9.2(a)A.1.(c)	equal Common
11											Plant multiplied by the Electric Salaries
12											Allocation Factor and further m the
13											Transmission Wages and Salari Allocation Factor.
14											Transmission Related Intangibl
15	Intangible Plant		100.00%		-	13.00%	(c)	$0	FF1 205.5g	14.1.9.2(a)A.1.(d)	equal Intangible
16											Electric Plant multiplied by the Transmission Wages and
17											Salaries Allocation Factor.
18									Workpaper		Transmission Related Plant Hel
19	Transmission Plant Held for Future Use	$0						$0	10, Line 1	14.1.9.2(a)A.1.(e)	Use shall equal
20											the balance in Plant Held for Fu associated with
21											property planned to be used for transmission service within
22											five years
23	Transmission Accumulated Depreciation										Transmission Related Deprecia
24	Transmission Accum. Depreciation							$0	FF1 219.25b	14.1.9.2(a)A.1.(f)	Reserve shall equal the balance of: (i) Transmission De
25	General Plant Accum.Depreciation		100.00%		$0	13.00%	(c)	$0	FF1 219.28b		Reserve, plus (ii)
26	Common Plant Accum Depreciation		83.50%	(a)	$0	13.00%	(c)	$0	FF1 356.1 end of year balance		the product of Electric General

27	Amortization of Other Utility Plant		100.00%	$0	13.00%	(c)	$0	FF1 200.21c	Depreciation Reserve multiplied by the Transmission Salaries
28	Wholesale Meters	#DIV/0!					#DIV/0!	Workpaper 1, Line 46	Allocation Factor, plus (iii) the Common Plant
29	Total Depreciation (Sum of line 24 - Line 28)						#DIV/0!		Depreciation Reserve multiplie Electric Wages and
30									Salaries Allocation Factor and t multiplied by the
31									Transmission Wages and Salari Allocation Factor plus (iv)
32									the product of Intangible Electr Depreciation Reserve
33									multiplied by the Transmission Salaries
34									Allocation Factor plus (v) depre reserve associated with
35									the Wholesale Metering Investr
36									

Allocation Factor Reference
(a) Schedule 5, line 1
(b) Schedule 5, line 32 - not used on this Schedule
(c) Schedule 5, line 3
(d) Schedule 5, line 19 - not used on this Schedule

Niagara Mohawk Power Corporation **Attachment 1**
Annual Revenue Requirements of Transmission Facilities **Schedule 7**
Transmission Investment Base (Part 2 of 2)

Attachment H Section 14.1.9.2 (a) A. 1.
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Line No.		(1) Total	(2) Allocation Factor	(3) = (1)*(2) Electric Allocated	(4) Allocation Factor		(5) = (3)*(4) Transmission Allocated	FERC Form 1/PSC Report Reference for col (1)		Definition
1	Transmission Accumulated Deferred Taxes									
2	Accumulated Deferred Taxes (281-282)		100.00%	$0	#DIV/0!	(d)	#DIV/0!	FF1 275.2k	14.1.9.2(a)A.1.(g)	Transmission Related Accumulated Deferred Income Taxes
3	Accumulated Deferred Taxes (283)	$0	100.00%	$0	#DIV/0!	(d)	#DIV/0!	Workpaper 2, Line 5 (link)		shall equal the electric balance of Total Accumulated Deferred
4	Accumulated Deferred Taxes (190)		100.00%	$0	#DIV/0!	(d)	#DIV/0!	FF1 234.8c		Income Taxes (FERC Accounts 190, 55,281, 282, and 283 net of
5	Accumulated Deferred Inv. Tax Cr (255)		100.00%	$0	#DIV/0!	(d)	#DIV/0!	FF1 267.8h		stranded costs), multiplied by the Gross Transmission Plant
6	Total (Sum of line 2 - Line 5)			$0			#DIV/0!			Allocation Factor.
7										
8	Other Regulatory Assets									
9	FAS 109 (Asset Account 182.3)		100.00%	$0	#DIV/0!	(d)	#DIV/0!	FF1 232 lines	14.1.9.2(a)A.1.(h)	Transmission Related Regulatory Assets shall be Regulatory

Line	Description							Source	Reference	Explanation
								2,4,9,17		
10	FAS 109 (Liability Account 254)		100.00%	$0	#DIV/0!	(d)	#DIV/0!	FF1 278.1 lines 4&21(f)		Assets net of Regulatory Liabilities multiplied by the Gross
11	Total (line 9 + Line 10)	$0		$0			#DIV/0!			Transmission Plant Allocation Factor.
12										
13	<u>Transmission Prepayments</u>							FF1 111.57c	14.1.9.2(a)A.1.(i)	Transmission Related Prepayments shall be the product of
14	Less: Prepaid State and Federal Income Tax							FF1 263 lines 2 & 9 (h)		Prepayments excluding Federal and State taxes multiplied by
15	Total Prepayments	$0	#DIV/0! (b)	#DIV/0!	#DIV/0!	(d)	#DIV/0!			the Gross Electric Plant Allocation Factor and further
16										multiplied by the Gross Transmission Plant Allocation Factor.
17										
18	<u>Transmission Material and Supplies</u>								14.1.9.2(a)A.1.(j)	Transmission Related Materials and Supplies shall equal: (i)
19	Trans. Specific O&M Materials and Supplies						$0	FF1 227.8		the balance of Materials and Supplies assigned to
20	Construction Materials and Supplies		#DIV/0! (b)	#DIV/0!	#DIV/0!	(d)	#DIV/0!	FF1 227.5		Transmission plus (ii) the product of Material and Supplies
21	Total (Line 19 + Line 20)						#DIV/0!			assigned to Construction multiplied by the Gross Electric
22										Plant Allocation Factor and further multiplied by Gross
23										Transmission Plant Allocation Factor.
24										
25	<u>Cash Working Capital</u>								14.1.9.2(a)A.1.(k)	Transmission Related Cash Working Capital shall be an
26	Operation & Maintenance Expense						$0	Schedule 9, Line 23		allowance equal to the product of: (i) 12.5% (45 days/ 360 days = 12.5%)
27							0.1250	x 45 / 360		multiplied by (ii) Transmission Operation and Maintenance Expense.
28	Total (line 26 * line 27)						$0			
29										
30										

Allocation Factor Reference
(a) Schedule 5, line 1 - not used on this Schedule
(b) Schedule 5, line 32
(c) Schedule 5, line 3 - not used on this Schedule
(d) Schedule 5, line 19

Niagara Mohawk Power Corporation **Attachment 1**
Annual Revenue Requirements of Transmission Facilities **Schedule 8**
Cost of Capital Rate

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Line No.

1 **The Cost of Capital Rate shall equal the proposed Weighted Costs of Capital plus Federal Income Taxes and State Income Taxes.**

2 The Weighted Costs of Capital will be calculated for the Transmission Investment Base using NMPC’s actual capital structure and will equal the sum of (i), (ii), and (iii) below:

3

4 (i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of NMPC’s long-term debt outstanding during the year and the sum of (a) the ratio of actual long-term debt to total capital at year-end; and

5 (b) the extent, if any, by which the ratio of NMPC's actual common equity to total capital at year-end exceeds fifty percent (50%). Long term debt shall be defined as the average of the beginning of the year and end of year balances of the following: long term debt less the unamortized

6 Discounts on Long-Term Debt less the unamortized Loss on Reacquired Debt plus unamortized Gain on Reacquired Debt. Cost to maturity of NMPC's long-term debt shall be defined as the cost of long term debt included in the debt discount expense and

7 any loss or gain on reacquired debt.

8 (ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of NMPC’s preferred stock then outstanding and the ratio of actual preferred stock to total capital at year-end;

9

10 (iii) the return on equity component shall be the product of the allowed return on equity of 11.5% and the ratio of NMPC’s actual common equity to total capital at year-end, provided that such ratio

11 shall not exceed fifty percent (50%).

12

Line No.			CAPITALIZATION	Source:	CAPITALIZATION RATIOS	COST OF CAPITAL	Source:	WEIGHTED COST OF CAPITAL	EQUITY PORTION
13									
14									
15									
16									
17	(i)	Long-Term Debt	$0	Workpaper. 6, Line 16b	#DIV/0!	#DIV/0!	Workpaper 6, Line 17c	#DIV/0!	
18	(ii)	Preferred Stock		FF1 112.3c	#DIV/0!	#DIV/0!	Workpaper 6, Line 24d	#DIV/0!	#DIV/0!
19	(iii)	Common Equity		FF1 112.16c - FF1 112.3,12,15c	#DIV/0!	11.50%		#DIV/0!	#DIV/0!
20									
21		Total Investment Return	$0		#DIV/0!			#DIV/0!	#DIV/0!

22

23

24

25

26 14.1.9.2.2.(b) Federal Income Tax shall equal

$$= \frac{\left(A. + [B / C] \times \text{Federal Income Tax Rate} \right)}{\left(1 - \text{Federal Income Tax Rate} \right)}$$

27

28

29 where A is the sum of the preferred stock component and the return on equity component, each as determined in Sections (a)(ii) and for the ROE set forth in (a)(iii) above, B is the Equity AFUDC component of Depreciation Expense for

30 Transmission Plant in Service as defined at Section 14.1.9.1.16 (FF1 117.38c), and C is the Transmission Investment Base as shown at Schedule 6, Page 1 of 2, Line 28.

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31
32 =
(#DIV/0! +($0) / #DIV/0! X)
33 (1 - 0)
34
35 = #DIV/0!
36
37
38 [14.1.](#)9.2.2.(c) State Income Tax shall equal = (A. + [B / C] + Federal Income Tax Rate) X State Income Tax Rate
39 (1 - State Income Tax Rate)
40
41 where A is the sum of the preferred stock component and the return on equity component as determined in (a)(ii) and (a)(iii) above , B is the Equity AFUDC component of Depreciation Expense for Transmission Plant in
42 Service as defined at Section 14.1.9.1.16 above, and C is the Transmission Investment Base as shown at Schedule 6, Page 1 of 2, Line 28.
43
44
45
46 = (#DIV/0! +($0) / #DIV/0! + #DIV/0!) X
47 (1 - 0)
48
49 = #DIV/0!
50
51
52
53 (a)+(b)+(c) Cost of Capital Rate = #DIV/0!
54
55
56 **14.1.9.2(a) A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate**
57
58
59

60	Transmission Investment Base	#DIV/0!	Schedule 6, page 1 of 2, Line 28
61			
62	Cost of Capital Rate	#DIV/0!	Line 53
63			
64	= Investment Return and Income Taxes	#DIV/0!	Line 60 X Line 62

Niagara Mohawk Power Corporation **Attachment 1**

Annual Revenue Requirements of Transmission Facilities **Schedule 9**

Transmission Expenses

Attachment H Section 14.1.9.2 | **0**

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Line No.		(1) Total	(2) Allocation Factor	(3) = (1)*(2) Electric Allocated	(4) Allocation Factor	(5) = (3)*(4) Transmission Allocated	FERC Form 1/ PSC Report Reference for col (1)		Definition
	Depreciation Expense								
1	Transmission Depreciation					$0	FF1 336.7f	14.1.9.2.B.	Transmission Related Depreciation Expense shall equal the sum of:
2	General Depreciation		100.0000%	$0	13.0000% (c)	$0	FF1 336.10f		(i) Depreciation Expense for Transmission Plant in Service, plus (ii)
3	Common Depreciation		83.5000% (a)	$0	13.0000% (c)	$0	FF1 356.1		the product of Electric General Plant Depreciation Expense multiplied
4	Intangible Depreciation		100.0000%	$0	13.0000% (c)	$0	FF1 336.1f		by the Transmission Wages and Salaries Allocation Factor plus (iii)
5	Wholesale Meters					#DIV/0!	Workpaper 1, Line 47		Common Plant Depreciation Expense multiplied by the Electric
6	Total (line 1+2+3+4+5)					#DIV/0!			Wages and Salaries Allocation Factor, further multiplied by the
7									Transmission Wages and Salaries Allocation Factor plus (iv)
8									Intangible Electric Plant Depreciation Expense multiplied by the
9									Transmission Wages and Salaries Factor plus (v) depreciation
10									expense associated with the Wholesale Metering Investment.
11									
12	Real Estate Taxes		100.0000%	$0	#DIV/0! (d)	#DIV/0!	FF1 263.25i	14.1.9.2.C.	Transmission Related Real Estate Tax Expense shall equal the
13									electric Real Estate Tax Expenses multiplied by the Gross
14									Transmission Plant Allocation Factor.
15									
16	Amortization of Investment Tax Credits		#DIV/0! (b)	#DIV/0!	#DIV/0! (d)	#DIV/0!	FF1 117.58c	14.1.9.2.D.	Transmission Related Amortization of Investment Tax Credits shall
17									equal the product of Amortization of Investment Tax Credits multiplied
18									by the Gross Electric Plant Allocation Factor and further multiplied by
19									the Gross Transmission Plant Allocation Factor.
20	Transmission Operation and Maintenance								
21	Operation and Maintenance					$0	FF1 321.112b	14.1.9.2.E.	Transmission Operation and Maintenance Expense shall equal
22	less Load Dispatching - #561					$0	FF1 321.84-92b		the sum of electric expenses as recorded in
23	O&M (Line 21 - Line 22)	$0				$0			FERC Account Nos. 560, 562-574.
24									
25	Transmission Administrative and General							14.1.9.2.F.	Transmission Related Administrative and General Expenses shall
26	Total Administrative and General						FF1 323.197b		equal the product of electric Administrative and General Expenses,
27	less Property Insurance (#924)						FF1 323.185b		excluding the sum of Electric Property Insurance, Electric Research and
28	less Pensions and Benefits (#926)						FF1 323.187b		Development Expense and Electric Environmental Remediation Expense,
29	less: Research and Development Expenses (#930)	$0					Workpaper 12, Line 3		and 50% of the NYPSC Regulatory Expense
30	Less: 50% of NY PSC Regulatory Expense						FF1 351.4h		multiplied by the Transmission Wages and Salaries Allocation Factor,

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31	Less: 18a Charges (Temporary Assessment						FF1 351.1.h, Workpaper 16, Line 15, Column f
32	less: Environmental Remediation Expense	$0					Workpaper 11, Line 3
33	Subtotal (Line 26-27-28-29-30-31-32)	$0	100.0000 %	$0	13.0000% (c)	$0	
34	PLUS Property Insurance alloc. using Plant Allocation	$0	100.0000 %	$0	#DIV/0! (d)	#DIV/0!	Line 27
35	PLUS Pensions and Benefits	$88,644,000	100.0000 %	$88,644,000	13.0000% (c)	$11,523,720	Workpaper 3
36	PLUS Transmission-related research and development	$0				$0	Workpaper 12
37	PLUS Transmission-related Environmental Expense	$0				$0	Workpaper 11
38	Total A&G (Line 33+34+35+36+37)	$88,644,000		$88,644,000		#DIV/0!	
39							
40	Payroll Tax Expense						
41	Federal Unemployment						FF1 263.4i
42	FICA						FF1 263.3i
43	State Unemployment						FF1 263.17i
44	Total (Line 41+42+43)	$0	100.0000 %	$0	13.0000% (b)	$0	

Allocation Factor Reference
(a) Schedule 5, line 1
(b) Schedule 5, line 32
(c) Schedule 5, line 3
(d) Schedule 5, line 19

plus the sum of Electric Property Insurance multiplied by the Gross
Transmission Plant Allocation Factor, plus transmission-specific Electric

Research and Development Expense, and transmission-specific Electric Environmental Remediation Expense. In addition, Administrative

and General Expenses shall exclude the actual Post-Employment Benefits Other than Pensions ("PBOP") included in FERC Account 926,
and shall add back in the amounts shown on Workpaper 3, page 1,
or other amount subsequently approved by FERC under Section 205 or 206.

14.1.9.2.G. Transmission Related Payroll Tax Expense shall equal the product of
electric Payroll Taxes multiplied by the Transmission Wages and Salaries Allocation Factor.

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Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Billing Adjustments, Revenue Credits, Rental Income

Attachment 1
Schedule 10

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Attachment H Section 14.1.9.2 (a)

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Line No.		(1) Total	Source		Definition
1	Billing Adjustments			14.1.9.2.H.	Billing Adjustments shall be any adjustments made in accordance with Section 14.1.9.4.4 below.
2					
3					
4	Bad Debt Expense	$0	Workpaper 4, Line 4	14.1.9.2.I.	Transmission Related Bad Debt Expense shall equal
5					Bad Debt Expense as reported in Account 904 related to NMPC's wholesale transmission billing.
6					
7	Revenue Credits	$0	Workpaper 5, Line 11	14.1.9.2.J.	Revenue Credits shall equal all Transmission revenue recorded in FERC account 456
8					excluding (a) any NMPC revenues already reflected in the WR, CRR, SR, ECR and Reserved
9					components in Attachment H of the NYISO TSC rate; (b) any revenues associated
10					with expenses that have been excluded from NMPC's revenue requirement; and (c) any
11					revenues associated with transmission service provided under this TSC rate, for which the
12					load is reflected in the calculation of BU.
13					
14	Transmission Rents	$0	Workpaper 7	14.1.9.2.K.	Transmission Rents shall equal all Transmission-related rental income recorded in FERC account 454.615
15					
16					
17				14.1.9.4(d)	
18				1	Any changes to the Data Inputs for an Annual Update, including but not limited to
19					revisions resulting from any FERC proceeding to consider the Annual Update, or
20					as a result of the procedures set forth herein, shall take effect as of the beginning
21					of the Update Year and the impact of such changes shall be incorporated into the
22					charges produced by the Formula Rate (with interest determined in accordance
23					with 18 C.F.R. § 38.19(a)) in the Annual Update for the next effective Update
24					Year. This mechanism shall apply in lieu of mid-Update Year adjustments and
25					any refunds or surcharges, except that, if an error in a Data Input is discovered
26					and agreed upon within the Review Period, the impact of such change shall be
27					incorporated prospectively into the charges produced by the Formula Rate during
28					the remainder of the year preceding the next effective Update Year, in which case
29					the impact reflected in subsequent charges shall be reduced accordingly.
30				2	The impact of an error affecting a Data Input on charges collected during the
31					Formula Rate during the five (5) years prior to the Update Year in which the error
32					was first discovered shall be corrected by incorporating the impact of the error on
33					the charges produced by the Formula Rate during the five-year period into the
34					charges produced by the Formula Rate (with interest determined in accordance
35					with 18 C.F.R. § 38.19(a)) in the Annual Update for the next effective Update
36					Year. Charges collected before the five-year period shall not be subject to correction.

(b)	List of Items excluded from the Revenue Requirement	Reason

Niagara Mohawk Power Corporation
System, Control, and Load Dispatch Expenses (CCC)
Attachment H, Section
14.1.9.5

The CCC shall equal the annual Scheduling, System Control and Dispatch Costs (i.e., the transmission component of control center costs) as recorded in FERC Account 561 and its associated sub-accounts using information from the prior calendar year, excluding NYISO system control and load dispatch expense already recovered under Schedule 1 of the NYISO Tariff.

1	**Scheduling and Dispatch Expenses**			**0**	**Source**
2					
3	Accounts	561	Load Dispatching		FF1 321.84b
4	Accounts	561.1	Reliability		FF1 321.85b
5	Accounts	561.2	Monitor and Operate Transmission System		FF1 321.86b
6	Accounts	561.3	Transmission Service and Schedule		FF1 321.87b
7	Accounts	561.4	Scheduling System Control and Dispatch		FF1 321.88b
8	Accounts	561.5	Reliability, Planning and Standards Development		FF1 321.89b
9	Accounts	561.6	Transmission Service Studies		FF1 321.90b
10	Accounts	561.7	Generation Interconnection Studies		FF1 321.91b
11	Accounts	561.8	Reliability, Planning and Standards Dev. Services		FF1 321.92b
12					
13		Total Load Dispatch Expenses (sum of Lines 3 - 11)			sum lines 3 - 11
14					
15	Less Account 561 directly recovered under Schedule 1 of the NY ISO Tariff				
16					
17	Accounts	561.4	Scheduling System Control and Dispatch		line 7
18	Accounts	561.8	Reliability, Planning and Standards Dev. Services		line 11
19		Total NYISO Schedule 1			line 17 + line 18
20					
21	Total CCC Component				line 13 - line 19

Niagara Mohawk Power Corporation

Attachment 1
Schedule 12

Billing Units - MWH
Attachment H, Section 14.1.9.6

BU shall be the total Niagara Mohawk load as reported to the NYISO for the calendar billing year prior to the Forecast Period, including the load for customers taking service under Niagara Mohawk's TSC Rate. The total Niagara Mohawk load will be adjusted to exclude (i) load associated with wholesale transactions being revenue credited through the WR, CRR, SR, ECR and Reserved components of Workpaper H of the NYISO TSC rate including Niagara Mohawk's external sales, load associated with grandfathered OATT agreements, and any load related to pre-OATT grandfathered agreements; (ii) load associated with transactions being revenue credited under Historical TRR Component J; and (iii) load associated with netted station service.

Line No.		**Dec 06- Nov 07**	**SOURCE**
1	Subzone 1		NIMO TOL (transmission owner load)
2	Subzone 2		NIMO TOL (transmission owner load)
3	Subzone 3		NIMO TOL (transmission owner load)
4	Subzone 4		NIMO TOL (transmission owner load)
5	Subzone 29		NIMO TOL (transmission owner load)
6	Subzone 31		NIMO TOL (transmission owner load)
7	Total NIMO Load report to NYISO	**0.000**	sum lines 1-6
8	LESS: All non-retail transactions		
9	Watertown		FF1 page 329.11.j
10	High Load Factor Fitzpatrick		NIMO TOL (transmission owner load)
11	Disputed Station Service		NIMO TOL (transmission owner load)
12	Other non-retail transactions		All other non-retail transactions (Sum of 300,000 series PTID's from TOL)
13	Total Deductions	**0.000**	sum lines 9 - 12
14	PLUS: TSC Load		
15	NYMPA Muni's, Misc. Villages, Jamestown (X1)**		FF1 page 329.19.j ****
16	NYPA Niagara Muni's (X2)		FF1 page 329.1.j ****
17	Total additions	**0.000**	sum lines 15 -17
18	Total Billing Units	**0.000**	line 7 - line 13 + line 18

**** In 2007, the volumes were not detailed in FERC Form 1 as shown. Detail for 2007 will be provided as requested.
On 8/31/07, the contracts for Jamestown and the NYPA Niagara Municipal expired. The previous contract was billed at demand.
The 2007 energy values for the NYPA Niagara Municipals and Jamestown are proxy numbers representing a full year of metered load for December 2006 - November 2007 as billed in January - December. These entities transitioned to the TSC rate on September 1, 2007 for billing effective October 2007. However, the full year billing load was included above.

** One of the Misc Villages at Line 15 is reported on the TOL file with one of the NYPA Niagara Muni's labeled X2.

14.2.2 NYPA Transmission Adjustment Charge ("NTAC")

14.2.2.1 Applicability of the NYPA Transmission Adjustment Charge

Each Billing Period, the ISO shall charge, and each Transmission Customer shall pay, the applicable NYPA Transmission Adjustment Charge ("NTAC") calculated in accordance with Section 14.2.2.2 of this Attachment for the first two (2) months of LBMP and in accordance with Section 14.2.2.1 of this Attachment thereafter. The NTAC shall apply to Transmission Service:

14.2.2.1.1 from one or more Interconnection Points between the NYCA and another Control Area to one or more Interconnection Points between the NYCA and another Control Area ("Wheels Through");[1] or

14.2.2.1.2 from the NYCA to one or more Interconnection Points between the NYCA and another Control Area, including transmission to deliver Energy purchased from the LBMP Market and delivered to such a Control Area Interconnection ("Exports");[1] or

14.2.2.1.3 to serve Load within the NYCA.

In summary the NTAC will be applied to all Energy Transactions, including internal New York State Loads and Wheels Through and Exports out of the NYCA at a uniform, non-discountable rate.

14.2.2.2 NTAC Calculation

14.2.2.2.1 NTAC Formula

Beginning with January 2001, NYPA shall calculate the NTAC applicable to Transmission Service to serve New York State Load, Wheels Through and Exports as follows:

NTAC = {(RR÷12) - (EA) - (IR÷12) - SR - CRN - WR - ECR - NR - NT}/(BU÷12)

Where:

RR = NYPA's Annual Transmission Revenue Requirement, which includes the Scheduling, System Control and Dispatch Costs of NYPA's control center, as approved by FERC;

EA = Monthly Net Revenues from Modified Wheeling Agreements, Facility Agreements and Third Party TWAs, and Deliveries to directly connected Transmission Customers;

SR = $SR_1 + SR_2$

SR_1 will equal the revenues from the Direct Sale by NYPA of Original Residual TCCs, and Grandfathered TCCs associated with ETAs, the expenses for which are included in NYPA's Revenue Requirement where NYPA is the Primary Owner of said TCCs.

SR_2 will equal NYPA's revenues from the Centralized TCC Auction allocated pursuant to Attachment M; this includes revenues from: (a) TCCs associated with Residual Transmission Capacity that are sold in the Centralized TCC Auction; and (b) the sale of Grandfathered TCCs associated with ETAs, if the expenses for these ETAs are included in NYPA's Revenue Requirement.

Revenue from TCCs associated with Residual Transmission Capacity includes payments for Original Residual TCCs that the Transmission Providers sell through the Centralized TCC Auction and the allocation of revenue for other TCCs sold through the Centralized TCC Auction (per the Facility Flow-Based Methodology described in Attachment N).

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[1] The NTAC shall not apply to Wheels Through or Exports scheduled with the ISO to destinations within the New

SR_1 shall be updated prior to the start of each month based on actual data for the calendar month prior to the month in which the adjustment is made (*i.e.,* January actual data will be used in February to calculate the NTAC effective in March). SR_1 for a month in which a Direct Sale is applicable shall equal the total nominal revenue that NYPA will receive under each applicable TCC sold in a Direct Sale divided by the duration of the TCC (in months).

SR_2 shall equal the Transmission Owner's share of Net Auction Revenue for all rounds of a Centralized TCC Auction, as calculated pursuant to Attachment N, divided equally among the months covered by the Centralized TCC Auction. SR_2 shall be adjusted after each Centralized TCC Auction, and the revised SR_2 shall be effective at the start of each Capability Period;

ECR = NYPA's share of Net Congestion Rents in a month, calculated pursuant to Attachment N. The computation of ECR is exclusive of any Congestion payments or Rents included in the CRN term;

CRN = Monthly Day-Ahead Congestion Rents in excess of those required to offset Congestion paid by NYPA's SENY governmental customers associated with the NYPA OATT Niagara/St. Lawrence Service reservations, net of the Initial Cost.

IR = A. The amount that NYPA will credit to its RR assessed to the SENY Load on account of the foregoing NYPA Niagara/St. Lawrence OATT reservations for SENY governmental customers. Such annual revenues will be computed as the product ("Initial Cost") of NYPA's current OATT system rate of $2.23 per kilowatt per month and the 600 MW of TCCs (or the amount of TCCs reduced by Paragraph C below). In the event NYPA sells these TCCs (or any part thereof), all revenues from these sales will offset the NTAC and the Initial Cost will be

England Control Area provided that the conditions listed in Section 2.7.2.1.4 of this Tariff are satisfied.

concomitantly reduced to reflect the net amount of Niagara/St. Lawrence OATT Reservations, if any, retained by NYPA for the SENY Load. The parties hereby agree that the revenue offset to NTAC will be the greater of the actual sale price obtained by NYPA for the TCCs sold or that computed at the applicable system rate in accordance with Paragraph B below;

B. The system rate of $2.23 per kilowatt per month will be benchmarked to the RR for NYPA transmission initially accepted by FERC ("Base Period RR") for the purposes of computing the Initial Cost. Whenever an amendment to the RR is accepted by FERC ("Amended RR"), the system rate for the purpose of computing the Initial Cost will be increased (or decreased) by the ratio of the Amended RR to the Base Period RR and the effect of Paragraph A on NTAC will be amended accordingly.

C. If prior to the Centralized TCC Auction all Grandfathered Transmission Service including NYPA's 600 MW Niagara/St. Lawrence OATT reservations held on behalf of its SENY governmental customers are found not to be feasible, then such OATT reservations will be reduced until feasibility is assured. A reduction, subject to a 200 MW cap on the total reduction as described in Attachment M, will be applied to the NYPA Niagara/St. Lawrence OATT reservations held on behalf of its SENY governmental customers.

WR = NYPA's revenues from external sales (Wheels Through and Exports) not associated with Existing Transmission Agreements in Attachment L, Tables 1 and 2 and Wheeling revenues from OATT reservations extending beyond the start-up of the ISO;

NR = NYPA Reserved_1 + NYPA Reserved_2

NYPA Reserved_1 will equal NYPA's Congestion payments for a month received pursuant to Section 20.2.3 of Attachment N of this Tariff for NYPA's RCRR TCCs. NYPA Reserved_2 will equal the value that NYPA receives for the sale of RCRR TCCs in a month, with the value for each RCRR TCC sold divided equally over the months remaining until the expiration of that RCRR TCC.

NT = The amount of actual NYPA transmission revenues minus NYPA's monthly revenue requirement.

BU = Annual Billing Units are New York State Loads and Loads associated with Wheels Through and Exports in megawatt-hours ("MWh").

The RR and SR will not include expenses for NYPA's purchase of TCCs or revenues from the sale of such purchased TCCs or from the collection of Congestion Rents for such TCCs.

The ECR, EA, CRN, WR, NR, and NT shall be updated prior to the start of each month based on actual data for the calendar month prior to the month in which the adjustment is made (*i.e.*, January actual data will be used in February to calculate the NTAC effective in March).

The NTAC shall be calculated as a $/MWh charge and shall be applied to Actual Energy Withdrawals, except for Wheels Through and Exports in which case the NTAC shall be applied to scheduled Energy quantities. The NTAC shall not apply to scheduled quantities that are Curtailed by the ISO.

14.2.2.2.2 Implementation of NTAC

At the start of LBMP implementation certain variables of the NTAC equation will not be available. For the first and second months of LBMP implementation, the only terms in the NTAC equation that will be known by NYPA are its historical Annual Transmission Revenue

Requirement (RR) and the historical Billing Units (BU), which have been approved by or filed with FERC. For these two months NYPA shall calculate the NTAC using the following equation:

NTAC = {(RR÷12) - (EA) - (IR÷12)}/(BU÷12)

SR_2 shall not be available until after the first Centralized TCC Auction. For the third month of LBMP implementation until the second month of the Capability Period corresponding to the first Centralized TCC Auction, NYPA shall recalculate the NTAC using the following equation:

NTAC = {(RR÷12) - (EA) - (IR÷12) - WR - CRN - SR_1 - ECR}/(BU÷12)

Prior to and during implementation of LBMP those current NYPA transmission customers wishing to terminate their Third Party TWAs shall notify the ISO. The ISO shall duly inform NYPA of such conversion so that NYPA can calculate revenues (EA) to be derived from Existing Transmission Wheeling Agreements.

14.2.2.2.2.1 NYPA's recovery pursuant to NTAC initially is limited to expenses and return associated with its transmission system as that system exists at the time of FERC approval of the NTAC ("base period revenue requirement"). Additions to its system may be included in the computation of NTAC only if: a) upgrades or expansions do not exceed $5 million on an annual basis; or b) such upgrades or expansions have been unanimously approved by the Transmission Owners. Notwithstanding the above, NYPA may invest in transmission facilities in excess of $5 million annually without unanimous Transmission Owners' authorization outside the NTAC recovery mechanism. In that case, NYPA cannot recover any expenses or return associated with such additions under NTAC and any TCC or other revenues associated with such additions will not be considered NYPA transmission revenue for purposes of developing the NTAC nor be used as a credit in the allocation of NTAC to transmission system users.

14.2.2.2.3 Filing and Posting of NTAC

NYPA shall coordinate with the ISO to update certain components of the NTAC formula on a monthly or Capability Period basis. NYPA may update the NTAC calculation to change the RR, initially approved by FERC, and such updates shall be submitted to FERC. An integral part of the agreement between the other Transmission Owners and NYPA is NYPA's consent to the submission of its RR for FERC review and approval on the same basis and subject to the same standards as the Revenue Requirements of the Investor-Owned Transmission Owners. Each January, beginning with January 2001, the ISO shall inform NYPA of the prior year's actual New York internal Load requirements and the actual Wheels Through and Exports and shall post this information on the OASIS. NYPA shall change the BU component of the NTAC formula to reflect the prior calendar year's information, with such change to take effect beginning with the March NTAC of the current year. NYPA will calculate the monthly NTAC and provide this information to the ISO by no later than the fourteenth day of each month, for posting on the OASIS to become effective on the first day of the next calendar month. Beginning with LBMP implementation, the monthly NTAC shall be posted on the OASIS by the ISO no later than the fifteenth day of each month to become effective on the first day of the next calendar month.

14.2.2.3 NTAC Calculation Information

NYPA's Annual Transmission Revenue Requirement (RR), for facilities owned as of January 31, 1997, and Annual Billing Units (BU) of the NTAC are:

RR = $165,449,297

BU = 133,386,541MWh

NYPA's Annual Transmission Revenue Requirement is subject to Commission approval in accordance with Section 14.2.3 of this Attachment.

14.2.2.4 Billing

The New York State Loads, Wheels Through, and Exports will be billed based on the product of: (i) the NTAC; and (ii) the Customer's billing units for the Billing Period. The billing units will be based on the metered energy for all Transactions to supply Load in the NYCA during the Billing Period, and hourly Energy schedules for the Billing Period for all Wheels Through and Exports.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) ☐ An Original (2) ☒ A Resubmission	09/16/2011	End of 2010/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	10,213,935,917	9,775,017,649
3	Construction Work in Progress (107)	200-201	230,792,266	209,726,174
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		10,444,728,183	9,984,743,823
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	3,163,857,114	3,051,901,859
6	Net Utility Plant (Enter Total of line 4 less 5)		7,280,871,069	6,932,841,964
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		7,280,871,069	6,932,841,964
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		11,174,213	10,965,343
19	(Less) Accum. Prov. for Depr. and Amort. (122)		750,193	811,363
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	5,415,013	5,519,424
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		2,679,852	2,090,001
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		24,309,215	25,573,193
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		50,430,841	1,750
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		93,258,941	43,358,348
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		10,572,861	8,338,978
36	Special Deposits (132-134)		32,351,860	30,607,937
37	Working Fund (135)		64,000	64,000
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		72,976	72,976
40	Customer Accounts Receivable (142)		530,883,181	462,447,255
41	Other Accounts Receivable (143)		26,310,475	31,894,296
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		191,979,368	173,735,300
43	Notes Receivable from Associated Companies (145)		0	78,350,000
44	Accounts Receivable from Assoc. Companies (146)		15,690,063	13,340,933
45	Fuel Stock (151)	227	0	0
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	32,612,163	31,396,604
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) ☐ An Original (2) ☒ A Resubmission	09/16/2011	End of 2010/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	413,923	141,012
55	Gas Stored Underground - Current (164.1)		55,790,086	63,998,984
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		58,577,794	384,221,020
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		749	14,916
60	Rents Receivable (172)		4,951,641	10,409,650
61	Accrued Utility Revenues (173)		162,268,000	157,195,000
62	Miscellaneous Current and Accrued Assets (174)		2,760,411	1,299,032
63	Derivative Instrument Assets (175)		1,446,990	3,636,445
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		561,592	96,000
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		743,349,397	1,103,789,738
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		23,882,297	25,982,764
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	2,631,642,271	3,315,956,477
73	Prelim. Survey and Investigation Charges (Electric) (183)		7,793,403	10,298,662
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		544	544
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		2,187,942	2,019,903
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	4,421,705	2,721,255
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		25,339,795	32,019,130
82	Accumulated Deferred Income Taxes (190)	234	713,010,876	1,049,954,541
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		3,408,278,833	4,438,953,276
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		11,525,756,240	12,518,943,326

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) ☐ An Original (2) ☒ A Resubmission	09/16/2011	end of 2010/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	187,364,863	187,364,863
3	Preferred Stock Issued (204)	250-251	28,984,700	28,984,700
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	2,913,140,406	2,913,140,406
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	883,594,219	943,518,910
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-1,842,210	-1,737,799
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-1,191,714	-1,884,145
16	Total Proprietary Capital (lines 2 through 15)		4,010,050,264	4,069,386,935
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,486,305,000	1,486,305,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	500,000,000	850,000,000
21	Other Long-Term Debt (224)	256-257	413,760,000	413,760,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		415,359	477,312
24	Total Long-Term Debt (lines 18 through 23)		2,399,649,641	2,749,587,688
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		1,190,438	1,785,677
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		4,784,570	4,514,570
29	Accumulated Provision for Pensions and Benefits (228.3)		0	0
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		11,038,291	10,448,955
35	Total Other Noncurrent Liabilities (lines 26 through 34)		17,013,299	16,749,202
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		255,038,553	243,436,478
39	Notes Payable to Associated Companies (233)		1,404,064	0
40	Accounts Payable to Associated Companies (234)		45,091,116	92,563,055
41	Customer Deposits (235)		35,895,856	35,780,394
42	Taxes Accrued (236)	262-263	108,356,828	120,837,580
43	Interest Accrued (237)		41,053,589	48,824,295
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) ☐ An Original (2) ☒ A Resubmission	09/16/2011	end of 2010/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		11,691	1,508,421
48	Miscellaneous Current and Accrued Liabilities (242)		100,603,947	103,230,839
49	Obligations Under Capital Leases-Current (243)		595,242	595,242
50	Derivative Instrument Liabilities (244)		35,176,345	53,556,040
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		18,044,115	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		641,273,346	700,332,344
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		4,310,097	4,161,224
57	Accumulated Deferred Investment Tax Credits (255)	266-267	25,399,133	27,063,097
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	1,427,728,833	1,642,148,960
60	Other Regulatory Liabilities (254)	278	607,574,059	585,233,843
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		1,550,844,579	1,436,265,213
64	Accum. Deferred Income Taxes-Other (283)		841,914,989	1,288,014,800
65	Total Deferred Credits (lines 56 through 64)		4,457,771,690	4,982,887,157
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		11,525,758,240	12,518,943,326

Name of Respondent Niagara Mohawk Power Corporation	This Report Is: (1) ☐ An Original (2) ☒ A Resubmission	Date of Report 09/16/2011	Year/Period of Report End of 2010/Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

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NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1. Significant Accounting Policies

A. Nature of Operations

Niagara Mohawk Power Corporation (the "Company", "we", "us", and "our") was organized in 1937 under the laws of New York State and is engaged principally in the regulated energy delivery business in New York State. The Company provides electric service to approximately 1.6 million electric customers in the areas of eastern, central, northern and western New York and sells, distributes and transports natural gas to approximately 0.6 million gas customers in areas of central, northern and eastern New York.

The Company is a wholly-owned subsidiary of Niagara Mohawk Holdings, Inc., which is wholly-owned by National Grid USA ("National Grid"), a utility holding company with regulated subsidiaries engaged in the generation of electricity and the transmission, distribution, and sale of both natural gas and electricity in New England and New York State. National Grid is a wholly-owned subsidiary of National Grid plc, a public limited company incorporated under the laws of England and Wales.

B. Basis of Presentation

The Company's financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission ("FERC"), (see note 2 – Rates and Regulatory) as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than generally accepted accounting principles in the United States of America ("GAAP").

The accounts of the Company are maintained in accordance with Uniform System of Accounts prescribed by regulatory bodies having jurisdiction, primarily the New York State Public Service Commission ("NYPSC") and FERC.

The preparation of financial statements in conformity with FERC requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

C. Revenue Recognition

The Company bills its customers on a monthly cycle basis at approved tariffs based on energy delivered, a minimum customer service charge, and, in some instances, their demand on the electric system. Revenues are determined based on these bills plus an estimate for unbilled energy delivered between the cycle meter read date and the end of the accounting period. These amounts are billed to customers in the next billing cycle following the December month end. Total unbilled revenues at December 31, 2010 and 2009 were approximately $162 million and $157 million, respectively.

As approved by the NYPSC, the Company is allowed to pass through for recovery commodity-related costs. Additionally, a transmission revenue adjustment mechanism is in place that reconciles actual and forecast wholesale transmission revenue for pass back to, or recovery from, retail customers. The commodity adjustment clause and the transmission revenue adjustment mechanism have remained in effect under the Merger Rate Plan ("MRP") which became effective on January 31, 2002.

The Company's gas utility tariffs contain weather normalization adjustments that largely offset shortfalls or excesses of firm net revenues (revenues less gas costs and revenue taxes) during a heating season due to variations from normal weather. Revenues are adjusted each month the clause is in effect.

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D. Property, Plant and Equipment

Property, plant, and equipment are stated at original cost. The cost of additions to utility plant and replacements of retirement units of property are capitalized. Costs include direct material, labor, overhead and allowance for funds used during construction ("AFUDC"). Replacement of minor items of utility plant and the cost of current repairs and maintenance are charged to expense. Whenever utility plant is retired, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation.

AFUDC

The Company capitalizes AFUDC as part of construction costs. AFUDC represents the composite interest and equity costs of capital funds used to finance that portion of construction costs not yet eligible for inclusion in rate base. AFUDC is capitalized in "Net Utility Plant" with offsetting credits to "Other Interest Expense" and "Other Income and (Deductions)." This method is in accordance with established rate-making practices under which our utility subsidiaries are permitted to earn a return on, and the recovery of, prudently incurred capital costs through their ultimate inclusion in rate base and in the provision for depreciation. AFUDC rates vary by company and regulatory jurisdiction. Capitalized interest for the years ended December 31, 2010 and 2009 was $1.3 million and $0.8 million, respectively, and is reflected as a reduction to interest expense.

The Company's repair and maintenance costs are expensed as incurred unless they represent replacement of property to be capitalized.

Depreciation

The Company's depreciation is computed on the straight-line basis using the average service lives. The depreciation rates are based on periodic studies of the estimated useful lives of the assets and the estimated cost to remove them, net of salvage value. The Company performs depreciation studies to determine service lives of classes of property and adjusts the depreciation rates when necessary.

The provisions for depreciation, as a percentage of weighted average depreciable property, and the weighted average service life, in years are presented in the table below:

	December 31, 2010		December 31, 2009	
	Provision	**Service Life**	Provision	Service Life
Asset Category:				
Electric	**2.7%**	**36**	2.8%	36
Gas	**2.3%**	**44**	2.3%	44
Common	**4.2%**	**24**	4.3%	23

E. Goodwill

In accordance with current accounting guidance for goodwill and other intangible assets, the Company tests goodwill for impairment on an annual basis and on an interim basis when certain events or circumstances exist. Goodwill impairment is determined by comparing the estimated fair value of a reporting unit with its respective book value. If the estimated fair value exceeds the book value, goodwill at the reporting unit level is not deemed to be impaired. If the estimated fair value is below book value, however, further analysis is required to determine the amount of the impairment. Additionally, if the forecasted returns utilized in the analysis are not achieved, an impairment of goodwill may result. For example, within our calculation of forecasted returns, we have made certain assumptions around the amount of pension and environmental costs to be recovered in future periods. Should we not benefit from improved rate relief in these areas, the result could be a reduction in fair value of the Company, which in turn could give rise to an impairment of goodwill.

The Company utilizes a discounted cash flow approach incorporating its most recent business plan forecasts together with a projected terminal year calculation in the performance of the annual goodwill impairment test. Critical assumptions used in the Company's analysis include a discount rate of 6% and a terminal year growth rate of 3% based upon expected long-term average growth rates. Our forecasts assume long-term recovery and rate of returns that are in line with historical levels within the utility industry. The resulting fair value of the annual analysis determined that no adjustment of the goodwill carrying value was required.

F. Cash and Cash Equivalents

The Company classifies short-term investments that are highly liquid and have maturities of three months or less at the date of purchase as cash equivalents. These short-term investments are carried at cost which approximates fair value.

G. Restricted Cash

Restricted cash consists of health care claims deposits, New York State Department of Conservation securitization for certain site cleanup, mortgage lien release deposits, worker's compensation premium deposits and collateral for derivative transactions.

H. Income and Excise Taxes

Federal and state income taxes are recorded under the current accounting provisions for the accounting and reporting of income taxes. Income taxes have been computed utilizing the asset and liability approach that requires the recognition of deferred tax assets and liabilities for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. Deferred investment tax credits are amortized over the useful life of the underlying property. Additionally, the Company follows the current accounting guidance relating to uncertainty in income taxes which applies to all income tax positions reflected on the Company's Balance Sheets that have been included in previous tax returns or are expected to be included in future tax returns.

We report our collections and payments of excise taxes on a gross basis. Revenues include the collection of excise taxes, while operating taxes include the related expenses. For the years ended December 31, 2010 and 2009, excise taxes paid were $42 million and $35 million, respectively.

I. Derivatives

We employ derivative instruments to hedge a portion of our exposure to commodity price risk. Whenever hedge positions are in effect, we are exposed to credit risk in the event of non-performance by counter-parties to derivative contracts, as well as non-performance by the counter-parties of the transactions against which they are hedged. We believe that the credit risk related to the futures, options and swap instruments is no greater than that associated with the primary commodity contracts which they hedge.

Firm Sales Derivatives Instruments
We use derivative financial instruments to reduce cash flow variability associated with the purchase price for a portion of future natural gas and electricity purchases associated with our gas and electric distribution operations. Our strategy is to minimize fluctuations in firm gas and electricity sales prices to our regulated customers. The accounting for these derivative instruments follows current accounting guidance for rate regulated enterprises. Therefore, the fair value of these derivatives is recorded as current or deferred assets and liabilities, with offsetting positions recorded as regulatory assets and regulatory liabilities on the Balance Sheets. Gains or losses on the settlement of these contracts are initially deferred and then refunded to or collected from our firm gas sales customers consistent with regulatory requirements.

Physically-Settled Commodity Derivative Instruments
Certain of our contracts for the physical purchase of natural gas and certain power supply contracts were assessed as no longer being exempt as normal purchases. As such, these contracts are recorded on the Balance Sheets at fair market value. However, since such contracts were executed for regulated utility customers, and pursuant to the requirements for rate regulated enterprises, changes in the fair market value of these contracts are recorded as a regulatory asset or regulatory liability on the Balance Sheets.

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J. Comprehensive Income (Loss)

Comprehensive income (loss) is the change in the equity of a company, not including those changes that result from shareholder transactions. While the primary component of comprehensive income (loss) is reported net income or loss, the other primary component of comprehensive income (loss) is unrealized gains and losses associated with certain investments held as available for sale. (See Note 10. Accumulated Other Comprehensive Income (Loss))

K. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The following is the fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

Level 1 — quoted prices (unadjusted) in active markets for identical assets or liabilities that a company has the ability to access as of the reporting date. Derivative assets and liabilities utilizing Level 1 inputs include active exchange-based derivatives (e.g. natural gas futures traded on the New York Mercantile Exchange ("NYMEX")).

Level 2 — inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data. Derivative assets and liabilities utilizing Level 2 inputs include non-exchanged-based financial contracts (e.g. over-the-counter ("OTC") gas financial swap) and standard North American Energy Standards Board physical gas supply contracts.

Level 3 — unobservable inputs, such as internally-developed forward curves and pricing models for the asset or liability due to little or no market activity for the asset or liability with low correlation to observable market inputs. Derivative assets and liabilities utilizing Level 3 inputs are mainly customized physical gas contracts, certain financial contracts, as well as some standard physical gas supply contracts and over the counter financial options contracts.

L. Employee Benefits

In March 31, 2007, the Company adopted certain accounting guidance that requires employers to fully recognize all postretirement plans' funded status on the Balance Sheets as a net liability or asset and required an offsetting adjustment to accumulated other comprehensive income in shareholders' equity upon implementation. Consistent with past practice and as required by the current accounting guidance, the Company values its pension and other postretirement assets using the year-end market value of those assets. Benefit obligations are also measured at year-end. (See Note 3. Employee Benefits for additional details on the Company's pension and other postretirement plans.)

M. Reclassifications

Certain amounts from prior years have been reclassified in the accompanying financial statements to conform to the current year presentation. The Company has also made other immaterial adjustments to conform certain amounts from prior years to the current year presentation.

N. Inventory

Inventory is stated primarily at the lower of cost or market value under the average cost method. The company's write-down policy is to write-off obsolete inventory.

O. Power Purchase Agreements

The Company accounts for its power purchase agreements, which are not deemed to be derivatives or leases, as executory contracts. The Company assesses several factors in determining how to account for its power purchase contracts. These factors include: the term of the contract compared to the economic useful life of the facility generating the electricity; the involvement, if any, that the Company has in operating the facility; the amount of any fixed payments the Company must make, even if the facility does not generate

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electricity; and the level of control the Company has over the amount of electricity generated by the facility, and who bears the risk in the event the facility is unable to generate.

P. Recent Accounting Pronouncements

In December 2010, the FASB issued updated guidelines that addressed the diversity in practice about the interpretation of the pro forma revenue and earnings disclosure requirements for business combinations. This update specifies that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. The amendments in the updated guidelines are effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. Early adoption is permitted. The Company believes that adoption of these guidelines will not impact its financial condition, result of operations or cash flows.

In March 2010, the Patient Protection and Affordable Care Act and the Healthcare and Education Reconciliation Act of 2010 were passed in the United States Congress and signed into law. These laws eliminate the tax exempt status of drug subsidies provided to companies under Medicare Part D after December 31, 2012. In April 2010, the FASB issued the accounting guidance related to the Patient Protection and Affordable Care Act which requires the measurement of current and deferred tax liabilities and assets to be based on provisions of enacted tax law. As a result of this new legislation, the Company recorded a noncash charge in the first quarter of the current calendar year to reflect additional deferred income tax expense.

In March 2010, the FASB issued updated guidance that provides for scope exceptions applicable to financial instrument contracts with embedded credit derivative features. This FASB guidance is effective for financial statements issued for interim periods beginning after June 15, 2010. On an ongoing basis, the Company evaluates new and existing transactions and agreements to determine whether they are derivatives, or have provisions that meet the characteristics of embedded derivatives. Those transactions designated for any of the elective accounting treatments for derivatives must meet specific, restrictive criteria, both at the time of designation and on an ongoing basis. None of the financial instrument contracts or credit agreements the Company has entered were identified and designated as meeting the criteria for derivative or embedded derivative treatment. The adoption of this guidance did not have an impact on the Company's financial position, results of operations or cash flows.

In February 2010, the FASB issued an amendment to certain recognition and disclosure requirements for events that occur after the balance sheet date but before the financial statements are issued or are available to be issued. The amendment applies to both issued financial statements and financial statements revised as a result of either a correction of an error or retrospective application of GAAP. The new provisions require nonpublic entities to disclose both the date that the financial statements were issued, or available to be issued, and the date the revised financial statements were issued or available to be issued. The amendment is effective for interim or annual periods ending after June 15, 2010. The adoption of this guidance did not have an impact on the Company's financial position, results of operations or cash flows.

In January 2010, the FASB issued an amendment to the accounting guidance for fair value measurements that will provide for additional disclosures about (a) the different classes of assets and liabilities measured at fair value, (b) the valuation techniques and inputs used, (c) the activity in Level 3 fair value measurements, and (d) the transfers between Levels 1, 2, and 3. This FASB guidance is effective for financial statements issued for interim and annual periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements in the roll forward of activity in Level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. The provisions of this guidance have been adopted by the Company and have been applied to its financial statements for the period ending December 31, 2010.

In the preceding twelve months, the FASB and other authoritative bodies have issued numerous updates to GAAP. The Company has evaluated these guidelines and has deemed them as not applicable based on its nature of operations.

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Note 2. Rates and Regulatory

The Company's accounting records are maintained in accordance with the Uniform System of Accounts prescribed by the FERC. The financial statements reflect the ratemaking policies and actions of the NYPSC in conformity with GAAP for rate-regulated enterprises.

The Company applies the current accounting guidance for rate-regulated enterprises. The guidance recognizes the ability of regulators, through the ratemaking process, to create future economic benefits and obligations affecting rate-regulated companies. Accordingly, the Company records these future economic benefits and obligations as regulatory assets and regulatory liabilities.

In the event the Company determines that its net regulatory assets are not probable of recovery, it would no longer apply the principles of the current accounting guidance for rate regulated enterprises and would be required to record an after-tax, non-cash charge against income for any remaining regulatory assets and liabilities. In such an event, the resulting charge would be material to the Company's reported financial condition and results of operations. Management continues to believe that rates are based on the Company's incurred costs and investment levels and therefore should continue to apply the current accounting guidance for rate regulated enterprises.

The following table details regulatory assets and liabilities summarized in the Company's financial statements:

At December 31 *(in thousands of dollars)*	**2010**	2009
Regulatory liabilities included in other accrued expenses:		
Rate adjustment mechanisms	**$ (3,818)**	$ (18,824)
Total current regulatory assets, net	**(3,818)**	(18,824)
Regulatory assets:		
Merger rate plan stranded costs	**595,044**	1,112,793
Regulatory tax asset	**120,754**	132,251
Deferred environmental restoration costs	**539,580**	537,821
Pension and postretirement benefit plans	**1,389,765**	1,410,569
Other	**(13,501)**	122,522
Total non-current regulatory assets	**2,631,642**	3,315,956
Regulatory liabilities:		
Stranded costs and CTC related	**(82,688)**	(82,636)
Postretirement benefit	**(25,552)**	(25,552)
Medicare Act tax benefit deferral	**6,359**	(73,398)
Economic development fund	**(37,492)**	(38,084)
Unbilled gas revenue	**(19,044)**	(18,799)
Environmental insurance proceeds	**(4,741)**	(4,741)
Other	**(436,024)**	(342,024)
Total non-current regulatory liabilities	**(599,182)**	(585,234)
Net regulatory assets	**$ 2,028,642**	$ 2,711,898

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The following are descriptions of major types of regulatory assets and liabilities:

MRP Stranded Costs

Under the MRP, a regulatory asset was established that included the costs of the Master Restructuring Agreement ("MRA"), the cost of any additional Independent Power Producer ("IPP") contract buyouts and the deferred loss on the sale of the Company's generation assets. The MRA represents the cost to terminate, restate or amend IPP contracts. The Company is also permitted to defer and amortize the cost of any additional IPP contract buyouts. Since February 1, 2002, the MRP stranded cost regulatory asset has been amortized over ten years, consistent with projected recovery through rates. However, as discussed below regarding the Company's general rate case filed January 29, 2010, the Company proposed to extend the amortization period of stranded costs an additional three years in order to mitigate the impact of its proposed increase in transmission and distribution revenue to provide, in total, that delivery revenue would remain at the level reflected in the MRP. The NYPSC did not approve the Company's proposal and therefore the MRP stranded cost regulatory asset will be fully amortized by December 31, 2011.

Regulatory Tax Asset

The regulatory tax asset represents the expected future recovery from ratepayers of the tax consequences of temporary differences between the recorded book basis and the tax basis of assets and liabilities. This amount is primarily timing differences related to depreciation. These amounts are recovered and amortized as the related temporary differences reverse.

Deferred Environmental Restoration Costs

This regulatory asset represents deferred costs associated with the Company's share of the estimated costs to investigate and perform certain remediation activities at hazardous waste sites with which it may be associated as compared to the allowance in base rates pertaining to this cost. The Company's rate plans provide for specific rate allowances for these costs, with variances deferred for future recovery or pass-back to customers. The Company believes future costs, beyond the expiration of current rate plans, will continue to be recovered through rates.

Pension and Postretirement Benefit Plans

Costs of the Company's pension and postretirement benefits plans over amounts reflected in rates are deferred to a regulatory asset to be recovered in a future period. This regulatory asset includes the deferral of the fair value adjustments to the pension and postretirement benefit plans other than pensions ("PBOPs") (the Plans) as of the January 30, 2002 acquisition of the Company by National Grid. This deferral totaled $440 million at acquisition and is being amortized on a straight-line basis over the 10 years of the MRP. The Company has also recorded a regulatory asset as an offset to its yearly adjustment to the Plans recorded liability in the amounts of $665 million and $696 million at December 31, 2010 and December 31, 2009, respectively.

Cost of Removal Reserve and Asset Retirement Obligations

The Company adheres to the current accounting guidance relating to asset retirement obligations associated with tangible long-lived assets. Asset retirement obligations arising from legal obligations amounted to $11 million and $10 million at December 31, 2010 and 2009, respectively. Under the Company's current and prior rate plans, it has collected through rates an implied cost of removal for its plant assets. This cost of removal collected from customers differs from the accounting guidance definition of an asset retirement obligation in that these collections are for costs to remove an asset when it is no longer deemed usable (i.e. broken or obsolete) and not necessarily from a legal obligation. These collections have been recorded to accumulated depreciation to reflect future use. The Company estimates it has collected over time approximately $415 million and $400 million for the cost of removal through December 31, 2010 and 2009, respectively.

The regulatory assets above also reflect $7.4 million the Company has on energy efficiency programs in excess of the current rate agreements. The Company believes these amounts will be recovered pursuant to future rate filings.

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Rate Matters

Major Rate Proceedings: On August 3, 2009, the Company submitted a filing in compliance with the NYPSC's Opinion No. 01-6, Opinion and Order Authorizing Merger and Adopting Rate Plan, issued and effective December 3, 2001 in Case No. 01-M-0075 (Fourth Competitive Transition charges ("CTC") Reset Filing). The Fourth CTC Reset Filing complies with the Company's obligations under the MRP to: (i) reset its CTC in retail delivery rates to reflect changes in the forecast of commodity prices for the coming two years and (ii) adjust delivery rates to reflect estimated deferral recoveries through December 2011 because the deferral account balance was estimated to exceed $100 million as of June 30, 2009. On December 21, 2009, the NYPSC issued its order on this matter and directed, among other things, that there would be no change in the deferral recoveries currently reflected in customer rates because of the difficult economic circumstances faced by customers and because the deferral balances had not been fully audited.

On October 22, 2007, the Company made a compliance filing with the NYPSC regarding the implementation of the Follow-on Merger Credit associated with the acquisition by National Grid plc of KeySpan Corporation ("KeySpan") in August 2007. In its compliance filing, the Company calculated the share of the KeySpan Follow-on Merger savings allocable to the Company for the period from September 2007 through December 2011 to be approximately $40 million. The Company subsequently agreed, in its comments filed in the Third CTC Reset proceeding on October 31, 2007, to lower rates submitted in its August 1, 2007 CTC Reset filing to reflect a proposal by the parties in that proceeding to apply the KeySpan Follow-on Merger Credit to the Company's electric customers over a two year period instead of over the four remaining years of the MRP, which was approved by the NYPSC in December 2007. On May 29, 2008, the NYPSC issued its decision with respect to the Company's October 22, 2007 compliance filing rejecting the Company's proposed calculation and requiring a Follow-on Merger Credit of $52 million for the August 24, 2007 through December 2011 period. On June 30, 2008, the Company filed a petition for rehearing of the May 29, 2008 order from the NYPSC. The NYPSC denied the Company's rehearing petition in an order dated February 24, 2009, holding that its May 2008 order was consistent with the explicit language of the MRP.

The NYPSC further issued a notice on June 25, 2008 seeking additional comments on the Staff's Paper setting forth two Follow-on Merger savings issues that were not addressed in the compliance filing of October 22, 2007. In the notice, the NYPSC asked for comments on Staff's Paper and its two issues that called for the Company to credit an additional $35 million of synergy savings to electric and gas customers. Multiple Intervenors (a consortium of large commercial and industrial customers) filed comments in favor of a larger credit. Following settlement negotiations, on January 5, 2010, the Company, Staff, and Multiple Intervenors filed a joint proposal that provided for an incremental Follow-On Merger Credit of approximately $4 million, with $3.7 million going to the Company's Electric Deferred Account and $0.3 million plus carrying charges going to the Gas Contingency Reserve Account. On July 16, 2010, the NYPSC adopted the terms of the joint proposal and directed the Company to record the proposed credits accordingly. The deferred gas credit will be in the Company's next general gas rate proceeding.

Stimulus filing in connection with American Recovery and Reinvestment Act of 2009 ("ARRA"): On October 27, 2009, the Company learned that it was not successful in receiving any stimulus funding under its Smart Grid Investment Grant ("SGIG") application filed with the U.S. Department of Energy ("DOE") as part of National Grid's proposed Smart Grid programs. The Company is a partner in the New York Independent System Operator ("NYISO")–sponsored Phasor Measurement Unit ("PMU") Project and Capacitor Bank Project, and both of those projects received SGIG grants. Additionally, the Company is a partner in the Premium Power Corporation–sponsored Energy Storage Demonstration Project, which is a recipient of an award from the DOE under the Smart Grid Demonstration ("SGD") grant program. The Company is allowed to recover from customers the balance of the cost not covered by the SGIG grant in implementing the PMU Project and Capacitor Bank Project and the SGD grant in implementing the Premium Power Project. On April 1, 2010, the Company filed with the NYPSC a proposed tariff provision for the recovery of these projects through a surcharge mechanism. The NYPSC ruled that the Company was to defer the cost of these projects and include recovery of them in the next general rate case. Consequently, the Company withdrew its proposed tariff for the surcharge.

On January 15, 2010 the Company filed a modified Smart Grid Program ("Smart Program") for NYPSC approval which modified the Company's previous July 2, 2009 filing by reducing the program scope and size to an approximate $123 million investment, inclusive of the Company's contribution to the aforementioned NYISO–sponsored projects and the Premium Power Energy Storage Demonstration Project. The Smart Program proposed a Smart Grid Spine and four Clean Energy Modules to be deployed in the Syracuse, New York area, as well as developmental work in the Company's Smart Technology Center, a workforce training component, the NYISO-sponsored projects, and the Premium Power Project. The NYPSC has delayed ruling on the Company's proposed Smart Program upon completion of its review and development of regulatory policies for the encouragement of implementation of smart grid technologies. On February 11, 2011, the Company filed a letter with the NYPSC withdrawing its January 14, 2010 Smart Program proposal for a number of reasons including the fact that the NYPSC has opened a new smart grid proceeding to establish regulatory policies to guide smart grid development in New York. In addition, it has been over a year since the Company filed its Smart Program proposal and there have been significant developments in and experience gained with smart grid technologies during that time. Finally, Governor Cuomo is revisiting the state's energy plan which may influence the supply, delivery and/or use of electricity in New York. In that same letter to the NYPSC, the Company provided notice that it would not be proceeding with the Premium Power Energy Storage Demonstration Project but remained committed to continuing its participation in the NYISO-sponsored PMU and Capacitor Bank Projects.

On April 13, 2010 National Grid was awarded $2.18 million in DOE funding to develop its proposed smart grid work force training program. This DOE funding will be used to design and develop comprehensive training materials for Massachusetts and New York smart grid programs.

On July 16, 2010, the NYPSC initiated a new proceeding to focus attention on a longer term vision for the electric grid and a corresponding strategic plan now that the urgency of responding to ARRA funding opportunities has passed. The NYPSC has expressed concerns with layering smart grid expenditures on top of the expanding electric utility capital budgets. The purpose of this inquiry is to determine to what extent further development of regulatory policies is needed to encourage electric utilities to develop smart grid systems that will integrate new technologies while optimizing the efficient use of facilities and resources and maintaining equitable rates for electric customers. The NYPSC has posed a set of policy questions for certain utilities to which the Company filed its response on September 17, 2010 and reply comments on October 15, 2010.

Service Quality Penalties: In connection with the NYPSC order in the Company's recent electric rate case (see below) and the Gas Rate Plan Joint Proposal (see below), the Company is subject to maintaining certain reliability and service quality standards. Reliability and customer service measures focus on ten categories including electric reliability measures related to outages (System Average Interruption Frequency Index and Customer Average Interruption Duration Index), estimating, and standardized interconnection requirements ("SIR") and customer measures related to NYPSC complaint rate, residential and business customer satisfaction, meter reads, customer call response times, and administration of the AffordAbility Program. If a prescribed standard is not satisfied, the Company may incur a penalty, with the penalty amount applied as a credit or refund to customers. The total amount of pre-tax penalties that can be assessed each year for electric and gas service quality is $19.8 million and $18 million for electric reliability.

In addition, the Company's gas operations are also subject to six safety and reliability performance requirements stemming from National Grid plc's August 2007 acquisition of KeySpan. Similar to service quality, if the prescribed standards are not satisfied, the Company may incur a penalty, with the penalty amount applied as a credit or refund to customers. The total amount of pre-tax penalties that can be assessed each year is $6.51 million

Asset Condition and Capital Investment Plan: On October 22, 2007, the Company filed with the NYPSC the first required annual reports on its asset condition and capital investment plan for its electric transmission and distribution system. The Company's 2007 capital investment plan involved significant investment in capital improvements over the projections initially included in its MRP. On August 15, 2008, the NYPSC issued its order on the compliance filing. The NYPSC affirmed the Company's need to invest a minimum of $1.47 billion during the five year period 2007 – 2011 (calendar) and stated that further projects and investments "appear to be justified" with the possibility of further expansion over time. On January 29, 2010, the Company filed its capital investment plan with the latest five year projection for capital investment estimated at $2.86 billion for fiscal years 2011 through 2015. On that same date, the Company filed a proposal to revise its electric rates effective January 1, 2011. The rate case filing included a copy of the fiscal years 2011 to 2015 capital investment plan. On May 3, 2010, the Company filed its rate case corrections and updates, which included a downward adjustment to the five-year infrastructure investment of approximately $116 million. On August 6, 2010 the Company filed its rebuttal testimony in the rate case which included a downward adjustment to the five year infrastructure investment of approximately $108 million resulting in a five-year projected capital plan estimated at $2.64 billion.

On December 21, 2007, the Company filed with the NYPSC a Petition for Special Ratemaking seeking authorization to defer for later rate recovery 50% of the revenue requirement impact during calendar year 2008 of specified capital programs and operating expenses that are directly associated with these programs. In the order approving the KeySpan merger, the NYPSC had found that the rate impacts associated with certain incremental investments during the remaining period of the MRP would be limited to not more than

50% of the total rate impact as ultimately determined by the NYPSC.

On September 5, 2008, the NYPSC issued its order on the Company's Petition for Special Ratemaking. The NYPSC stated that the Company's investment program could "conceptually" be considered incremental to the level of investment assumed in the MRP and therefore could be eligible for deferral. However, the NYPSC ordered the Company to supplement its petition with actual expense information once results for calendar year 2008 were known. The Company was directed to show in its supplemental filing that the Company will not over earn in 2008 after the deferrals are allowed, that the expenditures on which the deferrals are based are incremental to what was reflected in the MRP forecast, that such expenditures have been offset by all relevant cost savings and related benefits, and to the extent that actual expenditures for 2008 differed from amounts in the budgets that were previously filed with the NYPSC, that the basis for such differences be explained. Finally, the NYPSC ordered a schedule of reporting requirements on the investment program which the Company has been working with the NYPSC to develop. In April 2009, the Company filed for authority to defer 2008 actual incremental capital and associated operating expenditures. When the NYPSC did not act on the Company's April 2009 petition, the Company filed a renewed request for such a deferral in May 2010. The NYPSC has not yet ruled on these petitions. In May 2010, the Company also filed a request for recovery of incremental investment in 2009 in another Petition for Special Ratemaking to the NYPSC. The NYPSC has not yet ruled on this petition.

Financial Protections: The Company made a filing on November 19, 2007 proposing certain financial protections for the Company as required by the NYPSC in the order approving the KeySpan merger and made an additional filing with the NYPSC regarding these protections. The NYPSC adopted the protections in March 2008 which provide, among other things, for restrictions on the payment of common dividends if certain credit ratings are not maintained by the Company or National Grid plc; credits to the Company's deferral account of any incremental increase in interest expense due to a decline in the Company's bond rating; a prohibition with respect to certain types of cross-default provisions; and the implementation of a class of preferred stock having one share (the "Golden Share"), subordinate to any existing preferred stock, the holder of which would have voting rights that limit the Company's right to commence any voluntary bankruptcy, liquidation, receivership or similar proceeding without the consent of the holder of such share of stock. On April 9, 2010, the Company petitioned the NYPSC for authorization to issue its Golden Share to GSS Holdings, Inc. ("GSS") under the same arrangements its sister utilities, The Brooklyn Union Gas Company d/b/a KeySpan Energy Delivery New York and KeySpan Gas East Corporation d/b/a KeySpan Energy Delivery Long Island, made with GSS, which terms were filed with the NYPSC on November 19, 2009.

Gas Rate Plan Joint Proposal: On May 15, 2009, the NYPSC approved a joint proposal ("Joint Proposal") that provides for a two-year rate plan, with an annual increase of $39.4 million in the first year and specific, incremental adjustments in the second year to reflect changes in such costs as postretirement benefit plans other than pensions and environmental site investigation and remediation costs. Among other deferral mechanisms, the Joint Proposal provides for a true up to the actual amount, cost and timing of certain new long-term debt issuance, subject to the actual costs falling outside of a defined range. The Joint Proposal provides for a 10.2% return on equity and a 43.7% equity ratio, and an earnings-sharing mechanism that requires the Company to share earnings with customers to the extent its return on equity exceeds 11.35%. The Joint Proposal also includes a revenue decoupling mechanism, negative revenue adjustments for failure to meet certain service quality performance metrics and a commodity-related bad debt recovery mechanism that adjusts for fluctuations in commodity prices. The new rates went into effect on May 20, 2009. Pursuant to the Joint Proposal, on April 12, 2010, the Company filed to increase rates by approximately $13.9 million effective May 20, 2010 based on increases in certain costs. On May 14, 2010, the NYPSC ordered the new rates to go into effect on a temporary basis as of May 20, 2010, subject to final approval by the NYPSC. On August 20, 2010, the NYPSC approved the permanent rates effective with the date of such order.

Temporary State Assessment Pursuant to PSL Section 18-a: On June 4, 2009 the Company made a gas compliance filing and on June 30, 2009 the Company made an electric compliance filing with the NYPSC regarding the implementation of the Temporary State Energy & Utility Conservation Assessment per §18-a of the New York Public Service Laws of 2009. The combined General & Temporary Conservation Assessment equals 2% of the prior calendar year's gross operating revenues derived from intra-state utility operations. Per order dated June 19, 2009, the NYPSC authorized recovery of the revenues required for payment of the Temporary State Assessment, including carrying charges, subject to reconciliation over five years, July 1, 2009 through June 30, 2014. In its initial compliance filing required by the Gas Rate Order, the Company filed a tariff to collect $25.1 million in incremental assessment expense from its customers over a 12-month period beginning May 20, 2009. Per order dated June 19, 2009, the Company was required to file a revised gas tariff authorizing imposition of a new surcharge amount for July 1, 2009 through June 30, 2010, recognizing that the Company had collected a portion of the revenues to date. The Company calculated the incremental gas assessment to be collected from customers, including carrying charges and an allowance for uncollectible amounts, to be $26.4 million for the period from July 1, 2009 through June 30, 2010. In its June 30, 2009 electric compliance filing, the Company calculated the incremental electric assessment to be collected from customers, including carrying charges and an allowance for uncollectible amounts, to be $83.1 million for the period from July 1, 2009 through June 30, 2010. The Company commenced collection of the Incremental State Assessment Surcharge as of July 1, 2009 from electric customers. On June 15, 2010, the Company submitted the second compliance filing in which it provided a reconciliation of the first year's combined General & Temporary State Assessment with revenue billed to its customers and noted that it intends to maintain its electric and gas Incremental State Assessment Surcharges at their current levels for the July 1, 2010 through June 30, 2011 recovery period. At December 31, 2010, $23.3 million was deferred pending recovery; $35.0 million was recorded at December 30, 2009.

Transmission Rate Case: In February 2008, the Company filed with the FERC a formula transmission rate for customers that take service under the NYISO tariff. In July 2008, the FERC issued an order accepting the proposed formula rate and approved a 50 basis point incentive return on equity applicable to all transmission facilities. This decision marked the first formula rate for a private transmission owner in New York. The rate took effect on October 1, 2008 subject to refund. The FERC directed hearing and settlement judge proceedings to resolve the remaining contested issues in the proceeding. On April 6, 2009, the Company filed a settlement agreement which was accepted by the FERC by its order issued on June 22, 2009, and which resolved all issues in the proceeding. The formula was initially projected to increase annual revenues by approximately $7.9 million. The settlement provided for an authorized return on equity of 11.5%, including any incentive return. The effective date for the settlement was January 30, 2009 with a phase-in of the settlement rate over the period January 30 through June 30. In July 2009, the Company refunded to customers a total of $7.1 million, inclusive of FERC required interest, for amounts collected in excess of the settlement rates for the period of October 2008 through June 2009. Under the Tariff, the Company is required to provide an annual informational filing before the FERC. The first Annual Update filing was made in June 2009. In response thereto, certain parties raised issues with the Company's Long-Term Debt Cost of Capital used in the formula. In November 2009, the Company filed a proposed Stipulation and Agreement modifying the calculation of the Long-Term Debt Cost of Capital Rate so that the amount of the Company's long-term debt used in the calculation of the Capital Rate is based on the average of the beginning-of-the-year and the year-end long-term debt balances. The Company agreed to give customers the benefit of the change from July 1, 2009 forward. On February 13, 2010, the proposed Stipulation and Agreement was accepted by the FERC. The Company filed its second Annual Update, as required, in June 2010. The 2010 Annual Update provided for a revenue decrease of $0.6 million which the Company began billing in July 2010. In response to certain parties' data requests on the 2010 Annual Update, the Company negotiated a settlement of the limited issues raised by those parties, including removal from the formula rate a component reflecting the Temporary State Assessment under Section 18-a of the New York Public Service Law to prevent duplicate charging of that 18-a assessment to entities who are directly assessed or are otherwise exempt from such assessment. The settlement was filed with the FERC on November 18, 2010, and accepted by the FERC in an unpublished letter order issued January 7, 2011. The revenues resulting from the formula rate are charged to wholesale transmission customers and credited back to retail electric distribution customers through the Transmission Revenue Adjustment Clause mechanism.

Electric Rate Filing: On January 29, 2010, the Company filed with the NYPSC an electric rate case for new base rates proposed to go into effect on January 1, 2011, which would terminate the MRP one year early. In its filing, the Company proposed a three-year rate plan commencing January 1, 2011 running through December 31, 2013. While the Company filed for a three-year rate case, NYPSC staff responded to a one-year rate case and the Company adopted the one-year rate case in this proceeding.

In its original request, the Company filed for an increase in the base transmission and distribution revenue of $390.6 million based on a return on equity of 11.1% and equity ratio of 50.01% for calendar year 2011. To mitigate the impact of this base rate increase on customers, the Company proposed to lengthen the amortization period for its fixed stranded generation costs, which were scheduled to be fully amortized at December 31, 2011. Throughout the procedural hearings, the Company revised its revenue requirement that, in turn, revised its requested revenue increase to $361.2 million while continuing to maintain its proposal to offset any base rate increase by reshaping recovery of certain stranded generation-related costs to result in no change in delivery revenues as compared to the MRP.

On January 24, 2010, the NYPSC issued its order. The Company received a revenue requirement increase of approximately $112 million, including recovery of $40 million in CTC, with a 9.1% return on equity. The NYPSC gave the Company the option of receiving a 9.3% return on equity, which would result in a revenue requirement increase of approximately $119 million, if it agreed not to file another general rate case prior to January 1, 2012. In correspondence dated January 31, 2011, the Company advised that it had filed tariffs to reflect a 9.3% return on equity and that it would create a deferral account for crediting to customers the prorated difference between revenues resulting from a 9.1% and a 9.3% return on equity in the event that it filed a base rate case before January 1, 2012. Fifty million dollars of the increase in revenue reflects revenue from "temporary" rates and is subject to the results of the

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NYPSC's audit of service company costs allocated to the Company. In addition, the NYPSC ruled that the Company's fixed stranded generation costs are to be fully amortized by December 31, 2011. The NYPSC also established a fixed level of $29.75 million per year for the Company's costs associated with the SIR of former manufactured gas plants ("MGPs") and other environmental sites. While the Company had previously recovered all prudently incurred SIR costs, for any annual spend above the fixed level, 80% will now be placed into a deferral account for recovery in a future rate case and the other 20% will be the responsibility of the Company. For any annual spend below the fixed level a credit will be applied to the deferral account.

The NYPSC adopted the Capital Expenditures Stipulation entered into between the Company, DPS Staff, and MI in the rate case, which addresses, among other things, the Company's capital budget and investments for fiscal years 2011 and 2012. The amount of capital reflected in the Company's rates for calendar year 2011 is subject to a one-way, downward only true up. In addition, the NYPSC approved the Revenue Decoupling Stipulation entered into between the Company, DPS Staff, the New York Power Authority, and Pace/NRDC which allows for the implementation of a revenue decoupling mechanism whereby the Company's base rates are adjusted annually as a result of the reconciliation between allowed revenue and billed revenue. The Company's revenue decoupling mechanisms includes the majority of customers, with exclusions only for streetlighting customers, the portion of customers' bills associated with delivery of NYPA load and those customers receiving service pursuant to special contracts.

Federal Income Tax Refund: The Company received federal income tax refunds covering the tax years of 1991 to 1995 in the amount of $25.6 million, inclusive of $13.3 million of interest, from the Internal Revenue Service ("IRS") in March 2003 and August 2004, respectively. As required by NYPSC regulations, the Company made a filing with the NYPSC and proposed to credit $7.2 million to its customers and recorded the resulting regulatory liability and earnings impact in March 2009. The Company subsequently agreed with the parties in the proceeding on several adjustments to the proposed disposition resulting in an additional $18.7 million credit to its customers, including approximately $7.3 million (through December 2009) in carrying charges due to the delay in filing the refund notice and $11.4 million in full settlement of all other outstanding issues. On March 19, 2010, the Company made a supplemental filing to provide procedures put in place by the Company to ensure that all future income tax refunds would be timely noticed. On April 16, 2010, the NYPSC issued an order adopting the submitted joint proposal. The Company will continue to accrue carrying charges for gas customers until such time as the deferred amounts are passed back to gas customers.

Service Company Audit: The NYPSC has instituted a proceeding to review the allocation and assignment of costs to the New York affiliates by the National Grid service companies. Overland Consulting has been selected to perform this review and a report to the NYPSC is anticipated in November 2011.

Site Investigation and Remediation Costs Proceeding: On February 18, 2011, the NYPSC instituted a statewide investigation to review its policies regarding the funding mechanisms supporting SIR expenditures and directing the state's utilities to assist the NYPSC in developing a comprehensive record of: (1) the current and future scope of utility SIR programs; (2) the current cost controls in place by utilities and opportunities to improve such cost controls; (3) the appropriate allocation of costs among customers and potentially shareholders; and (4) methods for recovering costs appropriately borne by ratepayers in a way that minimizes the impact. The NYPSC has requested that the Administrative Law Judge provide a presentation of recommendations to the NYPSC before the end of 2011.

Note 3. Employee Benefits

Summary

The Company participates in a non-contributory defined benefit pension plan and a postretirement benefits other than pensions ("PBOP") (the "Plans"). The Plans cover substantially all of the employees of the Company. The pension plan is a cash balance pension plan design and, under that design, pay-based credits are applied based on service time and interest credits are applied at rates set forth in the plan. In addition, a large number of employees hired by the Company prior to July 1998 are cash balance design participants who receive a larger benefit if so yielded under pre-cash balance conversion final average pay formula provisions. Employees hired by the Company following the July 1998 cash balance design conversion participate under cash balance design provisions only.

PBOPs include health care and life insurance coverage to eligible retired employees. Eligibility is based on age and length of service requirements and, in most cases, retirees must contribute to the cost of their coverage.

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A supplemental nonqualified, non-contributory executive retirement program provides additional defined pension benefits for certain executives.

The NYPSC's Statement of Policy requires that prior service costs and gains and losses be amortized over a 10-year period calculated on a vintage year basis.

Funding Policy

Funding policy is determined largely by the Company's rate agreements with the NYPSC and amounts recovered in rates. However, for the pension plan, the contribution for any year will not be less than the minimum amounts that are required under the Pension Protection Act of 2006.

Plan Assets

The target asset allocation for the benefit plans are:

	Pension		Non-union - PBOPs		Union - PBOPs	
	2010	2009	**2010**	2009	**2010**	2009
U.S. equities	**20%**	20%	**44%**	30%	**34%**	49%
Global equities (including U.S.)	**7%**	7%	**-**	-	**12%**	-
Global tactical asset allocation	**10%**	10%	**-**	-	**17%**	-
Non-U.S. equities	**10%**	10%	**26%**	20%	**17%**	21%
Fixed income	**40%**	40%	**30%**	50%	**20%**	30%
Private equity and other*	**13%**	13%	**-**	-	**-**	-
	100%	100%	**100%**	100%	**100%**	100%

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The percentage of the fair value of total plan assets at December 31:

	Pension		Non-union - PBOPs		Union - PBOPs	
	2010	2009	**2010**	2009	**2010**	2009
U.S. equities	**22%**	23%	**44%**	32%	**35%**	50%
Global equities (including U.S.)	**9%**	8%	-	-	**12%**	-
Global tactical asset allocation	**12%**	16%	-	-	**16%**	-
Non-U.S. equities	**11%**	10%	**25%**	20%	**18%**	22%
Fixed income	**41%**	40%	**31%**	48%	**19%**	28%
Private equity and other*	**5%**	3%	-	-	-	-
	100%	100%	**100%**	100%	**100%**	100%

*"Private equity and other" assest allocation includes target allocation to Private Equity (5%) along with new target allocation to Real Estate (5%) and Infrastructure(3%) assets. There is an investment plan in place to invest in these asset classes towards target allocations over a multi-year period.

The Company manages benefit plan investments to minimize the long-term cost of operating the plans, with a reasonable level of risk. Risk tolerance is determined as a result of a periodic asset/liability study which analyzes plan liabilities and plan funded status and results in the determination of the allocation of assets across equity and fixed income securities. Equity investments are broadly diversified across U.S. and non-U.S. stocks, as well as across growth, value, and small and large capitalization stocks. Likewise, the fixed income portfolio is broadly diversified across the various fixed income market segments. Small investments are also held in private equity, with the objective of enhancing long-term returns while improving portfolio diversification. For the PBOP plan, since the earnings on a portion of the assets are taxable, those investments are managed to maximize after tax returns consistent with the broad asset class parameters established by the asset allocation study. Investment risk and return are reviewed by National Grid's investment committee on a quarterly basis.

The discount rate is the rate at which plan obligations can be settled. The discount rate assumption is based on rates of return on high quality fixed income investments in the market place as of each measurement date (typically March 31). Specifically, the National Grid companies use the Hewitt Top Quartile Discount Curve along with the expected future cash flows from the retirement plans to determine the weighted average discount rate assumptions.

The estimated rate of return for various passive asset classes is based both on analysis of historical rates of return and forward looking analysis of risk premiums and yields. Current market conditions, such as inflation and interest rates, are evaluated in connection with the setting of the long-term assumption. A small premium is added for active management and rebalancing of both equity and fixed income. The rates of return for each asset class are then weighted in accordance with the Plan's year end asset allocation, and the resulting long-term return on asset rate is then applied to the market-related value of assets.

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Assumptions Used for Benefits Accounting

The following weighted average assumptions were used to determine the pension and PBOP benefit obligations and net periodic costs for the years ended December 31:

	Pension Benefits				
	Benefit obligation		Net periodic benefit cost		
				2009	
	2010	2009	**2010**	Jan - Mar	Apr - Dec
Discount rate	**6.10%**	7.30%	**7.30%**	6.50%	7.30%
Rate of compensation increase	**3.50%**	3.50%	**3.50%**	3.75%	3.50%
Expected long-term rate of return on assets	**8.00%**	8.00%	**8.00%**	8.00%	8.00%

	PBOP				
	Benefit obligation		Net periodic benefit cost		
				2009	
	2010	2009	**2010**	Jan - Mar	Apr - Dec
Discount rate	**6.10%**	7.30%	**7.30%**	6.50%	7.30%
Expected long-term rate of return on asset					
Non-union	**6.75%**	6.75%	**6.75%**	7.75%	7.75%
Union	**8.00%**	7.75%	**7.75%**	6.75%	6.75%
Health care cost trend rate					
Initial - Pre 65	**8.50%**	8.50%	**7.85%**	9.00%	7.85%
Initial - Post 65	**8.75%**	9.50%	**8.85%**	10.00%	8.85%
Ultimate	**5.00%**	5.00%	**5.00%**	5.00%	5.00%
Year ultimate rate is reached - Pre 65	**2017**	2016	**2015**	2014	2015
Year ultimate rate is reached - Post 65	**2019**	2017	**2016**	2015	2016

The Company participates in pension and PBOP plans with another National Grid subsidiary. The expected contributions to the pension and PBOP plans during calendar year 2011 are $173 million and $131 million, respectively. A portion of these contributions will be made by the Company.

Pension Benefits

The Company's net periodic benefit cost for the years ended December 31, 2010 and 2009 included the following components:

(In thousands of dollars)	**2010**	2009
Service cost	**$ 22,991**	$ 21,426
Interest cost	**70,072**	71,149
Expected return on plan assets	**(93,237)**	(86,711)
Amortization of unrecognized prior service cost	**4,748**	4,057
Amortization of unrecognized loss	**59,453**	42,667
Net periodic benefit costs before settlement	**64,027**	52,588
Settlement loss	**625**	132
Special termination benefits (VERO)*	**267**	8,615
Net periodic benefit cost	**$ 64,919**	$ 61,335

*Special termination benefits consist of costs related to Voluntary Early Retirement Offer ("VERO").

The benefit obligation, assets and funded status of the pension plans cannot be presented separately for the Company as the Company participates in the Plan with an affiliated National Grid Service Company. The following table provides the total funded

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status at December 31 of the pension plans in which the Company participates:

(In thousands of dollars)		2010		2009
Change in benefit obligation:				
Benefit obligation at beginning of year	$	**(1,139,552)**	$	(1,165,446)
Service cost		**(27,542)**		(25,137)
Interest cost		**(76,379)**		(76,720)
Actuarial gain (loss)		**(166,927)**		56,328
Benefits paid		**111,062**		99,577
Settlements (lump sums)		**2,543**		613
Plan amendments		**(1,147)**		(14,966)
Special termination benefits (VERO)		**(1,321)**		(13,801)
Benefit obligation at end of year		**(1,299,263)**		(1,139,552)
Fair value of plan assets at beginning of year		**1,265,490**		929,580
Actual return (loss) on plan assets		**171,166**		220,833
Company contributions		**192,016**		215,267
Benefits paid		**(111,062)**		(99,577)
Settlements (lump sums)		**(2,543)**		(613)
Fair value of plan assets at end of year		**1,515,067**		1,265,490
Funded status		**215,804**		125,938
Unrecognized actuarial loss and prior service cost to be recognized at fiscal year end*		**(55,991)**		(197,420)
Net amount recognized	$	**159,813**	$	(71,482)

*Under SFAS No. 158, the Company will recognize the funded status as of the date of the fiscal year-end. The unrecognized actuarial gains or losses and unrecognized prior service cost will be recorded as an increase or decrease to the pension liability with an offset to regulatory assets and other comprehensive income (loss).

The accumulated benefit obligation for all defined benefit pension plans in which the Company participates was $1.2 billion and $1.1 billion for the years ended December 31, 2010 and 2009, respectively.

The following table details the amounts recognized in the Company's Balance Sheets.

(In thousands of dollars)		2010		2009
Amounts recognized in the Company's Balance Sheet consist of:				
Other current liabilities	$	**(4,600)**	$	(1,300)
Employee pension and other benefits		**171,944**		(52,654)

(In thousands of dollars)		2010		2009
Amounts recognized primarily in regulatory assets consist of:				
Net actuarial loss	$	**353,276**	$	452,796
Prior service cost		**38,298**		43,056
Net amount recognized	$	**391,574**	$	495,852

The estimated net actuarial loss and prior service cost for the defined benefit pension plans that will be amortized from regulatory assets and accumulated other comprehensive income (loss) into net periodic benefit cost during calendar year 2011 is estimated to be $76 million and $5 million, respectively. The Company participates in the Plans with certain other National Grid subsidiaries. A portion of these amounts will be recorded as expense by the Company.

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The following payments are expected to be paid from the pension plans:

(In thousands of dollars)	**Pension Benefits**
2011	**$ 105,437**
2012	**$ 110,394**
2013	**$ 117,724**
2014	**$ 118,341**
2015	**$ 125,315**
2016 - 2020	**$ 621,585**

Defined Contribution Plan

The Company also has a defined contribution pension plan (employee savings fund plan) that covers substantially all employees. Employer matching contributions of approximately $7 million were expensed for each of the years ended December 31, 2010 and 2009.

Postretirement Benefit Plans Other than Pensions

The Company's total cost of PBOPs for the years ended December 31, 2010 and 2009 included the following components:

(In thousands of dollars)		**2010**		2009
Service cost	**$**	**15,016**	$	12,626
Interest cost		**81,692**		82,868
Expected return on plan assets		**(37,968)**		(31,277)
Amortization of unrecognized prior service cost		**12,696**		13,860
Amortization of unrecognized net loss		**41,833**		34,993
Net periodic benefit costs before settlement		**113,269**		113,070
Special termination benefits (VERO)*		**-**		140
Net periodic benefit cost	**$**	**113,269**	$	113,210

*Special termination benefits consist of costs related to VERO.

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The benefit obligation, assets and funded status of the PBOP plan cannot be presented separately for the Company as the Company participates in the Plan with another National Grid subsidiary. The following table provides the PBOP plans' funded status and the amounts recognized in the National Grid Consolidated Balance Sheets at December 31:

(In thousands of dollars)		2010		2009
Change in benefit obligation:				
Benefit obligation at beginning of year	$	**(1,228,488)**	$	(1,348,122)
Service cost		**(17,258)**		(14,494)
Interest cost		**(85,243)**		(86,014)
Actuarial gain (loss)		**(197,622)**		136,809
Medicare Part D subsidy received		**(4,890)**		(4,600)
Benefits paid		**70,030**		75,853
Plan amendments		**9,073**		12,400
Healthcare reform amendment		**(6,500)**		-
Special termination benefits (VERO)		**(9)**		(320)
Benefit obligation at end of year		**(1,460,907)**		(1,228,488)
Fair value of plan assets at beginning of year		**508,876**		419,938
Actual return (loss) on plan assets		**70,590**		109,147
Company contributions		**114,600**		53,810
Benefits paid		**(56,626)**		(74,019)
Fair value of plan assets at end of year		**637,440**		508,876
Funded status		**(823,467)**		(719,612)
Unrecognized actuarial loss and prior service cost to be recognized at fiscal year end*		**(34,753)**		(114,960)
Net amount recognized	$	**(858,220)**	$	(834,572)

*Under SFAS No. 158, the Company will recognize the funded status as of the date of the fiscal year-end. The unrecognized actuarial gains or losses and unrecognized prior service cost will be recorded as an increase or decrease to the PBOP liability with an offset to regulatory assets.

Amounts recognized in the Company's Balance Sheets consist of:

(In thousands of dollars)		2010		2009
Amounts recognized on the Company's Balance Sheet consist of:				
Regulatory asset	$	**275,469**	$	201,015
Employee pension and other benefits liability		**(866,824)**		(843,549)

(In thousands of dollars)		2010		2009
Amounts recognized primarily in regulatory assets:				
Net actuarial loss	$	**222,029**	$	176,090
Prior service cost		**53,440**		66,284
Deferred taxes on subsidy		**-**		(41,359)
Net amount recognized	$	**275,469**	$	201,015

The estimated net actuarial loss and prior service cost for the PBOP plans that will be amortized from regulatory assets into net periodic benefit cost during calendar year 2011 is estimated to be $48 million and $12 million, respectively. The Company participates in the Plans with certain other National Grid subsidiaries. A portion of these amounts will be recorded as expense by the Company.

As a result of the Medicare Act of 2003, the Company receives a federal subsidy for sponsoring a retiree healthcare plan that provides a benefit that is actuarially equivalent to Medicare Part D.

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The following PBOP benefit payments expected to be paid and subsidies expected to be received from the U.S. Federal Government, which reflect expected future services, as appropriate, are:.

(In thousands of dollars)		Payments		Subsidies
2011	$	78,419	$	4,878
2012	$	81,517	$	(5,473)
2013	$	84,806	$	6,071
2014	$	88,247	$	6,671
2015	$	91,612	$	7,270
2016-2020	$	508,615	$	46,160

A one-percentage point change in assumed health care cost trend rates would have the following effects:

(In thousands of dollars)		2010
Increase 1%		
Total of service cost plus interest cost	$	16,897
Postretirement benefit obligation	$	202,564
Decrease 1%		
Total of service cost plus interest cost	$	(14,301)
Postretirement benefit obligation	$	(177,871)

Health Care Reform

In March 2010, the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 became law. These laws' included provisions which resulted in the repeal, with effect from 2012, of the deduction for federal income tax purposes of the portion of the cost of an employer's retiree prescription drug coverage for which the employer received a benefit under the Medicare Prescription Drug Improvement and Modernization Act of 2003. The consequential reduction in the Company's deferred tax asset balance resulted in a net charge to the income statement of approximately $60.6 million. This was offset by credits to the income statement arising from the release of associated regulatory liabilities, net of tax.

Workforce Reduction Program

In connection with National Grid plc's acquisition of KeySpan, which was completed on August 24, 2007, National Grid plc and KeySpan offered certain nonunion employees VERO packages in June 2007 in an effort to achieve necessary staff reductions through voluntary means. Of the 560 enrolled in the VERO, 45 were the Company's employees. Employees enrolled in the early retirement program have retired by October 1, 2010. The Company's share of the cost of the VERO program was estimated to be $37 million, which includes VERO costs allocated from affiliates. The Company recorded $4 million and $13 million of expense for the years ended December 31, 2010 and 2009, respectively.

An additional VERO package was offered to 30 union employees in July 2008 as part of National Grid plc's acquisition of KeySpan to further the effort to achieve necessary staff reduction through voluntary means. Of the 30 eligible employees, 28 enrolled in the VERO and were all employees of a National Grid affiliate. Employees enrolled in the early retirement program will retire between October 1, 2008 and December 1, 2009. The Company recorded $1 million of allocated costs associated with this VERO package.

In December 2008, a third VERO package was offered by the Company. The VERO package was accepted by 42 union customer service employees who were all employees of the Company. Employees enrolled in this early retirement program retired as of December 31, 2008. The Company recorded $4.5 million associated with this VERO package.

In connection with the renewal of the collective bargaining agreement with NGUSA employees part of Local 101, National Grid plc offered 284 Local 101 union employees a VERO in an effort to reduce the workforce. Eligible employees must have been working in a targeted area as of October 15, 2010 and be retirement age eligible in accordance with the pension plan each employee participates in as of May 1st, 2011. For eligible employees who have elected to accept the VERO offer, NGUSA has the right to retain that employee for up to one year before VERO payments are made. An employee who accepts the VERO offer but elects to terminate employment with National Grid plc prior to the one year period, without consent of National Grid plc, forfeits all rights to VERO payments. The Company will accrue for a liability when the employees accept the offer and an amount can be reasonably estimated.

Note 4. Debt

Short-term Debt

The Company has regulatory approval from the FERC to issue up to $1.0 billion of short-term debt. The Company had no short-term debt outstanding to third-parties at December 31, 2010 or 2009.

Long-term Debt

Long-term debt consisted of the following at December 31:

Series	Rate %	Maturity	2010	2009
(In thousands of dollars)				
Senior Notes: (1)				
4.88%	4.881	August 15, 2019	**750,000**	750,000
3.55%	3.553	October 1, 2014	**500,000**	500,000
Tax exempt:				
5.15% (2)	5.150	November 1, 2025	**75,000**	75,000
2013	Variable	October 1, 2013	**45,600**	45,600
2015	Variable	July 1, 2015	**100,000**	100,000
2023	Variable	December 1, 2023	**69,800**	69,800
2025	Variable	December 1, 2025	**75,000**	75,000
2026	Variable	December 1, 2026	**50,000**	50,000
2027	Variable	March 1, 2027	**25,760**	25,760
2027	Variable	July 1, 2027	**93,200**	93,200
2029	Variable	July 1, 2029	**115,705**	115,705
Notes Payable: (1)				
NM Holdings Note	3.830	June 30, 2010	**-**	350,000
NM Holdings Note	5.800	November 1, 2012	**500,000**	500,000
Unamortized discounts			**(415)**	(477)
Total long-term debt			**2,399,650**	2,749,588
Long-term debt due within one year			**-**	350,000
Total long-term debt, excluding current portion			**2,399,650**	2,399,588

(1) Currently callable with make-whole provision
(2) Fixed rate pollution control revenue bonds first callable November 1, 2008 at 102%

State Authority Financing Bonds

Substantially all of the Company's operating properties are subject to mortgage liens securing its mortgage debt. Several series of First Mortgage Bonds amounting to $650 million were issued to secure a like amount of tax-exempt revenue bonds issued by the New York State Energy Research and Development Authority ("NYSERDA"). Approximately $575 million of such securities bear interest at short-term adjustable interest rates (with an option to convert to other rates, including a fixed interest rate) ranging from 0.570% to 0.885%, for the twelve months ended December 31, 2010. The bonds are currently in the auction rate mode and are backed by bond insurance. Credit rating agencies have downgraded the ratings of the bond insurers. The resulting interest rates on the bonds revert to the maximum rate which depends on the current commercial paper rates and the senior secured rating of the Company or the bond insurer, whichever is greater. The effect on interest expense has not been material at this time. The Company also has $75 million of 5.15% fixed rate pollution control revenue bonds issued through NYSERDA which are callable at par. Pursuant to agreements between NYSERDA and the Company, proceeds from such issues were used for the purpose of financing the construction of certain pollution control facilities at the Company's generation facilities (which the Company subsequently sold) or to refund outstanding tax-exempt bonds and notes.

Intercompany Notes

The Company has intercompany long-term notes outstanding with Niagara Mohawk Holdings, an affiliate of the Company, in the amount of $500 million and $850 million at December 31, 2010 and 2009, respectively.

Notes Payable

In August 2009, the Company issued $750 million of unsecured long-term debt at 4.881% with a maturity date of August 15, 2019. Additionally, in September 2009 the Company issued $500 million of long-term debt at 3.553% with a maturity date of October 1, 2014. The debt is not registered under the U.S. Securities Act of 1933 ("Securities Act") and was sold in the United States only to qualified institutional buyers in reliance on Rule 144A under the Securities Act and to certain non-U.S. persons in transactions outside the United States in reliance on Regulation S under the Securities Act. The proceeds from the financing were used to: (i) replenish internally generated cash funds that were provided by retained earnings and were used to finance past capital investments in long-lived utility plant assets and refund long-term debt that was issued to finance those investments; (ii) fund future capital expenditures; (iii) term out existing short-term debt so that these financing resources can be made available for ongoing working capital needs, and (iv) pay dividends. The payment of dividends will result in a more optimal and cost efficient capital structure for the Company and result in an appropriate capital structure for the nature of its business and attendant risk profile.

The aggregate maturities of long-term debt for the five years subsequent to December 31, 2010, excluding capital leases, are approximately:

(In thousands of dollars)		**Amount**
2011	$	-
2012		500,000
2013		45,600
2014		500,000
2015		-
Thereafter		1,354,465
Total		2,400,065

The current portion of capital lease obligations is reflected in the "Obligations Under Capital Leases – Current" line item on the Balance Sheets and was approximately $0.6 million at December 31, 2010 and 2009. The non-current portion of capital lease obligations is reflected in the "Obligations Under Capital Leases – Noncurrent" line item on the Balance Sheets and was approximately $2 million at December 31, 2010 and 2009, respectively.

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Note 5. Property, Plant and Equipment

The following table reflects the movements in our property, plant and equipment for the years ended December 31, 2010 and 2009:

(In thousand of dollars)	Plant and Machinery	Land and Buildings	Vehicles and Equipment	Assets in Construction	Goodwill	Total
Balance at December 31, 2008	$ 7,742,218	$ 458,866	$ 7,776	$ 113,401	$ 1,268,004	$ 9,590,265
Additions	-	-	-	432,119	-	432,119
Disposals	(52,765)	(3,337)	(2,666)	-	-	(58,768)
Reclassifications	329,371	488	5,935	(335,794)	-	-
Adjustments	-	-	-	-	21,128	21,128
Balance at December 31, 2009	8,018,824	456,017	11,045	209,726	1,289,132	9,984,744
Accumulated depreciation at December 31, 2009	(2,966,261)	(76,900)	(8,741)	-	-	(3,051,902)
Net book value at December 31, 2009	$ 5,052,563	$ 379,117	$ 2,304	$ 209,726	$ 1,289,132	$ 6,932,842
Balance at December 31, 2009	8,018,824	456,017	11,045	209,726	1,289,132	9,984,744
Additions	-	-	-	526,388	-	526,388
Disposals	(58,094)	(7,451)	(852)	(7)	-	(66,404)
Reclassifications	495,706	2,469	7,175	(505,350)	-	-
Balance at December, 31, 2010	$ 8,456,436	$ 451,035	$ 17,368	$ 230,757	$ 1,289,132	$ 10,444,728
Accumulated depreciation at December 31, 2010	(3,073,280)	(79,677)	(10,900)	-	-	(3,163,857)
Net book value at December 31, 2010	$ 5,383,156	$ 371,358	$ 6,468	$ 230,757	$ 1,289,132	$ 7,280,871

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Note 6. Income Taxes

Following is a summary of the components of federal and state income tax expense (benefit):

	Calendar Year Ended December 31,	
(In thousands of dollars)	**2010**	2009
Components of federal and state income taxes:		
Current tax expense (benefit):		
Federal	**$ 136,492**	$ (181,957)
State	**5,475**	(2,263)
Total current tax expense (benefit)	**141,967**	(184,220)
Deferred tax expense (benefit):		
Federal	**$ (81,498)**	$ 216,550
Investment tax credits (1)	**(1,664)**	(3,019)
State	**92,015**	18,693
Total deferred tax expense	**8,853**	232,224
Total income tax expense	**$ 150,820**	$ 48,004
Total income taxes in the consolidated statements of operations:		
Income taxes charged to operations	**$ 153,234**	$ 54,721
Income taxes credited to other income (deductions)	**(2,414)**	(6,717)
Total	**$ 150,820**	$ 48,004

(1) Investment tax credits (ITC) are being deferred and amortized over the depreciable life of the property giving rise to credits.

Income tax expense for the years ended December 31, 2010 and 2009 varied from the amount computed by applying the statutory rate to income before income taxes. A reconciliation of expected federal income tax expense, using the federal statutory rate of 35%, to the Company's actual income tax expense for the years end December 31 is presented in the following table.

	Calendar Year Ended December 31,	
(In thousands of dollars)	**2010**	2009
Computed tax	**$ 102,148**	$ 59,585
Increase (reduction) including those attributable to flow-through of certain tax adjustments:		
State income tax, net of federal benefit	**40,515**	13,238
Medicare subsidy, including Patient Protection & Affordable Care Act, net	**51,978**	(6,500)
Intercompany tax allocation	**(31,062)**	(1,510)
Removal costs not normalized	**(15,925)**	(9,401)
Depreciation differences not normalized	**14,748**	13,964
Audit and related reserve movements	**(7,642)**	(22,504)
Officer's life insurance	**-**	1,396
Investment tax credit	**(1,664)**	(2,935)
Provision to return adjustments	**(793)**	(65)
Other items, net	**(1,483)**	2,736
Total	**$ 48,672**	$ (11,581)
Federal and state income taxes	**$ 150,820**	$ 48,004

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Significant components of the Company's net deferred tax assets and liabilities at December 31 are presented in the following table:

(In thousands of dollars)	2010	2009 [1]
Pension, OPEB and other employee benefits	**$ 336,582**	$ 390,408
Reserve - Environmental	**187,423**	203,526
Allowance for uncollectible accounts	**80,823**	75,261
Other items	**108,183**	103,062
Total deferred tax assets [2]	**713,011**	772,257
Property related differences	**(1,550,845)**	(1,326,394)
Regulatory assets - Merger rate plan stranded costs	**(201,953)**	(415,705)
Regulatory assets - Environmental	**(216,961)**	(241,923)
Regulatory assets - Other	**(329,846)**	(429,935)
Other items	**(93,155)**	(32,625)
Total deferred tax liabilities	**(2,392,760)**	(2,446,582)
Net accumulated deferred income tax liability	**$ (1,679,749)**	$ (1,674,325)
Deferred investment tax credit	**$ (25,399)**	$ (24,063)

[1] The presentation of the deferred taxes in 2009 has been adjusted to be comparable with the presentation for 2010.

[2] There was no valuation allowance for deferred tax assets at December 31, 2009.

As of December 31, 2010, the Company has approximately $160 million of state net operating losses ("NOL") which will expire between 2011 and 2031. The Company believes that it is more likely than not that the benefit from the state NOL carryforwards will not be realized. In recognition of this risk, the Company has provided a valuation allowance of $11.6 million on the deferred tax assets relating to the state NOL carryforwards.

As of December 31, 2010, the Company has generated $303.5 million of state net operating losses which will expire between 2011 and 2031.

The Company is a member of the National Grid Holdings Inc. ("NGHI") and subsidiaries consolidated federal income tax return. The Company has joint and several liability for any potential assessments against the consolidated group. In December 2009, NGHI, the parent company of NGUSA, made an income tax accounting method change (in accordance with Internal Revenue Code Section 481(a)) to deduct routine repair and maintenance of network assets pursuant to Internal Revenue Code Section 162 and Treasury Regulation §1.162-4 in its consolidated federal income tax return for the tax year ended March 31, 2009 which resulted in a current tax benefit during the year ended March 31, 2010.

The Company adopted the provisions of the FASB guidance which clarifies the accounting for uncertain tax positions as modified by FERC Docket AI07-2-000. This guidance provides that the financial effects of a tax position shall initially be recognized when it is more likely than not, based on the technical merits, that the position will be sustained upon examination, assuming the position will be audited and the taxing authority has full knowledge of all relevant information. FERC Docket AI07-2-000 issues supplementary guidance requiring entities to continue to recognize deferred income taxes for FERC accounting and reporting purposes based on differences positions taken in tax returns filed or expected to be filed and amounts reported in the financial statements.

With the application of this guidance, as of December 31, 2010 and 2009, the Company's unrecognized tax benefits totaled $1.2 million and $1.9 million, respectively, of which $0.8 million and $1.2 million, respectively, would affect the effective tax rate, if recognized.

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The following table reconciles the changes to the Company's unrecognized tax benefits for the years ended December 31.

Reconciliation of Unrecognized Tax Benefits *(In thousands of dollars)*		**2010**		2009
Beginning balance	$	**60,157**	$	92,802
Gross increases related to prior period		**100,572**		19,556
Gross increases related to current period		**21,329**		20,634
Settlements with tax authorities		-		(72,835)
Ending balance		**182,058**		60,157
Less: Unrecognized tax benefits on temporary differences		**(180,881)**		(58,311)
Ending balance per FERC Form 1	$	**1,177**	$	1,846

As of December 31, 2010 and 2009, the Company has accrued for total interest of $12.6 million and $42.4 million, respectively. During the years ended December 31, 2010 and 2009, the Company recorded interest expense of ($3.0) million and $8.1 million, respectively. The Company recognizes interest accrued related to uncertain tax positions in interest expense or interest income and related penalties in non-operating expenses. No penalties were recognized during the years ended December 31, 2010 and 2009.

Federal income tax returns have been examined and all appeals and issues have been agreed with the Internal Revenue Service ("IRS") and the NGHI consolidated filing group through March 31, 2004. During the calendar year ended December 31, 2010, the NGHI consolidated group settled all agreed IRS audit adjustments related to fiscal years ended income tax returns for March 31, 2005, March 31, 2006 and March 31, 2007. Due to the settlement of the audit, the Company expects its total gross unrecognized tax benefits to be decreased by $1.2 million.

The Company is the process of appealing certain the aforementioned disputed issues with the IRS Office of Appeals relating to its tax returns for March 31, 2005 to March 31, 2007. The Company does not anticipate a change in its unrecognized tax positions in the next twelve months as a result of filing the appeals. However, the Company's tax sharing agreement may change the way tax is allocated as a result of current and future audits or appeals. The fiscal years ended March 31, 2008, March 31, 2009 and March 31, 2010 remain subject to examination by the IRS.

During the fiscal year ended March 31, 2010, the State of New York began a new audit cycle covering the years ended March 31, 2006 through March 31, 2008. As of fiscal year ended March 31, 2009, New York State completed its audit of the fiscal years ending March 31, 2005 for the Company.

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Note 7. Derivatives Contracts

Physical Derivatives

Current accounting guidance for derivative instruments establishes criteria that must be satisfied in order for option contracts, forward contracts with optionality features, or contracts that combine a forward contract and a purchase option contract to qualify for the normal purchases and sales exception. Certain contracts for the physical purchase of natural gas associated with our regulated gas utilities do not qualify for normal purchases. The fair value of these derivative instruments at December 31, 2010 was a liability of $3.6 million

Financial Derivatives

The Company is exposed to certain risks relating to its ongoing business operations, primarily commodity price risk. Financial and physical forward contracts on gas and electricity are entered into to manage this price risk and reduce the cash flow variability associated with the Company's forecasted purchases and sales of natural gas and electricity associated with the gas and electric operations. Our strategy is to minimize fluctuations in gas and electric sales prices to our regulated customers. The accounting for these derivative instruments follows the accounting guidance for rate regulated enterprises. Therefore, the fair value of these derivatives will be recorded as current and deferred asset and liabilities, with offsetting positions recorded as regulatory assets and regulatory liabilities on the Balance Sheets. Changes in the fair value of these contracts are recorded to the specific contract with the offset recorded against the corresponding regulatory asset or liability. As these derivative contracts are eligible for rate regulated accounting treatment, changes in fair value have no income statement impact. Gains or losses upon settlement of these contracts are initially deferred and then refunded to or collected from our firm gas and electric sale customers consistent with regulatory requirements.

Currently, the Company utilizes The New York Mercantile Exchange ("NYMEX") gas futures and swaps as well as NYMEX electric futures and over-the-counter ("OTC") swaps. The fair value of these derivative instruments at December 31, 2010 was a liability of $14.2 million and a gain of $15.8 million, respectively.

The following are commodity volumes associated with the above derivative contracts:

As of December 31, 2010		
		('000)
Physicals	Gas (dths)	20,370
	Gas swaps (dths)	13,400
	Gas options (dths)	1,030
	Electric swaps (Mwhs)	2,374
Financials	Electric options (Mwhs)	30,216
	Gas (dths)	**34,800**
Total	**Electric (Mwhs)**	**32,590**

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The following table presents the Company's derivative contract assets and (liabilities) on the Balance Sheets:

Fair Values of Derivative Instruments -Balance Sheets

	Asset Derivatives			Liability Derivatives	
(in thousands of dollars)	December 31, 2010	December 31, 2009		December 31, 2010	December 31, 2009
Regulated Contracts					
Gas Contracts:					
Gas Futures Contract	$ -	$ 146	Gas Futures Contract	$ -	$ (1,493)
Gas Swaps Contract	220	260	Gas Swaps Contract	(12,604)	(2,004)
Gas Options Contract	-	-	Gas Options Contract	(573)	-
Gas Purchase Contract	1,227	3,230	Gas Purchase Contract	(4,867)	(7,761)
Current Asset	*1,447*	*3,636*	*Current Liability*	*(18,044)*	*(11,258)*
Gas Futures Contract	-	2	Gas Futures Contract	-	-
Gas Swaps Contract	184	-	Gas Swaps Contract	(1,409)	(1,446)
Gas Purchase Contract	-	-	Gas Purchase Contract	-	(2,567)
Deferred Asset	*184*	*2*	*Deferred Liability*	*(1,409)*	*(4,013)*
Gas Subtotal	*1,631*	*3,638*		*(19,453)*	*(15,271)*
Electric Contracts:					
Electric Futures Contract	-	96	Electric Futures Contract	-	(290)
Electric Swaps Contract	562	-	Electric Swaps Contract	(34,998)	(23,230)
Current Asset	*562*	96	*Current Liability*	(34,998)	(23,520)
Electric Swaps Contract	739	-	Electric Swaps Contract	(181)	(14,765)
Electric Options Contract	49,692	-	Electric Options Contract	-	-
Deferred Asset	*50,431*	-	*Deferred Liability*	(181)	(14,765)
Electric Subtotal	*50,993*	*96*		*(35,179)*	*(38,285)*
Total Derivatives	$ 52,624	$ 3,734		$ (54,632)	$ (53,556)

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The following table presents the regulatory (assets) and liabilities whose change in fair value exactly correspond to the related derivative contracts in the preceding table. The Company had derivative contracts eligible for non-rate-regulated accounting treatment as of December 31, 2010 and 2009. As such, the changes in fair value of derivative contracts had income statement impact.

Fair Values of Derivative Instruments - Statements of Income

(in thousands of dollars)	YTD Movement	December 31, 2010	December 31, 2009
Regulated Contracts			
Gas Contracts:			
Gas Futures Contract - Regulatory Asset	$ 1,493	$ -	$ (1,493)
Gas Swaps Contract - Regulatory Asset	(10,563)	(14,013)	(3,450)
Gas Options Contract - Regulatory Asset	(573)	(573)	-
Gas Purchase Contract - Regulatory Asset	5,461	(4,867)	(10,328)
Gas Futures Contract - Regulatory Liability	(146)	-	146
Gas Swaps Contract - Regulatory Liability	142	404	262
Gas Swaps Options - Regulatory Liability	-	-	-
Gas Purchase Contract - Regulatory Liability	(2,003)	1,227	3,230
Gas Subtotal	*(6,189)*	*(17,822)*	*(11,633)*
Electric Contracts:			
Electric Futures Contract - Regulatory Asset	290	-	(290)
Electric Swaps Contract - Regulatory Asset	2,816	(35,179)	(37,995)
Electric Futures Contract - Regulatory Liability	(96)	-	96
Electric Swaps Contract - Regulatory Liability	1,301	1,301	-
Electric Options Contract - Regulatory Liability	49,692	49,692	-
Electric Subtotal	*54,003*	*15,814*	*(38,189)*
Total	**$ 47,814**	**$ (2,008)**	**$ (49,822)**

The aggregate fair value of the Company's derivative instruments with credit-risk-related contingent features that are in a liability position on December 31, 2010, for which the Company does not post any collateral in the normal course of business, is $38.0 million. If the Company's credit rating were to downgraded by one notch, it would not be required to post any additional collateral. If the Company's credit rating were to downgraded by three notches, it would be required to post $39.6 million additional collateral to its counterparties.

Credit and Collateral

Derivative contracts are primarily used to manage exposure to market risk arising from changes in commodity prices and interest rates. In the event of non-performance by a counterparty to a derivative contract, the desired impact may not be achieved. The risk of counterparty non-performance is generally considered a credit risk and is actively managed by assessing each counterparty credit profile and negotiating appropriate levels of collateral and credit support. In instances where the counterparties' credit quality has declined, or credit exposure exceeds certain levels, we may limit our credit exposure by restricting new transactions with counterparties, requiring additional collateral or credit support and negotiating the early termination of certain agreements. At December 31, 2010, the Company paid $11.2 million to its counterparties as collateral associated with outstanding derivative contracts.

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Note 8. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The following is a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

The Company's Level 1 fair value derivative instruments primarily consist of natural gas and power futures and swaps traded on the NYMEX. There is no liquidity or credit reserve associated with such trades, and no discounting as well.

The Company's Level 2 fair value derivative instruments primarily consist of power OTC swaps and forward physical gas deals where market data for pricing inputs is observable. Level 2 pricing inputs are obtained from NYMEX and Intercontinental Exchange ("ICE"), except cases when ICE publishes seasonal averages or there were no transactions within the last seven days. During periods prior to December 31, 2010 Level 2 pricing inputs were obtained from NYMEX and Platts M2M (industry standard, non-exchange-based editorial commodity forward curves) when it can be verified by available market data from ICE based on transactions within the last seven days. Level 2 derivative instruments may utilize discounting based on quoted interest rate curve as well as have liquidity reserve calculated based on bid/ask spread. Substantially all of these price curves are observable in the marketplace throughout at least 95% of the remaining contractual quantity, or they could be constructed from market observable curves with correlation coefficients of 0.95 or higher.

Level 3 fair value derivative instruments primarily consist of our gas OTC forwards, options, and physical gas transactions where pricing inputs are unobservable, as well as other complex and structured transactions. Complex or structured transactions can introduce the need for internally-developed models based on reasonable assumptions. Industry-standard valuation techniques, such as Black-Scholes pricing model, Monte Carlo simulation, and FEA libraries are used for valuing such instruments. The value is categorized as level 3. Level 3 is also applied in cases when forward curve is internally developed, extrapolated or derived from market observable curve with correlation coefficients less than 0.95, or optionality is present, or non-economical assumptions are made.

The internally developed forward curves have a high level of correlation with Platts M2M curves.

Available for sale securities are primarily equity investments based on quoted market prices and municipal and corporate bonds based on quoted prices of similar traded assets in open markets.

The following table presents assets and liabilities measured and recorded at fair value on the Company's Consolidated Balance Sheet on a recurring basis and their level within the fair value hierarchy as of December 31, 2010:

(In thousands of dollars) Recurring Fair Value Measurements	Level 1	Level 2	Level 3	Total
Derivatives				
Assets	$ -	$ 2,249	$ 50,375	$ 52,624
Liabilities	-	(49,953)	(4,679)	(54,632)
Net fair value - derivatives	-	(47,704)	45,696	(2,008)
Available for Sale Securities (AFS)				
Assets	17,388	6,745	-	24,133
Net fair value - AFS	17,388	6,745	-	24,133

Year to Date Level 3 Movement Table

The following table presents the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the twelve months ended December 31, 2010:

(in thousands of dollars)	Total
Beginning balance at December 31, 2009	$ (6,968)
Transfers in and out of Level 3	(177)
Total gains or losses	
included in earnings (or changes in net assets)	-
included in other comprehensive income	-
included in regulatory assets and liabilities	(24,739)
Purchases	77,580
Sales	-
Ending balance at December 31, 2010	$ 45,696
The amount of total gains or losses for the period included in earnings (or changes in net assets) attribute to the change in unrealized gains or losses relating to assets still held at December 31, 2010	$ -

The Company transfers amounts from Level 2 to Level 3 as of the beginning of each period and amounts from Level 3 to Level 2 as of the end of each period.

Long term debt is based on quoted market prices where available or calculated prices based on the remaining cash flows of the underlying bond discounted at the Company's incremental borrowing rate. The Company's Balance Sheet reflects the long term debt at carrying value. The fair value of this external debt at December 31, 2010 is $2 billion.

As discussed in Note 1, Significant Accounting Policies, current accounting guidance on fair value measurements establishes a framework for measuring fair value. That framework provides a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets and liabilities (level 1 measurements) and the lowest priority to unobservable inputs (level 3 measurements).

Following is a description of the valuation methodologies used at December 31, 2010 for pension and other postretirement benefit assets measured at fair value. The pension and other postretirement benefit assets can be invested in any of the following categories.

Cash and cash equivalent
Interest bearing cash is valued at the investment principal plus all accrued interest. Temporary cash investment and short-term investments are valued at either the investment principal plus all accrued interest or the net asset value of shares held by the Plans at year end.

Equity and preferred securities
Common stocks, preferred stocks, and real estate investment trusts are valued using the official close for the National Association of Securities Dealers Automated Quotations ("NASDAQ"), the last trade, or bid of the ask offer price reported on the active market on which the individual securities are traded.

Fixed income securities and future contracts
Fixed income securities, convertible securities, collateral received from securities lending (which include corporate debt securities, municipal fixed income securities, US Government and Government agency securities which are in turn comprised of government agency securities, government mortgage-backed securities, index linked government bonds, and state and local bonds), derivatives (except certain options traded on an exchange) and forward foreign exchange contracts (comprised of interest rate swaps, credit default

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swaps, index swaps, financial futures, and other derivatives), and investment of securities lending collateral (comprised of repurchase agreements, asset-backed securities, floating rate notes and time deposits) are valued with an institutional bid valuation or an institutional mid evaluation. A bid evaluation is an estimated price at which a dealer would pay for a security (typically in an institutional round lot). A mid evaluation is the average of the estimated price at which a dealer would sell a security and the estimated price at which a dealer would pay for a security (typically in an institutional round lot). Oftentimes, these evaluations are based on proprietary models which pricing vendors establish for these purposes. In some cases, there may be manual sources used when primary price vendors do not supply prices.

Private equity and real estate
Commingled equity funds, commingled special equity funds, limited partnerships, real estate, venture capital and other investments are valued using evaluations (a good faith opinion as to what a buyer in the marketplace would pay for a security – typically in an institutional round lot-in a current sale), based on proprietary models, or based on the net asset value.

The asset classes listed in the tables below may also be held in the following investment vehicles:

Mutual funds, common and collective trusts, and pooled separate accounts are valued at the net asset value of shares held by the Plan at year end.

103-12 investment entities (entities whose legal structure is in the form of a financial services product such as a collective trust or a limited partnership and whose underlying assets include "plan assets" of two or more plans that are not members of a related group of employee benefit plans in accordance with Department of Labor Regulation 2520.103-12) are valued using financial information received from the investment trustee, advisor and/or general partner. This information is received monthly and is based on the value of underlying securities. For some 103-12 investments, the financial information is provided in the quarterly statements that are typically provided more than 30 days after quarter end. Because of this time lag, investment units for these 103-12 investment entities are valued as of the Plan year end using the available statement from the prior quarter end.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. Furthermore, while management believes its valuation methodologies are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date. The table depicted below sets forth by level, within the fair value hierarchy, the investments in the pension plan and retirement benefits other than pension plans at fair value as of December 31, 2010:

(In thousands of dollars) Asset Type	Level 1	Level 2	Level 3	Total
Cash & cash equivalents	$ 790	$ 53,202	$ -	$ 53,992
Equity	445,677	685,290	41,429	1,172,396
Fixed income securities	264,385	464,566	115,432	844,383
Preferred securities	1,719	-	-	1,719
Private equity	-	-	51,495	51,495
Real estate	-	-	28,522	28,522
Net assets at fair value	$ 712,571	$ 1,203,058	$ 236,878	$ 2,152,507

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The following table sets forth a summary of changes in the fair value of the pension and retirement benefits other than pension plan's level 3 investments for the year ended December 31, 2010:

(In thousands of dollars)	Equity	Fixed Income Securities	Private Equity	Real Estate	Total
Balance, beginning of year	$ 11,870	$ 71,568	$ 37,269	$ -	$ 120,707
Realized gains	16	147	879	-	1,042
Unrealized gains at reporting date	4,080	10,782	4,245	2,283	21,390
Purchases, sales, issuance, and settlements (net)	25,463	32,935	9,102	26,239	93,739
Balance, end of year	41,429	115,432	51,495	28,522	$ 236,878

Note 9. Accumulated Other Comprehensive Income (Loss)

The following table details the components of accumulated other comprehensive income (loss) for the years ended December 31, 2010 and 2009:

(In thousands of dollars)	Unrealized Gains (Losses) On Available-for Sale Securities	Postretirement Benefit Liabilities	Cash Flow Hedges	Total Accumulated Other Comprehensive Income (Loss)
December 31, 2008 balance, net of tax	$ (3,248)	$ (1,064)	$ 2,373	$ (1,939)
Unrealized losses on securities	2,325	-	-	2,325
Hedging activity	-	-	(2,373)	(2,373)
Change in pension and other postretirement obligations	-	248	-	248
Reclassification adjustment for gain				-
included in net income	(145)	-	-	(145)
December 31, 2009 balance, net of tax	(1,068)	(816)	-	(1,884)
Unrealized gain on securities	1,202	-	-	1,202
Change in pension and other postretirement obligations	-	27	-	27
Reclassification adjustment for gain				-
included in net income	(537)	-	-	(537)
December 31, 2010 balance, net of tax	$ (403)	$ (789)	$ -	$ (1,192)

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Note 10. Commitments and Contingencies

Asset Retirement Obligations

The Company has various asset retirement obligations primarily associated with its gas distribution and electric generation activities. Generally, the Company's largest asset retirement obligations relate to: (i) legal requirements to cut (disconnect from the gas distribution system), purge (clean of natural gas and PCB contaminants) and cap gas mains within its gas distribution and transmission system when mains are retired in place; or dispose of sections of gas main when removed from the pipeline system; (ii) cleaning and removal requirements associated with storage tanks containing waste oil and other waste contaminants; and (iii) legal requirements to remove asbestos upon major renovation or demolition of structures and facilities.

Long-Term Contracts for the Purchase of Electric Power

The Company has several types of long-term contracts for the purchase of electric power. The Company is liable for these payments regardless of the level of service required from third parties. In addition, the Company purchases additional energy to meet its load through the NYISO at market prices but is not legally obligated to do so.

Gas Supply, Storage and Pipeline Commitments

In connection with its regulated gas business, the Company has long-term commitments with a variety of suppliers and pipelines to purchase gas commodity, provide gas storage capability and transport gas commodity on interstate gas pipelines.

Environmental Contingencies

The normal ongoing operations and historic activities of the Company are subject to various federal, state and local environmental laws and regulations. Like many other industrial companies, the Company's transmission and distribution businesses generate hazardous wastes. Under federal and state Superfund laws, potential liability for the historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if the activities were lawful when they occurred.

The U.S. Environmental Protection Agency ("EPA") and New York Department of Environmental Conservation ("DEC"), as well as private entities have alleged that the Company is a potentially responsible party under state or federal law for the remediation of numerous sites. The Company's most significant liabilities relate to former MGP facilities formerly owned or operated by the Company. The Company is currently investigating and remediating, as necessary, those MGP sites and certain other properties under agreements with the EPA and DEC.

The Company believes that obligations imposed on the Company because of the environmental laws will not have a material result on its operations or financial condition because the Company's MRP provides for the continued application of deferral accounting for variations in spending from amounts provided in rates related to these environmental obligations. As a result, the Company has recorded a regulatory asset representing the investigation, remediation and monitoring obligations it expects to recover from ratepayers.

The Company is pursuing claims against other potentially responsible parties to recover investigation and remediation costs it believes are the obligations of those parties. The Company cannot predict the success of such claims. As of December 31, 2010 and 2009, the Company had accrued liabilities related to its environmental obligations of $445 million and $449 million, respectively. The high end of the range of potential liabilities at December 31, 2010, was estimated at $615 million.

Nuclear Contingencies

As of December 31, 2010 and 2009, the Company has a liability of $167 million in non-current liabilities for the disposal of nuclear fuel irradiated prior to 1983. In January 1983, the Nuclear Waste Policy Act of 1982 (the Nuclear Waste Act) established a cost of $.001 per kilowatt-hour ("kWh") of net generation for current disposal of nuclear fuel and provides for a determination of the Company's liability to the DOE for the disposal of nuclear fuel irradiated prior to 1983. The Nuclear Waste Act also provides three payment options for liquidating such liability and the Company has elected to delay payment, with interest, until the year in which

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Constellation Energy Group Inc., which purchased the Company's nuclear assets, initially plans to ship irradiated fuel to an approved DOE disposal facility.

In March 2010, the DOE filed a motion with the Nuclear Regulatory Commission to withdraw the license application for a high-level nuclear waste repository at Yucca Mountain. In conjunction with this announcement, the US government announced that it has established a Blue Ribbon Commission to perform a comprehensive review and provide recommendations regarding the disposal of the nation's spent nuclear fuel and waste. Therefore, the Company cannot predict the impact that the recent actions of the DOE and the US government will have on our ability to dispose of the spent nuclear fuel and waste.

Sales and Use Tax Contingencies

The Company is subject to periodic audits by the New York State Department of Taxation and Finance concerning the Company's payments of sales and use taxes. An audit for the period from June 2001 through November 2005 is still ongoing and the Company has received material assessments that it is disputing. The Company believes that the eventual outcome of the audit will not result in a material change to the income statement in future periods.

Legal Matters

From time to time the Company is subject to various legal proceedings arising out of the ordinary course of business. The Company does not consider any such proceedings to be material to the business or likely to result in a material adverse effect on the financial statements.

Note 11. Related Party Transactions

Money Pool

The Company participates with National Grid and its affiliates in a system money pool. The money pool is administered by a National Grid service company as the agent for the participants. Short-term borrowing needs are met first by available funds of the money pool participants. Borrowings from the money pool bear interest at the higher of (i) the monthly average of the rate for high-grade, 30-day commercial paper sold through dealers by major corporations as published in the Wall Street Journal, or (ii) the monthly average of the rate then available to money pool depositors from an eligible investment in readily marketable money market funds or the existing short-term investment accounts maintained by money pool depositors or the National Grid service company during the period in question. In the event neither rate is one that is permissible for a transaction because of constraints imposed by the state regulatory commission having jurisdiction over a utility participating in the transaction, the rate is adjusted to a permissible rate as determined under the requirements of the state regulatory commission. Companies that invest in the money pool share the interest earned on a basis proportionate to their average monthly investment in the money pool. Funds may be withdrawn from or repaid to the money pool at any time without prior notice. The average interest rate for the money pool was 0.39% and 0.26% for the years ended December 2010 and 2009, respectively. The Company had short-term money pool debt outstanding of $1 million at December 31, 2010 and short-term money pool investment of $78 million at December 31, 2009, from affiliated companies.

Advances to/from Affiliates

Additionally, the Company has a net account payable to affiliates of $29 million and $33 million at December 31, 2010 and 2009, respectively, from various transactions with National Grid and its affiliates. In addition, certain activities and costs, such as executive and administrative, financial (including accounting, auditing, risk management, tax and treasury/finance) human resources, information technology, legal and strategic planning are shared between the National Grid affiliates and allocated to each company appropriately. In addition, the Company has a tax sharing agreement associated with filing consolidated tax returns. The Company's share of the tax liability is allocated resulting in a payment to or from the Company.

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Service Company Charges

The affiliated service companies of National Grid have furnished services to the Company at the cost of such services. These costs, including operating costs and capital expenditures, were approximately $521 million and $258 million for the years ended December 31, 2010 and 2009, respectively.

Parent Company Charges

For the year ended December 31, 2010, National Grid received charges from National Grid Commercial Holdings Limited (an affiliated company in the UK) for certain corporate and administrative services provided by the corporate functions of National Grid plc to its US subsidiaries.

These charges, which are recorded on the books of National Grid, have not been reflected on these financial statements.

Note 12. Preferred Stock

The Company has certain issues of non-participating preferred stock which provide for redemption at the option of the Company. In calendar years 2010 and 2009, the Company did not redeem any shares of its preferred stock.

Note 13. Restriction on Common Dividends

The indenture securing the Company's mortgage debt provides that retained earnings shall be reserved and held unavailable for the payment of dividends on common stock to the extent that expenditures for maintenance and repairs plus provisions for depreciation do not exceed 2.25% of depreciable property as defined therein. These provisions have never resulted in a restriction of the Company's retained earnings.

The Company is limited by the MRP, NYPSC orders (see Note 2 – Rates and Regulatory) and FERC orders with respect to the amount of dividends the Company can pay. As long as the bond ratings on the least secure forms of debt issued by the Company and National Grid plc remain rated investment grade and do not fall to the lowest investment grade rating (with one or more negative watch downgrade notices issued with respect to such debt), the Company is allowed to pay dividends in an amount up to the pre-merger (between the Company and National Grid) retained earnings balance plus any earnings subsequent to the merger, together with other adjustments that are authorized under the MRP and other applicable regulatory orders.

Note 14. Difference between Uniform System of Accounts and GAAP

In accordance with the FERC Form 1 instructions, these notes are included in the Company's published annual reports which may include reclassifications not made for FERC reporting purposes. For example, reclassifications for the current portions of regulatory assets and liabilities and deferred taxes are done for the published annual reports but not for FERC reporting. These financial statements are prepared in accordance with the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases. This is a comprehensive basis of accounting consistent with GAAP, except for:

- lack of disclosure of the current portion of long-term debt on the balance sheet
- the balance sheet classification of cost of removal collections from customers
- the presentation of income taxes
- the balance sheet classification of non-utility property

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Note 15. Subsequent Events

In accordance with current authoritative accounting guidance the Company has evaluated for disclosure subsequent events that have occurred up through May 18, 2011, the date of issuance of these financial statements. As of May 18, 2011, there were no subsequent events which required recognition or disclosure except as discussed below.

On January 31, 2011, National Grid announced substantial changes to the organization, including new global, US and UK operating models, and changes to the leadership team. The recently announced structure seeks to create a leaner, more-efficient business backed by streamlined operations that will help meet, more efficiently, the needs of regulators, customers and shareholders. The implementation of the new US business structure targets annualized savings of $200 million by March 2012 primarily through the reduction of approximately 1,200 positions. The Company continues to evaluate the impact of the restructuring initiative on its financial position, results of operations and operating cash flows.

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STATEMENT OF INCOME

Quarterly
1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	4,104,800,168	3,761,366,757		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,336,207,097	2,186,829,581		
5	Maintenance Expenses (402)	320-323	204,545,657	199,748,730		
6	Depreciation Expense (403)	336-337	230,379,265	221,459,832		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	29,616	26,792		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	1,354,070	3,421,858		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	36,913	36,913		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		658,477,256	629,245,866		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	261,277,684	222,293,298		
15	Income Taxes - Federal (409.1)	262-263	146,425,558	-182,256,727		
16	- Other (409.1)	262-263	5,288,899	-2,335,772		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	252,631,290	570,935,050		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	251,111,720	331,621,377		
19	Investment Tax Credit Adj. - Net (411.4)	266				
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)		465,874	465,874		
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		3,846,007,459	3,518,249,918		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		258,792,709	243,116,839		

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STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
3,357,497,010	2,977,100,572	746,702,265	783,670,115	600,893	596,070	2
						3
1,793,662,445	1,587,891,964	542,544,652	598,937,617			4
169,792,396	165,763,799	34,753,261	33,984,931			5
188,620,649	180,215,295	41,758,616	41,244,537			6
11,097	11,430	18,519	15,362			7
1,330,748	3,105,977	23,322	315,881			8
36,913	36,913					9
						10
						11
643,752,285	620,192,521	14,724,971	9,053,345			12
						13
210,137,908	175,731,018	51,139,776	46,562,280			14
115,366,063	-179,099,920	31,059,495	-3,156,807			15
3,819,166	-1,666,694	1,469,733	-669,078			16
252,230,136	570,600,032	401,154	335,018			17
251,402,313	331,385,619	-290,593	235,758			18
						19
						20
395,993	395,993	69,881	69,881			21
						22
						23
						24
3,127,753,486	2,791,792,709	718,253,973	726,457,209			25
229,743,524	185,307,863	28,448,292	57,212,906	600,893	596,070	26

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STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		258,792,709	243,116,839		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)		4,370,252	11,431,331		
35	Nonoperating Rental Income (418)		284,512	779,911		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-104,411	-59,924		
37	Interest and Dividend Income (419)		5,131,898	4,152,622		
38	Allowance for Other Funds Used During Construction (419.1)		4,082,548	-384		
39	Miscellaneous Nonoperating Income (421)		138,513	-252,629		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		5,162,808	-6,811,735		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		155,602	326,874		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		1,608,544	1,084,731		
46	Life Insurance (426.2)		2,544,625	3,987,916		
47	Penalties (426.3)		4,163	142,779		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,609,870	1,344,646		
49	Other Deductions (426.5)		53,323	8,798		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		5,976,127	6,895,744		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	883,282	874,645		
53	Income Taxes-Federal (409.2)	262-263	796,504	299,200		
54	Income Taxes-Other (409.2)	262-263	186,030	72,773		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277				
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	1,733,503	4,070,188		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		1,663,964	3,018,500		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-1,531,651	-5,842,070		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		718,332	-7,865,409		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		62,197,273	27,781,051		
63	Amort. of Debt Disc. and Expense (428)		2,434,668	2,023,893		
64	Amortization of Loss on Reaquired Debt (428.1)		6,576,120	6,648,300		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		60,460	60,460		
67	Interest on Debt to Assoc. Companies (430)		35,822,750	51,905,743		
68	Other Interest Expense (431)		12,806,036	25,512,951		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		1,296,742	797,204		
70	Net Interest Charges (Total of lines 62 thru 69)		118,479,645	113,014,274		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		141,031,396	122,237,156		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		141,031,396	122,237,156		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) __ An Original (2) X A Resubmission	09/16/2011	2010/Q4

FOOTNOTE DATA

Schedule Page: 114 Line No.: 6 Column: g

Includes FERC Account 413 in the amount of $64,266.

Niagara Mohawk Power Corporation
Notes to Financial Statements
Please refer to Statement AA, Pages 6 – 43, for Notes to Financial Statements

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) ☐ An Original (2) ☒ A Resubmission	09/16/2011	End of 2010/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		943,518,910	1,322,282,327
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		141,135,807	122,297,080
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24	(3.4% = $195.6k); (3.6% = $493.7k); (3.9% = $371.2k)		-1,060,498	(1,060,497)
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-1,060,498	(1,060,497)
30	Dividends Declared-Common Stock (Account 438)			
31			-200,000,000	(500,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-200,000,000	(500,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		883,594,219	943,518,910
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) ☐ An Original (2) ☒ A Resubmission	09/16/2011	End of 2010/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		863,594,219	943,518,910
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-1,737,799	(1,677,875)
50	Equity in Earnings for Year (Credit) (Account 418.1)		-104,411	(59,924)
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		-1,842,210	(1,737,799)

Niagara Mohawk Power Corporation
Notes to Financial Statements
Please refer to Statement AA, Pages 6 – 43, for Notes to Financial Statements

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) ☐ An Original (2) ☒ A Resubmission	09/16/2011	End of 2010/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	8,567,597,781	6,457,450,136
4	Property Under Capital Leases	1,785,680	
5	Plant Purchased or Sold		
6	Completed Construction not Classified	352,016,565	308,340,714
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	8,921,400,026	6,765,790,850
9	Leased to Others	3,403,815	3,403,815
10	Held for Future Use		
11	Construction Work in Progress	230,792,266	181,496,278
12	Acquisition Adjustments	1,289,132,076	1,061,730,254
13	Total Utility Plant (8 thru 12)	10,444,728,183	8,012,421,197
14	Accum Prov for Depr, Amort, & Depl	3,163,857,114	2,392,222,999
15	Net Utility Plant (13 less 14)	7,280,871,069	5,620,198,198
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	3,080,534,894	2,318,289,363
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	82,681,036	73,292,452
22	Total In Service (18 thru 21)	3,163,215,930	2,391,581,815
23	Leased to Others		
24	Depreciation	641,184	641,184
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)	641,184	641,184
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	3,163,857,114	2,392,222,999

Name of Respondent Niagara Mohawk Power Corporation	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 09/16/2011	Year/Period of Report End of 2010/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
1,812,931,605				297,216,040	3
				1,785,680	4
					5
27,804,653				15,871,198	6
					7
1,840,736,258				314,872,918	8
					9
					10
19,003,670				30,292,318	11
227,401,822					12
2,087,141,750				345,165,236	13
663,753,536				107,880,579	14
1,423,388,214				237,284,657	15
					16
					17
654,364,952				107,880,579	18
					19
					20
9,388,584					21
663,753,536				107,880,579	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
663,753,536				107,880,579	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [X] A Resubmission	09/16/2011	End of 2010/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	77,175,727	
4	(303) Miscellaneous Intangible Plant		
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	77,175,727	
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights		
9	(311) Structures and Improvements		
10	(312) Boiler Plant Equipment		
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units		
13	(315) Accessory Electric Equipment		
14	(316) Misc. Power Plant Equipment		
15	(317) Asset Retirement Costs for Steam Production		
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)		
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	8,220	
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment	33,132	
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	41,352	
36	D. Other Production Plant		
37	(340) Land and Land Rights		
38	(341) Structures and Improvements		
39	(342) Fuel Holders, Products, and Accessories		
40	(343) Prime Movers		
41	(344) Generators		
42	(345) Accessory Electric Equipment		
43	(346) Misc. Power Plant Equipment		
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)		
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	41,352	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [X] A Resubmission	09/16/2011	End of 2010/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
			77,175,727		3
					4
			77,175,727		5
					6
					7
					8
					9
					10
					11
					12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			8,220		27
					28
					29
					30
-342		-342	33,132		31
					32
					33
					34
-342		-342	41,352		35
					36
					37
					38
					39
					40
					41
					42
					43
					44
					45
-342		-342	41,352		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [X] A Resubmission	09/16/2011	End of 2010/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	96,813,636	-2,555
49	(352) Structures and Improvements	31,484,858	519,916
50	(353) Station Equipment	692,863,457	61,268,779
51	(354) Towers and Fixtures	125,740,163	-3,182,972
52	(355) Poles and Fixtures	384,702,625	55,000,336
53	(356) Overhead Conductors and Devices	257,182,555	44,207,993
54	(357) Underground Conduit	29,331,874	4,552,596
55	(358) Underground Conductors and Devices	106,578,217	7,508,087
56	(359) Roads and Trails	2,339,016	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,727,036,401	169,872,180
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	25,955,620	2,296,261
61	(361) Structures and Improvements	35,443,220	850,837
62	(362) Station Equipment	471,738,988	24,184,344
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	827,064,562	59,375,112
65	(365) Overhead Conductors and Devices	913,462,141	52,189,043
66	(366) Underground Conduit	136,496,579	5,666,975
67	(367) Underground Conductors and Devices	433,722,401	19,191,572
68	(368) Line Transformers	707,777,434	52,557,775
69	(369) Services	410,758,272	11,897,612
70	(370) Meters	112,012,900	8,439,408
71	(371) Installations on Customer Premises	8,195,067	1,278
72	(372) Leased Property on Customer Premises	220	
73	(373) Street Lighting and Signal Systems	199,174,109	12,549,492
74	(374) Asset Retirement Costs for Distribution Plant	116,000	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	4,281,917,513	249,199,709
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	2,514,319	
87	(390) Structures and Improvements	89,814,937	5,577,154
88	(391) Office Furniture and Equipment	9,225,246	414,687
89	(392) Transportation Equipment		56,363
90	(393) Stores Equipment	2,143,249	
91	(394) Tools, Shop and Garage Equipment	46,920,678	7,500,628
92	(395) Laboratory Equipment	20,746,799	1,494,937
93	(396) Power Operated Equipment		220,444
94	(397) Communication Equipment	75,633,008	417,478
95	(398) Miscellaneous Equipment	51,047,567	-1,509,450
96	SUBTOTAL (Enter Total of lines 86 thru 95)	298,045,803	14,172,241
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	467,500	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	298,513,303	14,172,241
100	TOTAL (Accounts 101 and 106)	6,384,684,296	433,244,130
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	6,384,684,296	433,244,130

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) ☐ An Original (2) ☒ A Resubmission	09/16/2011	End of 2010/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
140,405		-4,760	96,665,916		48
905,929		61,646	31,160,491		49
21,034,106		-34,271	733,063,859		50
455,875		-2,573,120	119,528,196		51
1,731,207		2,396,386	440,368,140		52
583,322		273,473	301,080,699		53
13,296			33,871,174		54
84,323			114,001,961		55
			2,339,016		56
					57
24,948,463		119,354	1,872,079,472		58
					59
		-12,471	28,239,410		60
76,118		21,062	36,239,001		61
6,467,967		-15,233	489,440,132		62
					63
4,813,748		147,709	881,773,635		64
2,448,735		308,279	963,510,728		65
489,178		61,052	141,735,428		66
1,390,745		192,790	451,716,018		67
4,462,704		-77,016	755,795,489		68
857,324		137,195	421,935,755		69
982,809			119,469,499		70
1,757			8,194,588		71
220					72
2,239,496		-876,909	208,607,196		73
	-79,000		37,000		74
24,230,801	-79,000	-113,542	4,506,693,879		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
		-24,335	2,489,984		86
2,973,972			92,418,119		87
			9,639,933		88
			56,363		89
			2,143,249		90
			54,421,306		91
			22,241,736		92
			220,444		93
37,267			76,013,219		94
			49,538,117		95
3,011,239		-24,335	309,182,470		96
					97
	150,450		617,950		98
3,011,239	150,450	-24,335	309,800,420		99
52,190,161	71,450	-18,865	6,765,790,850		100
					101
					102
					103
52,190,161	71,450	-18,865	6,765,790,850		104

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) __ An Original (2) X A Resubmission	09/16/2011	2010/Q4

FOOTNOTE DATA

Schedule Page: 204   Line No.: 104   Column: b

The beginning balance on this page for last year was correct in total, however due to an administrative oversight the balances within some utility accounts were misstated. We have made the corrections in this filing.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [X] A Resubmission	09/16/2011	End of 2010/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	2,237,481,035	2,236,919,607		561,428
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	176,647,047	176,647,047		
4	(403.1) Depreciation Expense for Asset Retirement Costs	11,097	11,097		
5	(413) Exp. of Elec. Plt. Leas. to Others	64,266			64,266
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	176,722,410	176,658,144		64,266
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	52,190,161	52,205,651		-15,490
13	Cost of Removal	50,442,680	50,442,680		
14	Salvage (Credit)	7,359,943	7,359,943		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	95,272,898	95,288,388		-15,490
16	Other Debit or Cr. Items (Describe, details in footnote):				
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,318,930,547	2,318,289,363		641,184
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production				
21	Nuclear Production				
22	Hydraulic Production-Conventional	616,509	-24,675		641,184
23	Hydraulic Production-Pumped Storage				
24	Other Production				
25	Transmission	526,326,494	526,326,494		
26	Distribution	1,607,392,740	1,607,392,740		
27	Regional Transmission and Market Operation				
28	General	184,594,804	184,594,804		
29	TOTAL (Enter Total of lines 20 thru 28)	2,318,930,547	2,318,289,363		641,184

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) __ An Original (2) X A Resubmission	Date of Report (Mo, Da, Yr) 09/16/2011	Year/Period of Report 2010/Q4

FOOTNOTE DATA

Schedule Page: 219   Line No.: 3   Column: c

The amount on Line No 3 Col C represents Electric Depreciation Expense only; there is no allocation of Common Depreciation Expense in this amount from page 336.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) ☐ An Original (2) ☒ A Resubmission	09/16/2011	End of 2010/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	22,321,962			420	1,378,864	
6							
7							
8	TOTAL	22,321,962				1,378,864	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12	4%	152,045			420	19,955	
13	10%	4,589,090			420	265,145	
14							
15	TOTAL	4,741,135				285,100	
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
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48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [X] A Resubmission	09/16/2011	End of 2010/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
20,943,098	30 years		5
			6
			7
20,943,098			8
			9
			10
			11
132,090	40 years		12
4,323,945	40 years		13
			14
4,456,035			15
			16
			17
			18
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			20
			21
			22
			23
			24
			25
			26
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			44
			45
			46
			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [X] A Resubmission	09/16/2011	End of 2010/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Energy Service Company Deposits	1,647,925	Various	161,014	11,014	1,497,925
2						
3	Unregulated Generator Capital					
4	Capital Work Reimb. - Oneida	10,484,718	Various	4,136,724	346,446	6,694,440
5						
6	Capital Work Reimb. - Salamanca	705,693				705,693
7						
8	Demutualization - UMICO Holdings	1,128,420				1,128,420
9						
10	Liability for Environmental					
11	Restoration Costs	448,707,190	182	45,995,184	42,472,684	445,184,690
12						
13	Supplemental Executive					
14	Retirement Plan Liability	4,738,322	Various	1,756,729	731,542	3,713,135
15						
16	FAS 106	843,549,169	131/128/182	160,892,459	184,167,333	866,824,043
17						
18	Liability for Nuclear Fuel					
19	Disposal Costs	167,264,688			218,385	167,483,073
20						
21	KS- Deriv MTM Regulated- LT		182	2,858,111	4,267,516	1,409,405
22						
23	Pension Cost	46,582,034	926/ 131	223,491,941	2,649,236	-174,260,671
24						
25	Other Post Employment Benefit					
26	Liability	30,216,776	926	2,724,259		27,492,517
27						
28	Def Incentive Comp - Pensions	6,085,536	128	4,764,421	995,797	2,316,912
29						
30	Fin48Sit - Timing Issues	1,177,042				1,177,042
31	Fin48Fit - Permanent Issues	16,115,407	431	16,115,407		
32	Fin48Sit - Permanent Issues	224				224
33	Long Term Interest Payable	20,617,099	431	12,307,810	4,887,468	13,196,757
34	NYPA-Tri-Lakes	38,773,343				38,773,343
35						
36	Large Project Salvage	70,050	143	203,893	746,236	612,393
37						
38	Sales Tax Exposure		431/ 144	5,000,000	28,598,721	23,598,721
39						
40	All Other	4,285,344	Various	4,280,213	175,640	180,771
41						
42						
43						
44						
45						
46						
47	TOTAL	1,642,148,980		484,688,165	270,268,018	1,427,728,833

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [X] A Resubmission	09/16/2011	End of 2010/Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

Name of Respondent Niagara Mohawk Power Corporation	This Report Is: (1) ☐ An Original (2) ☒ A Resubmission	Date of Report (Mo, Da, Yr) 09/16/2011	Year/Period of Report End of 2010/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
							4
							5
							6
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							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [X] A Resubmission	09/16/2011	End of 2010/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	1,082,785,271	309,069,193	229,187,872
3	Gas	353,479,942	111,094,002	76,395,957
4				
5	TOTAL (Enter Total of lines 2 thru 4)	1,436,265,213	420,163,195	305,583,829
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	1,436,265,213	420,163,195	305,583,829
10	Classification of TOTAL			
11	Federal Income Tax	1,424,232,999	234,326,346	235,676,313
12	State Income Tax	12,032,212	185,836,851	69,907,516
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [X] A Resubmission	09/16/2011	End of 2010/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
						1,162,666,592	2
						388,177,987	3
							4
						1,550,844,579	5
							6
							7
							8
						1,550,844,579	9
							10
						1,422,883,032	11
						127,961,547	12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [X] A Resubmission	09/16/2011	End of 2010/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Regulatory Assets - Meger rat	415,705,000		213,752,162
4	Regulatory Assets - Environmen	222,952,932		42,875,311
5	Regulatory Assets - Other	396,222,224		122,449,961
6	Other Items	184,733,641		107,414,937
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	1,219,613,797		486,492,371
10	Gas			
11	Regulatory Assets - Environmen	18,970,068	17,913,301	
12	Regulatory Assets - Other	33,712,776	22,361,061	
13	Other Items	15,718,159	118,198	
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	68,401,003	40,392,560	
18				
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	1,288,014,800	40,392,560	486,492,371
20	Classification of TOTAL			
21	Federal Income Tax	1,136,549,970	8,779,648	472,694,173
22	State Income Tax	151,464,830	31,613,212	13,798,198
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [X] A Resubmission	09/16/2011	End of 2010/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						201,952,838	3
						180,077,621	4
						273,772,263	5
						77,318,704	6
							7
							8
						733,121,426	9
							10
						36,883,369	11
						56,073,837	12
						15,836,357	13
							14
							15
							16
						108,793,563	17
							18
						841,914,989	19
							20
						708,265,173	21
						133,649,816	22
							23

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) ☐ An Original (2) ☒ A Resubmission	09/16/2011	End of 2010/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Federal Reg. Liab (SFAS 109)	17,730,552	190	1,003,100		16,727,452
2	Medicare Act Tax Benefit	73,398,363	various	93,131,801	21,766,471	2,033,033
3	Electric R&D Ventures Deferral	28,707				28,707
4	Proceeds from Sale of Emissions Allowan	1,907,035			46,800	1,953,835
5	Clean Air Act - Roseton	179,080			4,800	183,880
6	Purchase of Emission Reduction Credits	951,300				951,300
7	Gain on Redemption of 8.35 Series Bond	361,386	429.1	60,460		300,926
8	CSS Conv Savings Dist	1,400,206			39,618	1,439,824
9	CSS Conv Savings Gas	237,117			5,496	242,613
10	IRS Audit Refund (83-84)	307,485				307,485
11	Unbilled Gas Revenue	18,799,000	173	13,609,000	13,854,000	19,044,000
12	Gas Non-core Revenue Sharing	1,134,705	182	3,496,851	5,100,843	2,738,697
13	Electric Customer Service Penalty	23,999,476	456	539	34	23,998,971
14	Gas Contingency Reserve	1,150,156			273,132	1,423,288
15	Environment Insurance Recoveries	4,741,379				4,741,379
16	Gas Customer Service Penalty	83,748	495	6	1	83,743
17	Powerchoice Appendix E Netting Proposal	79,599,407				79,599,407
18	Electric Revenue Property Tax Credit	1,537,661			2,487,000	4,024,661
19	Loss on Sale of Building	2,914,368			518,898	3,433,266
20	SBC Program Deferred		456	243,206	843,869	600,663
21	MRA Interest Rate Savings	92,534,022				92,534,022
22	Petroleum Bus Tax Audit Refund (90-96)	5,752,659				5,752,659
23	Exit Fees	2,682,388	456	1,346,820	25,000	1,360,568
24	Affiliate Rule Employee Transfer Credit	166,725				166,725
25	Pension / OPEB Curtailment Gains	25,552,091				25,552,091
26	IRS Audit Refund (89-90)	48,100				48,100
27	State Reg. Liability (SFAS 109)	32,664,135				32,664,135
28	Diana Dolgeville - IPP Settlement	4,922,128				4,922,128
29	Electric Service Reestablishment Charges	464,158				464,158
30	Merchant Function Charge		495	33,553	241,571	208,018
31	SBC Program Cost - Electric	23,221,242	456	10,789,041	18,872,960	31,305,161
32	Merger Rate Plan Delay	12,555,000				12,555,000
33	New York State Sales Tax Refund (92-98)	1,477,332				1,477,332
34	Economic Development Fund	38,083,976	131	18,068,139	17,475,863	37,491,700
35	Incidental Service Revenues Deferred	508,073	451	512	37,366	544,927
36	GRT Customer Refund - Gas	376,415	431	522,929	200,900	54,386
37	Meter Read Connect/Disconnect Serv. Chg	128,205			3,440	131,645
38	Gas Millenium Fund Deferral	218,703	885	250,000	180,770	149,473
39	NYPA Residential Hydropower Benefit	15,169,648	182/456	51,645,236	49,207,399	12,731,811
40	NYPA ISO Memorandum of Understanding	16,676,906				16,676,906
1	Bonus Depreciation Adjustment	25,093,881			2,747,000	27,840,881
2	Pension/OPEB Interest on Recovery	4,145,621				4,145,621
3	STA Service Sale Growth Deferral	2,350,188				2,350,188
4	GRT Aud Ref (91-94) Electric	3,300,423				3,300,423
41	TOTAL	585,233,843		737,637,848	759,978,064	607,574,059

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) ☐ An Original (2) ☒ A Resubmission	09/16/2011	End of 2010/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
5	MHP Program Deferral	435,317			140,658	575,975
6	SERV Aggreg Lost Revenues	155,663	456	78,341		77,322
7	NEG Merger Savings	4,250,591			4,038,127	8,288,718
8	KS Merger Savings - Electric	5,153,183			20,574,077	25,727,260
9	Gas Futures - Gas Supply	3,638,195	175	6,187,503	4,180,404	1,631,096
10	KS Merger Savings - Gas	1,559,261	495	4,166,996	2,828,541	220,806
11	Electric Swaps - Electric Supply	96,000	175	533,002,447	583,898,880	50,992,433
12	Voltage Migration Fee Deferral	18,448	456	1,368		17,080
13	Long Term Debt True Up	5,413,194			9,659,606	15,072,800
14	Gratwick Park Prop Transfer	1,829			32,400	34,229
15	Fed Tax Refund 1991-1995	25,959,012			692,140	26,651,152
16						
17						
18						
19						
20						
21						
22						
23						
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26						
27						
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30						
31						
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34						
35						
36						
37						
38						
39						
40						
41	TOTAL	585,233,843		737,637,848	759,978,064	607,574,059

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) __ An Original (2) X A Resubmission	09/16/2011	2010/Q4

FOOTNOTE DATA

Schedule Page: 278 Line No.: 2 Column: a

Section 1.2.4.2 of the Joint Proposal: The Medicare Reform Act reduces the Company's tax expense. The reduction in tax expense is reflected in the deferral account under Section 1.2.4.2 of the Joint Proposal, which is quoted in connection with the Bonus Tax Depreciation discussed under Schedule 37 of Attachment 6.

Schedule Page: 278 Line No.: 3 Column: a

Merger Joint Proposal: Pursuant to the Merger Joint Proposal, Niagara Mohawk is required to credit customers fifty percent of any royalties received.

Schedule Page: 278 Line No.: 4 Column: a

Niagara Mohawk Power Corporation PSC Case no. 08-G-0609, Merger Joint Proposal

Schedule Page: 278 Line No.: 5 Column: a

Amounts are accounted for in accordance with: 09-M-0727

Schedule Page: 278 Line No.: 6 Column: a

Pursuant to the Commission's Order in Case 96-E-1155 issued and effective May 29, 1997: the Company established an account to track Emission Reduction Credit transactions in accordance with the terms and conditions of the Order.

Schedule Page: 278 Line No.: 7 Column: a

Amortization period: October 2002 - December 2015

Schedule Page: 278 Line No.: 8 Column: a

Pursuant to order in Case 07-M-0943: The Customer Service System (CSS) was developed by Niagara Mohawk pre-merger and was originally paid for by NY ratepayers. Since the merger, CSS has been implemented for other National grid Companies. This deferral is a result of allocating costs to the National Grid Companies utilizing CSS. The allocation method was agreed to with the NY PSC to appropriately allocate CSS cost and credit chargeback. This account carries the Electric allocation, with GAS accounted for via account 254507.

Schedule Page: 278 Line No.: 9 Column: a

Pursuant to order in Case 07-M-0943: The Customer Service System (CSS) was developed by Niagara Mohawk pre-merger and was originally paid for by NY ratepayers. Since the merger, CSS has been implemented for other National grid Companies. This deferral is a result of allocating costs to the National Grid Companies utilizing CSS. The allocation method was agreed to with the NY PSC to appropriately allocate CSS cost and credit chargeback. This account carries the GAS allocation, with Electric accounted for via account 254506.

Schedule Page: 278 Line No.: 10 Column: a

This account was authorized by the Commission in Section 2.6.5 of the PowerChoice Agreement in Case 94-E-0098.

Schedule Page: 278 Line No.: 12 Column: a

Account relates to relevant invoicing for an Oil Infrastructure Study referenced to Case 00-G-0096. Additional schedules also indicate margin calculations referenced to NYSERDA.

Schedule Page: 278 Line No.: 13 Column: a

Section 1.2.4.8 of the Joint Proposal: The Joint Proposal prescribes a comprehensive list of Service Quality Standards, and a schedule of penalties in the event Niagara Mohawk fails to meet the Standards. Under most circumstances, the penalties are included as an offset to the deferral account. Section 1.2.4.8 of the Joint Proposal provides that: "Niagara Mohawk shall include in the Deferral Account any penalties associated with failure to meet the Service Quality standards set forth in Attachment 9, not otherwise credited to customers under Section 1.2.3.7." The Stipulation included adjustments of $1.7 million that increased electric. This account comprises those allotted to Electric, and account # 254517 those recognized as GAS.

Schedule Page: 278 Line No.: 14 Column: a

Per the Commission's February 14, 2000 Order in Case 99-G-1369

Schedule Page: 278 Line No.: 16 Column: a

As per 254513 account results, Section 1.2.4.8 of the Joint Proposal: The Joint Proposal prescribes a comprehensive list of Service Quality Standards, and a schedule of penalties in the event Niagara Mohawk fails to meet the Standards. Under most circumstances, the penalties are included as an offset to the deferral account. Section 1.2.4.8 of the Joint Proposal provides that: "Niagara Mohawk shall include in the Deferral Account any

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penalties associated with failure to meet the Service Quality standards set forth in Attachment 9, not otherwise credited to customers under Section 1.2.3.7." The Stipulation included adjustments of $1.7 million that increased electric. This account comprises those allotted to GAS, and account # 254513 those recognized as Electric.

Schedule Page: 278 Line No.: 17 Column: a

Memorandum of Agreement dated 3/31/03 Section 1.2.3: Amounts are fixed as a result of outcomes within the latter Agreement

Schedule Page: 278 Line No.: 18 Column: a

NIMO Rate Case 08-G-0609, Joint Proposal 2.1(g) Appendix I: On May 23, 2008, Niagara Mohawk filed tariff leaves and supporting testimony and exhibits for new rates and charges for gas service to be effective June 23, 2008. The revenue requirement is based on several parameters including: A normalizing property tax adjustment of $2.487 million that represents a reallocation of property tax expense from the electric business to the gas business. Notwithstanding Clause 1.2.3.5 of the Merger Joint Proposal approved in Case 01-M- 0075, this increased gas expense will be offset by an electric deferred credit of $2.487 million

Schedule Page: 278 Line No.: 19 Column: a

Cases 03-M-1374, Order dated January 29, 2004 (O'Neill Building) and 03-M-1572, Order dated June 1, 2004 (Buffalo Electric Building): Following the merger, Niagara Mohawk undertook a program to consolidate offices and work locations. As part of that effort, the Company sold several facilities that it had used for offices. Specifically, Niagara Mohawk sold the Electric Building in Buffalo, the O'Neill Building in Syracuse, and Towpath properties, and the lease on the Dey's Building in Syracuse ended. The sale of the O'Neill Building and the Buffalo Electric building required the Commission's approval under Section 70 of the Public Service Law. Niagara Mohawk believed that these sales were necessary to realize the synergy savings and efficiency gains that were projected in the Rate Plan and reflected in the settled delivery rates. However, the sale of these properties occurred at a price below book value. Under standard accounting practice, the actual proceeds from the sale would be credited to the depreciation reserve, meaning that the net loss on the sale would remain in rate base and would be supported by customers. The Commission approved the sale of both buildings
in Cases 03-M-1374, Order dated January 29, 2004 (O'Neill Building) and 03-M-1572, Order dated June 1, 2004 (Buffalo Electric Building).
However, the Commission conditioned its approval on Niagara Mohawk's agreement to a further sharing of the savings associated
with the sale. Under the Orders, Niagara Mohawk was required to write-off 50 percent of the loss associated with the sale of the assets
and land. In addition, Niagara Mohawk was required to credit the deferral account for the benefit of customers 50 percent of (1)
the annual avoided depreciation savings associated with sale and equipment that was retired, and (2) the annual carrying charges
associated with sale proceeds received and the tax losses realized.

Schedule Page: 278 Line No.: 20 Column: a

Case 05-M-0090 orders in the matter of the System Benefits Charge, Order Constituting the System Benefots Charge (SBC) and the SBC-Funded Public Benefit Programs

Schedule Page: 278 Line No.: 21 Column: a

Memorandum of Agreement dated 3/31/03 Section 1.2.3

Schedule Page: 278 Line No.: 22 Column: a

Memorandum of Agreement dated 3/31/03 Section 1.2.3: Line 26 sets forth the credit to customers associated with a tax refund received by Niagara Mohawk before the merger. This item has been reviewed by the Staff and resolved as part of the Memorandum of Agreement dated March 31, 2003, and is a closed item.

Schedule Page: 278 Line No.: 23 Column: a

Pursuant to Rule 52 of the Tariff, in the event that a customer totally bypasses the Company's retail distribution system, the customer is required to pay a lump sum payment of transition costs. The purpose of this provision is to discourage total bypass of the Company's retail distribution services and charges where such bypass is not economic from society's standpoint and to prevent the shifting of the Company's Transition costs to

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other stakeholders. Amorization period: April 2005 - December 2011

Schedule Page: 278 Line No.: 24 Column: a

Memorandum of Agreement dated 3/31/03 Section 1.2.3.: This item is associated with pre-merger activity. No activity has occurred in this account since the merger, and none is forecast over the period of the CTC Reset. The balance in the deferral was resolved by the Memorandum of Agreement dated March 31, 2003.

Schedule Page: 278 Line No.: 25 Column: a

Memorandum of Agreement dated 3/31/03 Section 1.2.3: The account has been closed since before the merger and the balance is resolved by the Memorandum of Agreement dated March 31, 2003.

Schedule Page: 278 Line No.: 26 Column: a

Attachment 1 to Stipulation, page 4 of 5, item 6: A de minimus federal income tax refund from 1989-1990 ($48,100) was reclassified as a deferrable regulatory liability as part of the Stipulation (see referenced document). This item is fixed as of June 30, 2005.

Schedule Page: 278 Line No.: 29 Column: a

Case 00-E-1406, and Attachment 2, Section A, line 21: In Case 00-E-1406, the Commission ordered that the Company defer the increase in revenue resulting from increases in and changes to its service re-establishment charges, which was approximately $464,000. The Stipulation requires the reclassification of the deferred credit balance into the Deferral Account. Also, the account balance is final, as noted by the inclusion of the account in Attachment 2, Section A, line 21.

Schedule Page: 278 Line No.: 31 Column: a

Amounts relate to the Enhanced SBC Electric component program which falls under the NYSERDA Agreement dated as of March 1, 2006 as amended on January 22, 2009, September 1, 2009 and February 26, 2010. Amounts correspond to relevant SBC Payment Schedule amounts based on this NYSERDA Agreement.

Schedule Page: 278 Line No.: 32 Column: a

Section 1.2.4.20 of the Rate Plan, Memorandum of Agreement dated 3/31/03: The Joint Proposal was crafted based on the assumption that the Merger Rate Plan would become effective on January 1, 2002, and thus included a credit in the event the closing date was delayed. The credit is included in the deferral account pursuant to Section 1.2.4.20 of the Rate Plan, which provides that: "On the Effective Date, Niagara Mohawk shall include in the Deferral Account an electric customer credit equal to $405, 000 for each day between January 1, 2002 and the Effective Date as set forth in Attachment 2, p. 2" [the actual Effective Date]. This item was closed as part of the Stipulation, included in Attachment 2, Part A, line 12.

Schedule Page: 278 Line No.: 33 Column: a

Memorandum of Agreement dated /31/03 Section 1.2.3.: Niagara Mohawk received a refund of state taxes covering the period 1992 through 1998 during the period prior to the merger. This item is covered by the Memorandum of Agreement dated March 31, 2003, and there has been no activity in this account since the refund was credited. This account is included in the Stipulation, Attachment 2, Part A, line14 and is no longer subject to adjustment.

Schedule Page: 278 Line No.: 34 Column: a

Under the Rate Plan, Niagara Mohawk increased the funding for economic development in base rates, and the parties agreed that actual expenditures and economic development discounts above or below the rate allowance would be included in the deferral account under the methodology set forth in Section 1.2.4.7 of the Rate Plan. The reconciliation associated with the Economic Development Plan includes the following components: (1) Empire Zone Rider (EZR) discounts for new and expanding customers; (2) the discounts associated with flex rate contracts signed under SC-11 or SC-12; (3) the funding associated with incremental economic development initiatives in Niagara Mohawk's Economic Development Plan approved by the Commission and the DPS Staff pursuant to Section 1.2.10.2 of the Rate Plan; and (4) incremental expenditures for non-labor spending on new economic development initiatives. Section 1.2.4.7 requires that Niagara Mohawk complete a monthly reconciliation of the actual economic development discounts provided to customers and the actual incremental non-labor economic development spending to the allowance in rates for these activities. The allowance in rates is set forth in Attachment 15 to the Rate Plan.

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Schedule Page: 278 Line No.: 35 Column: a

Under Section 1.2.4.18 of the Rate Plan: Niagara Mohawk is required to "include in the Deferral Account 50 percent of any net incremental revenues from Currently Provided Incidental Services pursuant to Section 2.4.1 of Attachment 23." Section 2.4.1 of Attachment 23 applies to services currently provided pursuant to Rule 28 of the Company's tariff, P.S.C. 207. The services include such things as operation, maintenance, and construction services to the customer's equipment, at the customer's request and incidental to Niagara Mohawk's energy services. The balance in the account at June 30, 2005 cannot be adjusted according to Attachment 2, Part A, line 13 of the Stipulation.

Schedule Page: 278 Line No.: 36 Column: a

Rate Case 09-M-0727, Merger Joint Proposal

Schedule Page: 278 Line No.: 37 Column: a

Order dated May 22, 2002 in Case 02-E-0245: On February 25, 2002, Niagara Mohawk proposed an amendment to Rule 28 of its tariff to allow it to charge customers $20 when they request a field visit to read a meter when service is connected or disconnected. The Commission approved this filing in an order dated May 22, 2002 in Case 02-E-0245. Under the Order, at page 3, Niagara Mohawk is required to defer 100 percent of the revenue collected under the charge in the deferral account. The Order states that Niagara Mohawk be directed to place all revenue collected by the $20 meter reading/disconnect charge in a new and separate subaccount within the Deferral Account as set forth in Clause 1.2.4 of the National Grid USA and Niagara Mohawk Joint Proposal, dated October 11, 2001. All such deferred revenues will be used for future ratepayer benefit in accordance with the ratemaking also set forth in Clause 1.2.4.

Schedule Page: 278 Line No.: 38 Column: a

Pursuant to Tariff Rule 30 and the Commission's February 14, 2000 Order in Case 99-G-1369: Niagara Mohawk is to recover and reconcile research and development Millenium Fund Costs in accordance with these rules. The order was Issued & Effective February 14, 2000

Schedule Page: 278 Line No.: 39 Column: a

Per the Statement of Adjustment to Charges Pursuant to the New York Power Authority (NYPA) Hydropower Benefit Reconciliation Mechanism Statement No. 21 To P.S.C. No. 220 Electricity, Effective: December 1, 2010, the purpose of the filing was to implement the reconciliation mechanism associated with Schedule PSC No. 220 Electricity, Rule 40 - Adjustment to Changes Pursuant to the New York Power Authority (NYPA) Hydropower Benefit Reconciliation Mechanism. This rule was established in accordance with Section 1.2.3.2 and Attachment 6 of the Joint Proposal in P.S.C. Case No. 01-M-0075 as approved by the Commission in its Opinion No. 01-6, Opinion and Order Authorizing Merger and Adopting Rate Plan,issued and effective December 3, 2001, and subsequently amended by the Commission in its Order Approving Tariff Amendments, issued and effective August, 28, 2003 in Case No. 03-E-0905 and Order issued and effective December 17, 2007 in Case No. 01-M-0075

Schedule Page: 278 Line No.: 40 Column: a

Case 00-E-0073, order dated January 25, 2000: On October 11, 1999, Niagara Mohawk and NYPA entered into an agreement or Memorandum of Understanding regarding the treatment of ancillary services billed by the NYISO associated with the sale of NYPA power to Niagara Mohawk's retail customers. Rather than billing retail customers directly for these NYISO charges, NYPA agreed to offset the NYISO charges with a proportionate share of NYISO revenues that NYPA received for the ancillary service from the generation that NYPA used to provide Niagara Mohawk customers with electricity. In addition, NYPA agreed to furnish line loss and installed capacity services and to pay to offset the NYISO costs for scheduling services under the NYISO OATT. Niagara Mohawk agreed to pay and defer for later recovery any differences between the NYPA offsets and the actual NYISO charges. The MOU continued through August 31, 2003. The MOU and the reconciliation and deferral were approved by the Commission in Case 00-E-0073 in an order dated January 25, 2000.

Schedule Page: 278.1 Line No.: 1 Column: a

Section 1.2.4.2.1 of the Joint Proposal: A 2002 amendment to section 168 of Internal Revenue Code authorized additional first year tax depreciation for qualified property. Such accelerated depreciation has the effect of reducing the Company's revenue requirements by increasing deferred income taxes, which in turn results in a reduction to rate base. As noted above, section 1.2.4.2.1 of the Joint Proposal provides that the

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effect of such tax law changes be included in the Deferral Account if it exceeds $2.0 million per year. Section 3.4 of the Stipulation addresses the process for recording deferrals for bonus depreciation in several ways. First, that section clarifies that Niagara Mohawk may defer the effects of bonus depreciation only where it is associated with the forecasted construction budget and plant additions underlying the Joint Proposal rates. Second, it requires Niagara Mohawk to develop with Staff, and then, within 120 days of the Commission order on the Stipulation, file with the Commission, a methodology for determining the bonus depreciation benefit attributable to forecasted construction budget and plant additions. Finally, it specifically provides for adjustments to the deferral account following final IRS audit adjustments. Niagara Mohawk and Staff have not yet had the opportunity to jointly develop such a methodology; the methodology underlying the forecast is Niagara Mohawk's.

Schedule Page: 278.1 Line No.: 3 Column: a

Attachment 7 of March 22, 2007 Stipulation in Case 01-M-0075. Attachment 7 titled "Calculation of Certain Effects of Exclusion of Sales of Divested Generators".

Schedule Page: 278.1 Line No.: 4 Column: a

Adjustment agreed to in litigation on Case 01-M-0075:Among the Stipulation's provisions was a reclassification of a $3.3 million New York State Gross Receipts Tax refund from 1991-1994 as a deferrable regulatory liability. See Attachment 1 to Stipulation, page 4 of 5, at item 5. This deferral item is fixed as of June 30, 2007, and will not change through December 31, 2011.

Schedule Page: 278.1 Line No.: 5 Column: a

Case 03-E-0641 effective September 1, 2006: The Commission accepted the Company's August 2, 2006, compliance filing in Case 03-E-0641 effective September 1, 2006.

Schedule Page: 278.1 Line No.: 6 Column: a

Aggregation fee accounting treatment is referenced to Rule 47 in sighted correspondence, with such indicating treatment is similar to that adopted for exit fees (although these are specifically ruled not to be exit fees) which is itself referenced to part 1.2.17.3.4 of the Joint Proposal. Amortization referenced as ratable over the plan period. Balances will be fully amortized at the end of Dec 2011. Amortization period: August 2007 - December 2011.

Schedule Page: 278.1 Line No.: 7 Column: a

The Rate Plan, at Section 1.2.4.19: provides that in the event National Grid closes any additional mergers or acquisitions within the United States, Niagara Mohawk shall implement a Follow-on Merger Credit calculated pursuant to methodology set forth in Attachment 10, which is designed to credit the deferral Account by fifty percent of the additional synergies (net of costs to achieve) produced by the follow-on merger and allocable to Niagara Mohawk electric operations. The Follow-on Merger Credit to the Deferral Account shall remain in effect for the remaining term of the Rate Plan. Subsequent to the end of the Rate Plan, as the credit will have been in effect for more than five years, Niagara Mohawk will not make an adjustment to the revenue requirements in its Post Rate Plan Filing to recover the Follow-on Merger Synergy Allowance, and 100 percent of the net synergy savings from the New England Gas acquisition will flow through the cost of service for the benefit of customers. This approach is consistent with Section 1.2.6, Post Rate Plan Filing of the Rate Plan.

Schedule Page: 278.1 Line No.: 8 Column: a

The Rate Plan, at Section 1.2.4.19: provides that in the event National Grid closes any additional mergers or acquisitions within the United States, Niagara Mohawk shall implement a Follow-on Merger Credit calculated pursuant to methodology set forth in Attachment 10, which is designed to credit the deferral Account by fifty percent of the additional synergies (net of costs to achieve) produced by the follow-on merger and allocable to Niagara Mohawk electric operations. On July 20, 2006, National Grid and KeySpan filed with the NYPSC a joint petition of a proposed acquisition of the stock of KeySpan by National Grid. Case 06-M-0878 was instituted to provide a process for the NYPSC to consider the petition. On July 6, 2007, a Merger and Gas Revenue Requirement Joint Proposal ("KS Joint Proposal") by and among KeySpan, National Grid, DPS Staff, the Consumer Protection Board and other signatory parties, was submitted to the Commission. The KS Joint Proposal specifies an annual level of mature synergy savings of $156 million.

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In its Orders of August 23, 2007 and September 17, 2007 approving National Grid's merger with KeySpan Corporation, the Commission approved $156 million in mature synergy savings associated with the merger. By its Order of May 29, 2008, the Commission determined that the NMPC share of synergy savings from the KeySpan merger to be $52 million for the period August 2007 through December 2011.

Schedule Page: 278.1 Line No.: 10 Column: a

As per a/c 254568, The Rate Plan, at Section 1.2.4.19: provides that in the event National Grid closes any additional mergers or acquisitions within the United States, Niagara Mohawk shall implement a Follow-on Merger Credit calculated pursuant to methodology set forth in Attachment 10, which is designed to credit the deferral Account by fifty percent of the additional synergies (net of costs to achieve) produced by the follow-on merger and allocable to Niagara Mohawk electric operations. On July 20, 2006, National Grid and KeySpan filed with the NYPSC a joint petition of a proposed acquisition of the stock of KeySpan by National Grid. Case 06-M-0878 was instituted to provide a process for the NYPSC to consider the petition. On July 6, 2007, a Merger and Gas Revenue Requirement Joint Proposal ("KS Joint Proposal") by and among KeySpan, National Grid, DPS Staff, the Consumer Protection Board and other signatory parties, was submitted to the Commission. The KS Joint Proposal specifies an annual level of mature synergy savings of $156 million. In its Orders of August 23, 2007 and September 17, 2007 approving National Grid's merger with KeySpan Corporation, the Commission approved $156 million in mature synergy savings associated with the merger. By its Order of May 29, 2008, the Commission determined that the NMPC share of synergy savings from the KeySpan merger to be $52 million for the period August 2007 through December 2011.

Schedule Page: 278.1 Line No.: 12 Column: a

Pursuant to Rule 44 of the Tariff: in the event of any increase in a customer's delivery voltage pursuant to Rule 44.1.2, the customer shall be required to pay the difference between the distribution and CTC charges applicable to the customer's former delivery voltage and the distribution and CTC charges applicable to the higher delivery voltage at which the customer is to be served after the voltage increase. Amortization period: July 2008 - June 2023.

Schedule Page: 278.1 Line No.: 13 Column: a

This account represents relevant deferrals in relation to NYSERDA Promissory Notes, and Floating Series A and K, for which Interest and Amortization is calculated as relevant. Deferral schedule on file also references to "NYSERDA Auction Rate Debt (4.4.6)".

Schedule Page: 278.1 Line No.: 14 Column: a

Per Case 08-E-1390: Niagara Mohawk Power Corporation petitioned for approval under Section 70 of the PSL for the sale of two parcels of real property known as Gratwick Riverside Park to the City of Tonawanda. On May 28, 2009 permission was permission to NIMO, d/b/a National Grid, to transfer the property to the City of Tonawanda. The commission ordered that NIMO record an electric deferred credit in the amount of $2,700 per month from the time the property is transferred until new electric rates are established. New rates are expected to be in place January 2012. This represents the net expense of property built into base rates that will be avoided by the company.

Schedule Page: 278.1 Line No.: 15 Column: a

In proceeding 09-M-0554, dated July 14, 2009: NMPC d/b/a National Grid provides notice and seeks commission approval necessary for the disposition of the federal income tax refund and the associated interest pursuant to Section 113(2) of the NY PSL. This gives the Commission the authority to determine whether the refund should be passed through, in whole or in part, to the customers and to order the manner and the extent of such a distribution.

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OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Regulatory Tax Asset (FAS 109)	185,504,044	11,543,561	various	13,187,175	183,860,430
2	Deferred Environmental Restoration Costs	448,707,190	21,470,389	253	33,610,260	436,567,319
3	Storm Restoration Costs Deferred	172,035,891	1,147,425	571/593	115,604	173,066,712
4	Enhanced Severance Plan	60,056		926	29,487	30,569
5	Pension Settlement Loss FY 2003	31,225,615				31,225,615
6	Asset Retirement Obligation Reg Asset	8,992,955	873,580	230	621,244	9,245,291
7	Gas Futures - Gas Supply	16,332,718	115,488,649	245/253	106,599,407	25,221,960
8	Elec Swaps - Elec Supply	38,285,522	172,182,801	244	175,289,978	35,178,345
9	Deferred Loss - Sale of Oswego	931,749		411	465,874	465,875
10	Temp State Assessment 18-A	34,975,999	8,341,460	various	20,025,754	23,291,705
11	FAS 158 - Pension	494,496,318		253/926	104,927,987	389,568,331
12	FAS 158 - OPEB	201,015,097	166,746,290	926	92,292,317	275,469,070
13	Fuel Cost Deferred	924,400				924,400
14	Gas Adjustment Clause	44,919,105	41,484,237	various	34,379,736	52,023,606
15	RPS Program Cost Deferred	1,771,099	326,711	254/456	1,040,164	1,057,646
16	Excess AFUDC - Electric Plant in Service	230,742		406	17,242	213,500
17	Commodity Adjustment Clause	44,634,146	34,765,202	various	65,743,611	13,655,737
18	Other Post Retirement Benefits - Electric	8,782,639		926	2,766,000	6,016,639
19	Other Post Retirement Benefits - Gas	968,559		926	660,000	308,559
20	Electric Plant in Service Excess AFUDC	557,344		406	19,671	537,673
21	PFJ Tax Credit	3,633,275				3,633,275
22	NIMO Case 08-G-0609 JP Amort	37,536,238	14,106,439	254/407	28,831,410	22,811,267
23	SBC Program Cost Deferred - Electric	2,162,029	335,449	456	2,497,478	
24	Customer Service Backout Credit	10,309,579				10,309,579
25	NYPA Transmission Access Charge (NTAC)	13,050,967				13,050,967
26	NYISO Tariff Schedule 1 Costs	85,451,012				85,451,012
27	NYISO Tariff Schedule 2 Costs	13,286,552				13,286,552
28	Fossil / Hydro Auction Incentive	18,556,040				18,556,040
29	State Regulatory Asset (SFAS 109)	(53,252,638)	1,630,300	182/282	11,484,260	-63,106,598
30	80/20 Revenue Sharing Mechanism	7,290,022	34,367	495	6,134,479	1,189,910
31	NIMO - Merchant Function Charge	409,918		495	409,918	
32	SIR Expenditures Deferred - Gas	1,738,020	172,131	431/930	667,554	1,242,597
33	SBC Program Cost Deferred - Gas	6,805,743	2,659,487		10,490,000	-934,770
34	Transmission Revenue Adjustment Clause	4,705,193	11,043,983	456	11,731,392	4,017,784
35	Elevated Voltage Deferral	14,618,398	4,686,123			19,304,521
36	Low Income Allowance Discount Program	4,154,119	2,209,824			6,363,943
37	Customer Service Backout Credit	111,284,085	5,736,322			117,020,407
38	Electronic Data Interchange (EDI) Costs	3,849,301				3,849,301
39	Pension Settlement Loss	88,044,864		926	44,022,432	44,022,432
40	Voluntary Early Retirement Offer (VERO)	2,334,152		926	1,146,048	1,188,104
41	Merger Rate Plan Stranded Costs	1,077,269,521		407	520,164,176	557,105,345
42	Pension Expense Deferred - Electric	169,995,509	26,791,215	253	245,763	196,540,961
43	OPEB Expense Deferred - Electric	286,479,502	56,060,583	253/926	2,877,090	339,662,995
44	TOTAL	3,315,956,477	739,347,657		1,423,661,863	2,631,642,271

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OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS: Written off During the Quarter/Year Account Charged (d)	CREDITS: Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Religious Rate Revenue	4,062,277	112,180			4,174,457
2	City of Buffalo Settlement Agreement	684,320				684,320
3	SC7 Standby Service Lost Revenue	516,012	1,159,445	456	20,257	1,655,200
4	SIR Expenditures Deferred - Electric	89,114,041	16,753,721	431/930	2,855,326	103,012,436
5	Generation Stranded Costs Adjustments	35,523,449	2,415,322			37,938,771
6	OPEB Expense Deferred - Gas	5,723,683	19,141	253/926	3,015,394	2,727,430
7	Pension Expense Deferred - Gas	4,663,045	410,903	253/926	50,337	5,023,611
8	Incentive Return on Retirement Funding	73,174,913	11,488,736			84,663,649
9	Amortization of Deferral Recoveries	(547,176,225)		407	123,588,109	-670,764,334
10	RDM Revenue Decoupling	4,475,604	6,115,338	419/495	1,637,929	8,953,013
11	NIMO - Low Income Program	42,769	1,036,343			1,079,112
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44	TOTAL	3,315,956,477	739,347,657		1,423,661,963	2,631,642,271

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Schedule Page: 232 Line No.: 2 Column: a

Per Attachment 14, Joint Proposal dated October 11, 2001: Original approval obtained; Perorder in the NIMO Gas Rate Case 08-G-0609 modifications were made for the gas business.

Schedule Page: 232 Line No.: 3 Column: a

Under Section 1.2.4.5 of the Rate Plan, Niagara Mohawk is allowed to defer and recover the Incremental costs that exceed $2.0 million from any individual major storm as defined under NYCRR Part 97, provided that NIMO has first spent a total of $6.0 million on Incremental costs of Major Storms in that year, which has not been included in the deferral. Case 01-M-0075 - Rate Plan 1.2.4.5 - Niagara Mohawk shall include in the Deferral Account any Incremental Costs that exceed $2.0 million from any individual Major Storm occurring in a calendar year, provided that Niagara Mohawk has first spent a total of $6.0 million on Incremental Costs of Major Storms in that year, which has not been included in the Deferral Account. A Major Storm shall be defined in accordance with the Commission's definition in 16 NYCRR Part 97.

Schedule Page: 232 Line No.: 4 Column: a

Pursuant to Attachment 16 of the Merger Rate Plan, Niagara Mohawk records an offsetting regulatory asset equal to Separation and Early Retirement Costs and amortizes that balance by the established percentages (January 2002-December 2011).

Schedule Page: 232 Line No.: 5 Column: a

Case No. 03-M-0651 and Case No. 04-M-0938 (petition dockets) filed with the Commission requesting approval to include the settlement loss in the deferral account under the Commission's Statement of Policy Concerning the Accounting and Ratemaking Treatment for Pensions and Postretirement Benefits other than Pensions, Case 91-M-0890 (September 7, 1993) (Statement of Policy). During the fiscal years ended March 31, 2003 and 2004, Niagara Mohawk was required to recognize pension settlement losses under Statement of Financial Accounting Standards, (FAS) 88 equal to $29.0 million and $21.6 million, respectively.

Schedule Page: 232 Line No.: 9 Column: a

Pursuant to the Commission's Order in Case 07-M-0704, the Company absorbed the entire net book loss associated with the sale of Oswego Fire School. The Commission approved the sale of property and authorized the Company to amortize the net book loss over the term of the Merger Rate Plan (September 2008 - January 2011).

Schedule Page: 232 Line No.: 10 Column: a

Case 09-M-0311, dated June 19, 2009: Provides authorization to defer the difference between total assessment expense (Temporary State Assessment and General Assessment) and the amount collected from customers. Carrying charges should be calculated by applying the corporations' authorized pre-tax rate of return to the net of tax un-recovered Temporary State Assessment payments. The deferred assessment expense and accrued carrying charges are to be recovered through the Temporary State Assessment surcharge or adjustment and reconciliation mechanism over 5 years, 7/1/2009 through 6/30/14.

Schedule Page: 232 Line No.: 13 Column: a

Memorandum of Agreement dated 3/31/03

Schedule Page: 232 Line No.: 14 Column: a

PSC No: 219 GAS, Initial Effective Date 08/1/03

Schedule Page: 232 Line No.: 15 Column: a

Pursuant to the Commission's September 24, 2004 Order in Case No. 03-E-0188: The Renewable Portfolio Surcharge "RPS" is a mechanism which permits the Company to recover from customers costs associated with providing financial incentives for the development of renewable resources in New York State

Schedule Page: 232 Line No.: 16 Column: a

Amortization period: April 2004-June 2023

Schedule Page: 232 Line No.: 17 Column: a

Niagara Mohawk Power Corporation Statement of Commodity Adjustment Charge (CAC) P.S.C. No. 220 - Rule 29.2

Schedule Page: 232 Line No.: 18 Column: a

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Merger Joint Proposal incl Attachment 1, Page 6, Line 11

Schedule Page: 232 Line No.: 19 Column: a

Merger Joint Proposal; Rate Plan 08-G-0609

Schedule Page: 232 Line No.: 20 Column: a

Amortization period: April 2004 - April 2038

Schedule Page: 232 Line No.: 21 Column: a

Merger Joint Proposal section 1.2.4.2.1 "Tax and Accounting Changes - Externally Imposed": authorizes deferral of this category of costs

Schedule Page: 232 Line No.: 22 Column: a

Amortization period: April 2009 - July 2012

Schedule Page: 232 Line No.: 23 Column: a

Case 05-M-0090 orders in the matter of the System Benefits Charge, Order Constituting the System Benefots Charge (SBC) and the SBC-Funded Public Benefit Programs

Schedule Page: 232 Line No.: 24 Column: a

Balance fixed per Memorandum Of Agreement 3/31/03 section 1.2.3: The Customer Service Backout Credit of $10.3 million shown on Attachment 6 represents the deferral for customer service backout credits that accrued under Power Choice and prior to the Rate Plan, and was subsequently included in the audit resolved by the noted MOA. As such this balance is final.

Schedule Page: 232 Line No.: 25 Column: a

Balance fixed per Memorandum Of Agreement 3/31/03 section 1.2.3: Prior to the merger, Niagara Mohawk agreed as part of the establishment of the NYISO that it would be allowed to recover the lower of: (1) Niagara Mohawk's actual expenses for the sum of Low Income Consumer Assistance Program arrears forgiveness; Consortium co-funding in the form of in-kind services associated with a Department of Energy contract; and leveraged co-funding and grants received on SBC qualifying projects; or (2) Niagara Mohawk's NYPA Transmission Access Charge (NTAC). The costs under category (1) above total $13.1 million and are substantially below the NTAC of $24.8 million as of January 1, 2002. These costs were recorded prior to the effective date of the Rate Plan. This item was also the subject of the audit that was resolved by the Memorandum of Agreement dated March 31, 2003, and is final.

Schedule Page: 232 Line No.: 26 Column: a

Commission Order dated August 15, 2001 in Case 94-E-0098, et al, at page 18: On September 1, 2001 Niagara Mohawk began including these costs directly in its Commodity Adjustment Clause, which reconciles the charges under NYISO Tariff Schedules 1 and 2 in current rates. Through August 31, 2001, Niagara Mohawk included the charges by the New York Independent System Operator (NYISO) under its Tariff Schedules 1 and 2 in Niagara Mohawk's Deferral Account. However, the NYISO continues to adjust its prior billings under Tariff Schedules 1 and 2, and to the extent that these billings are associated with service provided prior to August 31, 2001, the charges or refunds are appropriately included in Niagara Mohawk's deferral account, rather than in its Commodity Adjustment Clause reconciliations. The Stipulation, at Section 2.4.2 allows adjustments on pre-July 1, 2005 deferral balances to reflect actual rebillings, refunds and reconciliations received by the Company after that date from the NYISO, if such adjustments affect pre-July 1, 2005 deferral balances for the NYISO's charges to Niagara Mohawk under Schedule 1 and/or Schedule 2 of the NYISO's tariff.
Otherwise, no other adjustments are permitted to the June 30, 2005 balance.

Schedule Page: 232 Line No.: 27 Column: a

Commission Order dated August 15, 2001 in Case 94-E-0098, et al, at page 18: On September 1, 2001 Niagara Mohawk began including these costs directly in its Commodity Adjustment Clause, which reconciles the charges under NYISO Tariff Schedules 1 and 2 in current rates. Through August 31, 2001, Niagara Mohawk included the charges by the New York Independent System Operator (NYISO) under its Tariff Schedules 1 and 2 in Niagara Mohawk's Deferral Account. However, the NYISO continues to adjust its prior billings under Tariff Schedules 1 and 2, and to the extent that these billings are associated with service provided prior to August 31, 2001, the charges or refunds are appropriately included in Niagara Mohawk's deferral account, rather than in its Commodity Adjustment Clause reconciliations. The Stipulation, at Section 2.4.2 allows adjustments on pre-July 1, 2005

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deferral balances to reflect actual rebillings, refunds and reconciliations received by the Company after that date from the NYISO, if such adjustments affect pre-July 1, 2005 deferral balances for the NYISO's charges to Niagara Mohawk under Schedule 1 and/or Schedule 2 of the NYISO's tariff.
Otherwise, no other adjustments are permitted to the June 30, 2005 balance.

Schedule Page: 232 Line No.: 28 Column: a

Balance fixed per Memorandum Of Agreement 3/31/03 section 1.2.3: Niagara Mohawk's generation sale incentive of $18.6 million was all accrued prior to the effective date of the Rate Plan and was resolved in the noted MOA.

Schedule Page: 232 Line No.: 30 Column: a

Rate Case 08-G-0609: The Revenue Sharing Targets are set within this case

Schedule Page: 232 Line No.: 31 Column: a

Rate Case 08-G-0609 Section 4.4.1: The Company will reconcile and defer the recovery of the costs for differences between actual and forecast costs of SC.1, 2, 12 and 13 customers purchasing supply service from the Company (which the forecasted amount is collected through the Merchant Function Charge - see section 2.2.3) See Appendix L-6 for sample calculation

Schedule Page: 232 Line No.: 32 Column: a

Rate Case 08-G-0609: Extract paragraph "2.2 Site Investigation and Remediation (SIR) Costs"

Schedule Page: 232 Line No.: 33 Column: a

Case 07-M-0548: Per the order, the Company shall implement an EEPS Fast Track program and defer any over or under collections.

Schedule Page: 232 Line No.: 34 Column: a

Per P.S.C. No. 207 Electricity Fourth Revised Leaf No. 71-Q1, Superseding Third Revised Leaf No. 71-Q1.

Schedule Page: 232 Line No.: 35 Column: a

Case 04-M-0159, January 5, 2005, and July 1, 2005: the Commission issued orders that imposed new obligations on Niagara Mohawk and other New York utilities to test and document their facilities that are accessible to the public for elevated voltage. Those orders require Niagara Mohawk to implement and document several new activities beyond those that it has traditionally undertaken to assure the integrity and safety of its facilities. Under Section 1.2.4.3 of the Rate Plan, Niagara Mohawk is authorized to include in the deferral account "all of the effects of any legislative, court, or regulatory change, which imposes new or modifies existing obligations or duties and which, evaluated individually, increases or decreases Niagara Mohawk's revenue or costs from electric operations at an annual rate of more than $2.0 million per year." The new testing and documentation protocols under the Orders in Case 04-M-0159 meet that test. The Stipulation further defines and clarifies the standards for determining what costs are "incremental" and thus deferrable. Section 3.7.1 of the Stipulation enumerates 10 categories of activities that are deferrable while excluding electric inspection activities
that Niagara Mohawk was carrying out before the referenced Commission orders, including the annual visual inspection of 20% of the Company's
overhead electric transmission and distribution systems. Sections 3.7.2 through 3.7.5 of the Stipulation further define deferral eligibility by category of
cost (for example, internal labor, contractors, materials, sales tax) and with reference to dollar thresholds and percentages.

Schedule Page: 232 Line No.: 36 Column: a

Under Section 1.2.9 of the Joint Proposal, Niagara Mohawk agreed to implement a Low Income Rate that consisted of a $5.00 per month discount from the customer charge for residential low income customers. The details of the program are set forth in Attachment 19, Section 2 to the Joint Proposal. The allowance in rates for the program was $2.0 million per year. On December 27, 2005, the Commission approved the Company's proposal to continue and expand the low income rate program for calendar years 2006 through 2009. The Commission authorized the Company to expand participation in the program to include all electric customers for whom the Company received a payment from the Home Energy Assistance Program ("HEAP") over the preceding fourteen (14) months. The Commission approved an

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increase of $2.4 million in base rates to fund the expanded program and authorized Niagara Mohawk to "defer any difference between the total discounts provided and the rate allowance in each calendar year".

Schedule Page: 232 Line No.: 37 Column: a

Section 1.3.3. of the Rate Plan: sets forth the Customer Service Backout Credits that Niagara Mohawk applies to customers moving to retail access. Specifically Niagara Mohawk provides a Customer Service Backout Credit of $.0004 per kilowatt-hour to residential customers served under Rate SC-1 and non-demand metered commercial customers served under SC-2, and a credit of $.002 per kilowatt-hour to all demand metered customers and street-lighting customers. The Section also specifies that Niagara Mohawk is entitled to defer the portion of the Customer Service Backout Credit that exceeds Niagara Mohawk's Short Run Avoided Costs, "for which the parties agree to use the figure of $.0005 per kilowatt-hour through the mechanism set forth in Section 1.2.4.9." Both the Customer Service Backout Credits and deferral mechanism outlined in Sections 1.3.3. and 1.2.4.9 remained in effect until April 20, 2006, the effective date of the Order Clarifying and Adopting Joint Proposal on Competitive Opportunities which was filed by Niagara Mohawk on December 19, 2005 in Case 05-M-0333.

Schedule Page: 232 Line No.: 38 Column: a

Both PSC Order No. 99-M-0631 Dated March 22, 2000, and PSC Order No. 98-M-0667 Dated April 25, 2001: issued orders authorizing transaction set standards, processing protocols and test plans. Notably Electric Data Interchange ("EDI") is the computer-to-computer exchange of routine information in a standard format using established data processing protocols. EDI transactions are used in retail access programs to switch customers from one supplier to another or to exchange customers' history, usage or billing data between a distribution utility or MDSP and an ESCO.

Schedule Page: 232 Line No.: 39 Column: a

Hewitt Report, Merger Joint Proposal: Opening balances are based on the "Hewitt Report", with straight line methodology adopted per the Merger Joint Proposal.

Schedule Page: 232 Line No.: 40 Column: a

Pursuant to Attachment 16 of the Merger Rate Plan, Niagara Mohawk records an offsetting regulatory asset equal to Separation and Early Retirement Costs and amortizes that balance by the established percentages.

Schedule Page: 232 Line No.: 41 Column: a

Pursuant to the Merger Rate Plan: the Company is authorized to recover certain deferred Fixed Competitive Transition Charges ("CTC") associated with the divestiture of generation (referred to as "stranded" or "fixed" costs).

Schedule Page: 232 Line No.: 42 Column: a

The Joint Proposal Section 1.2.4.13: provides that Niagara Mohawk will reconcile its allowed and actual pension expense in accordance with the Commission's Statement of Policy, with the noted section specifically providing that Niagara Mohawk is to include any under or over-recoveries of pension expense in the Deferral Account. The procedures for the reconciliation are set forth in Attachment 16 to the Joint Proposal, and the documentation for the pension expense reconciliation is provided in Attachment 6, Schedule 12. The Stipulation prescribes methodologies for determining (1) the percentage of pension costs that will be capitalized (section 3.8.1), and (2) the credit to be recorded for deferred pension costs associated with employees who transfer between Niagara Mohawk and National Grid USA Service Co. after the pension plan valuation for a given year (section 3.8.2).

Schedule Page: 232 Line No.: 43 Column: a

As with account 182554, The Joint Proposal: provides for the reconciliation of allowed and actual OPEB expense and for deferral of variances in accordance with the Statement of Policy. The procedures for OPEB reconciliation, which are included in Attachment 16 to the Joint Proposal, directly parallel the pension reconciliation set forth in the prior section. Documentation for OPEB expense reconciliation is included in Attachment 6, Schedule 13. Parallel treatment of pensions and OPEBs extends to the Stipulation, which makes OPEB expense subject to the same provisions that govern pension expense. These include the establishment of methodologies for determining capitalization and for capturing the impact of employee transfers between Niagara Mohawk and National Grid USA

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Service Co., as well as the provisions that do not directly affect the present filing.

Schedule Page: 232.1 Line No.: 2 Column: a

Clause 1.2.4 of the Joint Proposal approved in Case 01-M-0075: On December 31, 1999, Niagara Mohawk and the City of Buffalo entered into a settlement in Case 02-M-0340 on several billing issues including streetlights. The Settlement was approved by the Commission on May 29, 2002. As part of that Settlement, which was approved by the Commission, the parties agreed that "the portion of the Settlement, which goes beyond NMPC's tariff, be subject to recovery" and that "the resulting credit of approximately $171,000 annually . . . should be shown as a separate item on the billing statements to the City. The credit can then be recovered through rates by means of the creation of a separate deferral sub-account, the rate-making of which would be controlled by clause 1.2.4 of the Joint Proposal approved in Case 01-M-0075 (Niagara Mohawk/National Grid Merger)."

Schedule Page: 232.1 Line No.: 3 Column: a

Section 2.1.2 of the Joint Proposal: establishes a special Standby Service Lost Revenue Deferral Account that would be adjusted monthly. Section 2.1.3 authorizes the Standby Service Lost Revenue Rate Adjustment that allows Niagara Mohawk to make a compliance filing, detailed in Attachment 2 to the Standby Rate Joint Proposal, to adjust delivery rates at the time of the CTC Reset regardless of the balance of the Standby Service Deferral Account as of June 30, when the sum of the Standby Service Lost Revenue Deferral and balance in the major deferral account under Section 1.2.4 of the Joint Proposal is positive (that is, customers owe Niagara Mohawk money).

Schedule Page: 232.1 Line No.: 4 Column: a

Section 1.2.4.6 of the Rate Plan: allows Niagara Mohawk to include Site Investigation and Remediation ("SIR") Costs above $12.75 million per year in its deferral account. The $12.75 million deductible represents the portion of an overall $15.0 million allowance in base delivery rates that is allocated to electric operations. SIR Costs and potential offsets are defined in Attachment 14 of the Rate Plan. They include the remediation costs associated with Niagara Mohawk's manufactured gas waste sites, Industrial Waste Sites, Corrective Action Sites, and other sites where Niagara Mohawk is named as a Potentially Responsible Party.

Schedule Page: 232.1 Line No.: 5 Column: a

Under Section 1.2.4.11 of the Rate Plan, Niagara Mohawk is authorized to include in the deferral account "any reductions or additions to stranded costs associated with the implementation of the Niagara Mohawk Joint Proposal for Nine Mile Point (Case No. 01-E-0011), and the implementation of any of Niagara Mohawk's other agreements for the sale of the fossil and hydro generating assets to the extent allowed by the orders in those cases". The Stipulation provided for the resolution of all but two issues associated with Niagara Mohawk's March 27, 2006 Supplemental Compliance Filing in Case No. 01-E-0011, the Nine Mile divestiture proceeding. Specifically, Section 7 of the Stipulation included an agreement to settle a number of issues the net adjustments for which amounted to a net reduction in generation stranded costs of $39.1 million recognized effective June 30, 2005. At the same time, Section 2.1 of the Stipulation authorized Niagara Mohawk to record in the Deferral Account an increase of $38.9 million in nuclear-related SFAS 109 costs that had not previously been recorded.
The net effect of these agreed-upon adjustments was less than $200,000 for the year ending June 30, 2005.
The unresolved issues include (1) pension fair value deferral adjustment associated with Nine Mile, and (2) quantification of a nuclear transmission-related SFAS 109 adjustment, both as described in Section 2.4.1 of the Stipulation.

Schedule Page: 232.1 Line No.: 6 Column: a

Case 08-G-0609, Section 4.1.1: The company will defer and reconcile its actual annual OPEB Expenses to the level allowed in rates. See Appendix L-1 and JE 6264D for detailed calculation

Schedule Page: 232.1 Line No.: 7 Column: a

Rate Plan, Section 1.2.4.15: Niagara Mohawk is authorized to defer any "refunds or revenue effects associated with the resolution of Case No. 99-E-0503" which involves the

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application of Section 76 of Public Service Law to religious institutions. Section 76 allows certain facilities owned or leased by a "corporation or association organized and conducted in good faith for religious purposes" to obtain electric service "for such religious purposes" at residential rates. The interpretation and application of this provision was subject to a long history of disputes that have been addressed by the Commission in Case No. 99-E-0503. The revenue effects of those decisions, either via refund, rate reclassification, or both are included in the deferral account.

Schedule Page: 232.1 Line No.: 8 Column: a

Sections 1.1.2 and 1.1.3 of the Memorandum of Agreement: Among the most significant issues involved in the Memorandum of Agreement that was reached between the Staff and Niagara Mohawk on March 31, 2003 was the funding for pension costs that had been recognized but not recovered from customers during the Power Choice period, and for an early retirement program that Niagara Mohawk had completed in 1994, but for which it had never received rate recovery. The funding requirements for the one-time costs associated with unrecovered pension costs during Power Choice totaled $40.0 million. The costs associated with the early retirement program minus offsets agreed to in the Memorandum of Agreement equaled $169.7 million, for a total of $209.7 million. Niagara Mohawk had not funded these amounts in its pension and OPEB plans. Under Sections 1.1.2 and 1.1.3 of the Memorandum of Agreement, Niagara Mohawk agreed to fund these amounts by the end of the Rate Plan Period, but was also given the flexibility to complete the funding earlier during the Rate Plan Period. In the latter event, Niagara Mohawk was allowed to include a limited return on the funding in the deferral account.

Specifically, clause (2) of Section 1.1.2 and (3) of Section 1.1.3 provide that: "Niagara Mohawk shall be allowed to include in the deferral account established under Section 1.2.4 of the Rate Plan or any extensions thereof a return on this incremental . . . investment from the date at which it is made, which return shall be calculated in accordance with Attachment 5."

Schedule Page: 232.1 Line No.: 9 Column: a

Under the Fourth CTC Reset's alternative recovery method / Case 01-M-0075: the Company was allowed to recover $123.6 million in 2010 and 123.6 million in 2011.

Schedule Page: 232.1 Line No.: 10 Column: a

Case 08-G-0609, Section 2.2.5: Applies to service classes SC1, 2 and 7 and will reconcile actual delivery service revenues to allowed delivery service revenues. Any shortfall or excess will be refunded or surcharged (with interest) to customers in the next calendar year. That volumetric transaction will also be subject to reconciliation

Schedule Page: 232.1 Line No.: 11 Column: a

Case 08-G-0609, Section 4.4.4 (appendix L-8): The Company will defer and reconcile the amount of low income program costs recovered in rates (Section 6.1) to the actual costs of the program. The Company is only allowed to establish a deferred debit for actual costs greater than those recovered in rates if its actual annual earnings result in a return on equity that does not exceed 10.2%. The establishment of a deferred credit is not subject to an earnings test

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ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Pensions, OPEB and other employee benefits	338,485,948	292,565,066
3	Reserve - Environmental	176,458,195	162,912,183
4	Allowance for uncollectible accounts	65,251,713	70,253,489
5	Other items	330,120,680	94,034,768
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	910,316,536	619,765,506
9	Gas		
10	Pensions, OPEB and other employee benefits	51,922,052	44,017,193
11	Reserve - Environmental	27,067,805	24,510,572
12	Allowance for uncollectible accounts	10,009,287	10,569,824
13	Other items	50,638,861	14,147,781
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	139,638,005	93,245,370
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	1,049,954,541	713,010,876

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering		
5	(501) Fuel		
6	(502) Steam Expenses		
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses		
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)		
14	Maintenance		
15	(510) Maintenance Supervision and Engineering		
16	(511) Maintenance of Structures		
17	(512) Maintenance of Boiler Plant		
18	(513) Maintenance of Electric Plant		
19	(514) Maintenance of Miscellaneous Steam Plant		
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)		
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)		
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses		
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)		
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)		
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)		
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	982,545,653	893,468,338
77	(556) System Control and Load Dispatching		
78	(557) Other Expenses		
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	982,545,653	893,468,338
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	982,545,653	893,468,338
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,182,199	2,417,396
84	(561) Load Dispatching	2,862,601	2,549,318
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,572,962	2,238,754
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	4,436,211	3,413,097
89	(561.5) Reliability, Planning and Standards Development	1,303,697	1,552,052
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies	9,511	5,198
92	(561.8) Reliability, Planning and Standards Development Services	1,162,814	872,819
93	(562) Station Expenses	3,415,617	4,436,919
94	(563) Overhead Lines Expenses	3,856,268	2,974,095
95	(564) Underground Lines Expenses	27,605	29,001
96	(565) Transmission of Electricity by Others	282,774	171,356
97	(566) Miscellaneous Transmission Expenses	25,544,577	9,551,613
98	(567) Rents	10,228,227	10,034,509
99	TOTAL Operation (Enter Total of lines 83 thru 98)	57,887,063	40,246,127
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	1,903,396	2,046,865
102	(569) Maintenance of Structures	28,404	59,081
103	(569.1) Maintenance of Computer Hardware	370,808	467,498
104	(569.2) Maintenance of Computer Software	670,570	581,014
105	(569.3) Maintenance of Communication Equipment	26,882	40,602
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		120
107	(570) Maintenance of Station Equipment	8,472,573	9,721,269
108	(571) Maintenance of Overhead Lines	23,688,962	22,016,059
109	(572) Maintenance of Underground Lines	277,896	269,004
110	(573) Maintenance of Miscellaneous Transmission Plant	267,484	332,109
111	TOTAL Maintenance (Total of lines 101 thru 110)	35,706,975	35,533,621
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	93,594,038	75,779,748

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [X] A Resubmission	09/16/2011	End of 2010/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation	5,337,363	5,925,157
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	5,337,363	5,925,157
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	5,337,363	5,925,157
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	5,378,035	6,768,831
135	(581) Load Dispatching	12,784,898	12,221,738
136	(582) Station Expenses	10,917,829	12,224,480
137	(583) Overhead Line Expenses	9,829,323	9,192,041
138	(584) Underground Line Expenses	5,633,218	5,628,764
139	(585) Street Lighting and Signal System Expenses	860,676	1,262,361
140	(586) Meter Expenses	8,256,248	11,407,823
141	(587) Customer Installations Expenses	6,199,516	5,795,815
142	(588) Miscellaneous Expenses	51,793,589	49,185,390
143	(589) Rents	308,067	841,924
144	TOTAL Operation (Enter Total of lines 134 thru 143)	111,961,399	114,529,167
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	353,426	173,296
147	(591) Maintenance of Structures	762,699	1,002,996
148	(592) Maintenance of Station Equipment	9,659,964	10,157,492
149	(593) Maintenance of Overhead Lines	101,670,913	99,268,953
150	(594) Maintenance of Underground Lines	3,412,018	3,380,868
151	(595) Maintenance of Line Transformers	3,069,252	1,945,362
152	(596) Maintenance of Street Lighting and Signal Systems	6,096,288	4,672,694
153	(597) Maintenance of Meters	1,067,484	934,113
154	(598) Maintenance of Miscellaneous Distribution Plant	243,643	232,856
155	TOTAL Maintenance (Total of lines 146 thru 154)	126,335,687	121,768,630
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	238,297,086	236,297,797
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	3,052,521	2,643,468
160	(902) Meter Reading Expenses	4,182,335	4,606,263
161	(903) Customer Records and Collection Expenses	44,027,197	39,838,790
162	(904) Uncollectible Accounts	48,936,729	59,499,795
163	(905) Miscellaneous Customer Accounts Expenses	648,887	1,069,573
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	100,847,669	107,657,889

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Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [X] A Resubmission	09/16/2011	End of 2010/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	4,291	-452
168	(908) Customer Assistance Expenses	162,926,926	105,569,317
169	(909) Informational and Instructional Expenses	1,089,715	551,277
170	(910) Miscellaneous Customer Service and Informational Expenses	3,620,133	3,591,589
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	167,641,065	109,711,731
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	514	322
175	(912) Demonstrating and Selling Expenses	67,816	24,333
176	(913) Advertising Expenses		3,164
177	(916) Miscellaneous Sales Expenses	6,081	11,130
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	74,411	38,949
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	76,348,171	63,009,698
182	(921) Office Supplies and Expenses	55,034,305	55,647,754
183	(Less) (922) Administrative Expenses Transferred-Credit	-2,882	-48
184	(923) Outside Services Employed	11,432,793	12,737,383
185	(924) Property Insurance	64,126	110,662
186	(925) Injuries and Damages	14,098,578	15,311,171
187	(926) Employee Pensions and Benefits	92,041,066	94,953,663
188	(927) Franchise Requirements	1,128	67,948
189	(928) Regulatory Commission Expenses	98,609,735	53,037,289
190	(929) (Less) Duplicate Charges-Cr.		-1,693
191	(930.1) General Advertising Expenses	181,131	-991,260
192	(930.2) Miscellaneous General Expenses	16,434,691	16,046,581
193	(931) Rents	8,456,579	12,307,155
194	TOTAL Operation (Enter Total of lines 181 thru 193)	372,705,185	322,239,765
195	Maintenance		
196	(935) Maintenance of General Plant	2,412,371	2,536,389
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	375,117,556	324,776,154
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,963,454,841	1,753,655,763

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) ☐ An Original (2) ☒ A Resubmission	09/16/2011	End of 2010/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	6,067		
4	Transmission	9,833,880		
5	Regional Market			
6	Distribution	66,110,660		
7	Customer Accounts			
8	Customer Service and Informational	4,622,057		
9	Sales			
10	Administrative and General	42,899,948		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	123,472,612		
12	Maintenance			
13	Production			
14	Transmission	8,189,440		
15	Regional Market			
16	Distribution	50,054,680		
17	Administrative and General	1,692,151		
18	TOTAL Maintenance (Total of lines 13 thru 17)	59,936,271		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	6,067		
21	Transmission (Enter Total of lines 4 and 14)	18,023,320		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	116,165,340		
24	Customer Accounts (Transcribe from line 7)			
25	Customer Service and Informational (Transcribe from line 8)	4,622,057		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	44,592,099		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	183,408,883	7,554,661	190,963,544
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution	7,360,007		
37	Customer Accounts	5,296,262		
38	Customer Service and Informational	329,311		
39	Sales	1,960		
40	Administrative and General	6,038,626		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	19,026,166		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [X] A Resubmission	09/16/2011	End of 2010/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	17,514,909		
49	Administrative and General	17,627		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	17,532,536		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)	24,874,916		
58	Customer Accounts (Line 37)	5,296,262		
59	Customer Service and Informational (Line 38)	329,311		
60	Sales (Line 39)	1,960		
61	Administrative and General (Lines 40 and 49)	6,056,253		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	36,558,702	1,786,242	38,344,944
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	219,967,585	9,340,903	229,308,488
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	73,756,615	6,879,852	80,636,467
69	Gas Plant	17,688,196	1,438,324	19,126,520
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	91,444,811	8,318,176	99,762,987
72	Plant Removal (By Utility Departments)			
73	Electric Plant	10,536,438	763,367	11,299,805
74	Gas Plant	1,763,513	134,120	1,897,633
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	12,299,951	897,487	13,197,438
77	Other Accounts (Specify, provide details in footnote):			
78	Other Work In Progress	4,920,291	126,599	5,046,890
79	Preliminary Survey and Investigation	-318,607	-2,247	-320,854
80	Misc AP and Accruals	-4,398,645		-4,398,645
81	Expense of Non Utility Operation	932,417		932,417
82	Misc Income Deduction	318,346		318,346
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	1,453,802	124,352	1,578,154
96	TOTAL SALARIES AND WAGES	325,166,149	18,680,918	343,847,067

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) ☐ An Original (2) ☒ A Resubmission	09/16/2011	End of 2010/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			-582,086	1,912,836	1,330,750
2	Steam Production Plant					
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant					
7	Transmission Plant	31,479,119	2,893			31,482,012
8	Distribution Plant	132,837,876	8,204			132,846,080
9	Regional Transmission and Market Operation					
10	General Plant	13,112,567				13,112,567
11	Common Plant-Electric	11,126,821				11,126,821
12	TOTAL	188,556,383	11,097	-582,086	1,912,836	189,898,230

B. Basis for Amortization Charges

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [X] A Resubmission	09/16/2011	End of 2010/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Transmission:						
13	350.40	27,126					37.86
14	352	29,686					45.51
15	353	656,989					43.11
16	353.55	46,850					9.37
17	354	119,465					32.03
18	355	439,201					39.18
19	356.10	118,663					47.48
20	356.20	181,597					42.03
21	357	29,332					37.99
22	358	113,644					35.60
23	359	2,339					65.15
24	Subtotal	1,764,892					
25							
26	Distribution:						
27	360.25	16,603					50.25
28	361	36,247					46.98
29	362	456,650					38.78
30	362.55	30,456					8.87
31	364	879,840					30.86
32	365	961,911					20.24
33	366	141,740					52.77
34	367	450,796					38.19
35	368	753,673					28.42
36	369.10	296,466					24.55
37	369.20	9,763					34.53
38	369.21	115,172					30.93
39	370.10	52,415					25.74
40	370.20	37,815					30.05
41	371	8,195					6.03
42	373	208,034					20.31
43	374						
44	Subtotal	4,455,778					
45							
46	General:						
47	390	86,796					40.09
48	391	5,024					29.85
49	391.10	2,812					19.00
50	391.20	1,805					1.54

Name of Respondent Niagara Mohawk Power Corporation	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 09/16/2011	Year/Period of Report End of 2010/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used In Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	393	2,143					26.47
13	394	3,897					35.55
14	394.10	6,369					19.48
15	394.20	44,154					28.67
16	395	22,197					28.96
17	396						
18	397.20	54,764					13.75
19	397.40	2,779					0.10
20	397.60	17,636					7.37
21	398	8,627					6.77
22	398.10	962					24.76
23	398.56	13,726					4.08
24	399.1						
25	Subtotal	273,691					
26							
27							
28							
29							
30							
31							
32							
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) __ An Original (2) X A Resubmission	09/16/2011	2010/Q4

FOOTNOTE DATA

Schedule Page: 336 Line No.: 11 Column: b

Common Allocation of Deperciation is split to reflect 85% to electric and 15% to gas from page 356.

Schedule Page: 336 Line No.: 12 Column: b

This amount excludes FERC Acct 413 $64,266.

Schedule Page: 336.1 Line No.: 27 Column: a

Per requirements, all available information will be reported every five years. Next full reporting year is 2011. Outside of the full reporting years and assuming there are no rate changes, disclosure will be limited to column (a), (b) and (g).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) ☐ An Original (2) ☒ A Resubmission	09/16/2011	End of 2010/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Footnote:

Due to an administrative oversight the beginning balance on this page for last year was incorrectly stated with the difference between Gas and Common, however the companies over all total was correct, the balances within some utility accounts were misstated. We have made the corrections in this filing.

RESERVE FOR DEPRECIATION OF COMMON UTILITY PLANT

Balance January 1, 2010	105,720,192
Depreciation and Amortization Provisions for year charged to:	
Depreciation - Electric	11,126,821
Depreciation - Gas	1,963,557
Amortization - Electric	
Amortization - Gas	
Transportation - Clearing Account	
Total Depreciation and Amortization Provisions	13,090,378
Net Charges for Plant Retired:	
Book Cost of Plant Retired	(6,897,365)
Cost of Removal	(4,595,756)
Salvage (Credit)	604,500
Net Charges for Plant Retired	(10,888,621)
Other Debit or Credit Items:	
Net increase in Retirement Work in Progress	551,551
Transfer of Provisions to Electric Department	(592,921)
Accum. Amortization-Limited Term Property-Johnson Bldg.	
Balance December 31, 2010	$107,880,579

Common Utility Expenses and Departmental Allocation

Inquiry 3 - Operation and Maintenance expenses of common utility plant are charged directly to the electric and gas departments on the basis

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) ☐ An Original (2) ☒ A Resubmission	09/16/2011	End of 2010/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.)
Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	FEDERAL					
2	Income Taxes	108,373,977	316,980,246	136,492,006	-174,488,216	4,306,701
3	FICA Contribution	307,307		27,340,658	25,651,089	
4	Unemployment	4,661		233,681	236,702	
5	Other					
6	SUBTOTAL	108,685,945	316,980,246	164,066,345	-148,600,425	4,306,701
7						
8	STATE					
9	Franchise - Gross Income		15,812,668	5,474,929	8,384	1,602,264
10	Franchise - Gross Earnings	1,151,918		21,882,778	25,335,167	
11	Franchise - Excess Dividends					
12	Temporary Surcharges					
13	Sec. 186a (Gross Inc)					
14	Sec. 186 (Gross Earnings)					
15	Sec. 186 (Excess Dividends)					
16	MTA Surcharge					
17	Unemployment Insurance	8,583		529,672	535,276	
18	Disability Insurance					
19	Sales and Use	989,501	8,899,623	61,604	371,940	
20	Petroleum Business Tax - NY					
21	Other					
22	SUBTOTAL	2,150,002	24,712,291	27,948,983	26,250,767	1,602,264
23						
24	LOCAL					
25	Real Estate			175,773,088	175,773,088	
26	Special Franchise					
27	Municipal Gross Income	1,687,137		20,050,768	19,947,951	
28	NYC Special Franchise					
29	Public Utility Excise					
30	Sales and Use	716,536	6,444,554	44,609	269,336	
31	Other					
32	SUBTOTAL	2,403,673	6,444,554	195,868,465	195,990,375	
33						
34	OTHER					
35	New Jersey Unemployment					
36	Non - NY Franchise Tax					
37	Use Tax from STS	7,597,960		16,281,107	16,786,505	
38						
39						
40						
41	TOTAL	120,837,580	348,137,091	404,164,900	90,427,222	5,908,965

Name of Respondent Niagara Mohawk Power Corporation	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 09/16/2011	Year/Period of Report End of 2010/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
98,067,252		104,558,946			31,933,060	2
1,996,875		27,320,595			20,062	3
1,640		233,681				4
						5
100,065,767		132,113,222			31,953,122	6
						7
						8
	11,948,387	4,039,958			1,434,971	9
-2,300,471		17,134,813			4,747,965	10
						11
						12
						13
						14
						15
						16
2,979		529,672				17
						18
989,501	9,209,960	51,936			9,667	19
						20
						21
-1,307,991	21,158,347	21,756,379			6,192,603	22
						23
						24
		137,630,327			38,142,760	25
						26
1,789,954		16,684,446			3,366,321	27
						28
						29
716,536	6,669,281	37,609			7,000	30
						31
2,506,490	6,669,281	154,352,382			41,516,081	32
						33
						34
						35
						36
7,092,562						37
						38
						39
						40
108,356,828	27,827,628	308,221,983			79,661,806	41

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) __ An Original (2) X A Resubmission	09/16/2011	2010/Q4

FOOTNOTE DATA

Schedule Page: 262 Line No.: 2 Column: c

Corrected data in columns (d),(e),(g),(h),(i),(l) from what was originally submitted.

Niagara Mohawk Power Corporation
Transmission Working Capital

Line No.	Description	Source	December 31, 2010
1	Materials and Supplies	Schedule B	8,449,675
2	Prepayments	Schedule C	10,226,833
3	Cash Working Capital	Schedule D	8,185,584

Niagara Mohawk Power Corporation

Transmission Materials and Supplies

Line No.	Description	Source	December 31, 2010
1	Total Materials and Supplies (154)	Statement AA/FF1 48.c	32,612,163
2	Materials and Supplies Directly assigned to Transmission		
3	% Directly Assigned to Transmission		10.00%
4	Materials and Supplies allocated to Transmission	Line 3 * Line 1	3,261,216
5	Materials and Supplies Directly assigned to Distribution		
6	% Assigned to Electric Distribution		17.46%
7	Materials and Supplies allocated to Distribution	Line 6 * Line 1	5,694,084
8	Percentage not directly assigned	1 - Line 3 - Line 6	72.54%
9	Materials and Supplies not directly assigned	Line 8 * Line 1	23,656,863
10	Gross Electric Plant Allocation Factor		78.78%
11	Transmission Plant Allocation Factor		27.84%
12	Remainder Construction Materials & Supplies Allocated	Line 9 * Line 10 * Line 11	5,188,459
13	Total Transmission Materials & Supplies	Line 4 + Line 12	8,449,675

Niagara Mohawk Power Corporation
Transmission Prepayments

Line No.	Description	Source	December 31, 2010
1	Total Prepayments	Statement AA/FF1 57.c	58,577,794
2	Less Prepayments for Federal and State Income Tax		11,948,387
3	Subtotal of Prepayments	Line 1 - Line 2	46,629,407
4	% Assigned to Electric		78.78%
5	Materials and Supplies allocated to Electric	Line 4 * Line 5	36,736,898
6	% Assigned to Transmission		27.84%
7	Materials and Supplies allocated to Transmission	Line 5 * Line 6	10,226,833

Niagara Mohawk Power Corporation

Transmission Cash Working Capital

Line No.	Description	Source	December 31, 2010
1	Transmission Operations and Maintenance Expense	Statement AH/FF1 112.b	93,594,038
2	Less Load Dispatching	Acct # 561	12,349,796
3	Less Write off of Regional Delivery Venture Capital	Exhibit NMP-4 Schedule 9	10,942,773
4	Less Write off of Tonawanda Project		4,816,801
5	Subtotal	Line 1 - Line 2 - Line 3 - Line 4	65,484,668
6	Allocation Factor (45 days / 360 days = 1 month times 1.5)		12.50%
7	Transmission Cash Working Capital	Line 5 * Line 6	8,185,584

Niagara Mohawk Power Corporation
Construction Work In Progress

This statement is not applicable. The Company's revenue requirement formula under Attachment H of the NYISO OATT does not rely on data and supporting assumptions relating to construction work in progress amounts. In addition, the Company is not requesting inclusion of Construction Work in Progress in its revenue requirement formula in the RR component of Attachment H.

Niagara Mohawk Power Corporation
Notes Payable

This statement is not applicable. The Company's revenue requirement formula under Attachment H of the NYISO OATT does not rely on data and supporting assumptions relating to notes payable amounts. In addition, the Company is not requesting inclusion of Notes Payable in its revenue requirement formula in the RR component of Attachment H.

Niagara Mohawk Power Corporation
Rate for Allowance for Funds used During Construction

This statement is not applicable. The Company's revenue requirement formula under Attachment H of the NYISO OATT does not rely on data and supporting assumptions relating to rates for allowance for funds used during construction. In addition, the Company is not requesting inclusion of AFUDC in its revenue requirement formula in the RR component of Attachment H.

Niagara Mohawk Power Corporation
Federal Income Tax Deduction – Interest
(000)

Line No.			
1	Interest for Borrowed Funds Used for Electric Utility Construction - Account 432		$1,206
2			
3	Interest on Debt to Associated Companies		
4	Money Pool Interest Expense		$75
5	Niagara Mohawk Holdings, Inc.		$35,748
6		Total Account 430	$35,823
7			
8	Other Interest		
9	Miscellaneous Interest		$1,993
10	Interest Expense - Tax		$25,656
11	Interest on Customer Deposits		$1,033
12	Interest on Nuclear Fuel Disposal Costs		$218
13	Interest on OATT Deposits		$7
14	Interest on Deferred Compensation		$216
15	Other Interest - Commitment Fee		$5
16		Total Account 431	$29,128
17			
18			
19	Interest on Long Term Debt		
20	Rate Base	(Statement BJ/BK/BL Schedule 1)	$1,127,180
21	Weighted Long Term Debt Rate (Statement BJ/BK/BL Schedule 4)		2.08%
22		Interest on Long Term Debt	$23,445

Niagara Mohawk Power Corporation
Federal Income Tax Deduction – Other Than Interest
(000)

Line No.			
1	(I) Difference Between Tax and Book Depreciation		($49,010)
2	(II) Taxes, Insurance and Pension Costs Capitalized		$0
3	(III) Cost of Removal		$81,275
4	Preferred Dividend Paid Deduction		$297
5	**Total Other**		$81,572
6	**1/ Tax Depreciation and Amortization Under IRC:**		
7	Straight Line	$570	
8	ADR System	$0	
9	ACRS	$706	
10	MACRS	$181,514	
11	**Total Tax Depreciation and Amortization**		$182,790
12	Book Depreciation and Amortization:		
13	Book Depreciation	$231,800	
14	Total Book Depreciation and Amortization		$231,800
15	Difference Between Tax and Book Depreciation		($49,010)
16	Note: Amounts represent combined electric and gas business and tie to FERC Form 1 page 261-A.		

Niagara Mohawk Power Corporation
Federal Income Tax Expense
FERC Form 1 12/31/10

Line No.		Electric	Gas	Other	Total
1	**410**				
2	**Contra Account 282**				
3	Property Related Differences	94,881,066	29,962,442	0	124,843,508
4	**Contra Account 283**				
5	Property Taxes	851,963	174,498	0	1,026,461
6	Regulatory Asset - Environmental	(12,148,783)	6,524,347	0	(5,624,437)
7	Regulatory Asset - Pension	3,689,321	755,644	0	4,444,965
8	Regulatory Asset - Other	(61,826,085)	21,938,288	0	(39,887,797)
9	Regulatory Asset - Not in Rate Base	8,322,650	0	0	8,322,650
10	Unamortized Debt Discount	601,273	123,152	0	724,425
11	**Subtotal**	**(60,509,663)**	**29,515,930**	**0**	**(30,993,733)**
12	**Contra Account 190**				
13	FIT on Deferred SIT	5,063,583	2,037,970	0	7,101,553
14	Accrued Interest	7,864,842	3,370,647	0	11,235,489
15	Bad Debts	(3,707,046)	(1,441,629)	0	(5,148,675)
16	Deferred Compensation	600,340	122,961	0	723,301
17	Employee Compensation and Benefits	(2,316,932)	(474,552)	0	(2,791,484)
18	Hedging	0	3,122,107	0	3,122,107
19	OPEB Liability	52,561,201	10,765,547	0	63,326,748
20	Other Items	(29,791,415)	(6,101,856)	0	(35,893,271)
21	Pension Liability	17,917,402	3,669,829	0	21,587,231
22	Regulatory Liability - Other	1,393,890	597,381	0	1,991,271
23	Reserve - Environmental	5,942,698	0	0	5,942,698
24	Unbilled Revenue	3,870,067	0	0	3,870,067
25	**Subtotal**	**59,398,630**	**15,668,405**	**0**	**75,067,035**
26	**Total 410**	**93,770,034**	**75,146,777**	**0**	**168,916,810**

Niagara Mohawk Power Corporation
Federal Income Tax Expense
FERC Form 1 12/31/10

Line No.		Electric	Gas	Other	Total
1	**411**				
2	**Contra Account 282**				
3	Property Related Differences	(35,149,149)	(11,099,731)	0	(46,248,880)
4	**Contra Account 283**				
5	Executive Deferred Compensation Liability	(5,324)	(1,091)	0	(6,415)
6	Regulatory Asset - Environmental	3,762,070	(2,020,371)	0	1,741,699
7	Regulatory Asset - Merger Rate Stranded	(182,057,462)	0	0	(182,057,462)
8	Regulatory Asset - Pension	(13,900,249)	(2,847,039)	0	(16,747,288)
9	Regulatory Asset - Storm Costs	(985,176)	0	0	(985,176)
10	Regulatory Asset - Other	(2,912,665)	1,033,526	0	(1,879,139)
11	Regulatory Asset - Not in Rate Base	7,566,366	0	0	7,566,366
12	Unamortized Debt Discount	(3,238,471)	(663,301)	0	(3,901,773)
13	**Subtotal**	**(191,770,912)**	**(4,498,275)**	**0**	**(196,269,187)**
14	**Contra Account 190**				
15	FIT on Deferred SIT	1,261,486	442,003	0	1,703,489
16	Accrued Interest	(1,014,089)	(434,609)	0	(1,448,698)
17	Bad Debts	(2,150,459)	(836,290)	0	(2,986,749)
18	Deferred Compensation	(689,154)	(141,152)	0	(830,307)
19	Employee Compensation and Benefits	(2,252,630)	(461,382)	0	(2,714,012)
20	Hedging	0	(2,659,864)	0	(2,659,864)
21	OPEB Liability	3,845,270	787,586	0	4,632,856
22	Other Items	12,861,334	2,634,249	0	15,495,583
23	Pension Liability	1,960,437	401,535	0	2,361,972
24	Regulatory Liability - Other	(504,761)	(216,326)	0	(721,088)
25	Reserve - Other	(352,648)	(72,229)	0	(424,877)
16	**Subtotal**	**12,964,786**	**(556,479)**	**0**	**12,408,307**
27	**Total 411**	**(213,955,274)**	**(16,154,486)**	**0**	**(230,109,760)**
28	**Below the Line Reclass (411.2)**	1,438,807	294,696		1,733,503
29	**Adjusted Total 411**	**(212,516,467)**	**(15,859,791)**	**0**	**(228,376,257)**

Niagara Mohawk Power Corporation
Additional State Income Tax Deductions
($000)

Line No.		
1	**New York State Franchise Tax**	
2	Additional New York State Depreciation	$81,805
3	Regulatory Asset Amortization	$326,246
4	Additional New York State Loss on Asset Disposition	$0
5	Total Additional State Tax Deductions (L2 + L3 + L4)	$408,051
6	Tax Exempt Interest Income	($310)
7	Dividends Received Deduction	($72)
8	Bonus Depreciation	($205,911)
9	State Tax Expense	($6,597)
10	Total State Tax Unallowable Deductions (L6 + L7+L8 + L9)	($212,890)

NOTE: Amounts represent combined electric and gas business.

Niagara Mohawk Power Corporation
State Income Tax Expense
FERC Form 1 12/31/10

Line No.		Electric	Gas	Other	Total
1	**410**				
2	**Contra Account 282**				
3	Property Related Differences	58,472,952	18,465,143	0	76,938,095
4	**Contra Account 283**				
5	Property Taxes	276,031	56,536	0	332,567
6	Regulatory Asset - Environmental	(2,464,468)	1,323,510	0	(1,140,957)
7	Regulatory Asset - Merger Rate Stranded	(313,639)	0	0	(313,639)
8	Regulatory Asset - Pension	748,405	153,288	0	901,693
9	Regulatory Asset - Other	(6,601,851)	2,342,592	0	(4,259,259)
10	Regulatory Asset - Not in Rate Base	(819,728)	0	0	(819,728)
11	Unamortized Debt Discount	132,664	27,172	0	159,836
12	**Subtotal**	**(9,042,587)**	**3,903,099**	**0**	**(5,139,487)**
13	**Contra Account 190**				
14	Accrued Interest	1,732,191	547,008	0	2,279,199
15	Bad Debts	(752,001)	(292,445)	0	(1,044,446)
16	Deferred Compensation	121,783	24,944	0	146,727
17	Employee Compensation and Benefits	312,984	64,105	0	377,090
18	Hedging	0	93,769	0	93,769
19	OPEB Liability	10,286,677	2,106,910	0	12,393,586
20	Other Items	(4,929,867)	(1,009,732)	0	(5,939,599)
21	Regulatory Liability - Other	282,761	121,183	0	403,944
22	Reserve - Environmental	1,205,519	0	0	1,205,519
23	Unbilled Revenue	2,000,084	0	0	2,000,084
24	**Subtotal**	**10,260,130**	**1,655,742**	**0**	**11,915,872**
25	**Total 410**	**59,690,496**	**24,023,984**	**0**	**83,714,479**

Niagara Mohawk Power Corporation
State Income Tax Expense
FERC Form 1 12/31/10

Line No.		Electric	Gas	Other	Total
1	**411**				
2	**Contra Account 282**				
3	Property Related Differences	980,497	309,631	0	1,290,128
4	**Contra Account 283**				
5	Regulatory Asset - Environmental	763,163	(409,847)	0	353,316
6	Regulatory Asset - Merger Rate Stranded	(5,305,851)	0	0	(5,305,851)
7	Regulatory Asset - Pension	(2,685,616)	(550,066)	0	(3,235,682)
8	Regulatory Asset - Storm Costs	(199,850)	0	0	(199,850)
9	Regulatory Asset - Other	(1,611,286)	571,747	0	(1,039,539)
10	Regulatory Asset - Not in Rate Base	505,909	0	0	505,909
11	Unamortized Debt Discount	(601,445)	(123,188)	0	(724,633)
12	**Subtotal**	**(9,134,976)**	**(511,353)**	**0**	**(9,646,329)**
13	**Contra Account 190**				
14	Net Operating Loss	(15,084,821)	(6,464,923)	0	(21,549,744)
15	Accrued Interest	(223,348)	(70,531)	0	(293,879)
16	Bad Debts	(436,236)	(169,647)	0	(605,883)
17	Deferred Compensation	(203,079)	(41,595)	0	(244,674)
18	Employee Compensation and Benefits	1,681	344	0	2,026
19	Hedging	0	(539,572)	0	(539,572)
20	OPEB Liability	(470,673)	(96,403)	0	(567,076)
21	Other Items	3,911,741	801,200	0	4,712,941
22	Pension Liability	2,974,785	609,293	0	3,584,078
23	Regulatory Liability - Other	450,034	192,872	0	642,905
24	Reserve - Other	398,083	81,535	0	479,618
25	**Subtotal**	**(8,681,834)**	**(5,697,427)**	**0**	**(14,379,261)**
26	**Total 411**	**(16,836,312)**	**(5,899,150)**	**0**	**(22,735,462)**

Niagara Mohawk Power Corporation
Transmission Revenue Credit

Line No.		Source	Calendar Year 10
1	Transmission of Electricity for Others (456.1)	FF 1 300.22b	128,808,812
2	Less: Transmission of Electricity by ISO (ECR, CRR, SR)		62,608,329
3	Subtotal	Line 1 - Line 2	66,200,483
4			
5	Less:		
6	TSC Customers		19,918,015
7	Green Island & Richmondville		195,203
8	Subtotal Deductions	Line 6 + Line 7	20,113,219
9			
10	Subtotal Transmission Revenue Credit	Line 3 + Line 8	46,087,265
11			
12	Transmission Support Revenue (456010 & 456040)		1,134,884
13			
14	Total Transmission Revenue Credit	Line 10 + Line 12	47,222,149
15			

Niagara Mohawk Power Corporation
Transmission Rate of Return
December 31, 2010

Line No.		Source	Amount	Percent of Total	Rate	Return
1	Long Term Debt	Statement AA/FF1 112.24c	2,399,649,641			
2	Less Unamortized Loss on Reacquired Debt	Statement AA/FF1 111.81c	25,339,795			
3	Long Term Debt	Line 1 - Line 2	2,374,309,846	49.55%	4.20%	2.08%
4	Preferred Stock	Statement AA/FF1 112.3c	28,984,700	0.45%	3.66%	0.02%
5	Common Stock Issued	Statement AA/FF1 112.2c	187,364,863			
6	Other Paid in Capital	Statement AA/FF1 112.7c	2,913,140,406			
7	Retained Earnings	Statement AA/FF1 112.11c	883,594,219			
8	Common Equity	Lines 5 thru 7	3,984,099,488	50.00%	11.50%	5.75%
9						
10	Total Investment Return	Line 3 + Line 4 + Line 8	6,387,394,034			7.85%

Niagara Mohawk Power Corporation
Cost of Money
Twelve Months Ending December 31, 2010

Line No.		Source	Beginning Balance	Ending Balance	Average	2010
1	**Interest on Long Term Debt**					
2						
3	Total Niagara Mohawk Interest on Long Term Debt	Statement AB FF1/117 62c + 67c				98,020,023
4	Amortization of Debt Discount Expense	Statement AB/FF1 117 63c				2,434,668
5	Amortization of Loss on Reacquired Debt	Statement AB/FF1 117 64c				6,576,120
6	Less: Amortization of Premium on Debt	Statement AB/FF1 117 65c				
7	Less: Amortization of Gain on Reacquired Debt	Statement AB/FF1 117 66c				60,460
8	**Interest Costs plus Expense**	Sum Lines 3-7				106,970,351
9						
10	**Total Long Term Debt**					
11						
12	Total Niagara Mohawk Long Term Outstanding Debt	Statement AA/FF1 112.18 thru .21	2,750,065,000	2,400,065,000	2,575,065,000	
13	Unamortized Premium on Long Term Debt	Statement AA/FF1 112.22			0	
14	Less Unamortized Debt Discount Expense	Statement AA/FF1 112.23	477,312	415,359	446,336	
15	Less: Unamortized Loss on Reacquired Debt	Statement AA/FF1 111.81	32,019,130	25,339,795	28,679,463	
16	**Total Long Term Debt**	Sum Lines 12-15	2,717,568,558	2,374,309,846	2,545,939,202	
17	**Debt Cost as % of Debt**	Line 8 / Line 16 Average			4.20%	
18						
19						
20	**Preferred Stock**					
21						
22	Total Niagara Mohawk Dividends Declared	Statement AB/FF1 118 29c				1,060,498
23	Total Niagara Mohawk Preferred Stock	Statement AA/FF1 112.3c				28,984,700
24	**Preferred Stock Cost**	Line 22 / Line 23				3.66%

NIAGARA MOHAWK POWER CORPORATION
Cost of short-term debt

This statement is not applicable. The Company's revenue requirement formula under Attachment H of the NYISO OATT does not rely on data and supporting assumptions relating to cost of short term debt amounts. In addition, the Company is not requesting inclusion of Cost of Short Term Debt in its revenue requirement formula under Attachment H.

Recent and Pending Rate Changes

There are no operating revenues subject to refund for the Period I test year used in this filing, calendar year 2010.

The only application for a rate increase acted on during Period I, Period II, or the interval between, was a rate increase request filed in January 2010 before the by New York Public Service Commission (NYPSC) in Case #10-E-0050. A copy of the NYPSC's order from that proceeding, issued January 20, 2011, is attached to this Statement AX.

The attached order promulgated changes to NMPC's depreciation rates. Through this Section 205 filing, NMPC is seeking Commission approval to modify its depreciation rates specified as part of the TSC formula rate under Attachment H of the NYISO OATT to track the depreciation rate changes approved by the NYPSC.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on January 20, 2011

COMMISSIONERS PRESENT:

Garry A. Brown, Chairman
Patricia L. Acampora
Maureen F. Harris
Robert E. Curry, Jr.
James L. Larocca

CASE 10-E-0050 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation for Electric Service.

CASE 08-E-0827 - Comprehensive Management Audit of Niagara Mohawk Power Corporation d/b/a National Grid's Electric Business.

ORDER ESTABLISHING RATES FOR ELECTRIC SERVICE

(Issued and Effective January 24, 2011)

TABLE OF CONTENTS

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on January 20, 2011

COMMISSIONERS PRESENT:

Garry A. Brown, Chairman
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ORDER ESTABLISHING RATES FOR ELECTRIC SERVICE

(Issued and Effective January 24, 2011)

BY THE COMMISSION:

INTRODUCTION

In January 2010, Niagara Mohawk Power Corporation (the Company), doing business in upstate New York in the name of its parent company National Grid, filed to increase its electric delivery revenues by $390.6 million, an amount that is 12.5% of its total aggregate revenues and 26% of its electric delivery revenues.[1] On November 17, 2010, the Administrative Law Judges assigned to the case provided their recommended decision which addresses the contested issues and reports the stipulations the

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1 The amount of the Company-proposed delivery revenue increase has fluctuated during the course of this proceeding and it currently stands at $361.2 million.

parties reached in this case. The Judges recommended that Niagara Mohawk receive a delivery rate increase of approximately $111 million.[2] This figure includes a non-recurring increase of $40 million for Competition Transition Charge (CTC) recoveries.

The recommended decision determined that the increase for residential and small commercial customers should be offset entirely in 2011 by an extension of deferral recoveries. The recommended decision further recommended that CTCs should be recovered in full from large customers, rather than be extended into 2012 or beyond.

After considering the parties' positions on exceptions, we determine that an increase in revenues is necessary to meet the reasonable needs of the Company. This amount will include the non-recurring CTC collection of $40 million. The increase includes $50 million of temporary rates that are subject to the results of the pending audit of the National Grid service company expenses. The increase will, for 2011, be entirely offset by a reduction in collections made for deferred costs. No customer class will experience a rate increase in 2011, and the collection of CTCs will be completed in 2011.

This order provides that the Company, if it refrains from filing another rate case until after 2011, may base its revenue requirement increase on a return on equity of 9.3%. Rates based on a 9.3% return on equity result in an increased revenue requirement of approximately $119 million ($40 million

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[2] The increase, as initially reported in the recommended decision, was stated as $99.258 million. Subsequent to the release of the recommended decision, it was discovered that the figure reported by the Judges reflects calculation errors. Staff and the Company have agreed that, properly calculated, the Judges' recommendations amount to a delivery rate increase of $111.216 million.

in non-recurring CTC recovery and $79 million in recurring revenues).[3]

Multi-Year Ratemaking

With its $390.6 million rate proposal for 2011, Niagara Mohawk also submitted rate proposals for 2012 and 2013. In 2012, the Company proposed to increase electric delivery revenues by $32 million. In 2013, it proposed to decrease electric delivery revenues by $31 million. During the proceeding, it became clear that the Company's financial projections for 2012 and 2013 could not be examined sufficiently to permit any overall delivery rate determinations for an additional two years. Staff indicated that it would not extend its audit to include a review of Niagara Mohawk's operations and finances for 2012 and 2013 and would not present a case with respect to those years. Niagara Mohawk subsequently announced that it would only litigate a one-year rate case.

Nonetheless, in addressing several issues, the Judges have encouraged us to take actions that would allow automatic, inflation-based adjustments to the electric delivery rate levels for 2012 and 2013 and reduce the need for Niagara Mohawk to make any rate filings for these years.

Except for our discussions of return on equity and deferral amortization, we are not addressing multi-year ratemaking matters in this case. However, such matters should be fully presented and considered in any filing that will be submitted in the future for new rates.

We adopt in this order rates based on a one-year forecast. We recognize the circumstances that led the parties

[3] Should the Company elect not to accept the conditions for receiving a 9.3% return on equity, a 9.1% return on equity will be allowed, resulting in a revenue increase of approximately $113 million ($40 million in non-recurring CTC recovery and $73 million in recurring revenues).

to focus the record development in this case almost entirely on rate year 2011, and we agree with their approach in light of the complexities inherent in setting new rates for electric service which has not been addressed in a full rate case for nine years. We are concerned, however, that the record in the Company's next rate case may lack an analysis of the rates which may be set in rate years after the first rate year addressed in that filing. The absence of this information in the record could deprive the Commission of needed information for setting rates for the first year addressed in the Company's new filing, and of the opportunity to set rates for a longer period of time, if warranted.

In many cases, the development of a record which addresses the issues that could arise when rates after the first year are considered depends heavily on the availability, at the time of the Company's initial filing or very soon thereafter, of information concerning the years following the first rate year. Moreover, this information must come, in the first instance, from the Company. Accordingly, we expect that the Company will begin interacting with interested parties as soon as practicable, and prior to the filing of its next rate case, to share information concerning the scope of its intended filing and to develop an understanding of the information that may be required to address the multi-year scope of the record which should be developed through that rate case.

Service Company Matters

During the course of this proceeding, the need for a thorough examination of Niagara Mohawk's business arrangements with the National Grid service companies became apparent. The investigations performed by Department Staff, as well as a recently completed management audit of Niagara Mohawk's operations, revealed various weaknesses in the service companies' reporting and accounting systems, leading to concerns that these systems do not provide sufficient protection for the interests of New York ratepayers. As a result, we have started a separate proceeding (the "Service Company Audit" case) that is closely examining National Grid's cost allocations to Niagara Mohawk and the downstate operating companies located in New York City and on Long Island, as well as other processes used by the Company to determine and allocate service company expenses for ratemaking purposes.[4] We expect the results of the in-depth review to be available to us in advance of any further rate case determinations we may make. To ensure that the delivery rates we are establishing for 2011 are not overstated or excessive due to any incorrect service company allocations, $50 million of the rates set here will remain temporary through an adjustment clause, and they will only become permanent if and when they are supported by the final results of the service company proceeding.

Parties to the Proceeding

The parties in this case are Niagara Mohawk, Department Staff, and several intervenors. Staff is charged to represent the public interest and to perform a comprehensive audit of the rate filing. The staff team draws from various professional and academic disciplines including: accounting, finance, engineering, economics, environmental studies and consumer interests.

The intervenors include the State Consumer Protection Board (CPB); Multiple Intervenors (MI), an unincorporated association of 55 industrial, commercial and institutional energy consumers; and the New York Power Authority (NYPA) which

[4] Case 10-M-0451, Proceeding on Motion of the Commission to Investigate National Grid Affiliate Cost Allocations, Policies, and Procedures.

allocates some of its electricity to industrial customers in the Niagara Mohawk service area. PACE Energy and Climate Center and the National Resources Defense Council appeared jointly in this case, and an Alliance of Municipal Parties also participated,[5] as well as a coalition of towns and cities referred to as "the Municipalities".[6] The International Brotherhood of Electrical Workers, Local 97, also participated in this proceeding.

Settlement Efforts and Stipulated Matters

On August 10, 2010, Niagara Mohawk provided notice of its settlement discussions with the parties.[7] The parties' settlement efforts were conducted in mid-August 2010; however, they did not produce a joint proposal for this case. Instead, they resulted in six stipulations that address: energy supply issues (Exhibit 390); low income program, issues and economic development (Exhibit 391); revenue decoupling (Exhibit 392); rate design, customer and market issues (Exhibit 393); capital investment and operating & maintenance spending (Exhibit 394); and various adjustments proposed by the Staff auditors.[8]

Public Comments

Throughout this proceeding, the Commission has received customer comments in the mail, over the internet, by telephone and in person. Public statement hearings were held in Syracuse (October 26), the Albany area (October 27) and Buffalo

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5 Twenty-four towns and villages within the counties of St. Lawrence and Franklin.

6 The Towns of Amherst and Tonawanda, the Village of Kenmore, and the cities of Syracuse and Buffalo.

7 August 10, 2010 letter from Catherine L. Nesser, Esq. to the Secretary to the Commission pursuant to 16 NYCRR §3.9(a).

8 The parties did not reach their last stipulation until after the record closed. It accompanied the briefs submitted on October 8, 2010.

(November 3). As of January 5, 2011, 382 written comments had been received and posted on the Commission's website.

A large majority of the comments received were from residential customers, nearly all of whom oppose the proposed rate increase. Comments and resolutions in opposition to the increase were also received from businesses, elected officials, and municipalities.

Commenters expressed three principal types of arguments against the rate increase. Many cited the poor economy and the personal hardship it is causing, stating that under the current circumstances no increase is justified or bearable. A large number of commenters noted that the delivery portion of their Niagara Mohawk bill was significantly larger than the commodity portion. Customers wondered how that could be possible, and cited it as a reason to deny any increase in delivery rates. Related to this point, a significant number of customers wrote that they had undertaken efficiency measures but were not rewarded with lower delivery rates. Finally, a substantial, though smaller, group of customers wrote that utility employees were well paid and not as productive as employees in competitive industries.

Several regional economic development agencies, as well as individual businesses, wrote in support of a balanced approach, recognizing the need to maintain reliability as well as National Grid's role in fostering economic development. A number of civic associations also expressed support for Niagara Mohawk.

Summary of the Recommended Decision

Following discovery and stipulations, the Company's proposed rate increase was $361.2 million. On November 17, 2010, Administrative Law Judges William Bouteiller and Rudy Stegemoeller issued a recommended decision recommending that the Company's revenues be increased by $111 million per year.[9] The recommended decision adopted the Company's proposal that residential and small business customers should experience no increase; this should be accomplished by extending the recovery of regulatory assets.

The recommended decision proposed a return on equity of 9.3% and numerous other adjustments detailed below. It also endorsed the bulk of the stipulations entered into between Staff, the Company, and other parties.

With respect to the service company issues, the recommended decision cited the Service Company Audit case and recommended that $50 million of the Company's revenue increase be made temporary pending a determination in that proceeding.

The parties filed their exceptions to the recommended decision on December 8, 2010 and their responses on December 23, 2010.

SERVICE COMPANY ISSUES

During the course of this proceeding, Staff and various intervenors raised numerous concerns regarding the Company's treatment of service company expenses. The recommended decision found that the accounting and reporting errors uncovered by Staff are representative of a systemic problem that the Company's business organization, structured around "Lines of Business" and service companies, lacks the internal procedures and safeguards necessary to ensure the proper allocation of costs to the individual operating companies. Moreover, the recommended decision agreed with Staff

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[9] As initially released the recommended decision identified the revenue increase at $99.3 million. Subsequent clarification of two accounting matters disclosed that the recommendations in the recommended decision provided for a revenue increase of $111.2 million.

and the parties that National Grid's cost allocation formula does not appear to credit Niagara Mohawk for the economies of scale it creates as the largest company in the National Grid system. The Judges further found that the Company's process for normalizing historic rate year expenses did not provide the confidence needed to support a permanent rate increase for the service company costs.

a. Remedy

The remedy proposed by the Judges is to retain \$50 million of the Company's revenue increase in the form of temporary rates. The Judges proposed temporary rates as an alternative to a "macro" adjustment, because the audit to be performed in the Service Company Audit case will provide better information than is currently available. Neither the Company, Staff, nor CPB excepted to the Judges' recommended remedy.

MI does not object to the establishment of temporary rates, but argues that some level of macro adjustment should be imposed. MI argues that the Company has failed to meet its burden of proof and that a macro adjustment is justified, given the likelihood of further adjustments following the audit, to prevent delivery rates in the rate year from being set unnecessarily high. In the alternative, MI suggests that a partial macro adjustment could be imposed, offset by a reduction in the amount of temporary rates.

Niagara Mohawk responds that the recommendation of temporary rates in the recommended decision is a reasonable approach, because it recognizes that a decision should be based on the detailed analysis that the service company audit will produce.

We agree that a remedy providing for a refund or credit of any unreasonable charges is proper and sufficient under these circumstances. The audit will provide a full and extensive analysis that is not currently available. MI's concern that the rate year revenues may be unnecessarily high is allayed by our determination, below, that deferral recoveries should be delayed so that no customer class experiences a rate increase.

With regard to the mechanism used to effectuate this decision, $50 million of the revenue requirements associated with service company costs will be recovered through an adjustment clause mechanism. The adjustment clause mechanism must be designed to provide for the recovery to be performed in the same manner that the Company's delivery revenue requirements are recovered in base rates. This portion of the revenue requirement will continue to be recovered through an adjustment clause, subject to our audit, review and refund, until such a time as we determine that the expenses are reasonable or until a disallowance determination is made and a refund or credit to customers has been effectuated.[10]

b. Reporting Requirements

Staff also proposed that new reporting requirements be imposed, as follows: (1) service company budgets should be provided to the Commission; (2) variance reports of the service company budgets should be provided; and (3) budgets and variance reports should also be provided by Lines of Business.

The Judges agreed with the Company that these proposals were premature on the basis of the record in this case. Staff excepts, arguing that budget and variance reporting is a standard and fundamental practice. Staff is concerned that

10 We are requiring the Company to provide, within 60 days of this order, illustrative examples of how it would effectuate a reduction in revenue requirement pursuant to such an order. The filing will assist us in exercising our discretion regarding the manner in which a refund or credit would be effectuated.

another rate filing, without better reporting, will lead to a repetition of the problems experienced in this proceeding, and that the resolution of the issues in the Service Company Audit case may not occur before another rate filing must be processed.

The Company objects on two grounds. First, Staff did not propose these requirements until it submitted its brief on exceptions, hampering the ability of the parties to analyze the proposals, and undermining Staff's claim that the reporting is essential.

Second, the Company asserts that it already provides comparable reporting because the service company department budgets and variance reports are made available to Staff, as well as Line of Business department budgets and variance reports. The Company notes that the recent management audit found no inadequacy in the manner in which budget information is reported to senior management and provided to Staff.

The recommended decision explains how the Company's failure to anticipate the requirements of a rate case audit led to complications and delays in this proceeding. We share Staff's concerns. However, pending further analysis in the Service Company Audit case, we will not prescribe a new set of reporting requirements. Nonetheless, if the Company were to file for new rates before any new reporting requirements are determined, the Company will be expected to present its case in a manner that accommodates a timely and thorough audit of all cost categories, including the service company expenses.

c. Legal expenses

In its case related to the service company expenses, Staff included an adjustment of $2.2 million for outside legal expenses, arguing, in part, that legal expenses were not properly allocated and, in part, that they were excessive because many legal functions could be performed in-house at a lower cost. The Company agreed to a $0.7 million adjustment for allocation errors.

The recommended decision found that Staff had not demonstrated that the legal expenses incurred were excessive. The Judges noted, as well, that any such case is very difficult to make. Given the degree of judgment involved in selecting legal counsel, and the privileged nature of many communications and some billing invoices, the Judges recommended that legal expenses be considered in the context of the productivity and/or austerity adjustment we are making in this case.

Staff excepts, arguing that austerity measures are only temporary in nature. Staff also argues that the overcharges it identified are "quite possibly the tip of the iceberg," and while a precise adjustment might not have been shown, some level of adjustment is warranted.

The Company asserts that no disallowance adjustment was specifically supported, and that it would be improper to penalize the Company for relying on its attorney-client privilege.

We agree with the recommended decision's finding that no specific adjustment has been supported and that the Company should strongly consider reductions in this expense category as a means for achieving permanent productivity and temporary austerity savings.

REVENUES

Revenue Decoupling Mechanism (RDM)

The Company and Staff entered into a stipulation providing for the implementation of a revenue decoupling mechanism consistent with the actions we have taken for other electric distribution companies. The Judges described, in detail, the RDM for Niagara Mohawk and, on exceptions, there are three issues for us to resolve.

1. Revenue Targets for 2012 and 2013

The Company and Staff did not resolve the operation of the RDM beyond 2011. The Company supports the use of an index to adjust the revenue targets for inflation. Staff and Multiple Intervenors oppose the Company's proposal. The Judges support the use of an inflation index for 2012 and 2013 as a means to avoid a rate filing after this one.

On exceptions, Staff opposes the use of an inflation-based index for setting revenue targets. It believes it is better to examine Niagara Mohawk's support for any delivery rate increase it may seek for 2012 or 2013. According to Staff, an inflation index could provide the Company a rate increase that may not be cost justified. However, if we were to implement an index, Staff suggests that we temper its application by allowing the RDM targets to increase by only half the indicated rate of inflation.

Multiple Intervenors also opposes the use of a revenue index and sees no need for us to address ratemaking matters for 2012 and 2013 with the Company's withdrawal of these matters from active consideration in this case. In general, MI is opposed to piecemeal ratemaking and to automatic rate increases, particularly if the Company earns its authorized return and its costs have not increased. MI observes that we have not adopted an inflation index for any other utility company. MI believes we should refrain from adopting one here.

In opposition to Staff and MI, Pace/NRDC supports the use of a revenue target index to avoid unnecessary rate proceedings and the costs that parties incur to participate in them. They observe that the parties' working relationships can become strained by otherwise avoidable rate case litigation and their interests may be better served by collaborative efforts. Pace/NRDC supports a balanced and streamlined approach to ratemaking and administrative proceedings.

Niagara Mohawk states that its indexing proposal was intended to address consequences raised by the implementation of the RDM. The RDM does not allow the Company to retain increased revenues due to sales growth. For this reason, the Company believes that a mechanism, operating between rate cases, is needed to adjust for any lost revenues. Niagara Mohawk considers this matter ripe for consideration here and states that an index will mitigate the amounts it may otherwise seek through the rate case process.

As noted above, we find that it is better to consider the merits of the Company's indexing proposal, and any opposition and alternatives to it that the parties may present, in the next Niagara Mohawk rate proceeding. In the next rate case, the parties should fully explore the potential for establishing a multi-year rate plan and, in doing so, should consider the use or avoidance of an RDM revenue index. Our decision here does not prematurely decide the merits of any indexing proposal; it does support the full consideration of a multi-year rate plan. Until such time as any new RDM targets are established for periods beyond the rate year, the monthly targets established for 2011 should continue to be used for post-rate year revenue reconciliation.

2. Large Non-Residential Customers - RDM Exemption

Multiple Intervenors has sought to exclude large industrial and commercial customers from the RDM's operation. The Judges recommend that the RDM apply to all customer classes, including the large customers that are represented by MI.

MI believes large customers should receive an exemption because they do not pay volumetric rates. According to MI, a revenue decoupling mechanism is best applied to the customers who pay volumetric charges. Since the large customers' rates are cost-based, MI asserts that the link between the utility company's profit motive and the sales made to the large customers has been broken.

MI notes that the Commission has exempted some large customers from the RDM's operation and observes that many large customers have not made use of Niagara Mohawk's energy efficiency programs. MI also objects to any shift in business and revenue risks away from utility shareholders and towards customers as may accompany an RDM. Further, it states that large customers seek rate certainty and the RDM can frustrate their expectations. MI expects the RDM to produce substantial surcharges for the large customers whose revenues are declining. It also claims that the RDM reduces or eliminates the incentives utility companies provide large customers to engage in economic development and efficient energy consumption.

Addressing the Judges' concerns about a blanket exemption for all large customers, MI observes that the Commission has exempted the large customers in the Central Hudson service area from an RDM that otherwise applies to residential and small commercial customers. Given this instance, and allegedly similar circumstances here, MI believes that any disincentive to be eliminated by the RDM is outweighed by the disruptive rate impacts that large customers would experience. MI urges us to apply a RDM only in instances of real disincentives and not to any mere possibilities suggested by the Judges.

In sum, MI maintains that surplus generation capacity is available in upstate New York and its efficient use should be encouraged to increase economic activity and create jobs. According to MI, large customers are seeking to implement cost-effective energy efficient projects and processes that make good business sense and their interests are best served by an RDM exemption.

Pace/NRDC, Staff and Niagara Mohawk oppose MI's proposal to exclude large customers from the RDM's operation. Pace/NRDC and Staff believe that Niagara Mohawk continues to have a financial and revenue interest in the demand charges it collects from the large customers and this disincentive needs to be addressed. Staff also discounts MI's assertion that the large customers have not participated in energy efficiency programs provided by Niagara Mohawk. It notes that they can do so in the future as the Company will continue to make the programs available. According to Pace/NRDC, an exemption for the large customers would be contrary to the policy objectives that are served by having electric utility companies implement RDMs.

Staff disagrees with MI's analysis of the RDM's effect on large customers, their businesses and their energy usage. Staff concedes that the Company may have less of a short-term financial interest to offer economic development incentives to these customers; however, Staff states that the Company continues to have a strong, long-term incentive to seek load growth. Niagara Mohawk will earn a return on the plant additions and capitalized infrastructure it builds to serve load growth on its system. Moreover, Staff states that the Niagara

Mohawk RDM provides an exemption for individual contract customers in Service Classification No. 12. Thus, it believes there are sufficient incentives for load growth and efficient energy use. Finally, addressing Central Hudson's exemption for large customers, Staff states that the only reason for the exemption is the lack of a utility-provided energy efficiency program in that service area for large customers. Since Niagara Mohawk provides its large customers such programs, Staff reasons that there is no basis for any exemption here.

Niagara Mohawk points to the expert testimony of its witness which contradicts MI's assertion about the value of demand charge revenues to the Company. Niagara Mohawk states that it has an interest in preserving these revenues which undermines its incentive to promote conservation and energy efficiency. The Company concurs with the Judges' assessment that the benefits of energy efficiency and conservation apply to all customers, including large customers.

We find that MI has not provided a persuasive case for us to exempt all large customers from the operation of Niagara Mohawk's RDM. In the case involving Central Hudson, such action was unavoidable in light of that utility company's inability to offer large customers related conservation and efficiency programs. No such obstacle is present here given Niagara Mohawk's ability to provide customers these programs. In the future, the large customers would benefit from using them as we are denying the request here for a blanket exemption for all large customer service classes.

3. Large Customer Reconciliation Groups

The RDM proposed here would group all large customers into a single group for revenue reconciliation purposes. The Judges agreed with Multiple Intervenors that it would be better to retain some large customer service group characteristics by establishing an additional reconciliation group. However, the Judges did not go so far as to recommend separate reconciliation groups for each and every service classification as MI proposed. Instead, they asked Niagara Mohawk to provide, with its brief on exceptions, an alternative for grouping the large customers. The Company complied with their request.

While Niagara Mohawk continues to favor a single reconciliation group for all large customers, it can implement two reconciliation groups--one for the 4,500 customers in Service Classification No. 3 and another for about 300 customers in Service Classification No. 3A.[11] This approach is compatible with the Company's billing system.

Niagara Mohawk remains concerned about the possibility of the S.C. No. 3A reconciliation group incurring disproportionate impacts should any large customers leave the service area or shift their requirements to the other group. The Company is also concerned about the potential for large customers to game the process by controlling their demand levels and by moving strategically between the groups.

Multiple Intervenors opposes the Company's two reconciliation group proposal and remains concerned about improper interclass revenue reallocations. It does not believe that the large customer classes and subclasses, with their differing rates, should be consolidated for RDM purposes. With respect to the subclasses that have few customers, MI believes it is better to exempt them from the RDM than it is to lump them with customers with dissimilar characteristics which can lead to improper interclass revenue reallocations.

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[11] The large commercial and industrial customers receiving service in Service Classification Nos. 4, 7, 11 and 12 would be assigned to one of the two reconciliation groups in this proposal.

MI proposes that we establish four reconciliation groups for large customers consisting of Service Classification No. 3 Secondary (3,669 customers); S.C. No. 3 Primary (695 customers); S.C. No. 3 Sub-Transmission and Transmission (121 customers); S.C. 3A Secondary and Primary (80 customers). As to S.C. 3A Sub-Transmission (77 customers) and Transmission (53 customers), MI considers each of these subclasses as candidates for RDM exemptions because each is small and unique. MI's proposal is designed to avoid interclass revenue reallocations among dissimilar customers.

MI addresses the Company's concerns about gaming and states it is unlikely that S.C. No. 3A customers, with average demands and consumption far higher than those of S.C. No. 3 customers, will move to a more expensive rate solely to change their reconciliation group. If the Company's gaming concerns are real, which it doubts, MI believes the best solution is to exempt large customers from the RDM.

As stated above, the RDM will apply to all customer groups and classes, including the sub-classes that MI considers to be too small and unique to be grouped with others for reconciliation purposes. We find that Niagara Mohawk's proposal, provided in response to the Judges' request, is acceptable and provides properly for revenue reconciliations at the service classification level. Accordingly, we are adopting five reconciliation groups that will apply respectively to S.C. Nos. 1, 2D, 2ND, 3 and 3A.

Merchant Generator Stand-By Service Revenues

No estimate was provided in this case of the amount of revenue Niagara Mohawk will obtain during the rate year from its delivery of electricity to merchant generator plants when they do not operate. Absent a revenue imputation, deferral accounting is needed to capture these revenues for ratepayers.

The Judges recommend the use of deferral accounting but only to the extent that such revenues exceed the materiality threshold that is used for some of the expenses the Company is permitted to defer and recover from ratepayers.

On exceptions, Staff urges us to establish a separate and distinct deferral account for this source of revenue, without any materiality threshold. Staff observes that the materiality threshold for certain expenses that qualify for deferral accounting is $8.8 million (4% of Niagara Mohawk's net operating income after taxes). According to Staff, a similar threshold for merchant generator revenues would be unfair to ratepayers and it would provide stockholders the benefit of all sales up to $8.8 million. Rather than permit this, Staff would rather see us impute revenues to the Company. Staff believes that as much as $10.456 million of merchant generator revenue could be imputed.

Addressing the materiality threshold, Staff observes that "exogenous events" receive this treatment but there are other deferred cost categories for which there is no such materiality standard.[12] For this reason, Staff believes that a materiality standard need not apply to the merchant generator revenues. Staff states that the "exogenous events" deferral category does not current apply to merchant generator revenues and, as the category was conceived, it has no application to this source of revenues.

In response, Niagara Mohawk notes that Staff's support for a new deferral account for these revenues contrasts with its

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[12] "Exogenous events" is the vernacular term the parties have used to refer to expense (and revenue) deferrals made pursuant to the Merger Joint Proposal's provision that addresses mandatory regulatory, legislative or accounting changes. This deferral account has a 4% of net operating income threshold which limits its operation to large and significant events.

opposition elsewhere to the establishment of other deferral mechanisms. According to the Company, there is substantial uncertainty as to whether it will obtain merchant station revenues during the upcoming rate year. It states that changes in station service practices are being examined for their potential benefits to ratepayers and the timetable for implementing any such changes is uncertain. Niagara Mohawk considers the $10.456 million revenue imputation suggested by Staff to be unreasonable and points out that it was submitted too late for proper review. The Company suggests that the 2007 data Staff has referenced are unreliable for revenue imputation purposes. Addressing the deferral accounts without materiality thresholds, the Company states that they result from the Merger Joint Proposal process that does not provide a precedent for the resolution of the issue here.

We find that the circumstances prevailing in 2011 are too uncertain to impute to Niagara Mohawk a specific amount of merchant plant delivery revenues. Instead, we will require the use of deferral accounting for the revenues that the Company obtains from this source. We are granting Staff's exception and we will not apply a materiality standard to the amount of merchant plant delivery revenues that will be deferred. Instead, we will provide the Company an incentive to act as expeditiously as possible to maximize the collection of these delivery revenues during the coming rate year. Twenty percent of revenues obtained in 2011 will be credited to the Company. Eighty percent of revenues in 2011, and 100% of revenues thereafter, will be credited to ratepayers.

EXPENSES

Imputed Savings: Synergy, Business Initiatives, Productivity and Austerity

Numerous forms of imputed savings are at issue in this proceeding, including synergy, productivity, austerity, and individual business initiatives. Given the potential overlap among these savings, the recommended decision considered imputed savings both separately and cumulatively. The Judges supported each of the individual adjustments made by Staff, with the exception of austerity, which was reduced from $7.6 million to $5 million.

The Company objects to the recommended decision at three levels: first, specific business initiative savings should have been counted toward the general productivity adjustment; second, specific adjustments related to synergy and business initiatives were unwarranted; and third, the cumulative impact of the imputed savings adjustments is impossible for the Company to meet.

The specific categories of imputed savings are discussed below. Generally, Staff and MI argue the importance of noting that synergy, business initiative, and other savings do not reflect a windfall; the costs to achieve these savings are included in base rates. It is our responsibility to ensure that ratepayers secure the benefits of programs that they are paying for.

1. Synergy Savings

a. Narragansett Synergies[13]

The recommended decision supported Staff's $3.926 million reduction applied to the rate year, reflecting the portion of the synergies related to the Narragansett merger that had not yet been achieved during the historic test year.[14] The Company argues that the merger savings were accelerated and had been fully realized by the beginning of the test year.

The Judges cited uncertainties presented by the Company's discovery responses, the inherent difficulty in identifying which position reductions are attributable to synergy, and the substantial overall increase in A&G and service company costs, as factors casting doubt on the Company's claim that synergy savings were realized by the beginning of the test year. Stating that four years is the default presumption for realization of synergy savings, the recommended decision recommended Staff's adjustment.

Niagara Mohawk argues that there is no four-year "default presumption" with respect to synergy savings, and Narragansett savings were much more easily and quickly captured than other merger savings, because they resulted mostly from employee reductions. The Company explains that it took extra time to produce an analysis in the form requested by Staff, but

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[13] On August 24, 2006, National Grid acquired the Southern Union Company of Rhode Island. Pursuant to the current rate plan, Niagara Mohawk ratepayers are entitled to enjoy the benefits of a portion of the synergy savings from this National Grid merger. Case 01-M-0075, Case 01-M-0075, In the Matter of the Joint Petition of Niagara Mohawk, etc., Order Relating to Follow-on Merger Credit of the Southern Union Company in Rhode Island (issued October 1, 2007).

[14] MI supports Staff's arguments with respect to both Narragansett and KeySpan synergy savings, and many of the arguments attributed here to Staff are also raised in detail by MI.

that it has fully demonstrated that the employee reduction targets in the Narragansett merger were fully realized as of June 30, 2008, i.e., prior to the historic test year.

Staff argues that the Company's credibility is strained by the timing of its discovery response. The Company asserted that all savings had been accomplished prior to the test year, but then demurred that the tracking of Narragansett savings was not performed with the formality of tracking KeySpan savings, and two months were needed before the tracking of the savings could be demonstrated. Staff also argues that the Company has used a four-year period to phase in synergy savings for all of its other mergers.

The fact that the Company has used a four-year period for accomplishing synergy savings from other mergers does not preclude the Company from claiming that Narragansett savings were realized more quickly. Niagara Mohawk was not properly prepared to substantiate its claim, as demonstrated by the lengthy delay in discovery. As Staff has argued, the fact the Company had not tracked the savings in a manner that could easily be demonstrated casts doubt on the credibility of the initial claim. Nevertheless, while Staff has generally challenged the credibility of Niagara Mohawk's claim, the Company's specific demonstration of 173 position reductions as of June 30, 2008 has not been refuted. Under these circumstances, we find that the Company has made a sufficient showing. The adjustment of $3.926 million in the recommended decision is reversed.

b. KeySpan Synergies

Niagara Mohawk's rate filing reflects $18.5 million of savings related to the synergies of the National Grid and KeySpan Corporation merger. The Company's analysis assumes $200 million in total savings, which is the figure committed to in the KeySpan merger proceeding.[15] The recommended decision agreed with Staff and MI that the basis for the calculation of KeySpan merger savings should be $247 million, not $200 million, because $247 million represents the Company's actual target. Utilizing the $247 million figure produces an adjustment of $12.534 million.[16]

The Company argues that it committed to a target of $200 million, which in itself was a "stretch" that would be difficult to attain, at best, and impossible to attain if savings are also imputed to various other business initiatives.

Staff notes that when projects from the $247 million list were abandoned, other initiatives were added to replace them and maintain the total at $247 million.

The Company has not rebutted the argument that the $247 million target represents its actual internal target. Because the list is not static, it cannot represent an outside limit of potential savings. The fact that the list has been supplemented to maintain its total at $247 million indicates both that it is not an exhaustive list, and also that $247 million is the actual basis for calculating synergy savings. Therefore the Company's exception is denied.

A related issue stems from the Company having added back to the historic test year the actual incurred labor expense

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[15] Case 06-M-0078, Joint Petition of National Grid plc and KeySpan Corporation, etc., Order Authorizing Acquisition (issued September 17, 2007).

[16] Staff notes that this is a conservative adjustment because it does not account for other problems identified by Staff.

for employees that participated in the Voluntary Early Retirement Offer (VERO). The purpose for the add-back was to avoid a double count of imputed KeySpan merger savings. Staff agreed with this adjustment in theory, but only to the extent that the VERO savings could be demonstrated to overlap with synergy savings.

The Company performed an analysis and specifically identified a synergy overlap for 39 of 130 VERO'd employees; for the remainder of the employees, the Company affirmed that vacancies had been created somewhere in the organization. Staff took the position that only the specifically identified 39 employees represented a double-count; the remainder should be withdrawn from the test year, resulting in an adjustment of $1.3 million. The recommended decision agreed with Staff.

The Company argues that additional analysis, submitted with its rebuttal filing, demonstrated that 78 VERO employee reductions are directly linked to synergy savings. At a minimum, the Company argues, the adjustment should be reduced to reflect this updated number.

Staff argues that the task of tracking vacancies created by the VERO is extremely complex, by the Company's own admission. Some VERO'd positions were not filled because they had clearly been identified as merger efficiencies. Others were filled by other employees whose positions, in turn, went unfilled as merger efficiencies. In many cases, the VERO triggered a chain of job shifts, the tracking of which produces results that are speculative at best.

The Company, essentially, is arguing that the presumption should be reversed, <u>i.e.</u>, that a VERO vacancy should be assumed to overlap with a merger efficiency, unless demonstrated otherwise. Given the admitted difficulty of performing such an analysis, we agree with Staff that only the

39 initially identified positions should be treated as overlapping with synergy savings.

2. Savings Related to Business Initiatives

Staff argued that various initiatives and programs can be expected to produce significant efficiency savings that should be reflected in the revenue requirement. Niagara Mohawk believes that the standard 1% productivity adjustment, as well as the estimated synergy savings, adequately takes into account the savings for these initiatives and projects. The recommended decision agreed with Staff that identifiable savings from three distinct projects should be separately accounted for, so long as they do not represent a double count with synergy savings.

a. Electric Distribution Operations Transformation Program

The Electric Distribution Operations Transformation (EDOT) program is a broad effort to make National Grid's electric operations more efficient and effective. National Grid anticipates approximately $10 million in savings allocated to Niagara Mohawk, but argues that $7.9 million are already counted as KeySpan merger savings. Staff proposes that the savings from the program should be imputed to the revenue requirement for the rate year, on the basis of the savings information contained in the Company's adjusted business case.

The recommended decision found that there was confusion among various discovery responses related to this program, regarding the extent to which savings were already counted as merger savings. The recommended decision adopted Staff's $10 million adjustment, noting that this recommendation could change pending further clarification.

On exceptions, the Company demonstrates that the EDOT initiative is a single program, a portion of which was identified as KeySpan merger savings. Niagara Mohawk explains the confusion in discovery responses as caused by its treatment of EDOT as a single program, for management purposes, which led to responses that did not acknowledge the distinction drawn for ratemaking purposes. The Company shows that $20 million of savings from EDOT initiatives are contained within the $247 million of identified KeySpan merger savings. Staff and the Company agree that Niagara Mohawk's allocation of the $20 million is $7.9 million. The Company argues that the remainder should be counted toward the conventional productivity adjustment.

In response, Staff refers again to the testimony and discovery responses in which Niagara Mohawk referred to EDOT as incremental to synergy savings.

Staff further argues that the Company has not provided a clear and complete trail to support its savings computation. Staff refers to a business case projection provided by the Company, and argues that it has not been reconciled with the savings detailed in the exhibit accompanying the rate filing.

Until the briefs opposing exceptions, Staff and the Company had not differed as to the savings computation, and we will accept the estimate that had been agreed to with the Company.

The recommended decision invited Niagara Mohawk to clarify its position with respect to EDOT, and we find that the Company has satisfactorily explained its testimony and discovery responses.

For those reasons, we find that $7.9 million of imputed EDOT savings overlap with synergy savings and should not be separately reflected in the revenue requirement. With respect to the $2 million remainder, which the Company argues should be counted toward a productivity adjustment, we reject the Company's argument, as discussed below.

b. Other Business Initiatives

The global procurement transformation program (GPT) will use the corporate organization's large scale operations to improve materials sourcing and supplier relationship management. Savings in the rate year will be approximately $4.3 million, which the Judges recommended should be deducted from the revenue requirement. The transaction delivery center initiative (TDC) is expected to centralize and streamline transactions and activities, and thereby achieve better service and greater efficiency, saving $2.8 million in the rate year. The Judges agreed with Staff that these savings should be imputed into the revenue requirement. Niagara Mohawk does not dispute the figures, but argues that the savings are properly subsumed within a productivity adjustment. This argument is considered in the discussion of Productivity, below.

3. Productivity

In its rate filing, Niagara Mohawk included a productivity adjustment consistent with the Commission's established practice of applying a 1% productivity factor to major rate filings. In this instance, the adjustment is worth approximately $5.9 million, which is 1% of the Company's labor costs and payroll taxes. Niagara Mohawk argues that its productivity adjustment encompasses known and quantified savings such as the EDOT, GPT, and TDC, so imputation of savings from those programs constitutes a double count. Staff and MI disagree with the Company on this point. The recommended decision found that the 1% productivity adjustment was not duplicative of the savings from these initiatives.

Niagara Mohawk argues that the combined productivity savings of two mergers and three business initiatives produce great productivity savings. The Company also argues that the cumulative effect of the savings imputed by the recommended decision is an unrealistic and unachievable level of savings. Finally, the Company argues that it is unwise to "penalize" a company for proactively undertaking and identifying savings initiatives prior to a rate filing.

Staff observes that the savings from the business initiatives ($17 million) substantially exceed the value of a 1% productivity adjustment ($6 million). This remains true even when $8 million of EDOT savings are subtracted from the total, as determined above.

Staff also argues that the Company cannot credibly argue that the estimated savings are unrealistic and unattainable, when they are derived directly from the Company's own business plans. Staff also notes there are many areas of potential productivity improvement that are not encompassed within the specific initiatives that have been identified and quantified.

Staff and MI note that the savings from the initiatives do not represent net savings, but are offset by costs to achieve, which have been included in the revenue requirement.

MI notes that the nature and extent of efficiency savings claimed by Niagara Mohawk has varied and has been debated throughout the proceeding, undermining the Company's claim that the savings are clearly identifiable.

As described above, we agree with the Company that $8 million of EDOT savings have already been counted as synergy savings. We also agree that $4 million in Narragansett merger savings should be recognized. Each of the other specific items imputed to the Company is independently supported by the record. Although the cumulative effect of the imputed savings is a relevant factor, it is less important than the degree of support for each individual item. Moreover, after removing the adjustments for EDOT and Narragansett savings, the remainder of the imputed savings from mergers and business initiatives represent a reasonable and achievable level of savings, independent of the rationale for the conventional 1% productivity adjustment.

The Company argues that utilities will be deterred from identifying efficiency initiatives prior to rate filings. As MI and Staff observe, the costs to achieve identified programs are built into base rates, which provides the utility an incentive to identify initiatives prior to rate filings. More importantly, there is a significant converse to the Company's argument. We hold utilities responsible for operating in an efficient manner. Utilities that fail to identify efficiency programs may be subject to higher productivity adjustments, or other forms of adjustment, where circumstances indicate that the opportunity for efficiency savings exists.

MI argues that the productivity adjustment should be increased to 3%. MI argues that unquantified savings--i.e., the type of savings intended to be reflected in a productivity adjustment -- will occur due to the Company's capital program and the implementation of the management audit.

The recommended decision found that MI's claims were plausible but, noting the range of savings already being imputed to the Company, found that maintaining the conventional 1% productivity adjustment was the most reasonable course.

On exception, MI reiterates its arguments that capital spending will increase by 104% from 2006 to 2011, and that 86% of the management audit recommendations will have been completed by the end of the rate year. MI notes that the Judges found all of its arguments to be plausible and therefore had no basis for denying its proposed 3% adjustment. CPB supports MI's argument.

Niagara Mohawk responds that the cumulative effect of imputed savings adjustments is impossible to realize even without an increased productivity adjustment. The Company also addresses the specific items raised by MI. According to the Company, efficiency savings from capital investments are very limited, in part because inspection cycles for most assets do not vary with the age of the asset. With respect to management audit savings, the Company argues that if the savings could be identified, then according to the positions of Staff, MI and others, those savings should be specifically addressed rather than added to a non-specific productivity adjustment.

IBEW Local 97 also opposes MI's position, arguing that it would place an undue burden on the Company's workforce.

Staff opposes MI's 3% productivity proposal, but only to maintain the balance contained in the recommended decision. Because we are reversing $12 million in adjustments related to EDOT and Narragansett savings, the logic of Staff's argument would indicate support for a larger productivity and/or austerity adjustment.

As noted above, the cumulative effect of all imputed savings is a relevant factor. Although each of the specific imputed savings items discussed above is well-supported, each also represents an element of uncertainty. The total imputed savings identified by the recommended decision, as modified in this order, reflect a reasonable balancing of the challenge of achieving the attributed savings against the potential for achieving additional savings. For that reason, we adopt a 1% productivity adjustment.

4. <u>Austerity</u>

In the current economic climate and conditions, we have required public utilities to exercise austerity until the effects of the recession have diminished and customers, and local communities, are in a better position to incur cost increases for basic and essential services.[17]

Niagara Mohawk states that it has pursued austerity measures and it has reduced costs in a wide range of areas. Staff claimed that Niagara Mohawk's pre-rate year actions do not satisfy our austerity requirements. Staff recommended a $7.62 million austerity adjustment, derived from the Commission's actions in recent rate proceedings addressing Consolidated Edison and Central Hudson Gas & Electric. MI argued that the austerity adjustment, again derived from those two cases, should be $20.36 million. The Judges rejected a formulaic approach to austerity and recommended a $5 million adjustment, citing the range of imputed savings from synergy, productivity, and business initiatives. The Judges also cited the outcome of this case, in which rate increases are likely to be held at or near zero for most customers.

Staff concurs with the recommended decision's adjustment, but only if the remainder of the recommended decision's imputed savings are adopted.[18] The Company takes no exception to the adjustment, although in its arguments against a larger adjustment, it reiterates its position that no austerity adjustment is warranted.

MI argues that $5 million lacks an explicit mathematical foundation and is inadequate. MI argues that the extension of deferrals to accomplish a zero rate increase does

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[17] Case 09-M-0435, Proceeding on Motion of the Commission Regarding Development of Utility Austerity Programs, Order Approving Ratepayer Credits (issued December 22, 2009) at 3.

[18] The RD provided examples of potential austerity measures, including reduced salary increases for management and reduction in outside contracting costs. Staff argues that reduction in outside contracting costs, particularly legal expenses, should be recurring savings, as opposed to temporary austerity adjustments.

not implement the purpose of an austerity adjustment, but rather is simply a method of delaying rate impacts. MI further argues that there is no need to demonstrate that austerity savings are achievable; the burden of identifying austerity measures should be on utilities. CPB supports MI's argument.

In response to MI, the Company repeats its argument that it has already limited management salary increases and agreed to absorb the costs associated with implementing the management audit.[19] The Company argues that the total level of imputed efficiency savings is unachievable even in the absence of an austerity adjustment, much less the enhanced adjustment advocated by MI and CPB. IBEW Local 97 opposes MI's argument, stating that it would have an adverse impact on Company workers, and would disrupt the balance struck in the recommended decision.

Our austerity initiative is a response to a severe economic downturn.[20] An austerity adjustment must not be outside the bounds of what may be reasonably achievable, but it should place demands on the company to undertake aggressive and creative cost-cutting measures. Mathematical equivalence among utilities provides a starting point for an austerity analysis, but each utility must be evaluated in its own context.

We agree with Staff that the austerity measures claimed by the Company have a net impact of near zero, given the

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[19] Staff took the position that these savings were offset by cost increases in the rate year, caused by earlier decisions of the company to defer line repair work in the name of austerity.

[20] In this proceeding, deferrals will be utilized to achieve zero rate increases for all customer classes. The direct benefit of an austerity adjustment will therefore be experienced in the year following the rate year. It is reasonable to assume that the impacts of the current recession will still be affecting customers, to some extent, during that year.

increased rate year costs from previous measures undertaken by the Company that had no benefit to customers. Given our decision with respect to EDOT and Narragansett synergy savings, the total burden on the Company of imputed savings has been reduced substantially. The recommended decision, as well as Staff's testimony and Initial Brief, identified additional areas of potential savings for the Company. Taking these factors into consideration, we adopt Staff's initial proposed austerity adjustment of $7.6 million.

<u>Variable Pay</u>

The Judges generally agreed with Staff that variable pay for management employees should be excluded from rates. They understood that the Commission has distinguished variable pay from base pay and has determined, in various cases, that it should be self-supporting and covered by the cost savings obtained through the efforts and programs for which variable compensation is provided. The Judges, however, disagreed with Staff about eliminating, from rates, variable pay for union employees covered by the terms of collective bargaining agreements. Both Niagara Mohawk and Staff have filed exceptions. The Company seeks a rate allowance for management's variable pay; Staff seeks to exclude from rates the variable pay for union employees.

Niagara Mohawk would distinguish the circumstances presented here from those, in 1991, involving National Fuel Gas Distribution Corporation in one of the first cases involving an exclusion of variable pay from rates. In the 1991 rate case, Niagara Mohawk claims, there were no systematic efforts taken to capture incremental savings attributable to productivity, efficiency, austerity, and merger synergies like those we have considered here. In addition to such adjustments for which there were no counterparts in the 1991 rate case, Niagara Mohawk asserts that it simply cannot achieve another $22.5 million of cost savings related to the variable compensation paid to managers and union employees.

According to the Company, its circumstances are more like those of a 1992 Consolidated Edison rate case in which half the variable pay amount was allowed in rates. Comparable action here, Niagara Mohawk suggests, would permit in rates all of its variable pay expense, given the productivity, efficiency and synergy amounts that have been specifically identified. At a minimum, the Company believes it should receive rate recognition for the variable compensation that is used to attain customer satisfaction, safety and reliable service goals that the Commission has endorsed.

Niagara Mohawk insists that the total amount of compensation it has claimed for the rate year is well supported and enables the Company to attract and retain qualified personnel. Also, the Company is willing to return to ratepayers any portion of the variable pay that is not actually paid out. Overall, Niagara Mohawk considers the merits of its variable pay program to be better for ratepayers than any fixed compensation alternative.

For its part, Staff asserts that the variable pay union employees receive is no different than the variable pay for management employees. In both cases, the bonus payments must be earned and savings must be achieved to cover the cost of the incentive program. According to Staff, excluding variable pay from rates does not interfere with the collective bargaining process and it is only logical to apply the same approach to management and union employees. Staff stresses the point that union employees are not guaranteed their variable pay absent the performance needed to earn the pay.

Like Staff, Multiple Intervenors believes that all variable pay should be excluded from rates. It points to a 2008-09 Consolidated Edison electric rate case as recent support for this approach and to the 1991 National Fuel rate case for the approach's inception. From these rate decisions, MI claims there is an established policy that puts all utility companies on notice that their incentive compensation programs must be funded by cost savings or otherwise be borne by shareholders. Multiple Intervenors does not believe that the Judges correctly understood the established Commission policy and practice.

In response to Niagara Mohawk, MI asserts that the Company withheld from the record, and the parties, the financial parameters of its variable pay plan. For this reason, MI believes the Company should not receive any variable pay rate recovery. Until the financial parameters of the Company's variable pay plan are disclosed, MI insists there is no way to know if a basis exists for ratepayer funding. Moreover, if the pay plans are too expensive to be fully supported by offsetting cost savings, MI believes that the Company should incur the consequences of its actions.

MI states that the 1992 Consolidated Edison approach to variable pay has been superseded by more recent precedents and it asserts that there is no evidence that any financial parameters were in play in the 1992 rate case. MI does not believe a basis exists here to allow a portion of the variable pay related to specific service goals consistent with the Commission's standards and requirements, given the decision reached in the 2008-09 Consolidated Edison case. Having decided that no ratemaking allowance is needed for self-funding pay plans, Multiple Intervenors states that the benefits customers receive are irrelevant and they do not provide a basis for allowing the pay plan costs in rates.

In contrast to Niagara Mohawk's and Multiple Intervenors' citations to only three cases for variable pay matters, Staff states that the Commission has considered this matter in numerous rate proceedings. Staff agrees with MI that the Company should have revealed its financial goals and program measurements that are needed to determine if the achieved savings covered the program costs. Without such information, Staff believes we should not entertain any rate treatment for the costs. Also, without this information, Staff states that the amount related to customer safety and service cannot be determined.

As the final plank in support of its position, Staff states that the Niagara Mohawk variable pay program violates a Merger Joint Proposal provision precluding the compensation paid to regulated utility company employees from being tied to the performance of an unregulated affiliate. Staff states that Niagara Mohawk has admitted to the possibility of the variable pay plan being contrary to this requirement. Staff points out that the performance goals for Niagara Mohawk employees are tied to the financial performance of National Grid which it also considers to be unacceptable should Niagara Mohawk's performance, on its own, not warrant the payment of any incentive compensation.

We have examined the variable pay issues presented in this case and have considered them in addition to the issues addressed above pertaining to matters of productivity, efficiency, austerity and synergy. In light of the past cases cited by the parties to support their respective positions, we begin by pointing out that our decision in the 2009 Consolidated Edison rate case states the current approach we employ for matters pertaining to variable pay. Consequently, Niagara Mohawk's efforts to invoke the earlier National Fuel Gas and

Consolidated Edison cases, and any circumstances prevailing in 1991 or 1992, are inapposite here.

In the 2009 Consolidated Edison case, we recognized that variable pay compensation and incentive plans are common and they are used by management to seek performance improvements and greater competitiveness in their operations. We found that the positive aspects of such plans can include contributions to safe and adequate service, and, if they are reasonable, necessary and directed to these objectives, the costs of a variable pay plan which makes such contributions are includable in rates.

In the case involving Consolidated Edison, we determined that the company's incentive pay program was driven primarily by net income targets that were designed to be of benefit to shareholders. We found that ratepayers did not benefit directly from the use of the net income targets and incentives the company employed. Accordingly, we determined that the Consolidated Edison incentive compensation plan for its managers must be self-supporting for ratemaking purposes and it must provide sufficient productivity savings to offset the program's costs, or it is to be financed entirely by shareholders as they are the intended beneficiaries of the incentive plan.

Significantly, in the 2009 Consolidated Edison case we rejected trial staff's argument that all incentive pay plans must be self-supporting and accompanied by specific, quantifiable savings reflected in the utility company's cost of service.

> …[P]erformance indicators that address goals for safety, environmental protection, and customer service cannot readily be measured by dollar savings; others might further performance requirements for reliability and customer service that benefit ratepayers. Some of these types of performance measures might provide the

> kind of difficulty to identify or quantify savings intended to be captured by the productivity imputation. We do not see that it would be categorically unjust or unreasonable for ratepayers to bear the costs of an incentive plan limited to such factors and not including financial parameters.[21]

In this case, we find that Niagara Mohawk's incentive program, like Consolidated Edison's before it, focuses largely on financial targets that inure to the benefit of the Company's shareholders and the Company was unable to show how its programs tie to the Commission's goals. While the record indicates that the Company's incentive program also includes customer satisfaction, safety and reliability goals and objectives, Niagara Mohawk did not show the linkage between its metrics and the ratepayer benefits. Neither was Staff able, in the course of its audit and examination, to identify and separate the potentially allowable costs from the incentive amounts for financial performances that serve shareholders. Accordingly, we are disallowing the incentive compensation amounts the Company has claimed in this case, including the variable pay covered by the collective bargaining agreement that the Company has with its union-represented employees. While the amounts paid to the union employees may be distinguishable from the incentive compensation paid to the Company's managers, the amounts for the union employees not only suffer the same problem we have found with the managers' incentive compensation but they also suffer from the overall concern that the union program metrics weren't contractually defined and are solely at the discretion of management. The Company has failed to separate and distinguish any incentives and amounts serving ratepayers from those that serve shareholders. Staff's and Multiple Intervenor's

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21 Cases 080-E-0539 and 08-M-0618, Consolidated Edison Company of New York, Inc. - Electric Rates, Order Setting Electric Rates (issued April 24, 2009) p.54.

exceptions are granted and the Company's expense is denied for the reasons stated here.

Labor and Fringe Benefit Capitalization Rates

The Company and Staff provide differing methods for setting the rate year capitalization rates for labor and fringe benefits. The Company's method uses the historic test year data ended September 30, 2009, to project rate year total labor cost and allocate this cost between expense and capital in the rate year, through the use of the capitalization rate. Staff proposes to update only the capitalization rates by using the latest fiscal year ended March 31, 2010 (fiscal year) that became known after Niagara Mohawk filed to increase its revenue requirements. Staff believes using more recent data will provide a better estimate of the rate year labor expense. The Staff also asserted that Niagara Mohawk's own interrogatory response admitted that the fiscal year capitalization rate is more accurate than the historic test year rate that it calculated. The Judges concluded that it was not improper to depart from the base period and to use the fiscal year results to set the capitalization rates. The Company excepts.

Niagara Mohawk claims that Staff commits an error by using the capitalization rate from the fiscal year where the increase in the capitalization rate was caused by an increase in total labor costs and not a shift of labor from expense to capital. The Company agreed that Staff's proposal would be acceptable if total labor did not increase between the historic test year and the fiscal year, and instead there was a shift of total labor from expense to capital in the latter year. However, Niagara Mohawk asserts that this is not the case here. It notes that total labor costs increased by 10.8% between the end of the historic test period and the fiscal year with the largest increase occurring in capital labor (7.7%) while expensed labor increased by only 2.2%. The increase in the fiscal year capitalization rate was caused by an increase in total labor costs dedicated to capital work and not a shift of labor cost from expense to capital. Under Staff's proposal, by applying the fiscal year capitalization rate to the rate year projection of total labor costs, based on the lower costs in the historic test year, there is an improper shifting of the rate year costs away from operation and maintenance (O&M) expense. The example presented by Niagara Mohawk showed that under Staff's proposal the rate year expense would be less than the historic test year level even though the Company has demonstrated that the actual fiscal year level of the expense is not less than the historic test year amount. For this reason, the Company claims that Staff's method is illogical and produces an arbitrary reduction of the labor and fringe benefit expense amounts. According to Niagara Mohawk, this amounts to a mathematical error and the Judges should have recognized it as such. Were this approach to be used, the Company asserts that a corresponding increase to capital labor is needed to compensate for the decrease in expense labor.

Further, the Company claims that the Staff approach improperly double counts the synergy and productivity amounts for the historic test period through March 2010. Having separately reflected synergy and productivity savings in its rate year forecast, Niagara Mohawk states, such savings should not also be embedded in the capitalization rate as they are by the Staff approach. Thus, Niagara Mohawk does not consider the fiscal year results to be superior to the base period it provided, nor does it consider the fiscal year results to be a proper substitute for the historic test period data.

In addressing the Company's argument that it is incorrect to use the fiscal year labor capitalization rate to allocate the rate year total cost developed from an historic test year base amount, Staff focused on the example that Niagara Mohawk used to demonstrate the alleged error in Staff's approach. According to Staff's calculation of the example, the rate year expense under their proposal is above the historic test year level. This illustration shows an increased capitalization rate but, according to Staff, no inaccuracies or any false results. Staff states that an increase in total labor costs does not necessarily produce an increased capitalization rate. Of importance to Staff is the fact that Niagara Mohawk's labor expense increased between the time of the historic test period and the fiscal year, and the Company has supplied no explanation for the increase.

Concerning the alleged double count of synergy and productivity savings, Staff disagrees with Niagara Mohawk's premise that such savings only affect labor expense. It believes that changes in synergy and productivity are properly captured in the changed capitalization rates and the Company's argument lacks merit without a calculation demonstrating the source of any potential double count.

Staff and the Company continue to debate whether the Company has made any admission concerning the superior reliability of the fiscal year capitalization rate over the rate calculated by the Company for the historic year. Niagara Mohawk states that Staff misrepresented the Company's interrogatory response. It never admitted that the fiscal year capitalization rate is more reliable or accurate than the historic test year capitalization rate it calculated.

Finally, Staff denies that its adjustment requires that the amount of capitalized labor be increased. It states that no rate base adjustment is necessary because the Company's capital expenditure forecast for the rate year is not based on any expense-to-capital allocations of internal labor.

We agree with Niagara Mohawk that Staff's proposal to update the rate year forecast of labor and benefits expense by the higher fiscal year capitalization rate results in an improper understatement of the rate year expense and we reverse the Judges' acceptance of it.

The rate year forecast of labor and benefits expense is the product of both the forecasted total cost of labor and the capitalization rate that allocates the cost to expense. The Staff proposal attempts to update this forecast only for the higher fiscal year capitalization rate, thereby reducing rate year expense, while ignoring that the fiscal year total labor costs used to derive the capitalization rate are higher than the historic test year. Updating for only one element of the forecast in this case results in an improper understatement of the rate year expense.

Niagara Mohawk shows that the fiscal year amount of labor expense is 2.2% greater than the historic test year level. This level of expense is reasonably consistent with the amount in the historic test year increased by the wage and salary increases provided during this period. Clearly, the amount of labor expense between the historic test year and the fiscal has not declined, a result that would occur if Staff's method is applied. The increase in the fiscal year capitalization rate results from an increase in total costs where the increase is directed to capital and not by a shifting of work away from expense and to capital.

Staff's application of the higher fiscal year capitalization rate to the forecast rate year total costs, based on the lower historic year total costs, results in rate year labor and benefits expense amounts improperly below the historic test year expense level.

This infirmity in Staff's proposal is evident by examining the Staff example demonstrating the mechanics of its proposal to derive the rate year expense. Staff inflates the $100 fiscal year total cost by 3% to obtain the rate year amount of $103. It then applies the fiscal year capitalization rate of 80% to derive the rate year expense of $20.6 to show that under the Staff proposal the rate year expense is above the $20 historic test year amount.

This calculation is misleading because Staff's proposal only provides for updating the rate year expense calculation by the higher fiscal year capitalization rate and not also by the fiscal year's higher total labor cost. The proper calculation of the Staff proposal in this example should inflate the $80 historic test year total cost by 3% to arrive at the rate year amount of $82.40. Applying the 80% fiscal year capitalization rate results in a rate year expense of $16.48 that is below the historic test year level.

In an attempt to diminish the Company's evidence, Staff asserts that Niagara Mohawk has not explained the increase in the fiscal year labor expense and places the burden on the Company concerning the fiscal year data. However, it was Staff who first proposed the use of the fiscal year labor cost data to update the rate year forecast and it accepted the amount of the fiscal year expense in developing its capitalization rate. Therefore, it is inconsistent for the Staff to use the fiscal year data to calculate the capitalization rate it proposes on the one hand and at the same time question that the fiscal year data are appropriate for supporting the Company's total fiscal year cost. If Staff believed the fiscal year level of expense was improper, it had a duty to show this when presenting its fiscal year capitalization rate calculation. For the reasons stated here, we grant Niagara Mohawk's exception.

KeySpan Service Company Pension and OPEB Costs

In its brief on exceptions, Niagara Mohawk points out that the Judges misunderstood Staff's position concerning the treatment of KeySpan Service Company pension and other post-employment benefit costs. Staff has proposed that they be included in the deferral accounts, subject to the final results of the pending audit of the National Grid service companies. We accept this correction.

Major Storm Expense

At a late stage of the proceeding, Staff revised its position on major storm expenses and increased its proposed allowance to $18.086 million. The Judges used this figure as the uncontested, starting amount for major storm expenses and they asked the parties to address, in their briefs to us, the remaining difference between Staff's figure and the greater amount that Niagara Mohawk has sought.

According to the Company, the $18 million is taken from a seven-year average of deferred and non-deferred major storm costs and it does not include a portion of the non-deferred storm costs. Staff's figure excludes a $2 million per event deductible that the Company believes should be included in the expense allowance. The seven-year average for this item is $6.257 million.

Niagara Mohawk states that these storm costs are nominated "deductibles" for deferral accounting purposes (because not deferred), nevertheless, they are legitimate costs to be recovered in base rates. According to the Company, there is no good reason to disallow these costs appearing nowhere else in the Company's presentation of its cost of service.

Staff admits that the $2 million deductible amount is related to legitimate and recoverable costs; however, Staff explains it does not give rise to an expense allowance because the deductible recognizes that some routine maintenance is supplanted when emergency repairs are made. Without the deduction, ratepayers receive no recognition or credit for having paid maintenance costs that will not be incurred.

We disagree that Staff's deductible amount should be imputed in deriving the rate year storm expense. The Company properly points out that these per event deductible storm costs are only reflected in their base rate storm allowance and not reflected elsewhere in their cost of service. Staff by imputing a deductible amount for rate year storm costs neglects to consider that the historic test year routine maintenance was supplanted by the storm restoration activities during this period. Since Niagara Mohawk, in compliance with our requirements, used its historic test year costs of O&M and storms as the base to project the rate year cost of service the historic year "deductible" is reflected in the rate year levels of O&M. Staff has not demonstrated that in Niagara Mohawk's forecast of O&M from the historic test year it removed or offset the impact on O&M that resulted from the storms occurring in the historic test year. To also separately impute a rate year deductible for the effect of storm restoration on O&M in deriving the rate year, as Staff recommends, will understate rate year expense.

Based on this, we will allow a $22.959 million base rate storm allowance and, as described later, reserve accounting for storm costs will be provided.

Storm Reserve Accounting

The Judges recommend against a Company proposal to establish a $30 million fund to be used to pay the Company's storm costs as they are incurred. On exceptions, the Company maintains that a storm fund would provide a timely, equitable and balanced approach for recovering these substantial and unpredictable costs. It notes that other companies (Consolidated Edison, RG&E and NYSEG) have been allowed to implement and use storm reserve accounts. Also on exceptions, the Company points out that the Judges did not consider whether the existing, major storm deferral mechanism should be continued or allowed to lapse. Niagara Mohawk proposes that the deferral mechanism continue with the existing criteria.

In response, Multiple Intervenors concurs with the Judges' assessment of the confused and unclear record concerning this expense category and agrees with their conclusion that it is premature to consider a storm reserve fund. Further, MI asserts that there are flaws in the Company's approach and good reason for customers not to be required to incur any unnecessary obligations at this time.

MI maintains that the $30 million Niagara Mohawk requested is an arbitrary amount that lacks support. While, the Company states this figure as being its five-year average of deferred major storm costs, MI believes the costs of two abnormal storms should be disregarded to produce an average that is less than $6 million.

Addressing the Company's request for timely recovery of storm costs, MI states that the Company has only incurred incremental, deferred major storm costs twice recently, in 2006 and 2008. Thus, MI sees no compelling reason for establishing a fund. As to the electric utility companies with storm reserve accounts, MI notes that NYSEG and RG&E obtained them pursuant to a joint proposal. With respect to Consolidated Edison, MI observes that its rate allowance for storm costs is fully reconciled. Amounts not used to pay storm costs are preserved for ratepayers which is not the case with the fund proposed by Niagara Mohawk. Further, MI asserts that Niagara Mohawk's financial integrity does not depend on a storm fund. It points out that the Company's financial standing did not suffer in 2006 or in 2008 when the large storms were experienced and there was no storm fund. Given the current economic recession, MI believes it is not the time to burden customers with the cost of a storm fund.

According to Staff, a storm fund is unnecessary. The Company is receiving an allowance in rates to cover major storm costs and it has the opportunity to seek deferral accounting for storm costs exceeding a threshold. Staff disagrees with the Company's assertion that other companies have similar funds and it distinguishes this one-year rate proceeding from multi-year rate plans. Staff believes that the current rate treatment for storm costs favors the Company and a reserve account is not needed for financial integrity purposes.

Addressing the Company's request to continue the major storm deferral mechanism begun with the Merger Joint Proposal, Staff recommends against it from the audit and examination it conducted in this case. Staff is troubled by the deferral threshold the Company seeks to retain and the possibility that shareholders will keep the portion of the rate allowance for storm expenses not incurred.

We find that the results of this rate proceeding are not conducive to our taking any action to establish a $30 million storm fund as the Company has requested. Instead, we are setting a one-year rate allowance of $22.959 million for this expense item as stated above which is supported by the

Company's past experience.[22] Considering the amount of Niagara Mohawk's past major storm costs, and their volatility as presented in this proceeding, we find that there is sufficient potential for the Company to incur significant costs in the circumstances of severe weather that provides justification for the use of reserve accounting. This accounting will provide recovery for the costs that cannot be adequately forecast in advance and must be incurred by Niagara Mohawk to provide reliable service. Thus, we are establishing a reserve accounting approach for major storm costs that dedicates the ratemaking allowance provided for this expense item and provides for an annual reconciliation of the allowance and the expense, and preserves amounts for subsequent periods.

This accounting approach should be consistent with the major storm deferral accounting established in the Merger Joint Proposal and the March 22, 2007 Stipulation of the Parties in Case 01-M-0075. In this regard Niagara Mohawk and the Staff disagree as to the proper amount for the per storm deductible that should apply in the 2011 rate year under this approach. Staff derived a 2011 rate year deductible amount of $2.5 million. This amount was arrived at by increasing the $2 million set in the Merger Joint Proposal by inflation between the start of the rate plan in 2002 and the rate year used in this proceeding. Niagara Mohawk proposed a 2011 rate year per storm deductible of $2.064 million calculated by increasing the $2 million Merger Joint proposal amount only for inflation between the historic test year (ended September 30, 2009) and the rate year used in this proceeding. The Merger Joint Proposal $2 million per storm deductible was established as the

[22] The portion of this $22.959 million representing the rate case target for major storm deferral purposes will be determined in the collaborative discussion that is referenced in "Merger Joint Proposal Provisions" below.

average level of such costs expected during the 2002 through 2011 period. We find that the 2011 rate year per storm deductible amount established in this proceeding should be $2.205 million which represents the increase in the $2 million storm deductible by averaging the inflation-adjusted values of $2 million in each year of the 2002-2010 period, and then bringing this average forward to the latest projected 2011 price level.

Uncollectible Write-Off Allocations

The Company proposes to allocate its uncollectible write-offs to its electric and gas operations using the allocation factors that it developed in 1999 and has used in its rate proceedings since then. Thus, the Company would allocate 72% of the write-offs to electric and 28% to gas. The Judges were persuaded by Staff that the results of a more recent study should be used to allocate a greater portion of the uncollectibles to the gas operations. The Company excepts.

According to Niagara Mohawk, the recent study does not provide a sound basis for allocating uncollectible expenses. Due to data limitations, the study was unable to determine the net write-offs attributable to customers who receive a single bill for both electric and gas service. The study used an allocation process to approximate the responsibility for such costs. Having used its judgment for these allocations, the Company states that the recent study is not as precise, accurate or as reliable as the 1999 study. Further, Niagara Mohawk considers it to be unfair to use the 72%/28% allocation factors in its last gas rate case and to use different allocation factors in this case. It believes the use of a different factor here would trap a portion of the uncollectibles expense between the gas and electric operations and preclude their recovery.

In response, Staff states that the Company has used the recent study results for rate design purposes and this action belies the Company's claim that the study is unreliable. Staff believes the 1999 study results are outdated and the recent study should be used even if its results were not available for the Company's last gas rate case.

We find that Niagara Mohawk's efforts to discredit the recent examination of uncollectible expense write-offs does not bolster, or make any more reliable, the 1999 study results that it proposes be used here. If anything, the Company's points suggest that additional work must be performed to improve the current study of the amount of gas and electric write-offs. Its points do not suggest that we can gain any comfort from using the results achieved over a decade ago.

We are also not persuaded by the Company's argument claiming that we should not depart from the results of the last gas rate case. The new information provided here puts into question the past results and it is the proper purpose of this proceeding to evaluate and determine the best evidence currently available. Of course, the Company can continue to examine its distribution of electric and gas write-offs and we stand ready to implement any better performed study results that may be available the next time we set the Company's rates.

Property Taxes

The Judges recommend that we use Staff's 1.6% property tax escalation rate rather than the 3% proposed by the Company. They also recommend that we provide a separate allowance for plant additions. Niagara Mohawk and Staff except.

According to Niagara Mohawk, the 1.6% escalation rate is the unadjusted historic trend in property tax increases which understates the rate year property taxes because "obsolescence allowances" will not recur at the past levels. Excluding such allowances, the Company states that property taxes increased by 3.17% between 2007 and 2009 and by 4.28% between 2008 and 2009. As the obsolescence allowances continue to decrease, the Company believes its property taxes will increase and approach the 3% forecast.

Niagara Mohawk objects to the Judges' refusal to consider the statewide average in the determination of its property tax expense. Had it not been successful in managing its property tax expense, the Company believes its expense would have matched the statewide average. Given the economic conditions prevailing throughout the State, the Company expects to pay higher local taxes matching those experienced in many communities.

Further, Niagara Mohawk requests a property tax reconciliation that the Judges consider more appropriate for adoption in a multi-year rate plan. The Company points out that Consolidated Edison has a property tax reconciliation that was adopted in a one-year rate case. In support of its request, Niagara Mohawk states that property taxes are largely beyond its control and they are difficult to forecast with the current uncertainties in the State's economy.

Staff excepts to a separate property tax allowance for incremental plant additions and states that the plant additions are covered by the overall allowance for property taxes. According to Staff, when the Company's property tax forecast is back casted, and applied to past periods, it overstates the amounts for 2007 through 2009. Thus, Staff believes that the general approach amply covers plant additions and there is no need to supplement its results. According to Staff, a separate allowance for plant additions would overstate the rate year property taxes and the 1.6% general escalation rate would have to be scaled back and be set below 1.0%.

In response to Staff, Niagara Mohawk insists that separately calculated amounts for incremental plant additions and separately forecast property taxes on the new plant would not provide a double-count or overlap.

To begin, we reject the portion of Niagara Mohawk's property tax estimate that relies on the statewide average of property tax increases. Rather than use a statewide average, we expect the Company to examine its own recent property tax experience in the local communities it serves and to use such information to inform its rate year projections and forecast.

In this case, the forecast of the Company's local property taxes is complicated by the obsolescence allowances that Niagara Mohawk has previously received; however, Staff has demonstrated that the allowances will not fall off completely or abruptly during the rate year. The rate year forecast is also complicated by the parties' dispute about the sufficiency of the general escalation rate to cover incremental tax burdens arising from the placement of new plant into service. We have examined Niagara Mohawk's most recent tax bills and have found that an allowance must be made for plant additions to provide the Company coverage for the new plant at the current tax rates. Therefore, to provide a sufficient rate allowance for property taxes in this instance, we will use the 1.6% escalation as well as the separate allowance for plant additions that the Judges recommend. Since this case addresses only the Company's revenue requirements for 2011 and does not address them for 2012 or 2013, a property tax reconciliation is unnecessary. We note that the property taxes Niagara Mohawk incurs are a far smaller portion of its total cost than are Consolidated Edison's and its circumstances are therefore distinguishable.

PLANT AND RATE BASE

Capital Investments

The Judges provided a summary of the parties' stipulation for capital budgets and plant investments planned for 2011 and 2012. Niagara Mohawk takes exception to the Judges' characterization of the capital expenditure reconciliation mechanism which, according to the Judges, excludes expenditures made pursuant to the Regional Delivery Venture Arrangement. According to the Company, this description is overly broad and it should be understood that the Company will not include any portion of the "gain share" payments made under the arrangement. Niagara Mohawk does not disagree with the Judges' description of the treatment for the Regional Delivery Venture costs. With this clarification, it is clear that the Judges did not modify the terms of the stipulation that we accept.

Working Capital

Niagara Mohawk did not use a lead/lag study to determine the amount of working capital to include in rate base. It used the FERC formula for this purpose which is the standard practice. However, the Company did use a lead/lag study to determine the amount of working capital related to electric power purchases for inclusion in the merchant function charge. The Judges considered this to be an acceptable use of a lead/lag study. Staff excepts.

On exceptions, Staff states that the merchant function charge is nothing other than an unbundled delivery charge that affects customers' bills. If it is permissible to use a lead/lag study for this purpose, Staff believes that a lead/lag study of federal income taxes should be used to reduce the Company's working capital requirements. However, Staff is generally opposed to the selective use of lead/lag studies and is concerned that utility companies will be encouraged to submit such studies if the Judges' recommendation is adopted here.

In response, the Company states that the merchant function charge is designed to reflect the full cost for commodity service including working capital requirements. With the unbundling of rates, Niagara Mohawk believes the need arises and valid purpose exists for using a lead/lag study. According to the Company, Staff's approach would improperly exclude recovery of the working capital costs associated with commodity. Thus, Niagara Mohawk believes that the circumstances of competitive markets, and the Commission's policy objectives for retail access, require the approach it has presented here. The Company states that its reasons for providing the lead/lag study have nothing to do with either federal income taxes or the general use of the FERC formula to estimate the amount of working capital to be included in rate base.

We find that a working capital component related to commodity should be included in the merchant function charge. It is permissible to use a lead/lag study to determine this element of the charge. Our decision here does not alter the standard practice that relies on the FERC formula to calculate the amount of working capital to be included in rate base. Lead/lag studies will not be accepted or used for rate base purposes as long as the FERC formula continues to be an acceptable and preferred approach.

Smart Grid Investments

By letter dated December 9, 2010, Niagara Mohawk requests that we allow in rates the Smart Grid investments for which it has received approval.[23] Rather than defer the costs of these projects, the Company prefers to receive more timely recovery in rates. It specifically requests $1.5 million for the Smart Grid projects.

Multiple Intervenors points out that we established a deferral accounting approach for approved Smart Grid projects and indicated that the reasonableness of the deferred costs would be reviewed in a rate proceeding. MI believes we should not depart from the deferral accounting approach and observes that the Company's request was received very late in this case and it did not receive any record review. MI believes it would be better to examine the Company's Smart Grid costs in the next rate case that Niagara Mohawk files. Multiple Intervenors also questions whether the Company is seeking recovery for two or three projects, and notes that the Commission did not approve a "workplace development" project that will not receive customer funding.

Staff also objects to the Company's proposal, claiming it is premature and contrary to the approach announced in Case 09-E-2009. Staff insists that Niagara Mohawk should provide its support for the projects and demonstrate that adequate benefits flow to customers. Absent such data, Staff objects to the Company's $1.5 million request and notes, by the Company's admission it requires refinement. From its review of the December 9 letter, Staff believes that the $1.5 million is overstated.

From our review of Niagara Mohawk's request to include Smart Grid project costs in the rates being set here, we find that the Company's figures were too hastily prepared to qualify for any current cost recovery. In the short amount of time

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23 Cases 09-E-0310, *et al.*, American Recovery and Reinvestment Act of 2009, Order Authorizing Recovery of Costs Associated with Stimulus Projects (issued July 27, 2009).

since the submission of Niagara Mohawk's December 9, 2010 letter, it has not been possible to fully examine and correct the Company's figures to afford it the current cost recovery it has sought. Instead, the deferral accounting approach must be used and the costs can be included in rates in the Company's next rate proceeding.

Depreciation

Niagara Mohawk provided a depreciation study with its rate filing and it proposed that the current depreciation rates remain in effect. Thus, the Company proposed neither to increase nor decrease its depreciation expense for the rate year. Staff, on the other hand, examined the Company's depreciation study and proposed net salvage adjustments that decrease depreciation expense by about $25.5 million. Staff also proposes changes in average service lives that decrease depreciation costs by another $10.5 million. The Judges recommend that we adopt Staff's depreciation adjustments and the Company excepts.

Niagara Mohawk claims that the Judges did not fully consider the record on depreciation matters and they did not apply Commission precedents correctly. Further, the Company believes that the Judges' recommendation is result oriented and not well reasoned. Niagara Mohawk clarifies that it does not claim to have any greater expertise on depreciation matters than does the Staff, nor does it believe its technical experts are any better than Staff's. However, it does claim to have provided a superior engineering analysis in support of its position that the current depreciation rates should remain in effect without the modifications and reductions proposed by Staff.

1. Average Service Lives: H-Curves and Iowa Curves

According to the Company, it adhered to the Commission's established practice by providing a depreciation study that used H-curves. While Niagara Mohawk does not necessarily oppose the use of Iowa curves, it is troubled here by Staff's switch to Iowa curves in this instance. The Company insists that we should adhere to established precedent and not use the disfavored Iowa curves.

For eight plant accounts, Staff is proposing to set depreciation rates using Iowa curves which, according to the Company, departs from the past use of H-curves. In support of its position, Niagara Mohawk points to four instances in recent times in which H-curves were used for the purposes for which Staff has proposed to use the Iowa curves here. It points to the joint proposals adopted for the downstate KeySpan companies; to Niagara Mohawk's last gas rate case; and, relies mostly on the decision rendered in the last National Fuel Gas Distribution Corporation rate case.[24] According to the Company, Staff has not offered any good reason for departing from the use of H-curves in this instance.

Addressing recent rate proceedings in which Staff proposed and the Commission used Iowa curves, Niagara Mohawk states that there is no mention of this issue either in the Central Hudson rate case or in the joint proposals adopted in the NYSEG and RG&E cases which, it asserts, have no precedential value here. According to the Company, the Commission stated a policy preference in the 2007 NFG case that is controlling until we provide a reasoned basis for departing from the previous approach. National Grid believes we should not be arbitrary or capricious, nor should we simply select the set of curves that

[24] Case 07-G-0141, National Fuel Gas Distribution Corporation - Gas Rates, Order Adopting Rates For Gas Service (issued December 21, 2007), p. 23.

yields the lowest depreciation expense. It urges us to keep to a consistent practice.

Niagara Mohawk also claims the record in this case does not provide a sufficient basis for us to abandon H-curves. The Company criticizes Staff for using a visual analysis for its selection of the Iowa curves. Niagara Mohawk states that Staff did not observe a sufficient amount of retirement data and the survivor curves Staff plotted are therefore meaningless.

In support of this argument, Niagara Mohawk references Accounts 353.50 and 362.55 (remote terminal unit equipment accounts) in which 94% of the plant additions continue to remain in service. It states that a visual analysis of these accounts, to arrive at a 30-year service life, is belied by the fact that no plant retirements were recorded before 2003. According to the Company, with the bulk of this plant remaining in service, the accuracy of the service life statistics is suspect given the small size of the sample.

Rather than rely on the "common sense" approach the Company attributes to Staff, Niagara Mohawk asserts that we should accept the "engineering reality" supported by its depreciation study. In this regard, the Company references Accounts 353.55 and 362.5 (energy management systems including remote terminal units located at stations and power plants) to which Staff would apply a 30-year mean service life. Niagara Mohawk believes that the 30-year service life is excessive because electronic equipment can become obsolete due to technological changes and vendors who refuse to continue to support the equipment. The Company states that this equipment may need to be updated or replaced every five years.[25]

Next, Niagara Mohawk addresses Accounts 358, 367 and 361 (transmission and distribution facilities, and underground plant and distribution structures and improvements) and states that the 75-year service lives Staff proposes for them is not supported by sound engineering reasoning. It asserts that underground cables are apt to fail in less than 75 years and a 65-year life is more likely.

In sum, Niagara Mohawk states that Staff's service life estimates are unreliable as they are based on limited historical data and visual inspections that do not stand up to the engineering analysis the Company provided on the record.

In response, Staff states that no deference should be provided to any engineering analysis that Niagara Mohawk vaguely references but does not detail. Staff insists that it competently examined the Company's depreciation study and arrived at a different interpretation of the data that it supplied. Staff continues to believe that the curves it selected provide the best fit to the data.

Addressing the matter of any applicable precedents, Staff observes that the 2007 NFG rate case, upon which Niagara Mohawk places great reliance, was a natural gas rate proceeding that is not a precedent for any rate proceeding involving electricity. Moreover, as Staff reads the decision in the NFG case, the Commission refused to provide a general endorsement for either Iowa or H-curves and only found the H-curves to be better for use in that case. Further, Staff states, contrary to

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[25] The Company acknowledges that it "stretched" and applied a 20-year service life to these accounts and it did not use the 5-year life it now claims is supported by the "engineering reality" of the limited lifespan of computer hardware and software.

the Company's assertion, that Iowa curves were in fact used in Niagara Mohawk's last gas rate case and they have also been used for other New York utility companies, including the recent cases in which their use did not give rise to any issue or contest. Staff asserts that Niagara Mohawk's current, electric depreciation rates were set using Iowa curves and, in this case, they provide a better fit for the eight accounts for which Staff selected them.

Concerning the electronic equipment in Accounts 353.55 and 362.5 that Niagara Mohawk does not believe will last for 30 years, Staff states that the Company used a 20-year service life which has been in use for 23 years with very few retirements to date. According to Staff, this experience, and the Company's not identifying any specific retirements in the near future, supports the use of a 30-year service life.

As to Accounts 358, 367 and 361, where Staff used a 75-year average service life and the Company a 65-year life, Staff states that, without any Company-provided, specific indications of upcoming retirements, it stands by its examination and a 75-year average service life.

We find that there is no well-established precedent, as Niagara Mohawk suggests, dictating the use of H-curves or to disregard Iowa curves. The practice, over the years, has been to allow the parties to use the curves they believe are best supported in a given instance and, where the experts' professional judgments differ, we stand ready to determine which curve provides the best fit, be it an H-curve or an Iowa curve. In this case, we find that Staff has provided sufficient support for its selection of Iowa curves in the instances in which the Company believes the H-curves provide sounder results. Accordingly, Niagara Mohawk's exception is denied.

2. Net Salvage

Niagara Mohawk asserts that Staff's proposal to use a recent five-year average for determining net salvage is contrary to established Commission practice. Rather than use the current cost of retirement, the Company insists that prospective retirements must be considered and an equitable distribution of the removal costs should be made to current and future customers. According to the Company, Staff is attempting to spare current customers from paying removal costs and is improperly leaving their recovery for future customers. Niagara Mohawk states that the Commission addressed a similar practice in 1980 and rejected it then as it should do so here.[26]

The Company acknowledges that the approach Staff used has also been used in recent rate proceedings involving Central Hudson, NYSEG and RG&E. However, Niagara Mohawk distinguishes itself from those utility companies by noting that it did not propose to increase its depreciation rates and expense. Further, the Company asserts that the other companies did not present the concern it is raising here that Staff's approach departs from the decision in 1980 for Consolidated Edison and an explanation should be provided for doing so. Niagara Mohawk urges us to recognize greater net salvage costs in current rates to satisfy the accounting principle and requirement that costs be properly matched with the benefits customers receive.

Niagara Mohawk considers the results of Staff's recent five-year average of net salvage costs to be too low for future periods because no adjustment is made to anticipate the effect of inflation on salvage costs. The Company proposes that an estimate of inflation be used if its proposed net salvage rates

[26] Case 27544, Consolidated Edison Company of New York - Gas Rates, Opinion No. 80-8 (issued March 7, 1980), mimeo p. 15.

are not adopted. In sum, Niagara Mohawk believes no good reason has been provided for reducing its net salvage expenses.

In response, Staff states that the decision in the 1980 Consolidated Edison case has nothing to do with the matters presented here. In the Consolidated Edison case, the Commission rejected a Staff proposal to expense a portion of the company's salvage costs and to include a portion in its depreciation. Staff has made no such proposal here and, thus, the Consolidated Edison case has no application to the circumstances of this case. Using the recent average of net salvage costs, Staff has proposed lower salvage rates for 15 accounts and higher salvage rates for 13 other accounts.

Addressing the Company's complaint about Staff's recent average of net salvage costs not being adjusted upward for inflation, Staff states that an inflation factor is not necessary because the net salvage accruals will grow as the Company's plant balances increase. Thus, with the net salvage accrual rates Staff is proposing, the Company will recover an amount in excess of the net salvage costs currently being incurred with the current plant balances.

We find that the 1980 Consolidated Edison rate case cited by Niagara Mohawk has no bearing here given the differences in the issues presented then and now. Here, the issue is whether the net salvage values employed by Staff are adequate to cover plant removal costs when the time comes due for plant retirements. By using a recent average of the removal costs the Company has experienced, Staff has provided an acceptable basis for setting the net salvage accruals. If, for any reason, net salvage costs begin to exceed the amounts seen in the recent past, or if such costs escalate beyond the amounts that accrue for the new plant that enters the Company's rate base, the Commission can re-examine the net salvage for the various accounts, in an upcoming rate proceeding, and make any adjustments that appear to be warranted. In this case, we do not see that any effort has been made to artificially suppress the accrual rates for net salvage and we therefore adopt Staff's approach which has also been used in other recent rate proceedings without any objections stated by the utility company. Niagara Mohawk's exception is denied.

Jamestown Transmission Tie

In a recent proceeding involving the Jamestown Board of Public Utilities (Jamestown), the Commission imposed a requirement on Jamestown to report to Staff in July 2011 concerning the cost-effectiveness and reliability implications of options related to the continued operation or retirement of its coal-fired generation facility. The Order also required regular reporting as to the elimination of a transmission interconnection constraint between it and Niagara Mohawk.[27] The elimination of the constraint may enable Jamestown to retire its coal-fired unit, if otherwise warranted, while economically and reliably meeting its customers' energy needs.

The recommended decision adopted Staff's recommendation that Niagara Mohawk should be required to perform a study of the transmission constraint.

Niagara Mohawk, while reserving objections based on jurisdiction, provided in its Brief on Exceptions an outline and timetable of a study, with a targeted report date of September 6, 2011.

Pace/NRDC object that a study requirement is insufficient, and that the Company should be ordered to perform the necessary upgrades, as stated in the Jamestown order.

[27] Case 09-E-0862 - Minor Rate Filing by the Jamestown Board of Public Utilities, Order (issued July 20, 2010) at 28.

Niagara Mohawk responds that the Jamestown order did not explicitly direct the Company to remove the anticipated transmission constraint. The issue of whether a constraint exists, and the best options for addressing it if it does, are dependent on the outcome of the study. The Company also notes that non-wires alternatives might be a component of a strategy to address a constraint.

Niagara Mohawk has offered a reasonable timetable for studying the Jamestown transmission tie. We note that the Company at one point in its brief defines the objective of the study as the ability to provide 100 MW of transmission capacity. The objective should be defined more broadly, to include whatever transmission capacity is needed to enable the potential retirement of the Jamestown coal-fired facility. Until the analysis of feasibility and cost is complete, it is premature to order the construction of a project.

Non-Wires Alternatives

Pace/NRDC advocates for a proactive approach to the use of non-wires alternatives (demand-side management and distributed resources) for avoiding and delaying transmission and distribution system investments. The recommended decision recommended that Niagara Mohawk, Pace/NRDC and Staff each state, in briefs on exception, their preferred course of action for the next 24 to 36 months for the approach that should be taken (including a timetable for action and a list of critical path milestones) to address the use of non-wires alternatives in the Niagara Mohawk service area.

In response, the Company and Pace/NRDC present an agreed-upon plan. The plan would entail collaborative discussions between the Company and Pace/NRDC, resulting in a draft proposal for Staff's input, followed by comment from a larger group of interested parties, leading to a proposal to the

Commission. The plan would be oriented toward the development of pilot projects.

Staff concurs with this general approach, but states that the best forum for Commission consideration should be in a subsequent rate proceeding.

We agree that a cooperative effort between the Company and Pace/NRDC, followed by input from Staff and other parties, is an efficient use of resources toward this important goal. It is not necessary at this time to specify the forum in which any proposal will be brought to us for action.

COST OF CAPITAL

Capital Structure - The Common Equity Component

The Judges recommend the capital structure presented by Niagara Mohawk containing 50% common equity. They did not recommend Staff's proposal to set common equity at 46%. The Judges viewed the Company's "A-" bond rating favorably and they recommend against any action that could compromise it. The Judges were uncertain whether a 46% equity ratio would be viewed unfavorably and they did not consider the Company's 50% equity position excessive. Exceptions to the Judges' recommendation were filed by Staff and Multiple Intervenors.

Staff states that we should set Niagara Mohawk's capital structure, for ratemaking purposes, taking into account its relationship with its parent company, National Grid. Staff notes that Niagara Mohawk does not operate as a stand-alone company. And, while Staff agrees with the Judges that the Company should maintain an "A-" bond rating, it disagrees that a 50% equity ratio is necessary to support the current rating. Staff provides an assessment of Niagara Mohawk's financial metrics and states that they show (with Staff's equity ratio, cost of equity and the anticipated results of this case) that the criteria for an "A-" rating are met and the Company's targets are exceeded.

In particular, Staff points to three metrics: (1) funds from operations; (2) cash flow to debt ratio; and (3) retained cash flow to debt ratio. According to Staff, all three (with its proposals and anticipated rate case results) yield overall metrics superior to the targets Niagara Mohawk has advanced. Thus, Staff concludes that with Niagara Mohawk's equity ratio set at 46%, and its cost of equity at 9.0%, Niagara Mohawk would be able to maintain an "A-" rating.

In support of its position, Staff observes that Niagara Mohawk obtained an "A-" rating when its rates were set using a 43% equity ratio. From its analysis, Staff maintains that a 50% equity ratio does not provide any ratepayer benefits and it represents an unnecessary cost that customers should not bear.

Multiple Intervenors shares Staff's position and believes that the Judges' recommendation is flawed. MI sees a 46% equity ratio as an improvement from the 43% equity ratio that was previously used for ratemaking purposes. It notes that Niagara Mohawk achieved an "A-" rating when the ratio was set at 43% and the rating should not go down if the ratio is increased to 46%.

Next, MI states that Niagara Mohawk does not stand apart from its parent for its financial requirements, and it does not qualify for a stand-alone capital structure. MI believes that the Judges ignored these points which undermine the 50% equity ratio Niagara Mohawk has claimed in this case.

In response, Niagara Mohawk claims that Staff arbitrarily arrived at a 46% equity ratio that could jeopardize the Company's current bond ratings. According to it, the metric of greatest significance to Moody's and Standard & Poor's is the equity ratio that the Company actually maintains and not the 43% ratio the Commission previously used for earnings sharing purposes.[28] Of interest to the rating agencies is the equity cushion Niagara Mohawk maintains which reduces the possibility of a default on its debt instruments.

Niagara Mohawk also takes issue with Staff's financial metrics. The Company states that a 46% equity ratio does not meet Standard & Poor's criteria for an "A-" rating and that Moody's does not see adequate support for the Company's current rating. With a 46% equity position and a 9.0% equity return, Niagara Mohawk fears it will be downgraded. The Company also believes it will not be able to achieve all of the cost savings attributable to it and the savings adjustments will simply reduce its ability to achieve its cost of capital.

The Company states that Staff's financial metrics only appear to be more favorable than those it calculated because (1) a large portion of Staff's revenues are associated with the recovery of the competitive transition charges (CTC's) that have no corresponding expenses and (2) they assume that disallowed costs will be eliminated instead of being incurred by the Company. Looking beyond the 2011 rate year, Niagara Mohawk believes there is the possibility for a downgrading.

The Commission's acceptance of a 50% equity component, according to the Company, will not result in customers supporting more equity than is proper. Niagara Mohawk points out that Consolidated Edison and Central Hudson have been allowed equity positions greater than the 46% that Staff

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[28] The Company points out that the 43% equity ratio was modified in 2003 to allow the Company to include a larger percentage of equity in its capital structure for earnings sharing purposes. According to the Company, the action taken in 2003 allowed the equity percentage to rise to 48.3% for earnings sharing purposes.

advocates here, and notes that companies with "A" ratings have, on average, equity ratios closer to 50% than to 46%.

Addressing Niagara Mohawk's relationship to National Grid, the Company states that its senior unsecured debt has been rated apart from National Grid's and it received a better rating than did National Grid. If a consolidated capital structure were to be used, the Company states that National Grid's equity component is 51.6% and the record contains no lower figure than this.

Finally, Niagara Mohawk states that, with a 50% equity component, it has managed to obtain long-term debt at favorable rates. The Company notes that it will be accessing the long term debt markets in the near future to fund its capital expenditures.

We are aware that Niagara Mohawk has improved its equity position substantially since the time of its merger with National Grid. Since 2002, the Company has regained its ability to issue debt at favorable rates. Our actions in this rate proceeding fully support this corporate achievement and we fully support movement and growth in Niagara Mohawk's equity position to the range recently achieved that supports its "A-" rating. Specifically, the introduction of an RDM for the Company's electric operations represents a significant risk reduction, meaning a smaller equity cushion can be used.

Significantly, Staff has provided metrics indicating that the results of this rate proceeding are in keeping with the Company's current financial standing. Our rate decision sustains the achieved metrics that are used to determine Niagara Mohawk's creditworthiness and our actions do not detract from the metrics the Company has previously met.

Nonetheless, in recent rate proceedings involving other public utility companies with corporate parents, integrated operations and combined finances, we have authorized a 48% equity position for ratemaking purposes and we have not exceeded this level for any such company. Were we to go beyond this level for Niagara Mohawk, we would add to ratepayer costs about $10 million without obtaining any greater strength or confidence in the Company's financial metrics. Without an incremental advantage accompanying a movement from a 48% to a 50% equity position, we are not inclined to add to ratepayers' costs. Consequently, we do not find a sufficient basis here to exceed for Niagara Mohawk the 48% equity positions we have previously established for similarly rated companies such as Consolidated Edison and Central Hudson. To this extent, the Staff and MI exceptions are granted and the Judges' recommendation is modified.

Rate of Return on Equity

The Judges recommend a 9.3% equity return for Niagara Mohawk. Their recommendation is 155 basis points less than that proposed by the Company's financial expert and 30-60 basis points more than the amounts proposed by Staff, CPB and MI.

Niagara Mohawk insists that the allowed return should be commensurate with the returns that comparable enterprises receive for incurring corresponding risks.[29] For its evidence of commensurate returns for comparable enterprises with corresponding risks, the Company turns to state regulatory

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[29] Niagara Mohawk asserts that the ROE recommended by the Judges would not satisfy the constitutional requirement of *Hope Natural Gas v. Federal Power Commission*, 320 U.S. 591 (1944). This argument is misplaced. *Hope*, as reaffirmed in *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989), makes clear that only the end result, not any particular formula or component of the rate-making process, is relevant to any question of regulatory taking. The end result of this order reflects a balancing of ratepayer and investor interests. *See also*, *Abrams v. Public Service Commission*, 67 NY 2d 205 (1986).

actions throughout the nation and points to allowed returns exceeding those in New York for electric and gas companies that are, broadly speaking, similar to the companies we regulate.

Niagara Mohawk's analysis shows, during calendar year 2010, the allowed equity returns in New York were between 75 and 107 basis points lower than those in other states. Niagara Mohawk does not believe that its business and financial risks are the least risky of all the electric and gas utilities in the nation.

Turning from the allowed equity returns in other states to the equity returns we have allowed other electric and gas utility companies in New York, Niagara Mohawk claims that the Judges' 9.3% recommendation is not comparable to the equity returns recently provided to NYSEG and RG&E (9.6% and 9.55% excluding stayout premiums, but after incentive adders, respectively) or the equity return provided to Consolidated Edison in March 2010 (which Niagara Mohawk believes suggests a 9.85% return for it after adjusting out a stay-out premium that does not pertain here). If Niagara Mohawk's allowed return is set at 9.3%, the Company believes its ability to attract capital and maintain its current credit rating are in jeopardy.

On exceptions, Staff asserts that the Judges 9.3% recommendation is not supported by the well-established approach the Commission has consistently used to set utility companies' allowed equity returns. Staff asserts that setting Niagara Mohawk's allowed return is not as simple a matter as suggested by the Judges efforts that sought to adjust the recent results had for Consolidated Edison. Adhering to the established methodology produces either the 9.0% return that the parties (other than the Company) supported on the record or a 8.7% allowed equity return if we were to update the methodology of record with the most recent financial data that became available after the close of the record. Staff insists that we should adhere to the established method and we should continue to recognize that the equity return allowance can change over time, as has occurred since the time Consolidated Edison's allowed return was set using the joint proposal for the multi-year rate plan that reached us for action in September 2010. In support of the lower indicated equity return for Niagara Mohawk, Staff points to the drop in Treasury interest rates in 2010 that explains much of the difference between the results for Consolidated Edison and those for Niagara Mohawk.

Like Staff, Multiple Intervenors excepts to the Judges' departure from the conventional methods that are used to calculate the allowed equity return. Inasmuch as the Judges' 9.3% equity recommendation is not tied to any specific elements of the established methodologies, MI believes their approach requires greater clarity than was provided in the recommended decision. Also, to the extent the Judges may have "copied and tweaked" the allowed equity return recently had for Consolidated Edison, RG&E and NYSEG, Multiple Intervenors states that Niagara Mohawk's allowed equity return should not be based on decisions made for other utility companies.

According to MI, Niagara Mohawk's circumstances differ from the other utility companies' in many important ways. Also, it does not believe that cases involving joint proposals and multi-year rate plans are comparable to those that are litigated and provide results for only one year. Further, MI points out that the timing of this case does not coincide with the timing of the other rate proceedings and significant financial data changed in the intervening months.

CPB asserts that two errors are manifest in the Judges' recommendation. The first relates to the timing differences between the rate cases involving multi-year rate plans and those processed as traditional rate cases. The second pertains to prevailing market uncertainty and fluctuations that have a significant impact on the methodologies used to calculate the allowed equity return.

According to CPB, the Judges should have focused on the changes in stock prices, interest rates, dividend yields and growth rates at the time of their recommended decision. Had they done so, they would have properly applied the established methods for calculating the allowed equity return. By focusing on the Commission results from September 2010, they did not capture the market indicators for November 2010. Instead, they perpetuated the use of market data from July 2010 and they did not take into account credit quality differences among the various utility companies. Given the substantial timing differences in the various utility companies' rate cases, CPB asserts that the Judges' recommendation is not useful.

We, like the Judges assigned to this case, recognize the value of the consistent application of our conventional approach in setting the allowed return on equity for the utilities under our jurisdiction. The same approach was used to render all of our rate of return determinations in 2010 and it is detailed in Staff's testimony. In this case, to Niagara Mohawk's advantage, we are not updating the Staff methodology with the post-record financial data. Also, as explained below, we reject Staff's proposed adjustment to the allowed equity return related to the adoption of a revenue decoupling mechanism in this case. Thus, we are adopting a 9.1% allowed equity return for a single-year case, or 9.3% with an additional stay-out year.

In addition to addressing the Judges' overall recommendation for Niagara Mohawk, the Company has raised five technical points on which it differs with Staff and CPB. These issues pertain to the specific methods used to calculate the allowed equity return.

1. DCF Long-Term Growth Factors

The Discounted Cash Flow (DCF) analysis used by Staff and CPB to estimate the cost of equity capital employs a two-stage growth factor. The first stage relies on a forecast of dividend growth and the second employs an analysis of sustainable growth. This approach has long been used and it has become a standard feature of the DCF methodology we employ. Niagara Mohawk proposes instead that we use a single growth rate derived from a consensus of financial analysts' forecasts of earnings growth. Specifically, the Company proposes that we use the 5.3% mid-point between Value Line's 4.8% long-term forecast of earnings growth and Zack's 5.7% growth forecast.[30]

According to the Company, 5.3% growth is sustainable and consistent with 5.5% nominal growth expected in the Gross Domestic Product and the GDP growth projections provided by the Congressional Budget Office and the Office of Management and Budget. Niagara Mohawk does not believe that growth in the GDP will exceed growth in the electric utility industry by 50 to 100 basis points and, for this reason, considers the Staff and CPB growth estimates to be too low. It also believes that the Staff and CPB growth estimates are too low because the first stage of their analysis, the Value Line forecasts of dividend growth, does not account for declining utility payout ratios. The Company states that investors are expecting growth from all earnings that are not paid out, however, the analyses provided by Staff and CPB do not include this source of growth.

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[30] In contrast, Staff's and CPB's two-stage DCF methods produce median growth rates of 3.38% (for the first stage) and 4.46% (for the second stage).

In response, Staff states that a constant growth model assumes identical growth rates in earnings and dividends. However, when the two deviate, a two-growth model is needed to accurately reflect investors' expectations. Staff denies that it has understated the cost of equity and ignored a decline of dividend payout ratios in the electric utility industry. It states that when dividend payouts are decreasing and short-run dividend growth is declining, Staff's long-run sustainable growth factor is higher than it would otherwise be if dividend growth had not declined. Thus, declining dividend payouts are not ignored. Further, Staff states that this matter was raised previously in a Consolidated Edison rate proceeding and the Company's position was rejected there.

Staff also responds to the Company's assertion that its 3.38% short-term growth rate and its 4.46% long-term sustainable growth rate are too low. According to Staff, the Company's 5.5% GDP nominal growth lacks support and Staff disagrees that the GDP has any link to expected dividend growth rates. Staff insists that its 4.46% sustainable growth rate is consistent with the nominal GDP growth rate forecast when Staff filed its testimony and it remains consistent with more recent long-term forecasts.

We have considered Niagara Mohawk's request to depart from the two-stage growth factor analysis that is the customary and ordinary practice in our rate proceedings and the Company's request for a higher, long-run growth factor. We find no reason to depart from a two-stage growth model which provides us flexibility to consider both near-term growth factors and the sustainable, long-term growth when there are differences in the two.

Concerning the Company's claim that the Staff and CPB long-term, sustainable growth rates are too low, we find that the 4.5% growth rate they employed is closer to the Blue Chip GDP estimate running to 2022 than is the 5.5% growth estimate provided by the Company's witness. We are satisfied that the approach that has been used by Staff and CPB here, and has been consistently used in numerous previous rate proceedings, is entirely acceptable and no good basis exists for eliminating its use or to shift to a one-stage growth model of the kind suggested by Niagara Mohawk.

2. DCF Proxy Group Results - Mean vs. Median

Niagara Mohawk requests that we rule on whether the mean or median of the proxy group DCF results should be used to determine the DCF-derived cost of equity. The Company does not believe that this matter has been previously addressed by the Commission. According to it, the mean, rather than the median, should be used. The Company states that when there is a difference between the two it indicates that the distribution of observations in the sample is skewed. In such circumstances, according to the Company, the median incorrectly treats a number of observations as outliers when, in fact, they are representative of the sample as a whole. Thus, it supports the use of the mean.

Staff states that the mean only provides accurate results when data are clustered in a normal distribution. Since its proxy group results did not fall into a normal distribution, Staff argues the median is better suited. Further, Staff states that the median has been consistently used in all recent rate proceedings.

The difference between the Company and Staff involves the consideration to be given to the sample outliers when observations and data are not normally distributed. Niagara Mohawk suggests that the outliers not be automatically excluded and instead receive consideration unless they are specifically excluded from the group for some other reason. Staff, on the other hand, would routinely dismiss and disregard the outliers in an effort to arrive at results suggestive of a normal distribution. In this instance, the difference between the two is 20 basis points which makes the issue significant here. We find that the use of the median is the preferable approach, particularly, in this case where the influence to be eliminated is an exceptional, 18% return on equity for a company that was included in the sample.

3. CAPM Risk-Free Rate - 30-Year Treasury Bond Yields

We have consistently used the average of 10-year and 30-year Treasury bond yields for the risk-free rate in the Capital Asset Pricing Model (CAPM). Niagara Mohawk asks us to reconsider this practice and claims that the past rationale given for this practice does not withstand scrutiny. The justification given for the practice has been that a ten- to thirty-year period matches the typical investor's holding period. National Grid states that it has held Niagara Mohawk's equity for a decade and there is no indication that there will be any sale or transfer to another investor any time soon. Given the permanent nature of National Grid's holding, the Company believes the estimate for the risk free rate should be set using the longest term securities, the 30-year Treasury bonds.

The Company asserts that sole reliance on the 30-year Treasury bond yield would increase the CAPM result by about 40 basis points. Niagara Mohawk observes that the current spread between 10-year and 30-year Treasury yields is far larger than it was at the time of the Generic Financing Case. This change in circumstances, according to the Company, warrants a change in the method we use to determine the CAPM risk-free rate.

In response, Staff confirms that it uses the average of 10-year and 30-year Treasury yields to represent the time horizon of the average investor. On a technical basis, Staff does not believe that the method for calculating the risk-free interest rate is related to the differing yields for the two types of Treasury bonds. Nor does it believe that National Grid's intentions for Niagara Mohawk have any relevance here because the long-term Treasury rate applies to the proxy group and not to National Grid or Niagara Mohawk.

We observe that the difference in the parties' respective approaches is only worth about four basis points on the overall ROE recommendation, not the 40 basis points implied by the Company. The risk-free rate derived from the three-month average of 10 and 30 year Treasury yields in Staff's testimony was 4.10%. Whereas the three-month average of 30 year Treasury yields was 4.54%, or 44 basis points higher. Using this higher risk free rate would only increase the CAPM result by 12 basis points, and that increase, given that the CAPM is only one-third of the final result, only moves the final recommended ROE by four basis points (and it would still round to 9.0%).

We find that there is no well-established or any set convention for the "long-term" investment characteristic that is captured by the use of the Treasury bonds. We have consistently used the average of the 10-year and the 30—year bonds and we find no clear or convincing reasons for altering the established practice or to shift to a "long-term" measure that fixes the holding period at 30 years. The average of the two terms is suggestive of a reasonable range of holding periods and, as such, is representative of investors' holding times. Niagara Mohawk's exception is, therefore, denied.

4. DCF and CAPM - Credit Quality Adjustment

Staff and CPB applied an adjustment to their proxy group results to account for Niagara Mohawk's differing credit quality. The proxy group's credit quality is lower than Niagara Mohawk's and the group has greater financial risk. Staff and CPB therefore reduced their DCF and CAPM results for Niagara Mohawk due to its lower risk.

On exceptions, the Company states that the inclusion of lower credit quality companies in the proxy group, in this instance, had the reverse effect. According to Niagara Mohawk, they reduced the proxy group's cost of equity rather than increasing it as suggested by the theory to which Staff and CPB subscribe. This being the case, Niagara Mohawk states that there is no need to make a downward adjustment to the proxy group cost of equity capital. Also, from a policy perspective, the Company asserts that it makes no sense to encourage it to maintain an "A-" bond rating and to make a credit quality adjustment that encourages it to reduce its bond rating to obtain a higher return on equity.

As noted in several cases, we believe that it is logical that the returns for companies with lower risk be set lower than those for companies with higher risk. Standard & Poor's (S&P) and Moody's Investors Service (Moody's) ratings are for debt investors; they weigh both the financial and business risk of a company when developing their ratings. The risk assignments are also relevant to equity investors. Shareholders only receive a return if bondholders have been paid; bond ratings (which measure default risk) are therefore a useful tool to measure risk for shareholders as well.

To not implement a credit quality adjustment would be the same as saying that all utility companies in New York should receive the same rate of return, regardless of their business and financial risks and the specific rate plans we approve, which we do not believe is true. While the use of the credit ratings may be an imprecise way to measure the varying risks to equity investors, we find that this approach recognizes the fundamental financial principle that the lower the risk, the lower the return required by investors. We remain open to considering other analytical approaches to measure such risk, but have not seen another from the Company in this case. Consequently, we deny Niagara Mohawk's exception.

5. Revenue Decoupling Mechanism (RDM) Adjustment

Staff and CPB reduced their rate of return recommendations for Niagara Mohawk to reflect the Company's lower risk by virtue of the RDM that allows it to reconcile the revenues it collects with the estimates adopted in this case. Niagara Mohawk believes no adjustment is warranted because many of the companies included in the proxy group either have an RDM or they will soon be implementing an RDM, a lost revenue adjustment clause or some other earning stabilization mechanism. Without a difference between itself and the proxy group, Niagara Mohawk believes there should be no adjustment. Further, the Company doubts that an RDM has an observable impact on an electric utility company's cost of debt or equity. The Company states that an RDM can actually increase risk to shareholders, as the recovery of balances owed a Company under such a mechanism might be denied by regulators, or the repayment could be lagged. Absent proof of a quantifiable impact on the cost of debt or equity, the Company does not believe the adjustment should be made.

We agree with Niagara Mohawk that an RDM adjustment is not required in this case. With RDMs and other similar mechanisms becoming common place with the proxy group companies, there is a declining risk difference between the proxy group and Niagara Mohawk with its RDM in place.

In addition, Standard & Poor's and Moody's have each affirmed Niagara Mohawk's and National Grid's bond ratings over the past few months. The rating agencies have undoubtedly assumed an RDM will be in place for Niagara Mohawk in 2011, as we have instituted such mechanisms for every other electric utility. Staff used National Grid's as the rating to compare the proxy group to. We do not believe that the expected implementation of an RDM for the electric operations of one of National Grid's subsidiaries will have a material impact on the parent company's rating.

Finally, we note that part of our rationale for using a 48% equity ratio in the case, a level slightly below Standard & Poor's "A" rating guideline, is to reflect the lower business risk brought about by an RDM. Adding a separate adjustment to the cost of equity could be seen as a double count of that benefit of an RDM that should be avoided.

Updating the Return on Equity Calculation

Our typical practice in a rate proceeding like this one is to update the equity return methodology at the time of our decision. This practice reflects the long-held belief that the most recent data is generally the best indicator of investor requirements during the rate year. However, we have recently seen a volatile interest rate environment. The yield on ten-year Treasury bonds has gone from 4.0% in April 2010 to 2.4% in October 2010, and back up to 3.4% in January 2011.

In addition, in November 2010, the Federal Reserve began a planned buy back of up to $900 billion of long-term Treasury securities. This action is artificially suppressing Treasury yields in order to stimulate the economy. When merger activity produces price impacts on utility company stocks, we do not include such companies in the proxy group used to estimate the cost of equity. A similar situation exists with Treasury yields at this time.

Treasury yields are an input to the CAPM model. Staff's update in its reply brief on exceptions is based on Treasury yields when they are almost the lowest in history. Given the impact of the Treasury buy back program, and the extreme low point in the interest rates at the time Staff ran its model, we are concerned that updating the indicated equity return at this time would not lead to a result that is indicative of the return on equity investors will require in 2011.

When Staff first calculated its equity return recommendation, in its direct testimony, Treasury yields were not influenced by the recent buy back program. Therefore, we are using Staff's 9.0% recommended return from its direct testimony as the base allowance. In general, we continue to believe that the allowed return is best estimated using the most recent data. However, when those results are being impacted by an atypical situation, such as the Treasury buy back program, we must be cautious in assuming that current conditions will adequately represent investor expectations.

<u>Stay Out Premium</u>

In 2010, most of the rate proceedings we considered, including the Consolidated Edison, NYSEG and RG&E cases we decided in September, reflected multi-year Joint Proposals. As such, the return on equity in those cases reflected a premium for the utility's commitment not to file for a base rate increase for a set period of time. This premium is known as a "stay out" premium. Notwithstanding the absence of a Joint Proposal in this case, we still want to provide Niagara Mohawk a benefit, through an enhanced ROE, for staying out for an additional year.

We typically examine the yield that investors demand between Treasury securities of different maturities to determine the appropriate stay out premium. In recent cases (including Niagara Mohawk's recent gas case, Case 08-G-0609) we have used a 20 basis point stay out premium for a two-year rate plan. Therefore, in this case we will include a 20 basis point stay out premium and set the ROE at 9.3% so long as Niagara Mohawk refrains from filing new base rates prior to January 1, 2012. This will provide a measure of rate certainty to customers for approximately another year. Should the Company accept the opportunity for a 9.3% ROE as set forth in this order, it would also agree not to seek judicial review of the revenue requirement provisions of this order.

If, notwithstanding its election of rates based on the 9.3% return on equity, the Company files for an increase in electric base rates before January 1, 2012, the Company will be required to defer for the benefit of electric customers an amount equal to the stay out premium of $6.585 million for the rate year 2011, plus the *pro rata* portion of the stay out premium of $6.585 million for the portion of 2012 that it received such a premium. Notwithstanding a Company filing prior to January 1, 2012, if the filing is due to circumstances described in Ordering Clause 2(b)(ii), the filing will not prompt the creation of this deferral.

In conclusion, starting with Staff's 9.0% ROE recommendation, and eliminating Staff's RDM adjustment of 8.5 basis points, we arrive at an ROE of 9.1%, or 9.3% when the 20-basis-point stay out premium is included.

Short-term Debt Interest Rates

Niagara Mohawk proposed that the short-term interest rates for this case be set using the published forward interest rate curves available when we render our decision. Instead, the Judges recommend Staff's proposal to use the actual short-term interest rates in effect at the time of our decision.

On exceptions, the Company continues to support the use of forward interest rate curves as a practice more consistent with our use of a fully forecast test year for rate proceedings. Alternatively, Niagara Mohawk requests authority to defer and reconcile its rate year, short-term debt expense. According to the Company, current interest rates are at very low levels and they may increase significantly when the economy improves and the Federal Reserve curtails its current practices. Inasmuch as it cannot anticipate or control the Federal Reserve's policies and practices, Niagara Mohawk believes it is appropriate to establish a short-term debt deferral and reconciliation.

In response, Staff states that we should not entertain the Company's request for a deferral and reconciliation which appeared for the first time in its brief on exceptions and not earlier in the proceeding. According to Staff, the record contains no evidence demonstrating the need for this true-up.

Staff continues to prefer to set the current interest rate using high-grade, unsecured 30-day commercial paper. Staff explains that this is the Company's actual borrowing costs from its money pool. Staff states that Niagara Mohawk neither provided testimony or evidence in this case to support the use of its forward yield curves which have not been updated since January 2010 when the rate case was filed.

Consistent with the practice we have employed in other recent rate proceedings, the short-term debt interest rate will be set using the commercial paper rates available at the time of our rate decision. Inasmuch as we are making a one-year rate determination, the current interest rates are reasonably representative for the immediate future. We are not persuaded by Niagara Mohawk's arguments on brief that it would be better to use the forward yield curves for ratemaking purposes absent any record evidence supporting the Company's position. Also, since this is a one-year rate determination, there is far less reason for us to establish a deferral and reconciliation for any variance in short-term interest rates that may occur during 2011. Similar to our equity return determination on updating, we will use the 0.41% rate at the time of Staff's testimony for this rate and we are not updating it to 0.38% that is currently indicated.

Auction Rate Debt Securities

Niagara Mohawk's capital structure includes variable rate pollution control revenue bonds. An auction process is used to reset periodically the interest rate for these bonds. When the auction process fails, as has occurred recently, a default interest rate is used. The Company and Staff agreed that the cost of this debt should be updated at the time of our rate decision. They also agreed that the differences between the actual interest expense and the amount reflected in rates should be deferred and reconciled. We accept the parties' proposals.

DEFERRAL ACCOUNTING

Federal Income Taxes - Repair Costs

For federal income tax purposes, Niagara Mohawk stopped capitalizing its routine repair maintenance costs in 2009 and started to expense them. This change in the Company's federal income tax practices reduced its tax bill and increased its cash flow. Staff has proposed to capture the cash flow enhancement in 2009 by applying a $28.89 million credit to the Company's deferred balances. According to Staff, the Merger Joint Proposal permits this action and the Judges agreed. According to the Company, the Merger Joint Proposal did not capture the benefit of this change for ratepayers and it excepts to the Judges' recommendation.

On exceptions, Niagara Mohawk provides its understanding of the Merger Joint Proposal provision that address externally imposed tax and accounting changes (MJP §1.2.4.2.1). It states that this provision limits the Company's establishment of deferred debits or credits for income tax changes to those involving changes in rates, laws, regulations or precedents. It applies a $2 million deferral threshold for such items. Niagara Mohawk states that its 2009 tax deduction was not externally imposed and, therefore, it is not covered by this provision.

Niagara Mohawk also provides its understanding of the Merger Joint Proposal provision that addresses internally adopted accounting changes (MJP §1.2.3.2.2). It states that this provision does not apply to the 2009 tax deduction because it contains no language addressing tax changes. The Company claims that the DPS Director of Accounting and Finance, by the terms of this provision, approves accounting changes but it does not provide the Director authority to approve any tax accounting changes. Further, Niagara Mohawk claims that the term "accounting changes" refers to financial accounting matters and it does not cover tax accounting changes. The Company contends that a plain reading of the Merger Joint Proposal's provisions, coupled with a proper understanding of the distinction between "financial accounting" and "tax accounting," leads to no other conclusion than the Company was under no obligation to defer for ratepayers the financial impacts associated with the 2009 tax account change.

Niagara Mohawk criticizes the Judges for not ruling explicitly on the merits of the above-stated understanding of the Merger Joint Proposal's provisions. The Company also disagrees with the Judges' finding that a tax accounting change amounts to financial accounting and a regulatory accounting change and, as such, is covered by the Merger Joint Proposal. In response to this finding, the Company states that the accounting method used for repair costs, for financial and regulatory purposes, did not change and it remained unaffected by the tax accounting change.

Niagara Mohawk also disagrees with the Judges' finding that it would be unfair to customers to make them responsible (as the Merger Joint Proposal does) for adverse tax and accounting changes without also providing them the benefit of any tax and financial statement improvements that may become available. The Company believes that its approach to the 2009 tax accounting change is not unfair to customers and states that MJP §1.2.4.2 provides for a symmetrical sharing of the costs and benefits from changes in tax rates, laws, regulations and precedents, to the extent individual changes exceeds $2 million. The Company also states that the Merger Joint Proposal is symmetrical in that it does not provide customers the benefits of a new tax strategy that does not involve any change in rates, laws, regulations or precedents. Nor does the Merger Joint Proposal permit the Company to recover increased costs or taxes associated with a new tax strategy not arising from a change in rates, laws, regulations or precedents. In contrast, it asserts that the Judges would require an improper asymmetrical treatment of the benefits of a new tax strategy which, according to the

Company, is inconsistent with the intent of the parties who entered into the Merger Joint Proposal.

Finally, Niagara Mohawk argues that "regulatory lag" typically permits a utility company that is successful in pursuing a strategy that reduces its costs to retain such benefits between rate proceedings. It believes that this principle should operate here.

In response, Staff asserts that the Company's arguments are convoluted and unclear. Staff doubts that Niagara Mohawk can speak definitively about the intentions of the parties who entered into the Merger Joint Proposal. Staff also disagrees with the Niagara Mohawk assertion that the Merger Joint Proposal would require, but does not have, an additional provision to cover and capture new tax strategies that increase or decrease the Company's taxes.

Addressing Niagara Mohawk's understanding of MJP §1.2.4.2, Staff states that this provision is not limited to financial accounting changes and it covers all accounting changes be they related to financial matters or to taxes. Concerning the Company's reliance on "regulatory lag," Staff states that the Company was not operating between rate cases in 2009. It was operating under the Merger Joint Proposal's requirements which included an obligation to defer the revenue requirement impact of the cash flow enhancement for ratepayers.

To put this matter into perspective, Staff states that the Company has deferred costs in excess of $800 million during the term of the Merger Joint Proposal that ratepayers are required to pay. Staff believes it is only fair to capture one of the few deferral items that provides a benefit for ratepayers.

Initially, we must point out that the Merger Joint Proposal is not a contract and its provisions are not to be parsed in the manner the Company has attempted here to determine its proper operation during the term of the rate plan for ratepayers and shareholders alike. In ruling on the issue raised here, we look to the regulatory purposes and objectives that the Merger Joint Proposal is intended to serve and our actions are in keeping with the proper achievement of these goals. The Merger Joint Proposal was crafted to cover substantial changes in material items that alter the Company's ongoing operations from those in place at the time that the Merger Joint Proposal was adopted. It recognizes that such changes can go in both directions and they can be either advantageous or disadvantageous to the Company. The Merger Joint Proposal provides the Company protection from unknown, adverse changes and it captures for ratepayers advantages that were not and could not be known at the time it was adopted.

In this instance, we find that the change in federal income tax practice in 2009 was material and it achieved a significant cash flow reduction that is both captured by the Merger Joint Proposal and inures to the benefit of the ratepayers who have also been paying a large body of deferred costs that built up during the course of the Merger Joint Proposal. We agree with the Judges that fairness requires that the $28.89 million cash flow enhancement for 2009 be treated as a deferred credit to offset an equivalent amount of deferred liabilities arising from the operation of the Merger Joint Proposal.

REVENUE ALLOCATION AND RATE DESIGN

Staff and the Company entered a stipulation and settlement[31] regarding a wide range of rate design, customer and markets issues. Several items were contested. Except as

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[31] Exhibit 393.

discussed below, the recommendations in the recommended decision were not challenged by any parties.

1. Flex Rate Issues

The recommended decision recommended that, to the extent CTC recoveries are extended beyond 2011, there should be no special exemptions for customers with existing SC-11 and SC-12 rate agreements expiring at the end of 2011. MI argued that such exemptions should continue beyond 2011 if CTC obligations remain. Because CTC recoveries will be complete by the end of 2011, as discussed below, this issue is moot.

2. Exit Fees

The recommended decision approved the provision of the stipulation that the Rule 52 exit fee will be retained, but limited to the recovery of the Company's unamortized CTC. MI argues that there is no reason for Rule 52 to be continued in any form, because it was created to address a situation of financial distress that no longer exists. Customer exodus is a risk borne by all utilities in the normal course of business.

Staff responds that the limited continuation of Rule 52 is needed to ensure the full recovery of CTCs. Niagara Mohawk argues that Rule 52 is competitively neutral, and its elimination prior to the expiration of CTCs would potentially award customers for bypassing the Company's system.

MI is correct that the financial conditions giving rise to Rule 52 no longer exist. Our commitment to the Company regarding the recovery of CTCs, however, remains in place, and that commitment was also a rationale for the creation of Rule 52. The modified version of Rule 52 agreed to by Staff and the Company is a reasonable transition. By the end of the rate year, CTC recovery will be complete.

3. Revenue Allocation, Amortization of CTCs and Deferrals

The stipulation between Staff and the Company, regarding revenue allocation, was designed to apply to a wide range of potential revenue requirements. As such, it presented several issues that were raised by MI and discussed at length in the recommended decision. At the level of revenues recommended in the recommended decision and modified in this Order, the concerns raised by MI can be accommodated while adhering to the stipulation's goal of avoiding rate increases for all customer classes.

a. The Company's initial proposal, the stipulation, and the Recommended Decision

Niagara Mohawk's initial filing, covering a three year period, would have increased the Company's revenues by $390 million without appreciably increasing the rates paid by any customer class. This was possible because recoveries of CTCs, in amounts exceeding $500 million per year, were scheduled to be completed at the end of 2011. As of December 31, 2010, the balance of unrecovered CTCs was estimated to be $557 million. Rather than recovering the entire sum in rates in 2011, as scheduled, the Company proposed extending that recovery over a period of four years, thus enabling a substantial increase in its base revenues without an increase in customers' rates.

Although Staff advocated a much lower revenue increase, Staff and the Company were able to agree on a revenue allocation methodology that would accomplish the goal of providing zero rate increases for all customer classes. This would be accomplished by allocating revenues, in part, based on the level of CTC payments from each class.

MI objected that the mechanism used to accomplish this goal would result in potential long-term distortions of revenue allocation among customer classes. MI also objected to any extension of CTC recovery; MI stated that rate increases in 2011 would be preferable to extending CTC recovery beyond 2011, at least for large customers.

The Judges agreed with MI on both points. The recommended decision noted, however, that at its lower revenue level, the primary concerns of MI could be accommodated while still providing zero rate increases for smaller customers. The Judges recommended that only the conventional elements of the stipulation, i.e., application of the Embedded Cost of Service results, and adoption of a 15% tolerance band, should be adopted. The Judges further recommended that the extension of CTCs, if necessary to achieve a zero rate increase in 2011, should be performed only for residential and small business customers.

Staff and the Company disagreed as to the priority for recovering CTCs versus deferral accounts remaining from the current rate plan. The recommended decision agreed with Staff, that deferral accounts should be recovered only after CTCs are fully recovered.

b. Positions on Exceptions

No party took exception to the recommended decision's principal determinations. The Company provided, in compliance with a request from the Judges, a revenue allocation model demonstrating the effect of the recommended decision for 2011 and illustrating the likely effect, all other things being equal, of a continuation into 2012 of the rate plan as determined by the Judges.

Staff and the Company noted that the formula proposed in the recommended decision could be modified to produce a result of zero rate increases for all customer classes. As noted above, $39.6 million of the revenue increase approved in this Order reflects a non-recurring increase in CTC recoveries.[32] The Company and Staff proposed an alternative to the recommended decision methodology, in which the $39.6 million increase in CTC recoveries would be allocated with respect to bill impact considerations, rather than following the existing allocation formula applicable to the bulk of the CTCs.[33] This would allow full recovery of CTCs in 2011, while holding all customer classes to a zero increase.[34] Both MI and NYPA express support for this alternative.

c. Discussion of revenue allocation for the rate year

We endorse the initial goal, proposed by the Company, of avoiding any net rate increase for customers during 2011. It is essential, however, to implement that goal in a manner that does not create substantial future liabilities for ratepayers, or long-term distortions in revenue allocation.

The modification proposed by Staff and the Company is reasonable and accomplishes the goals of avoiding rate increases for all classes, retiring CTCs in an equitable manner, and maintaining revenue allocations on a cost-of-service basis. Therefore the revenue allocation recommended in the recommended decision will be adopted, except that a portion of the revenue

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[32] Total CTC recoveries in 2011, absent a change in revenues, would have fallen short of allowed recoveries by approximately $39.6 million. The revision of the sales forecast contained in this Order has the effect of a reset, allowing full recovery of CTCs by the Company.

[33] Specifically, the Company proposes that the $39.6 million in CTCs be allocated in inverse proportion to revenue change by class.

[34] A second alternative proposed by Staff was to apply the CTC allocation in a way that would require CTCs to be extended for some classes to avoid a rate increase, but to exempt any customers with expiring negotiated rates from paying the extended CTCs. Staff's first alternative is preferable, because it retires all CTCs within the rate year.

increase representing $39.6 million in CTC recovery will be allocated in an inverse proportion to the revenue change by class, so that no class will experience a net delivery increase.

d. Subsequent process for CTCs and deferrals

No party excepted to Staff's suggested process for removing CTCs from rates and establishing a surcharge for deferrals. The Company expresses concern that the transition should be seamless, i.e., that there should be no gap during which rates include neither CTCs nor deferrals. The Company questions whether five months is sufficient time for the Commission to process and approve the mechanism.

Staff states that the Company can reduce the time needed to process the filing by ensuring that the filing is thorough and accurate. Staff also notes that the five-month deadline does not prohibit the Company from submitting the filing earlier.

The Company's underlying concern is reasonable. Although we see no reason why five months would not be sufficient time, we will not preclude the Company from filing its mechanism earlier, to provide better assurance of timely action.

With respect to the amortization schedule for the deferral account, the Judges adopted Staff's recommendation that deferral accounts should not be collected until after CTCs are completely recovered.

The Company's Brief on Exceptions provided an illustrative case for 2012, using assumptions similar to those adopted here. The illustrative case shows the impact of CTCs being removed from rates, and deferral recoveries and a Legacy Transition Charge being inserted.[35] Assuming a full recovery of

[35] See below.

deferrals in 2012, the model shows delivery rates dropping substantially for large customer classes and most small commercial customers, while increasing modestly for most residential customers.[36] Although the model does not illustrate impacts in 2013, all other factors being equal, the removal of regulatory deferrals from rates in 2013 would result in a substantial decrease for residential customers at that time.

The Company states that rate changes in 2012 should be addressed either in the commodity filing that will be due 45 days following this order, or in a subsequent rate case.

Considering the likely trends identified in the 2012 scenario, it is not clear that a complete recovery of regulatory deferrals in the year following the rate year is in the best interest of customers. Residential customers, in particular, could be subject to an unnecessary fluctuation in rates.

We agree with the Judges that recovery should not occur until after the full recovery of CTCs. Beyond that, we will not rule at this time on the amortization schedule for regulatory deferrals. We intend to rule on that issue in the context of approving the surcharge mechanism discussed above. In doing so, we expect that we will adhere to the goal of no residential or small commercial class experiencing a rate increase while this rate order remains in effect. The Company should take this expectation into account in crafting its filing.

e. Legacy transition charge

The Company proposed creating a Legacy Transition Charge (LTC) in 2012. This charge would replace the Over-Market

[36] The difference among these classes reflects the fact that a relatively smaller portion of CTCs is allocated to residential customers, compared with other regulatory deferral recoveries.

Variable Charge that is currently contained within the CTC.[37] Under the stipulation on energy supply, this proposal would be addressed in a subsequent proceeding.

On exceptions, the Company expressed concern that if CTCs are fully recovered in 2011, it should be clear that no customer class would be exempt from recovery of the LTC. Staff concurs with the Company.

Reserving the possibility of establishing alternative methods in a subsequent proceeding, the provisions of this Order related to expiration of CTC obligations should not be interpreted to provide for exemption of any customer class from collection of LTCs.

f. Rate design changes to street lighting service.

The Company proposed several changes to street lighting service for municipal customers, which were unopposed on briefs. In hearings, it was established that the cumulative effect of the changes on the five municipal customers concerned is a net reduction of $51,000. Staff concurs with the Company. The recommended decision did not discuss these changes. They are adopted here.

MERCHANT FUNCTION CHARGE MATTERS

With everything else in this case, Niagara Mohawk will implement a merchant function charge to cover the following costs: (1) commodity procurement costs; (2) commodity-related credit and collection costs; (3) working capital associated with commodity costs and (4) commodity-related uncollectibles. The

[37] The proposed Legacy Transition Charge represents over-market or under-market costs of power purchase contracts currently contained within the CTC. Although the portion of the CTC reflecting the Company's fixed costs will be fully recovered by the end of 2011, potential losses or savings from long-term purchase contracts will remain.

Retail Energy Supply Association and the Small Customer Marketer Coalition (RESA/SCMC) raised two issues. One concerns Niagara Mohawk's proposal to true up the discount rate used for the purchase of receivables (POR) program. The other concerns the two billing options for the customers of energy service companies (ESCOs).

Purchase of Receivables

Niagara Mohawk proposed to true-up the discount rate it uses to purchase ESCO accounts receivable. The Judges agreed with RESA/SCMC that the proposed true-up runs counter to the ESCO business practices and it is adverse to their competitive market offerings. For these reasons, the Judges did not recommend the Company's proposal.

On exceptions, Staff supports the proposal to true-up the POR discount rate. Staff states that, if the POR discount rate is not trued-up, Niagara Mohawk's full-service customers will unfairly bear the entire reconciliation of the credit and collection costs. Staff points out that Niagara Mohawk performs its credit and collection function for ESCO customers and full-service customers alike, and asserts that the reconciliation should apply to both groups of customers. Staff also observes that credit and collection costs are fully reconciled by such other utility companies as NYSEG and RG&E.

In response, RESA/SCMC does not consider Staff's position persuasive, and they assert that the POR discount rate need not be modified. According to RESA/SCMC, both the utility company and the ESCO should stick to and live with the discount rate established for the annual period and no true-up should be made under any circumstances. RESA/SCMC supports the establishment of a reasonable POR discount rate for each annual period but they strongly oppose any out-of-period adjustments.

On exceptions, Niagara Mohawk seeks a clarification about a proposal it made in this case to recalculate monthly the commodity cost component of the merchant function charge and the purchase of receivables discount, using monthly commodity-related uncollectible pricing data. It states that Staff supported its proposal and no other party opposed it.

RESA/SCMC states that they were unaware of Niagara Mohawk's proposal to modify the POR discount rate on a monthly basis until they saw the reference to it in the Company's brief on exceptions.[38] They consider the proposal to be unreasonable. RESA/SCMC insists that the POR program is without recourse and the Company's and Staff's proposals for true-ups are inconsistent with the "without recourse" attributes of the program.

We find that it is necessary to adopt monthly recalculations and the annual true-ups proposed by the Company and Staff for the merchant function charge to operate properly as it pertains to both full service customers and to customers who receive their electric commodities from ESCOs. For this reason, we grant the Niagara Mohawk and Staff exceptions.

Dual and Consolidated Billing

In this case, RESA/SCMC have requested that the ESCOs who operate in Niagara Mohawk's service area be provided the ability to use either dual billing or the utility company's consolidated billing for any individual customer. Niagara Mohawk opposed this proposal, and the Judge agreed with the Company, that it was not unreasonable to continue to require ESCOs to choose between the dual billing and consolidated

[38] RESA/SCMC claim the proposal appeared, for the first time, in Niagara Mohawk's brief and it lacks record support. However, the Company provides record citations for its proposal and for Staff's response and acceptance of the monthly recalculations.

billing for their entire service groups, as is the current practice.

RESA/SCMC except and claims that the only justification Niagara Mohawk has for limiting ESCO discretion to use dual or consolidated billing is the Company's belief that the ESCOs will use the option to place only their customers with bad credit ratings on consolidated billing. Niagara Mohawk believes this practice would cause it to experience higher amounts of bad debt than it otherwise would. In response to this argument, RESA/SCMC states the Company's concern is not supported by any study, analysis or data, and it only rests on Niagara Mohawk's subjective beliefs.

RESA/SCMC insists that there is no merit to the Company's position. According to them, ESCO customer defaults are unrelated to the purchase of receivables program available to ESCOs through the consolidated billing option. They state that customers will default irrespective of the entity that provides their commodity service. Thus, they believe the purchase of receivables program does not impact the Company's bad debt. They also state that bad debt is ever present and the utility company may be better off with customers on the purchase of receivables program because of the discount rate that is used.

In further response to Niagara Mohawk, RESA/SCMC state that ESCOs have no reason to take on bad risk customers and the purchase of receivables program does not insulate ESCOs from incurring losses due to customer defaults. They also note that other utility companies, including Consolidated Edison, allow ESCOs the billing option they are seeking here and the negative impacts Niagara Mohawk fears have not been an obstacle elsewhere.

To be clear, RESA/SCMC points out that the discount rate for the purchase of receivables program does not reflect the uncollectible experience of any individual ESCO or the ESCOs in the aggregate. Inasmuch as the uncollectible rate is the same across the Company, and is not linked to the ESCO customer pool, RESA/SCMC believe it is unreasonable to assume that the ESCO's selection between consolidated billing and dual billing on an individual customer basis will produce any negative results for Niagara Mohawk. It believes that the Company, and the Judges' recommendation, is too restrictive, discriminatory and unduly limits customer choice. With the individual customer option, RESA/SCMC states that ESCOs will be in a better position to offer customer options and customized products.

In response, Niagara Mohawk states that ESCOs should not be able to place their bad credit customers in the purchase of receivables program while retaining similarly sized customers with better credit ratings on the dual billing program. The Company does not believe that ESCOs should be permitted to game the program and it insists that no study need be prepared to demonstrate that ESCOs will take advantage of the option to increase their profits at the expense of the general body of customers.

In instances where electric utility companies have been willing to implement an individual ESCO customer billing option, we have allowed them to do so, as in the case involving Consolidated Edison. However, to date, we have not mandated that any utility company do so on the basis of any detailed examination of the comparative merits of the two approaches. Nor have we required that there be provided to us any study, data or analysis pertaining to this matter. For now, we find that ESCOs have sufficient access to the utility company's purchase of receivables program with the application of the dual bill/consolidated bill option at the service group level. We do not believe that the greater flexibility that RESA/SCMC seek for ESCOs to use the purchase of receivables program is essential for them to operate, nor are we persuaded that the current approach presents any real or serious barriers to the provision of product options for customers.

MISCELLANEOUS MATTERS

Merger Joint Proposal Provisions

Niagara Mohawk requests that we establish a collaborative process for interested parties to consider the provisions of the Merger Joint Proposal and determine which should survive now that we are at the end of the multi-year rate plan that was adopted in 2002. Among the matters the Company believes require the parties' consideration are corporate structure, affiliate rules and regulatory approvals. Staff concurs with this proposal and suggests that the collaborations begin soon and the parties report their results in a month.

We are adopting this proposal and the parties should deliver a report of the matters they addressed, and their proposals, to the Secretary within 30 days.

Rate Year Deferrals - Carrying Charges

The Judges concluded, as a matter of general principle, that Niagara Mohawk's deferred balances during the rate year should receive carrying charges in recognition of the cost of money that accompanies customer obligations that are put off for future recovery. On exceptions, Staff reiterates its position that the Company should be provided an incentive to avoid or minimize cost deferrals. Staff believes that precluding carrying charges would be one good way to provide the Company such an incentive. Staff observes that Niagara Mohawk has previously not received carrying charges on its rate year deferrals and it see no strong reason for carrying charges to begin now. According to Staff, this matter is further complicated by the record not containing the method for how the carrying charges should be calculated.

In response, Niagara Mohawk states that it has no need for an incentive to minimize its cost deferrals because it has an overall obligation to manage costs and ensure that they are reasonable. Further, it observes that its deferred costs are always subject to Staff's audit, examination and challenge. The Company states that the deferrals are largely outside of its control and carrying charges should be recognized as a true cost of doing business when customer obligations are put off for future recovery.

Addressing Staff's concerns about the method to be used to calculate the carrying charges, Niagara Mohawk states that they should be set at the pre-tax weighted average cost of capital as determined by the Commission in this proceeding. The Company believes it would be punitive and unfair for us to require it to defer costs and not provide it the proper compensation for doing so.

We find that there is a cost of doing business associated with the deferred recovery of current costs. The Company has its cost of money to cope with and, in all fairness, this cost must be recognized. In the past, it appears that the matter of carrying charges was the subject of negotiations in the process used to address Niagara Mohawk's poor financial condition and the means to be used to improve its standing. Here, there are no such comparable conditions and we are satisfied that deferred costs are capable of being audited for their reasonableness and propriety. Accordingly, we will allow carrying charges, only on deferrals recorded after December 31, 2010,[39] on the rate year deferred balances and we permit the Company to use the pre-tax weighted average cost of capital for this purpose as set by the results of this case.

Site Investigation and Remediation

Staff proposed an incentive mechanism for Niagara Mohawk to improve the management of the site investigation and remediation costs incurred when environmental remediation is required at locations polluted due to early activity in the gas and electric industry during the 1800's and 1900's. Staff proposed an 80/20 sharing mechanism for the costs incurred in excess of the projections make in a rate proceeding. The Judges have not recommended the Staff proposal, citing the potential disincentives for optimal site remediation, the potential disturbance of a cooperative working relationship between the Company and the state and federal environmental agencies that oversee Niagara Mohawk's performance, and the limits on the Company's ability to control the scope and timing of the environmental remediation efforts.

On exceptions, Staff continues to support the use of an incentive mechanism and asserts that it is the Company's business to manage and limit the cost of necessary remediation work. Staff does not believe that it would be counterproductive to the Company's working relationship with the state and federal environmental agencies for it to use its abilities it pursue the least cost solutions available for site remediation work. Finally, Staff states there is a precedent for its proposal and it points out that previously an 80/20 cost sharing arrangement was applied to the Company for it to maintain costs in this category.

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[39] All pre-2011 deferrals have been estimated and included in rate year rate base and therefore no carrying charges can be recorded on these deferrals.

Niagara Mohawk responds by noting the unavoidability of the site investigation and remediation work and its inability to control entirely the scope of the work, the cleanup techniques and the timetable for the work. According to the Company, no other utility company in New York is subject to the incentive mechanism that Staff has proposed here. Further, Niagara Mohawk insists that it aggressively pursues cost-reducing measures and the lowest project costs that are consistent with the protection of human health and the environment. When necessary, the Company states that it has purchased land to reduce remediation costs and has brought legal actions to modify a lead agency's remediation standards. It insists that the incentive mechanism proposed by Staff is unnecessary.

As a result of this proceeding, the amount included in rates for environmental site investigation and remediation work will increase from the $12 million provided annually by the Merger Joint Proposal to $30 million. Staff's 80/20 sharing proposal is a reaction to the substantial amount of SIR costs that the Company continues to incur.

We are well aware of the importance of thorough, timely cleanups, both for public health and for the economic vitality of affected communities. We intend that utility efforts should further these twin goals. We are concerned, however, that, in practice, the design and implementation of SIR projects may not cost effectively focus the utility's remediation efforts. The current process may lack an effective deterrent to excessive costs in the design and/or implementation of projects. Where neither the agency overseeing the project, nor the company implementing it, has a tangible incentive to minimize costs, the goal of designing and implementing projects in the most reasonable and cost-effective manner, on behalf of ratepayers, might not be properly represented.

In addition, the historic allocation of responsibility for SIR costs should be reexamined, to find relief for ratepayers and to consider arrangements for equitably sharing the burdens of clean-up. The costs represent a legacy of environmental damage that began in the 1880's and continued into the early 1900's. The damage was not incurred in service of today's customers, who are nonetheless bearing the burden of paying for the remediation. It is not clear to us that today's ratepayers should bear the sole responsibility for all of these costs.

Finally, we are generally aware that ratepayers are exposed to SIR cost recovery in most of the gas or electric utilities in the State, and that this exposure statewide is large, in the range of two billion dollars. This makes this matter one of substantial significance to ratepayers throughout the State.

For these reasons, at this time we will adopt Staff's recommendation of an 80/20 mechanism for sharing SIR costs in excess of the rate year allowance.[40] Further, we direct advisory staff to present us with a proposal for a proceeding to examine this issue on a statewide basis. That proceeding should develop a comprehensive record to describe the scope of the utility SIR programs in our State and their anticipated scope in the future, review the processes used by our utilities to develop and implement the SIR implementation plans, and review existing and

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[40] The mechanism would remain in effect until revised by a Commission order. Because this provision will only apply to costs exceeding the allowance, it reflects a reasonable interim approach pending the development and analysis of alternative cost sharing arrangements which could focus incentives more directly on the cost effective, timely and thorough remediation of the contaminated sites.

alternative cost sharing mechanisms or other forms of incentive that could be adopted to further the goal of accomplishing thorough, timely clean-ups with the least impact on ratepayers.

Updates

Consistent with the Judges' recommendations, the rate year revenue requirements include an updated figure for the fuel the Company uses for motor vehicles. We have also updated the inflation factor that is applied to various items. Where necessary, and as noted in the parties' respective briefs, we have corrected the mathematical errors in the Judges' revenue requirement calculations to arrive at the correct figure here.

Term of stipulation provisions

Some provisions of the stipulations adopted here contain specific language regarding their term; others are silent on that question. Unless an expiration date is explicitly identified within a stipulation, its terms will remain in effect until replaced or modified by Commission order.

Merger Joint Proposal - Mandated Regulatory, Legislative & Accounting Changes

In its reply brief on exceptions, Niagara Mohawk states that the Judges incorrectly understood the Company's position concerning the Merger Joint Proposal provisions that address deferred accounting for mandated regulatory, legislative and accounting changes (§§ 1.2.4.3 and 1.2.4.2). The Judges did not understand that the Company was proposing a change in the scope of the deferral accounting to include changes in industry standards. In its exceptions, Staff opposes the Company's proposal and expresses opposition to an expansion of the scope of the deferral accounting provisions.

Niagara Mohawk states that the agencies responsible for reviewing the reliability of the transmission network are making changes to the standards for the electric network. The

Company believes that these changes in industry standards are similar to the kinds of changes contemplated and addressed by the Merger Joint Proposal. The Company considers its proposal to be a modest expansion of the existing deferral accounting mechanism and it urges us to permit deferral accounting for this category as well.

Having approached this case largely as a single-year, litigated ratemaking proceeding, we are reluctant to introduce any new deferrals, which are more appropriately considered as potential elements of a multi-year rate plan. Rather than address here the terms of the rate plan that is soon to expire, or approach a new rate plan in a piecemeal fashion, Niagara Mohawk should present all the proposals it may have for a multi-year approach in its next rate filing. In that way, we can consider all the elements of a well-rounded rate plan that should proceed into the future.

Electric Delivery Adjustment Mechanism (EDAM)

The Judges concluded that it was premature in this case to consider or adopt any electric delivery adjustment mechanism that could be used to reconcile annually the amounts in the Company's deferral accounts. While the Judges believe that such a mechanism can be made a part of a multi-year rate plan, they observed that this proceeding is largely limited to being a one-year rate proceeding.

On exceptions, Staff states that an EDAM is problematic. It fears that the automatic surcharge mechanism would recover unaudited deferrals and ratepayer interests would not be well served. In response, Niagara Mohawk continues to state its support for an EDAM and gives its reasons for believing that Staff can continue to perform any necessary audits and ensure that ratepayer interests are properly served.

We agree with the Judges' finding. Any further consideration to be given to the development and the use of an EDAM should be undertaken in the Company's next rate case. Niagara Mohawk is not precluded from including its next proposal with its rate case filing.

NorthStar Management Audit Impacts

On July 16, 2008, we ordered a comprehensive management audit of National Grid pursuant to PSL §66(19) as part of proceeding 08-E-0827. The consultant's final report was issued on December 4, 2009. On December 16, 2009, we ordered the Company to submit an implementation plan addressing the final report's recommendations. The Company provided a responsive filing, its Audit Implementation Plan, dated January 29, 2010. The Implementation Plan provides responses to each of the 45 recommendations contained in the NorthStar audit report. On the same day, the Company filed a petition for a three year rate plan.

Due to the simultaneous release of these documents and the lead time to implement the management audit recommendations, Staff testified that it was premature to quantify any savings from individual audit recommendations. Several of the audit recommendations have been implemented. The major audit recommendations that have not been implemented to date, however, were addressed primarily in the capital expenditure/O&M stipulations. The audit found problems with the Company's ability to accurately forecast the cost of capital projects. The stipulation includes a negative $2 million revenue adjustment if more than 20% of capital projects costing $100,000 or more are 10% above or below their estimated cost. The stipulation also includes a one-way true-up of capital cost overages, whereby if project costs, on a whole, are higher than planned ratepayers do not pay the added cost, while if project costs are lower, on a whole, the benefit is preserved for ratepayers. The management audit also found that use of a single contractor approach for transmission and distribution projects could increase overall project costs. The capital expenditure/O&M stipulation requires an immediate phase-out of the Regional Delivery Venture to address this recommendation. Finally, the Company agreed not to seek recovery of costs associated with implementing management audit recommendations, estimated at approximately $6 million.

We will ensure the Company's continued progress in addressing the management audit recommendations during the pendency of this rate plan. The Commission has established a periodic reporting mechanism for monitoring the Company's progress on the 45 recommendations in the NorthStar audit report. We expect National Grid to dedicate itself effectively and comprehensively to the implementation of the management audit recommendations and to focus on tangible work products like the improvement in its project estimating and execution, the development of an electric long-range plan, and provide a comprehensive report on its efforts and results in its next rate filing.

The Commission orders:

1. Niagara Mohawk Power Corporation is directed to file, on not less than one day's notice, cancellation supplements cancelling the tariff amendments and supplements specified in Appendix 1 to this order, to take effect January 31, 2011.

2. Niagara Mohawk Power Corporation is directed to file, on not less than one day's notice:

(a) such tariff revisions as are necessary to effectuate the provisions adopted by this order, including a $119,349 million annual revenue increase to take effect February 1, 2011 as detailed in Appendix 2 of this order; provided, however, that compliance by the Company with this rate order by the filing of tariff revisions in accordance with this subdivision (a) will also require the unconditional commitment by the Company, evidenced in writing on or before January 28, 2011:

(i) to refrain from seeking judicial review pursuant to Article 78 of any provision of this order or of any modification of this order which may result from a petition for rehearing that defines or implements the company's annual revenue increase under this order or modified order, and

(ii) to create a deferral account for the benefit of ratepayers in an amount equal to the stay out premium collected in rates pursuant to this order in the event that the Company shall not refrain from filing a rate case seeking an increase in base delivery rates before January 1, 2012; unless, in the judgment of the Commission, circumstances so threaten the economic viability of the Company or the Company's ability to maintain safe, reliable or adequate service as to warrant the filing of a rate case prior to January 1, 2012;

or, in the alternative,

(b) such tariff revisions as are necessary to effectuate the provisions adopted by this order, including a $112,764 million annual revenue increase to take effect February 1, 2011 as detailed in Appendix 3 of this order.

3. Niagara Mohawk Power Corporation shall make a filing within 60 days of this Order which provides the journal entries required to effectuate the one-month make whole provision discussed in the Order in this proceeding dated

December 22, 2010, adopting a Stipulation on Make Whole Provision. The filing shall include a full explanation of how those journal entries comply with all aspects of the allowed one month make-whole.

4. Niagara Mohawk Power Corporation is directed to file, on not less than one day's notice to become effective February 1, 2011, such further tariff revisions as are necessary to effectuate an adjustment clause mechanism to recover, in the same manner as the Company's delivery revenue requirement is recovered in base rates, $50 million of the revenue requirement associated with service company costs. Such language shall specify that this portion of the revenue requirement will be subject to further Commission audit and review and refund and continue to be recovered in this manner until such time as the Commission determines otherwise. The tariff amendments specified above shall not become effective on a permanent basis until approved by the Commission.

5. Niagara Mohawk Power Corporation is directed to file, within 60 days of this order, illustrative examples of how it would effectuate a Commission-ordered refund and reduction in the revenue requirement, pursuant to the adjustment clause described in Ordering Clause 4 above.

6. The requirement of Section 66(12)(b) of the Public Service Law that newspaper publications be completed prior to the effective date of the proposed amendments directed in Clauses 2 and 4 above is waived and the Company is directed to file with the Commission, not later than six weeks following the amendments' effective date, proof that a notice to the public of the changes made by the amendments has been published once a week for four successive weeks in newspapers having general circulation in the areas affected by the amendments.

7. Niagara Mohawk Power Corporation is directed to file, not later than July 31, 2011 and to become effective January 1, 2012, such tariff revisions as are necessary to remove the Competitive Transition Charge from electric rates and to establish a surcharge for recovery of deferral accounts, as detailed in this Order. The tariff amendments shall not become effective until approved by the Commission.

8. Niagara Mohawk Power Corporation is directed to file, within 45 days of this order, and to become effective January 1, 2012, proposed modifications to its commodity rate mechanisms, under the terms addressed in the Stipulation Regarding Energy Supply Issues (Exhibit 390). The tariff amendments shall not become effective until approved by the Commission.

9. Niagara Mohawk Power Corporation is directed to file, within 30 days of this order, a report of collaborative discussions with Staff and interested parties, regarding the continuation of provisions of the Merger Joint Proposal adopted by the Commission in Case 01-M-0075 on December 3, 2001. The report shall include a detailed description of all ratemaking aspects of the allowed major storm deferral account's compliance with both the Merger Joint Proposal and Attachment 3 of the Stipulation of the Parties in Case 01-M-0075 et al.

10. Niagara Mohawk Power Corporation is directed to file, within 60 days of this order, the journal entries recording the Commission's ruling on the issue involving delayed work order closings. Niagara Mohawk Power Corporation is also directed to file, in its next electric and gas rate proceedings, a report documenting the results of its efforts to improve its accounting entries and system for closing work orders and including new projects in the plant in service accounts.

11. The Company shall serve copies of all required filings on the Secretary and all parties to the proceeding, electronically, unless a party requests service of paper copies.

12. Except as herein granted, all exceptions to the November 17, 2010 Recommended Decision are denied.

13. Except as herein modified, the November 17, 2010 Recommended Decision is adopted as part of this Order.

14. The Secretary is authorized, at her sole discretion, to extend any dates specified herein.

15. This proceeding is continued.

By the Commission,

Jaclyn A. Brilling

Digitally Signed by Secretary
New York Public Service Commission

JACLYN A. BRILLING
Secretary

CASE 10-E-0050 APPENDIX 1

SUBJECT: Filing by Niagara Mohawk Power Corporation d/b/a National Grid

Amendments to Schedule P.S.C. No. 220 – Electricity

Original Leaves Nos. 222.1, 263.2, 263.3
First Revised Leaves Nos. 113, 173, 211, 213, 216, 222, 223, 224, 225, 228, 229, 231, 236, 237, 238, 239, 350, 388, 395, 416, 425, 436, 441, 464
Second Revised Leaves No. 3, 381
Third Revised Leaves Nos. 2, 182, 192, 349, 359, 370, 371, 375, 376, 379, 380, 391, 392, 407, 408, 432, 438
Fourth Revised Leaves Nos. 421, 422, 423, 424
Statement of Merchant Function Charge No. 1
Supplement Nos. 3, 5, 8

Amendments to Schedule P.S.C. No. 214 – Electricity

First Revised Leaves Nos. 2, 79
Second Revised Leaves Nos. 1, 3, 4, 6, 9.2, 9.4, 9.5, 9.6, 9.7, 13, 14, 16, 17, 18, 69, 71
Third Revised Leaves Nos. 8, 9.1, 9.3, 12, 21, 60, 65, 67, 70, 74, 80, 83, 88, 89, 91
Fourth Revised Leaves Nos. 5, 14.1, 15, 20, 30, 35, 58, 62, 63, 68, 78, 81, 84, 90
Fifth Revised Leaves Nos. 25, 29, 31, 33, 33.1, 34, 36, 38, 45, 46, 47, 49, 54, 56, 57, 64, 66, 67.1, 75, 76, 77
Sixth Revised Leaves Nos. 11, 23, 24, 26, 28, 37, 39, 41, 43, 44, 50, 51, 52, 55, 61
Seventh Revised Leaves Nos. 32, 40, 42, 48, 53, 73.1, 87
Ninth Revised Leaves Nos. 10, 27
Tenth Revised Leaf No. 86
Eleventh Revised Leaves Nos. 22, 85
Twelfth Revised Leaf No. 9
Twentieth Revised Leaf No. 73
Twenty-Third Revised Leaf No. 72
Twenty-Ninth Revised Leaves Nos. 7, 19, 59
Thirtieth Revised Leaf No. 82
Statement of Merchant Function Charge No. 1
Supplement Nos. 17, 18, 19

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
PSC Case No. 10-E-0500
Statement of Operating Income
For the Rate Year Ending December 31, 2011
($000's)

	ALJ RD Rate Year Ending December 31, 2011		Commission Adjustments	Per Commission Before Reshaping Rate Year Ending December 31, 2011	Commission Reshaping Adjustment	Per Commission With Reshaping Rate Year Ending December 31, 2011
Operating Revenues	$ 3,207,204	(1)	$ 8,133	$ 3,215,337	$ (8,133)	$ 3,207,204
Deductions						
Purchased Power Costs	982,533		-	982,533		982,533
Revenue Taxes	33,659	(2)	141	33,800	(141)	33,659
Total Deductions	1,016,192		141	1,016,333	(141)	1,016,192
Gross Margin	2,191,012		7,992	2,199,004	(7,992)	2,191,012
Total Operation & Maintenance Expenses	947,652	(3)	16,096	963,748	(99)	963,649
Amortization of Regulatory Deferrals	546,256		-	546,256	(8,125)	538,131
Depreciation, Amort. & Loss on Disposition	160,886		-	160,886		160,886
Taxes Other Than Revenue & Income Taxes	157,254	(4)	33	157,287		157,287
Total Operating Revenue Deductions	1,812,048		16,129	1,828,177	(8,224)	1,819,953
Operating Income Before Income Taxes	378,964		(8,137)	370,827	232	371,059
Income Taxes						
Federal Income Taxes	91,222		(3,715)	87,507	75	87,582
State Income Taxes	21,400		(859)	20,541	16	20,558
Total Income Taxes	112,622		(4,574)	108,048	92	108,140
Operating Income After Income Taxes	$ 266,342		$ (3,563)	$ 262,779	$ 140	$ 262,919
Rate Base	$ 4,034,118	(5)	$ 2,000	$ 4,036,118	$ 2,158	$ 4,038,276
Rate of Return	6.60%			6.51%		6.51%

	Recommended Decision	Commission Adjustments	Per Commission Order
Rate Increase(Decrease) Before Reshaping	111,216	8,133	119,349
CTC Amortization	546,256	10,849	557,105
Deferral Amortization	-	(18,974)	(18,974)
Total Amortization (After Reshaping)	546,256	(8,125)	538,131

APPENDIX 2

Commission Order
Schedule 2

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
PSC Case No. 10-E-0500
Other Operating Expenses
For the Rate Year Ending December 31, 2011
($000's)

	ALJ RD Rate Year Ending December 31, 2011	Adj. #	Commission Adjustments	Rate Year As Adjusted By Commission
Consultants	26,901			26,901
Contractors	111,348			111,348
Donations	-			-
Employee Expenses	10,211			10,211
Hardware	4,036			4,036
Software	8,450			8,450
Other	23,987			23,987
Rents	32,254			32,254
AFUDC - Debt	-			-
Service Co. Equity	(1,287)			(1,287)
Conservation Load Management	(0)			(0)
Construction Reimbursement	(578)			(578)
Co Contributions/Cr to Jobs	61			61
Bill Interface Expense Type	(917)			(917)
Capital Overheads	99			99
Supervision & Admin	124			124
Service Co Operating Costs	702			702
Sales Tax	997			997
FAS 106	102,885	a	1,839	104,724
FAS 112	2,666	b	44	2,710
Health Care	22,082	c	316	22,398
Group Life Insurance	1,380	d	19	1,399
Other Benefits	471			471
Pension	47,842	e	754	48,596
Thrift Plan	6,329	f	68	6,397
Workers Comp	1,731	g	34	1,765
Payroll Taxes	-			-
Materials Outside Vendor	20,295			20,295
Materials From Inventory	5,908			5,908
Materials Stores Handling	1,010			1,010
Total Labor	268,241	h	3,004	271,245
Transportation	19,401	i	703	20,104
Energy Efficiency Program	49,618			49,618
Injuries & Damages	10,312			10,312
Other Initiatives	19,828			19,828
Productivity Adjustment	(5,912)			(5,912)
Austerity	(5,000)	j	(2,620)	(7,620)
Rate Case Expense	2,119			2,119
Regulatory Assessment Fees	95,106			95,106
Renewable Portfolio Standard	36,619			36,619
Site Investigation & Remediation Expens	29,750			29,750
Storm Fund	-			-
Synergy Savings	(34,975)	k	3,926	(31,049)
System Benefits Charge	45,058			45,058
Uncollectible Accounts	36,144	l	99	36,243
Miscellaneous	(47,645)	m	7,910	(39,735)
Total Other Operating Expenses	$ 947,652		16,096	$ 963,748

APPENDIX 2

Commission Order
Schedule 3

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Federal Income Taxes - Electric
For the Rate Year Ended December 31, 2011
($000's)

Electric	Commission Adjusted Rate Case: FEDERAL TAXABLE INCOME	DEFERRABLE BASIS	BOOK TAXABLE INCOME	@ THE STATUTORY RATE	DFIT REVERSALS	NET FIT
NET INCOME BEFORE FEDERAL & STATE INCOME TAXES	$ 370,827		$ 370,827	$ 129,789		$ 129,789
ADDITIONS						
MERGER RATE PLAN STRANDED COSTS-AMORTIZATION	546,256		546,256	191,190	(191,190)	0
PROVISION FOR DEPRECIATION	160,621		160,621	56,217		56,217
REAL ESTATE TAXES PER BOOKS	137,860		137,860	48,251		48,251
BUSINESS MEALS 50% DISALLOWANCE	306		306	107		107
DEDUCTIONS						
GAIN ON REDEMPTION BONDS	0		0	0		0
INTEREST	(81,819)		(81,819)	(28,637)		(28,637)
V-M BOOK GAIN AMORTIZATION	0		0	0	375	375
OSWEGO 6 TRANS SERVICE CONTRACT EXIT AGREEMENT	0		0	0		0
NEW YORK STATE INCOME TAXES - CURRENT PROVISION	(20,541)		(20,541)	(7,189)		(7,189)
OTHER STATE INCOME TAXES	(6)		(6)	(2)		(2)
COST OF REMOVAL	(35,586)	28,469	(7,117)	(2,491)	(8,609)	(11,100)
TAX DEPRECIATION	(151,167)	2,097	(149,070)	(52,175)		(52,175)
REAL ESTATE TAXES FOR TAX	(137,860)		(137,860)	(48,251)		(48,251)
AMORTIZATION PASNY CONTRACT	0		0	0		0
CLASS B CONTRACTS AMORTIZATION	0		0	0	0	0
CREDITS						
Adjustment for Tax Credits						(98)
TOTAL FIT EXPENSE	$ 788,891	$ 30,566	$ 819,457	$ 286,810	$ (199,424)	$ 87,288

calculated effective Federal tax rate	30.2%

State Income Taxes - Electric
For the Rate Year Ended December 31, 2011
($000's)

	Commission Adjusted Rate Case: STATE TAXABLE INCOME	DEFERRABLE BASIS	BOOK TAXABLE INCOME	@ BLENDED * STATUTORY RATE	DSIT REVERSALS	NET SIT
NET INCOME BEFORE FEDERAL & STATE INCOME TAXES	$ 370,827		$ 370,827	$ 26,329		$ 26,329
ADDITIONS						
REAL ESTATE TAXES PER BOOKS	137,860		137,860	9,788		9,788
BUSINESS MEALS 50% DISALLOWANCE	306		306	22		22
DEDUCTIONS						
GAIN ON REDEMPTION BONDS	0		0	0		0
INTEREST	(81,819)		(81,819)	(5,809)		(5,809)
V-M BOOK GAIN AMORTIZATION	0		0	0		0
OSWEGO 6 TRANS SERVICE CONTRACT EXIT AGREEMENT	0		0	0		0
REAL ESTATE TAXES FOR TAX	(137,860)		(137,860)	(9,788)		(9,788)
TOTAL SIT EXPENSE	$ 289,314	$ -	$ 289,314	$ 20,541	$ -	$ 20,541

7.1%

calculated effective NYS tax rate	7.1%
calculated effective Combined Fed & NYS tax rate	37.3%

APPENDIX 2

Commission Order
Schedule 4

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
PSC Case No. 10-E-0500
Rate Base
For the Rate Year Ending December 31, 2011
($000's)

	ALJ RD Rate Year Ending December 31, 2011	Adj.	Commission Adjustments	Rate Year as Adjusted per Commission	Reshaping Adjustment	Rate Year Ending December 31, 2011
Net Utility Plant	$ 4,688,478			$ 4,688,478	$ -	$ 4,688,478
Regulatory Assets / Liabilities	467,666			467,666	4,049	471,715
Accumulated Deferred Income Taxes - Federal	(944,410)			(944,410)	(1,891)	(946,301)
Accumulated Deferred Income Taxes - State	(161,386)			(161,386)	-	(161,386)
Total Accumulated Deferred Income Taxes	(1,105,796)			(1,105,796)	(1,891)	(1,107,687)
Working Capital						
Materials and supplies	27,232			27,232	-	27,232
Prepayments	(67,999)			(67,999)	-	(67,999)
O&M Cash Allowance (1/8 O&M exp)	87,048	a.	2,000	89,048	-	89,048
Supply Cash Allowance	33,582			33,582	-	33,582
Change in Supply Cash Allowance	2,635			2,635	-	2,635
subtotal Working Capital	82,498		2,000	84,498	0	84,498
subtotal avg. before EBCAP adj.	4,132,845		2,000	4,134,845	2,158	4,137,003
Excess Earnings Base adjustment	(98,727)			(98,727)	-	(98,727)
Total Electric Rate Base	$ 4,034,118		$ 2,000	$ 4,036,118	$ 2,158	$ 4,038,276

APPENDIX 2

Commission Order
Schedule 5

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
PSC Case No. 10-E-0500
Capital Structure
For the Rate Year Ending December 31, 2011
($000's)

Capital Structure, ALJ Recommended Decision Rate Year Ending December 31, 2011	Total NM Annual Avg	Weighting Percent	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long Term Debt	$ 2,400,065	46.68%	4.08%	1.90%	1.90%
Notes Payable	103,814	2.02%	0.41%	0.01%	0.01%
Gas Supplier Refunds	-	0.00%	0.00%	0.00%	0.00%
Customer Deposits	36,794	0.72%	2.45%	0.02%	0.02%
Preferred Stock	29,286	0.57%	3.62%	0.02%	0.03%
Common Equity	2,571,269	50.01%	9.30%	4.65%	7.70%
Total	$ 5,141,228	100.00%		6.60%	9.67%

Capital Structure, Commission Order Rate Year Ending December 31, 2011	Total NM Annual Avg	Weighting Percent	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long Term Debt	$ 2,503,565	48.70%	4.11%	2.00%	2.00%
Notes Payable	103,814	2.02%	0.41%	0.01%	0.01%
Gas Supplier Refunds	0	0.00%	0.00%	0.00%	0.00%
Customer Deposits	36,794	0.72%	2.45%	0.02%	0.02%
Preferred Stock	29,286	0.57%	3.62%	0.02%	0.03%
Common Equity	2,467,769	48.00%	9.30%	4.46%	7.39%
Total	$ 5,141,228	100.00%		6.51%	9.45%

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
PSC Case No. 10-E-0050
Commission Order
For the Rate Year Ending December 31, 2011
($000's)

				Amount
Adj. 1	**Operating Revenues** To reflect the cumulative revenue requirement impact of all Commission adjustments before reshaping CTC stranded cost and net regulatory asset amortizations			8,133
Adj. 2	**Revenue Taxes** To reflect the change in revenues tax associated with the ALJs' Operating Revenue adjustment			141
Adj. 3	**Operating and Maintenance Expenses**			
a	**FAS 106** To reverse the ALJs' decision to update the fringe benefit capitalization rate			1,839
b	**FAS 112** To reverse the ALJs' decision to update the fringe benefit capitalization rate			44
c	**Health Care** To reverse the ALJs' decision to update the fringe benefit capitalization rate			316
d	**Group Life Insurance** To reverse the ALJs' decision to update the fringe benefit capitalization rate			19
e	**Pensions** To reverse the ALJs' decision to update the fringe benefit capitalization rate			754
f	**Thrift Plan** To reverse the ALJs' decision to update the fringe benefit capitalization rate			68
g	**Workers Compensation** To reverse the ALJs' decision to update the fringe benefit capitalization rate			34
h	**Labor** To reverse the ALJs' decision to update the labor capitalization rate			3,004
i	**Transportation Expense** To update fuel forecast for latest known information			703
j	**Austerity** To reflect Staff's recommended level of austerity savings			(2,620)
k	**Synergy Savings** To reverse ALJs' decision on Narragansett synergy savings			3,926
l	**Uncollectible Expense** To reflect the change in uncollectible expenses associated with the Commission's Operating Revenue adjustment			99
m	**Miscellaneous**			
(1)	Adjustment for major storm expenses		4,873	
(2)	To reverse ALJs' decision on union variable pay		(5,047)	
(3)	To reverse ALJs' decision to reflect the portion of the savings associated with EDO Transformation program that are inherent in the KeySpan synergy savings amount.		7,923	
(4)	To update the inflation adjustment		161	
				7,910
	Total Operating & Maintenance Expense Adjustments			16,096

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
PSC Case No. 10-E-0050
Commission Order
For the Rate Year Ending December 31, 2011
($000's)

		Amount	
Adj. 4	Taxes Other Than Revenue & Income Taxes		
a	Payroll Taxes		
(1)	Flow through adjustment related to labor capitalization adjustment	221	
(2)	Flow through adjustment related to union variable pay	(188)	
			33
	Total Taxes Other Than Revenue & Income Taxes		33
Adj. 5	Rate Base		
a	Working Capital		
	Flow through adjustment related to O&M expense adjustments		2,000
	Total Rate Base Adjustments		2,000

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
PSC Case No. 10-E-0500
Statement of Operating Income
For the Rate Year Ending December 31, 2011
($000's)

	ALJ RD Rate Year Ending December 31, 2011		Commission Adjustments	Per Commission Before Reshaping Rate Year Ending December 31, 2011	Commission Reshaping Adjustment	Per Commission With Reshaping Rate Year Ending December 31, 2011
Operating Revenues	$ 3,207,204	(1)	$ 1,548	$ 3,208,752	$ (1,548)	$ 3,207,204
Deductions						
Purchased Power Costs	982,533		-	982,533		982,533
Revenue Taxes	33,659	(2)	27	33,686	(27)	33,659
Total Deductions	1,016,192		27	1,016,219	(27)	1,016,192
Gross Margin	2,191,012		1,521	2,192,533	(1,521)	2,191,012
Total Operation & Maintenance Expenses	947,652	(3)	16,016	963,668	(19)	963,649
Amortization of Regulatory Deferrals	546,256		-	546,256	(1,521)	544,735
Depreciation, Amort. & Loss on Disposition	160,886		-	160,886		160,886
Taxes Other Than Revenue & Income Taxes	157,254	(4)	33	157,287		157,287
Total Operating Revenue Deductions	1,812,048		16,049	1,828,097	(1,540)	1,826,557
Operating Income Before Income Taxes	378,964		(14,528)	364,436	19	364,455
Income Taxes						
Federal Income Taxes	91,222		(5,780)	85,442	6	85,448
State Income Taxes	21,400		(1,310)	20,090	1	20,092
Total Income Taxes	112,622		(7,090)	105,532	8	105,540
Operating Income After Income Taxes	$ 266,342		$ (7,438)	$ 258,904	$ 11	$ 258,915
Rate Base	$ 4,034,118	(5)	$ 2,000	$ 4,036,118	$ 180	$ 4,036,298
Rate of Return	6.60%			6.41%		6.41%

	Recommended Decision	Commission Adjustments	Per Commission Order
Rate Increase(Decrease) Before Reshaping	111,216	1,548	112,764
CTC Amortization	546,256	10,849	557,105
Deferral Amortization	-	(12,370)	(12,370)
Total Amortization (After Reshaping)	546,256	(1,521)	544,735

Commission Order
Schedule 2

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
PSC Case No. 10-E-0500
Other Operating Expenses
For the Rate Year Ending December 31, 2011
($000's)

	ALJ RD Rate Year Ending December 31, 2011	Adj. #	Commission Adjustments	Rate Year As Adjusted By Commission
Consultants	26,901			26,901
Contractors	111,348			111,348
Donations	-			-
Employee Expenses	10,211			10,211
Hardware	4,036			4,036
Software	8,450			8,450
Other	23,987			23,987
Rents	32,254			32,254
AFUDC - Debt	-			-
Service Co. Equity	(1,287)			(1,287)
Conservation Load Management	(0)			(0)
Construction Reimbursement	(578)			(578)
Co Contributions/Cr to Jobs	61			61
Bill Interface Expense Type	(917)			(917)
Capital Overheads	99			99
Supervision & Admin	124			124
Service Co Operating Costs	702			702
Sales Tax	997			997
FAS 106	102,885	a	1,839	104,724
FAS 112	2,666	b	44	2,710
Health Care	22,082	c	316	22,398
Group Life Insurance	1,380	d	19	1,399
Other Benefits	471			471
Pension	47,842	e	754	48,596
Thrift Plan	6,329	f	68	6,397
Workers Comp	1,731	g	34	1,765
Payroll Taxes	-			-
Materials Outside Vendor	20,295			20,295
Materials From Inventory	5,908			5,908
Materials Stores Handling	1,010			1,010
Total Labor	268,241	h	3,004	271,245
Transportation	19,401	i	703	20,104
Energy Efficiency Program	49,618			49,618
Injuries & Damages	10,312			10,312
Other Initiatives	19,828			19,828
Productivity Adjustment	(5,912)			(5,912)
Austerity	(5,000)	j	(2,620)	(7,620)
Rate Case Expense	2,119			2,119
Regulatory Assessment Fees	95,106			95,106
Renewable Portfolio Standard	36,619			36,619
Site Investigation & Remediation Expense	29,750			29,750
Storm Fund	-			-
Synergy Savings	(34,975)	k	3,926	(31,049)
System Benefits Charge	45,058			45,058
Uncollectible Accounts	36,144	l	19	36,163
Miscellaneous	(47,645)	m	7,910	(39,735)
Total Other Operating Expenses	$ 947,652		16,016	$ 963,668

Commission Order
Schedule 3

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Federal Income Taxes - Electric
For the Rate Year Ended December 31, 2011
($000's)

Electric	Commission Adjusted Rate Case					
	FEDERAL TAXABLE INCOME	DEFERRABLE BASIS	BOOK TAXABLE INCOME	@ THE STATUTORY RATE	DFIT REVERSALS	NET FIT
NET INCOME BEFORE FEDERAL & STATE INCOME TAXES	$ 364,436		$ 364,436	$ 127,553		$ 127,553
ADDITIONS						
MERGER RATE PLAN STRANDED COSTS-AMORTIZATION	546,256		546,256	191,190	(191,190)	0
PROVISION FOR DEPRECIATION	160,621		160,621	56,217		56,217
REAL ESTATE TAXES PER BOOKS	137,860		137,860	48,251		48,251
BUSINESS MEALS 50% DISALLOWANCE	306		306	107		107
DEDUCTIONS						
GAIN ON REDEMPTION BONDS	0		0	0		0
INTEREST	(81,779)		(81,779)	(28,623)		(28,623)
V-M BOOK GAIN AMORTIZATION	0		0	0	375	375
OSWEGO 6 TRANS SERVICE CONTRACT EXIT AGREEMENT	0		0	0		0
NEW YORK STATE INCOME TAXES - CURRENT PROVISION	(20,090)		(20,090)	(7,032)		(7,032)
OTHER STATE INCOME TAXES	(6)		(6)	(2)		(2)
COST OF REMOVAL	(35,586)	28,469	(7,117)	(2,491)	(8,609)	(11,100)
TAX DEPRECIATION	(151,167)	2,097	(149,070)	(52,175)		(52,175)
REAL ESTATE TAXES FOR TAX	(137,860)		(137,860)	(48,251)		(48,251)
AMORTIZATION PASNY CONTRACT	0		0	0		0
CLASS B CONTRACTS AMORTIZATION	0		0	0	0	0
CREDITS						
Adjustment for Tax Credits						(98)
TOTAL FIT EXPENSE	$ 782,991	$ 30,566	$ 813,557	$ 284,745	$ (199,424)	$ 85,223

calculated effective Federal tax rate 30.2%

State Income Taxes - Electric
For the Rate Year Ended December 31, 2011
($000's)

	Commission Adjusted Rate Case					
	STATE TAXABLE INCOME	DEFERRABLE BASIS	BOOK TAXABLE INCOME	@ BLENDED * STATUTORY RATE	DSIT REVERSALS	NET SIT
NET INCOME BEFORE FEDERAL & STATE INCOME TAXES	$ 364,436		$ 364,436	$ 25,875		$ 25,875
ADDITIONS						
REAL ESTATE TAXES PER BOOKS	137,860		137,860	9,788		9,788
BUSINESS MEALS 50% DISALLOWANCE	306		306	22		22
DEDUCTIONS						
GAIN ON REDEMPTION BONDS	0		0	0		0
INTEREST	(81,779)		(81,779)	(5,806)		(5,806)
V-M BOOK GAIN AMORTIZATION	0		0	0		0
OSWEGO 6 TRANS SERVICE CONTRACT EXIT AGREEMENT	0		0	0		0
REAL ESTATE TAXES FOR TAX	(137,860)		(137,860)	(9,788)		(9,788)
TOTAL SIT EXPENSE	$ 282,963	$ -	$ 282,963	$ 20,090	$ -	$ 20,090

7.1%

calculated effective NYS tax rate 7.1%

calculated effective Combined Fed & NYS tax rate 37.3%

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
PSC Case No. 10-E-0500
Rate Base
For the Rate Year Ending December 31, 2011
($000's)

	ALJ RD Rate Year Ending December 31, 2011	Adj.	Commission Adjustments	Rate Year as Adjusted per Commission	Reshaping Adjustment	Rate Year Ending December 31, 2011
Net Utility Plant	$ 4,688,478			$ 4,688,478	$ -	$ 4,688,478
Regulatory Assets / Liabilities	467,666			467,666	752	468,417
Accumulated Deferred Income Taxes - Federal	(944,410)			(944,410)	(572)	(944,982)
Accumulated Deferred Income Taxes - State	(161,386)			(161,386)	-	(161,386)
Total Accumulated Deferred Income Taxes	(1,105,796)			(1,105,796)	(572)	(1,106,368)
Working Capital						
Materials and supplies	27,232			27,232	-	27,232
Prepayments	(67,999)			(67,999)	-	(67,999)
O&M Cash Allowance (1/8 O&M exp)	87,048	a.	2,000	89,048	-	89,048
Supply Cash Allowance	33,582			33,582	-	33,582
Change in Supply Cash Allowance	2,635			2,635	-	2,635
subtotal Working Capital	82,498		2,000	84,498	0	84,498
subtotal avg. before EBCAP adj.	4,132,845		2,000	4,134,845	180	4,135,025
Excess Earnings Base adjustment	(98,727)			(98,727)	-	(98,727)
Total Electric Rate Base	$ 4,034,118		$ 2,000	$ 4,036,118	$ 180	$ 4,036,298

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
PSC Case No. 10-E-0500
Capital Structure
For the Rate Year Ending December 31, 2011
($000's)

Capital Structure, ALJ Recommended Decision Rate Year Ending December 31, 2011	Total NM Annual Avg	Weighting Percent	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long Term Debt	$ 2,400,065	46.68%	4.08%	1.90%	1.90%
Notes Payable	103,814	2.02%	0.41%	0.01%	0.01%
Gas Supplier Refunds	-	0.00%	0.00%	0.00%	0.00%
Customer Deposits	36,794	0.72%	2.45%	0.02%	0.02%
Preferred Stock	29,286	0.57%	3.62%	0.02%	0.03%
Common Equity	2,571,269	50.01%	9.30%	4.65%	7.70%
Total	$ 5,141,228	100.00%		6.60%	9.67%

Capital Structure, Commission Order Rate Year Ending December 31, 2011	Total NM Annual Avg	Weighting Percent	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long Term Debt	$ 2,503,565	48.70%	4.11%	2.00%	2.00%
Notes Payable	103,814	2.02%	0.41%	0.01%	0.01%
Gas Supplier Refunds	0	0.00%	0.00%	0.00%	0.00%
Customer Deposits	36,794	0.72%	2.45%	0.02%	0.02%
Preferred Stock	29,286	0.57%	3.62%	0.02%	0.03%
Common Equity	2,467,769	48.00%	9.10%	4.37%	7.23%
Total	$ 5,141,228	100.00%		6.41%	9.29%

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
PSC Case No. 10-E-0050
Commission Order
For the Rate Year Ending December 31, 2011
($000's)

				Amount
Adj. 1	**Operating Revenues** To reflect the cumulative revenue requirement impact of all Commission adjustments before reshaping CTC stranded cost and net regulatory asset amortizations			1,548
Adj. 2	**Revenue Taxes** To reflect the change in revenues tax associated with the ALJs' Operating Revenue adjustment			27
Adj. 3	**Operating and Maintenance Expenses**			
a	**FAS 106** To reverse the ALJs' decision to update the fringe benefit capitalization rate			1,839
b	**FAS 112** To reverse the ALJs' decision to update the fringe benefit capitalization rate			44
c	**Health Care** To reverse the ALJs' decision to update the fringe benefit capitalization rate			316
d	**Group Life Insurance** To reverse the ALJs' decision to update the fringe benefit capitalization rate			19
e	**Pensions** To reverse the ALJs' decision to update the fringe benefit capitalization rate			754
f	**Thrift Plan** To reverse the ALJs' decision to update the fringe benefit capitalization rate			68
g	**Workers Compensation** To reverse the ALJs' decision to update the fringe benefit capitalization rate			34
h	**Labor** To reverse the ALJs' decision to update the labor capitalization rate			3,004
i	**Transportation Expense** To update fuel forecast for latest known information			703
j	**Austerity** To reflect Staff's recommended level of austerity savings			(2,620)
k	**Synergy Savings** To reverse ALJs' decision on Narragansett synergy savings			3,926
l	**Uncollectible Expense** To reflect the change in uncollectible expenses associated with the Commission's Operating Revenue adjustment			19
m	**Miscellaneous**			
(1)	Adjustment for major storm expenses		4,873	
(2)	To reverse ALJs' decision on union variable pay		(5,047)	
(3)	To reverse ALJs' decision to reflect the portion of the savings associated with EDO Transformation program that are inherent in the KeySpan synergy savings amount.		7,923	
(4)	To update the inflation adjustment		161	
				7,910
	Total Operating & Maintenance Expense Adjustments			16,016

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
PSC Case No. 10-E-0050
Commission Order
For the Rate Year Ending December 31, 2011
($000's)

		Amount	
Adj. 4	Taxes Other Than Revenue & Income Taxes		
a	**Payroll Taxes**		
(1)	Flow through adjustment related to labor capitalization adjustment	221	
(2)	Flow through adjustment related to union variable pay	(188)	
			33
	Total Taxes Other Than Revenue & Income Taxes		33
Adj. 5	Rate Base		
a	**Working Capital**		
	Flow through adjustment related to O&M expense adjustments		2,000
	Total Rate Base Adjustments		2,000

NIAGARA MOHAWK POWER CORPORATION
Income & Revenue Tax Rate Data

FEDERAL INCOME TAX RATE	35.00%
STATE INCOME TAX RATE	7.10%
PROPORTION OF FED INC TAX DEDUCTIBLE	NONE
REVENUE TAX RATE	N/A

Wholesale Customer Rate Group

Municipals

Village of Akron
Village of Andover
Village of Arcade
Municipal Commission of Boonville
Village of Brocton
Village of Churchville
Village of Frankfort
Village of Holley
Village of Ilion
Village of Little Valley
Village of Mohawk
Village of Philadelphia
City of Salamanca
Village of Skaneateles
Village of Springville
Village of Theresa
Village of Wellsville
Village of Westfield
Village of Fairport
New York Municipal Power Agency
Bergen
Lake Placid
Oneida Madison
Tupper Lake
Jamestown
Green Island
Richmondville

Other

Barclays Bank PLC
Black Oak Capital
Black Oak Energy
BP Energy Company
Brookfield Energy Marketing, Inc.

Other (Cont.)

Bruce Power Inc.
Calpine Energy Service
Cargill Alliant, LLC
Centre Lane Trading
Fortis Energy Marketing
Citigroup Energy
City Power Market, LLC
Conectiv Energy Supply
Constellation Energy Commondities Group
Constellation New Energy
Coral Power LLC
Dayton Power and Light
DC Energy LLC
DTE Energy Trading
Dynegy Power Marketing
EDF Trading North America LLC
Epcor
Exelon Generation LLC (formerly PECO)
Capital Power Corporation
FPL Energy Marketing
Gotham Energy marketing
Hess Corporation
HQ Energy Services (US)
Integrys (formerly WPS) Energy Services
J. Aron and Company
KeyTex Energy LLC
Lehman Brothers
Lighthouse Energy Trading
Macquarie Energy LLC
Mirant Energy Trading
Morgan Stanley
NexEra Energy Power Marketing LLC
Northern States Power
North Point Energy
NRG Power Marketing
NYPA
NYSEG (LSE)
Ontario Power Generation

Other (Cont.)

Powerex Corporation
PP&L Energy Plus Co
PPM Energy Inc.
PSEG Energy Resources & Trading, LLC
Iberdrola Renewables, Inc
RBC Energy Services
Rochester Gas and Electric
S.A.C Energy Invest
Saracen Merchant Energy LP
Sempra Energy Trading Corp.
SESCO Enterprises LLC
Sempra Energy Trading LLC
Shell Energy North America (US) L.P.
SIG Energy LLP
Silverhell Ltd.
Sithe
Split Rock Energy, LLC
Strategic Energy, Ltd.
Susquehanna Energy
TransAlta Energy Mar
Twin Cities Power Generation
Vitol Inc.
West Oaks Energy NY NE LP

NIAGARA MOHAWK POWER CORPORATION
Allocation Demand and Capability Data

This statement is not applicable as the allocation of demand and capability data are not provided because they are not used as a basis for allocating related costs or charges in Niagara Mohawk's component RR of Attachment H of the NYISO OATT in this proceeding.

NIAGARA MOHAWK POWER CORPORATION
Reliability Data

This statement is not applicable as it relates to reference standards of the filing utility for electric power supply reliability, and to information designed to reflect monthly availability of generating capacity reserves. Cost support for this transmission tariff filing does not rely on such data.

NIAGARA MOHAWK POWER CORPORATION
Allocation Energy and Supporting Data

This statement is not applicable as it contains information relating to electric utility energy data to be considered as bases for allocating energy related costs to the wholesale services subject to the changed rate. Cost support for this transmission rate does not rely on energy data.

NIAGARA MOHAWK POWER CORPORATION
Specific Assignment Data

This statement is not applicable as it lists specific components of the cost of service that do not rely on (a) demand, capability or energy, (b) a proportional relationship based on select plant or expense categories, or (c) an exclusive use commitment. This filing does not include such components.

NIAGARA MOHAWK POWER CORPORATION
Exclusive-Use Commitments of Major Power Supply Facilities

This statement is not applicable as it describes and justifies the commitment to exclusive-use for particular services of all or a stated portion of electric utility generation units or plants, or major transmission facilities. There is no specific exclusive-use of major transmission facilities under this tariff.

Niagara Mohawk Power Corporation

Summary of Present and Proposed Revenues - CY 2010

Line No.		Billing Units	Proposed Rate	Proposed Revenue	Current Rate	Current Revenue	Change in Revenue	% Change in Revenue
1	January-10	315,825		2,327,060		2,303,752		
2	Februay-10	332,183		2,447,588		2,423,073		
3	March-10	304,165		2,241,151		2,218,703		
4	April-10	282,103		2,078,590		2,057,771		
5	May-10	226,971		1,672,365		1,655,614		
6	June-10	233,464		1,720,213		1,702,983		
7	July-10	238,957		1,760,683		1,743,048		
8	August-10	279,849		2,061,984		2,041,331		
9	September-10	273,056		2,011,935		1,991,783		
10	October-10	247,825		1,826,021		1,807,732		
11	November-10	294,815		2,172,255		2,150,498		
12	December-10	288,041		2,122,341		2,101,084		
13	Total	3,317,253	7.3682	24,442,185	7.2944	24,197,372	244,813	1.01%

Billing Units equals TSC Sales from Statement BJ/BK/BL line 31.

Current Rate from Statement BJ/BK/BL, Period I Line 30. Current Revenue Requirement divided by Total Billing Units

Proposed Rate from Statement BJ/BK/BL, Period II Line 30. Proposed Revenue Requirement divided by Total Billing Units

Niagara Mohawk Power Corporation

Summary of Present and Proposed Revenues - CY 2010

Line No.	Customer Impacts	Billing Units	Proposed Rate	Proposed Revenue CY 2010	Current Rate	Current Revenue CY 2010	Change
1	Municipals						
2	Customer 1	3,003		22,125		21,903	222
3	Customer 2	16		114		113	1
4	Customer 3	439,181		3,235,976		3,203,564	32,412
5	Customer 4	57,501		423,681		419,437	4,244
6	Customer 5	8,779		64,683		64,035	648
7	Customer 6	157,269		1,158,787		1,147,181	11,606
8	Customer 7	83,954		618,588		612,392	6,196
9	Customer 8	16,666		122,799		121,569	1,230
10	Customer 9	24,188		178,221		176,436	1,785
11	Customer 10	464,335		3,421,316		3,387,048	34,268
12	Customer 11	28,820		212,348		210,222	2,127
13	Customer 12	33,256		245,040		242,586	2,454
14	Customer 13	69,987		515,679		510,514	5,165
15	Customer 14	24,243		178,626		176,837	1,789
16	Customer 15	25,114		185,042		183,188	1,853
17	Customer 16	10,642		78,415		77,630	785
18	Customer 17	126,277		930,437		921,118	9,319
19	Customer 18	33,946		250,121		247,616	2,505
20	Customer 19	67,271		495,666		490,701	4,965
21	Customer 20	7,905		58,243		57,660	583
22	Customer 21	66,927		493,132		488,193	4,939
23	Customer 22	82,599		608,609		602,513	6,096
24	Customer 23	8,735		64,361		63,717	645
25	Customer 24	36,601		269,680		266,979	2,701
26	Customer 25	159,762		1,177,161		1,165,371	11,790
27	Customer 26	82,176		605,492		599,428	6,065
28	Total Municipals	2,119,153	7.3682	15,614,344	7.2944	15,457,951	156,394
29							
30	Other						
31	Customer 27	331		2,439		2,414	24
32	Customer 28	7,778		57,310		56,736	574
33	Customer 29	9,500		69,998		69,297	701
34	Customer 30	559		4,119		4,078	41
35	Customer 31	2,932		21,604		21,387	216
36	Customer 32	25		184		182	2
37	Customer 33	425		3,131		3,100	31
38	Customer 34	4,047		29,819		29,520	299
39	Customer 35	3,575		26,341		26,077	264
40	Customer 36	14,047		103,501		102,464	1,037
41	Customer 37	4,274		31,492		31,176	315
42	Customer 38	4,018		29,605		29,309	297

Niagara Mohawk Power Corporation
Summary of Present and Proposed Revenues - CY 2010

Line No.	Customer Impacts	Billing Units		Present Rates Total CY 2010		Proposed Rates Total CY 2010	Change
	Other Continued						
1	Customer 38	48		354		350	4
2	Customer 39	149		1,098		1,087	11
3	Customer 40	3,432		25,288		25,034	253
4	Customer 41	585		4,310		4,267	43
5	Customer 42	17		125		124	1
6	Customer 43	891		6,565		6,499	66
7	Customer 44	142,990		1,053,579		1,043,026	10,553
8	Customer 45	0		0		0	0
9	Customer 46	438		3,227		3,195	32
10	Customer 47	324		2,387		2,363	24
11	Customer 48	13,464		99,205		98,212	994
12	Customer 49	17		125		124	1
13	Customer 50	167		1,230		1,218	12
14	Customer 51	25		184		182	2
15	Customer 52	464		3,419		3,385	34
16	Customer 53	214,099		1,577,524		1,561,724	15,801
17	Customer 54	686,429		5,057,746		5,007,088	50,658
18	Customer 55	284		2,093		2,072	21
19	Customer 56	1,142		8,414		8,330	84
20	Customer 57	77		566		561	6
21	Customer 58	10,074		74,227		73,484	743
22	Customer 59	3,179		23,424		23,189	235
23	Customer 60	4,297		31,661		31,344	317
24	Customer 61	11,656		85,884		85,024	860
25	Customer 62	848		6,248		6,186	63
26	Customer 63	396		2,918		2,889	29
27	Customer 64	2,169		15,982		15,822	160
28	Customer 65	15,156		111,672		110,554	1,119
29	Customer 66	894		6,587		6,521	66
30	Customer 67	1,245		9,173		9,082	92
31	Customer 68	3,539		26,076		25,815	261
32	Customer 69	12,005		88,455		87,569	886
33	Customer 70	526		3,876		3,837	39
34	Customer 71	2,606		19,202		19,009	192
35	Customer 72	7,769		57,244		56,670	573
36	Customer 73	844		6,219		6,156	62
37	Customer 74	2,341		17,249		17,076	173
38	Customer 75	345		2,542		2,517	25
39	Customer 76	545		4,016		3,975	40
40	Customer 77	644		4,745		4,698	48
41	Customer 78	469		3,456		3,421	35
42	Total Other	1,198,100	7.3682	8,827,840	7.2944	8,739,420	88,420
43							
44	Total increase	3,317,253	7.3682	24,442,185		24,197,372	244,813

NIAGARA MOHAWK POWER CORPORATION
Fuel Cost Adjustment Factors

This statement is not applicable as The Company's revenue requirement formula under the NYISO OATT Attachment H does not rely on fuel cost adjustment factors to drive rates for the transmission service included in this filing.

Niagara Mohawk Power Corporation
Network Transmission Revenue Requirement
Summary Page

Line No.	Description	Source	(1) Present Rates CY10	Source	(2)	(3) Effect of change in Depreciation Rates	(4) = (1) + (3) Proposed Rates CY 10
1	Transmission Investment Base:						
2	Transmission Plant In Service	Schedule 2 line 3	1,872,168,717				1,872,168,717
3	General Plant	Schedule 2 line 5	40,274,055				40,274,055
4	Common Plant	Schedule 2 line 7	34,179,455				34,179,455
5	Intangible Plant	Schedule 2 line 9	10,032,845				10,032,845
6	Subtotal Plant	Sum of Lines 2 -5	1,956,655,071				1,956,655,071
7	Accumulated Depreciation Reserve	Schedule 2 line 18	(571,581,816)	Schedule 7 line 5		(3,590,134)	(575,171,950)
8	Accumulated Deferred Taxes	Schedule 3 line 12	(304,830,100)	Schedule 7 line 10		(3,607,215)	(308,437,315)
9	Other Regulatory Assets	Schedule 3 line 21	20,074,963				20,074,963
10	Transmission Prepayments	Schedule 3 line 23	10,226,833				10,226,833
11	Transmission Materials & Supplies	Schedule 3 line 25	8,449,675				8,449,675
12	Transmission Working Capital	Schedule 3 line 27	8,185,584				8,185,584
13	Total Transmission Investment Base	Sum of Lines 6 - 12	1,127,180,209			(7,197,348)	1,119,982,861
14	Cost of Capital Rate	Schedule 4 line 18	11.87%				11.87%
15	Transmission Revenue Requirement						
16	Return and Assoc. Income Taxes	Schedule 4 Line 21	133,829,768	Schedule 4 line 25		(854,539)	132,975,229
17	Transmission Depreciation Expense	Schedule 5 Line 6	34,783,085	Schedule 7 line 5		3,590,134	38,373,219
18	Transmission Real Estate Tax Expense	Schedule 5 Line 8	38,313,586				38,313,586
19	Transmission Amort. Of ITC	Schedule 5 Line 10	(364,943)				(364,943)
20	Transmission Operation and Maintenance Expense	Schedule 5 Line 17	65,484,668				65,484,668
21	Transmission A&G	Schedule 5 Line 32	47,417,836				47,417,836
22	Transmission Payroll Tax Expense	Schedule 5 Line 41	2,374,562				2,374,562
23	Gross Transmission Revenue Requirement		321,838,562			2,735,595	324,574,157
24	less Account 456 Other Electric Revenues	Schedule 6 Line 7	47,222,149				47,222,149
25	less Transmission Rents	Schedule 6 Line 14	1,589,444				1,589,444
26	plus Billing Adjustments	Schedule 6 Line 1	(2,487,006)				(2,487,006)
27	plus Bad debt Expense	Schedule 6 Line 4	(796)				(796)
28	Net Transmission Revenue Requirement		270,539,167			2,735,595	273,274,762
29	Total Billing Units	Exhibit NMP-4 Schedule 12	37,088,552			37,088,552	37,088,552
30	Rate per Billling Unit	Line 28 / Line 29	7.2944			0.0738	7.3682
31	TSC Sales	Schedule 9 Column I Line 1 + Line 16 + Line 17				3,317,253	
32	Increase in Revenue Requirement associated with TSC Sales					244,813	

Net Transmission Revenue Requirement foots to Page 2 of 34 Exhibit No. 4(NMP-4)

Niagara Mohawk Power Corporation

Network Transmission Revenue Requirement

Transmission Investment Base

Line No.	Description	**Source**	(1) Calendar Year 10	(2) Allocation Factor	(3) = (1) * (2) Electric Allocated	(4) Allocation Factor	(5) = (3) * (4) Transmission Allocated
1	Transmission Plant	Statement AD/FF1 207.58g	1,872,079,472				1,872,079,472
2	Wholesale Meter Plant	Exh No. NMP-4 /WP4/Schedule 6	89,245				89,245
3	Total Transmission Plant	Line 1 + Line 2	1,872,168,717				1,872,168,717
4							
5	General Plant	Statement AD/FF1 207.99g	309,800,420	100.00%	309,800,420	13.00%	40,274,055
6							
7	Common Plant	Statement AD/FF1 201.8h	314,872,918	83.50%	262,918,887	13.00%	34,179,455
8							
9	Intangible Plant	Statement AD/FF1 205.5g	77,175,727	100.00%	77,175,727	13.00%	10,032,845
10							
11							
12	Transmission Accumulated Depreciation						
13	Transmission Accum. Depreciation	Statement AE/FF1 219.25b	(526,326,494)				(526,326,494)
14	General Plant Accum. Depreciation	Statement AE/FF1 219.28b	(184,594,804)	100.00%	(184,594,804)	13.00%	(23,997,325)
15	Common Plant Accum. Depreciation	Statement AD/FF1 201.18h	(107,880,579)	83.50%	(90,080,283)	13.00%	(11,710,437)
16	Amortization of Other Utility Plant	Statement AD/FF1 200.21c	(73,292,452)	100.00%	(73,292,452)	13.00%	(9,528,019)
17	Wholesale Meters	Exh No. NMP-4 /WP4/Schedule 6	(19,542)				(19,542)
18	Total Depreciation (Sum Line 13 - Line 17)						(571,581,816)
19							
20	Allocation Factors are Wages and Salaries Allocation Factors which are Fixed per settlement						
21	Column 5 foot to page 8 of 34 Schedule 6 Exhibit No.4(NMP-4)						

Niagara Mohawk Power Corporation
Network Transmission Revenue Requirement
Transmission Investment Base

Line No.	Description	**Source**	(1) Calendar Year 10	(2) Allocation Factor	(3) = (1) * (2) Electric Allocated	(4) Allocation Factor	(5) = (3) * (4) Transmission Allocated
1	Transmission Accumulated Deferred Taxes						
2	Accumulated Deferred Taxes (281-282)	Statement AF/FF1 275.2k	(1,162,666,592)	100.00%	(1,162,666,592)	27.84%	(323,663,598)
3							
4	Accumulated Deferred Taxes (283)	Statement AF/FF1 277.9k	(733,121,426)				
5	less Merger Rate Plan Accumulated Deferred Taxes	Statement AF/FF1 277.3k	(201,952,838)				
6	Subtotal of Deferred Taxes (283)		(531,168,588)	100.00%	(531,168,588)	27.84%	(147,866,927)
7							
8	Accumulated Deferred Taxes (190)	Statement AG/FF1 234.8c	619,765,506	100.00%	619,765,506	27.84%	172,530,573
9							
10	Accumulated Deferred Taxes (255)	Statement AF/FF1 267.8h	(20,943,098)	100.00%	(20,943,098)	27.84%	(5,830,148)
11							
12	Total Deferred Taxes (lines 2,6,8,10)						(304,830,100)
13							
14	Other Regulatory Assets						
15	FAS 109 (Asset Account 182.3)	Statement AG/FF1 232.1f	183,860,430	100.00%	183,860,430	27.84%	51,183,141
16	FAS 109 (Asset Account 182.3)	Statement AG/FF1 232.16f	213,500	100.00%	213,500	27.84%	59,434
17	FAS 109 (Asset Account 182.3)	Statement AG/FF1 232.20f	537,673	100.00%	537,673	27.84%	149,678
18	FAS 109 (Asset Account 182.3)	Statement AG/FF1 232.29f	(63,106,598)	100.00%	(63,106,598)	27.84%	(17,567,640)
19	FAS 109 (Liability Account 254)	Statement AF/FF1 278.1 line 1(f)	(16,727,452)	100.00%	(16,727,452)	27.84%	(4,656,595)
20	FAS 109 (Liability Account 254)	Statement AF/FF1 278.1 line 27(f)	(32,664,135)	100.00%	(32,664,135)	27.84%	(9,093,055)
21	Total (Sum Line 15 thru Line 20)						20,074,963
22							
23	Transmission Prepayments	Statement AL Schedule C					10,226,833
24							
25	Transmission Materials and Supplies	Statement AL Schedule B					8,449,675
26							
27	Cash Working Capital	Statement AL Schedule D					8,185,584
28							
29	Column 5 foot to page 9 of 34 Schedule 7 Exhibit No.4(NMP-4)						

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Cost of Capital Rate

Line No.	Description	Source	Amount	
1	**Weighted Cost of Capital**			
2	LONG-TERM DEBT	Statement AV	2.08%	
3	PREFERRED STOCK	Statement AV	0.02%	
4	COMMON EQUITY	Statement AV	5.75%	
5	**TOTAL INVESTMENT RETURN**		7.85%	**(a)**
6	**Federal Income Tax**			
7	Preferrd Stock + Common Equity	Line 3 + Line 4	5.77%	A
8	Equity AFUDC component of Depreciation Expense	Statement AB/FF1 117.38c	$4,082,548	B
9	Transmission Investment Base	Schedule 1	$1,127,180,209	C
10	Federal Tax Rate	Statement AY	35.00%	D
11	**Federal Tax**	((A+(B/C))*D)/(1-D)	3.30%	**(b)**
12	**State Income Tax**			
13	Preferrd Stock + Common Equity	Line 3 + Line 4	5.77%	E
14	Equity AFUDC component of Depreciation Expense	Statement AB/FF1 117.38c	$4,082,548	F
15	Transmission Investment Base	Schedule 1	$1,127,180,209	G
16	State Tax Rate	Statement AY	7.10%	H
17	**State Tax**	((E+b+(F/G))*H)/(1-H)	0.72%	**(c)**
18	**Cost of Capital Rate**	a + b + c	11.87%	
19	Transmission Investment Base		$1,127,180,209	
20	Cost of Capital Rate		11.87%	
21	Investment Return and Income Taxes		$133,829,768	
22	Transmission Investment Base		$1,119,982,861	
23	Cost of Capital Rate		11.87%	
24	Investment Return and Income Taxes		$132,975,229	
25	Adjustment		($854,539)	
26	Line18 foots to page 10 of 34 Schedule 8 Exhibit No.4(NMP-4)			

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Transmission Expenses
Attachment H Section 9.2

Line No.	Description	Source	(1) Total	(2) Allocation Factor	(3) = (1)*(2) Electric Allocated	(4) Allocation Factor	(5) = (3)*(4) Transmission Allocated
	Depreciation Expense						
1	Transmission Depreciation	Statement AJ / FF1 336.7f	$31,482,012				$31,482,012
2	General Depreciation	Statement AJ/FF1 336.10f	$13,112,567	100.0000%	$13,112,567	13.0000%	$1,704,634
3	Common Depreciation	Statement AJ/FF1 356.1	$13,090,378	83.5000%	$10,930,466	13.0000%	$1,420,961
4	Intangible Depreciation	Statement AJ/FF1 336.1f	$1,330,750	100.0000%	$1,330,750	13.0000%	$172,998
5	Wholesale Meters	EXH No. NMP-4 /Schedule 9					$2,481
6	Total (Line 1+2+3+4+5)						$34,783,085
7							
8	Real Estate Taxes	Statement AK/FF1 263.25i	$137,630,327	100.0000%	$137,630,327	27.8380%	$38,313,586
9							
10	Amortization of Investment Tax Credits	Statement AB/FF1 117.58c	$1,663,964	78.7848%	$1,310,951	27.8380%	$364,943
11							
12	Transmission Operation and Maintenance						
13	Operation and Maintenance	Statement AH/FF1 321.112b	$93,594,038				$93,594,038
14	less Load Dispatching - #561	Statement AH/FF1 321.84-92b	$12,349,796				$12,349,796
15	less Regional Delivery Venture adjustments		$10,942,773				$10,942,773
16	less Write off of Tonawanda Project		$4,816,801				$4,816,801
17	O&M (Line 14-15-16)		$65,484,668				$65,484,668
18							
19	Transmission Administrative and General						
20	Total Administrative and General	Statement AH/FF1 323.197b	$375,117,556				
21	less Property Insurance (#924)	Statement AH/FF1 323.185b	$64,126				
22	less Pensions and Benefits (#926)	Statement AH/FF1 323.187b	$92,041,066				
23	less: Research and Development Expenses (#930)	EXH No. NMP-4 /Schedule 9	$2,474,429				
24	Less: 50% of NY PSC Regulatory Expense	EXH No. NMP-4 /Schedule 9	$4,074,213				
25	Less: 18a Charges (Temporary Assessment)	EXH No. NMP-4 /Schedule 9	$80,854,971				
26	less: Environmental Remediation Expense	EXH No. NMP-4 /Schedule 9	$13,055,876				
27	Subtotal (Line 26-27-28-29-30-31-32)		$182,552,875	100.0000%	$182,552,875	13.0000%	$23,731,874
28	PLUS Property Insurance alloc. using Plant Allocatior	Line 20	$64,126	100.0000%	$64,126	27.8380%	$17,851
29	PLUS Pensions and Benefits	EXH No. NMP-4 /Schedule 9	$179,778,267	100.0000%	$179,778,267	13.0000%	$23,371,175
30	PLUS Transmission-related research and development	EXH No. NMP-4 /Schedule 9	$296,936				$296,936
31	PLUS Transmission-related Enviromental Expense	EXH No. NMP-4 /Schedule 9	$0				$0
32	Total A&G (Line 26+27+28+29-24)		$281,837,232		$362,395,268		$47,417,836
33							
34	Payroll Tax Expense						
35	Federal Unemployment	Statement AK/FF1 263.4i	$233,681				
36							
37	FICA	Statement AK/FF1 263.3i	$27,320,595				
38	less Gas FICA incorrectly included in line 34		$9,818,084				
39	Subtotal FICA		$17,502,511				
40	State Unemployment	Statement AK/FF1 263.17i	$529,672				
41	Total (Line 34+38+39)		$18,265,864	100.0000%	$18,265,864	13.0000%	$2,374,562
42							
43	Per November 18, 2010 Supplemental Information Filing, National Grid has agreed to exclude the costs of section 18-a Temporary Assessmet under NY PSC in any future update.						

Column 5 foot to page 11 of 34 Schedule 9 Exhibit No.4(NMP-4)

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Billing Adjustments, Revenue Credits, Rental Income

Line No.	Description	Source	(1) Total
1	Billing Adjustments *	EXH No. NMP-4 /Schedule 10 line 1	(2,487,006)
2			
3			
4	Bad Debt Expense	EXH No. NMP-4 /Schedule 10 line 4	(796)
5			
6			
7	Revenue Credits	Statement AU	47,222,149
8			
9			
10			
11			
12			
13			
14	Transmission Rents	EXH No. NMP-4 /Schedule 10 line 14	(1,589,444)
15			

Niagara Mohawk Power Corporation

Calculation of Change in Depreciation Expense, Accumulated Depreciation Reserve and Accumulated Deferred Taxes

Line No.	Description	Source		(1) Change in CY10 Depreciation Expense Using Proposed Rates	(2) Allocation Factor	(3) = (1) * (2) Electric Allocated	(4) Allocation Factor	(5) = (3) * (4) Transmission Allocated
1	**Depreciation calculation**							
2	Change in Transmission Plant Depreciation Expense	Schedule 8 line 21		3,464,649				3,464,649
3	Change in General Plant Depreciation Expense	Schedule 8 line 75		(145,933)	100.00%	(145,933)	13.00%	(18,971)
4	Change in Common Depreciation Expense	Schedule 8 line 104		1,330,776	83.50%	1,111,198	13.00%	144,456
5	Total Change to Depreciation Expense and Accumulated Depreciation (line 2+3+4)							3,590,134
6								
7	**Accumulated Deferred Tax calculation**							
8	Total Change in Electric Depreciation Expense	Schedule 8 line 106	(a)	(30,778,766)				
9	Tax rate	Statement AY	(b)	42.10%				
10	Total Change to Deferred Taxes (line 8+9)		=(a)*(b)	(12,957,861)	100.00%	(12,957,861)	27.84%	(3,607,215)
11	Allocation Factors are Wages and Salaries Allocation Factors which is Fixed per settlement							

Niagara Mohawk Power Corporation

Calculation of Change in Accumulated Depreciation Reserve, Accumulated Deferred Taxes, & Depreciation Expense

Line No.	Description	Source	(1)	(2) Allocation	(3) = (1) * (2) Electric	(4) Allocation	(5) = (3) * (4) Transmission
12	Transmission Accumulated Depreciation						
13	Transmission Accum. Depreciation	Schedule 2 Line 13	(526,326,494)				
14	Less change in Transmissio Depreciation due to rate change	Schedule 8 line 21	3,464,649				
15	Transmission Accum. Depreciation using Proposed Rates	Line 13 - Line 14	(529,791,143)				(529,791,143)
16	General Plant Accum. Depreciation	Schedule 2 Line 14	(184,594,804)				
17	Less change General Plant Depreciation due to rate change	Schedule 8 line 75	(145,933)				
18	General Plant Accum. Depreciation using Proposed Rates	Line 16 - Line 17	(184,448,871)	100.00%	(184,448,871)	13.00%	(23,978,353)
19	Common Plant Accum. Depreciation	Schedule 2 Line 15	(107,880,579)				
20	Less change in Common Plant Depreciatio due to change in rate	Schedule 8 line 104	1,330,776				
21	Common Plant Accum. Depreciation with Proposed Rates	Line 19 - Line 20	(109,211,355)	83.50%	(91,191,482)	13.00%	(11,854,893)
22	Amortization of Other Utility Plant	Schedule 2 Line 16	(73,292,452)	100.00%	(73,292,452)	13.00%	(9,528,019)
23	Wholesale Meters	Schedule 2 Line 15	(19,542)				(19,542)
24	Total Depreciation	Lines 15,18,21,22,23					(575,171,950)
25							
26	Allocation Factors are Wages and Salaries Allocation Factors which is Fixed per settlement						

Line	Description	Reference	(1)	(2)	(3) = (1) * (2)	(4)	(5) = (3) * (4)
27			(1)	(2)	(3) = (1) * (2)	(4)	(5) = (3) * (4)
28				Allocation	Electric	Plant Allocation	Transmission
29	Transmission Accumulated Deferred Taxes			Factor	Allocated	Factor	Allocated
30	Accumulated Deferred Taxes (281-282)	Schedule 3 Line 2	(1,162,666,592)				
31	Plus Change to Deferred taxes due to reduction in Book Depreciation Expense	Line 11	(12,957,861)				
32	Accumulated Deferred Taxes (281-282) with estimated changes to Depreciation Expense	Line 30 + Line 31	(1,175,624,453)	100.00%	(1,175,624,453)	27.84%	(327,270,813)
33							
34	Accumulated Deferred Taxes (283)	Schedule 3 Line 4	(733,121,426)				
35	less Merger Rate Plan Accumulated Deferred Taxes	Schedule 3 Line 5	(201,952,838)				
36	Subtotal of Deferred Taxes (283)	Schedule 3 Line 6	(531,168,588)	100.00%	(531,168,588)	27.84%	(147,866,927)
37							
38	Accumulated Deferred Taxes (190)	Schedule 3 Line 8	619,765,506	100.00%	619,765,506	27.84%	172,530,573
39							
40	Accumulated Deferred Taxes (255)	Schedule 3 Line 10	(20,943,098)	100.00%	(20,943,098)	27.84%	(5,830,148)
41							
42	Total Deferred Taxes	Lines 32,36,38,40					(308,437,315)
43							
44	Plant Allocation factor is calculated on page 6 of 34 Schedule 5 Exhibit No.4(NMP-4)						
45				(2)	(3) = (1)*(2)	(4)	(5) = (3)*(4)
46			(1)	Allocation	Electric	Allocation	Transmission
47	Depreciation Expense		Total	Factor	Allocated	Factor	Allocated
48	Transmission Depreciation	Schedule 5 Line 1	31,482,012				
49	Change in Transmission Plant Depreciation Expense	Line 2	3,464,649				
50	Transmission Depreciation Expense with Proposed Rate Change	Line 47 + Line 48	34,946,661				34,946,661
51	General Depreciation	Schedule 5 Line 2	13,112,567				
52	Change in General Plant Depreciation Expense	Line 3	(145,933)				
53	General Depreciation With Proposed Rate Change	Line 51 + Line 52	12,966,634	100.0000%	$12,966,634	13.0000%	$1,685,662
54	Common Depreciation	Schedule 5 Line 3	13,090,378				
55	Change in Common Depreciation Expense	Line 4	1,330,776				
56	Common Depeciation with Proposed Rate Change	Line 55 + Line 56	14,421,154	83.5000%	$12,041,664	13.0000%	$1,565,416
57	Intangible Depreciation	Schedule 5 Line 4	1,330,750	100.0000%	$1,330,750	13.0000%	$172,998
58	Wholesale Meters	Schedule 5 Line 5					2,481
59	Total (Line 50+53+56+57+58)						38,373,219

Niagara Mohawk Power Corporation
Depreciation Provision

Line No	Account Description	provision	Rate in 2010	Rate in 2011	Provision at New Rate	Change
1	30200 FRANCHISES AND CONSENTS	138,992				
2	30200 FRANCHISES AND CONSENTS	15,670				
3	30200 FRANCHISES AND CONSENTS	399,970				
4	40200 GAS FRANCHISES & CONSENTS	23,322				
5		577,954				
6						
7	35040 LAND RIGHTS-TRANSMISSION LINE	360,777	1.33%	1.32%	358,064	-2,713
8	35200 STRUCT&IMPROVE - TRANSMISSION	577,399	1.92%	2.08%	625,516	48,117
9	35300 TRANSMISSION STATION EQUIPMNT	96,319	0.00%	0.00%		-96,319
10	35300 TRANSMISSION STATION EQUIPMNT	6,834	0.00%	0.00%		-6,834
11	35300 TRANSMISSION STATION EQUIPMNT	12,072,072	1.90%	2.44%	15,503,081	3,431,010
12	35310 STA EQUIP POLL CONTL FAC	42,348	1.90%	2.44%	54,384	12,036
13	35355 STATION EQUIPMENT -EMS RTU	2,305,417	5.00%	3.40%	1,567,684	-737,733
	35400 TOWERS AND FIXTURES - TRANS	1,805,984	1.47%	1.71%	2,100,838	294,855
14	35500 POLES AND FIXTURES - TRANS	7,826,248	1.91%	2.00%	8,195,024	368,776
15	35610 COND AND DEVICES ON STEEL TOW	1,580,560	1.40%	1.60%	1,806,354	225,794
16	35620 CONDUCTOR AND DEVICES ON WOOD	2,645,594	1.58%	1.60%	2,679,083	33,489
17	35710 UG TRANS MANHOLES & HANDHOLES	150,228	2.02%	1.33%	98,912	-51,315
18	35720 UG TRANSMISSION CONDUIT	447,642	2.02%	1.33%	294,734	-152,907
19	35800 UG TRANS CONDUCTORS & DEVICES	1,530,589	1.40%	1.49%	1,628,984	98,395
20	35900 ROADS AND TRAILS	31,109	1.33%	1.33%	31,109	0
21		31,479,119			34,943,768	3,464,649
22						
23	36015 LAND RIGHTS & OTH COSTS DIST	28,341	1.82%	1.33%	20,711	-7,630
24	36025 LAND RIGHTS-UNDR DISTRIB LINE	302,021	1.82%	1.33%	220,707	-81,313
25	36100 STRUCT & IMPROVEMENTS DISTRIB	831,482	2.31%	1.67%	601,115	-230,367
26	36200 STATION EQUIPMENT	9,491,108	2.12%	1.83%	8,192,796	-1,298,312
27	36210 STATION EQUIP-POLLUTION CONTR	36,018	2.12%	1.83%	31,091	-4,927
28	36255 STATION EQUIPMENT - EMS RTU	1,504,561	5.00%	3.30%	993,010	-511,551
29	36400 POLES,TOWERS AND FIXTURES	25,388,715	2.97%	1.62%	13,848,390	-11,540,325
30	36500 OVERHEAD CONDUCTORS AND DEVIC	34,850,731	3.71%	2.50%	23,484,320	-11,366,411
31	36610 UNDERGROUND MANHOLES AND HAND	1,272,138	1.71%	1.47%	1,093,593	-178,546
32	36620 UNDERGROUND CONDUIT	1,111,522	1.71%	1.47%	955,519	-156,003
33	36710 UNDERGROUND CONDUCTORS AND DE	7,960,559	1.80%	1.53%	6,766,475	-1,194,084
34	36810 TRANSFORMER STATIONS	1,078,873	3.19%	2.67%	903,006	-175,866
35	36820 LINE TRANSFORMERS - BARE COST	14,203,014	3.19%	2.67%	11,887,789	-2,315,225
36	36830 LINE TRANSFORMERS - INSTALL C	8,025,473	3.19%	2.67%	6,717,246	-1,308,228
37	36910 OVERHEAD SERVICES	11,753,180	4.00%	2.60%	7,639,567	-4,113,613
38	36920 UNDERGROUND SERVICES-CONDUIT	213,956	2.20%	1.35%	131,291	-82,665
39	36921 UNDERGROUND SERVICES-CABLE	2,134,265	1.90%	1.40%	1,572,616	-561,649
40	37010 METERS - BARE COST (DOMESTIC)	1,613,750	3.13%	6.25%	3,222,344	1,608,594
41	37020 METERS - INSTALL COST (DOMEST	790,567	2.78%	6.25%	1,777,354	986,787
42	37030 LRG METER INSTALL- BARE COST	218,686	2.78%	5.05%	397,254	178,568
43	37035 LRG METER - INSTALLATION COST	793,746	2.78%	5.05%	1,441,876	648,131
44	37100 INSTALLATION ON CUSTOMERS' PR	600,572	7.33%	3.50%	286,767	-313,805
45	37310 OH STEETLIGHTING	2,795,799	3.80%	2.60%	1,912,915	-882,884
46	37320 UG STREETLIGHTING	4,949,667	3.80%	1.86%	2,422,732	-2,526,935
47		131,948,746			96,520,486	-35,428,259

Line No	Account Description	provision	Rate in 2010	Rate in 2011	Provision at New Rate	Change
49	39000 STRUCT AND IMPROV ELEC GENL	115,147	0.00%	0.00%	115,147	0
50						
51	39000 STRUCT AND IMPROV ELEC GENL	1,638,603	1.91%	2.00%	1,715,815	77,212
52	39100 OFFICE FURN &FIXT-ELEC GENRL	113,926	2.38%	4.55%	217,800	103,874
53	39110 OTHER OFFICE EQUIPMENT	93,622	3.33%	4.55%	127,923	34,300
54	39120 OFFICE DATA PROCESSING EQUIP	360,900	20.00%	20.00%	360,900	0
55	39200 PASSENGER CARS - TRANSP EQUIP	8,530	0.00%	0.00%		-8,530
56	39300 STORES EQUIPMENT	53,581	2.50%	4.55%	97,518	43,937
57	39400 SHOP EQUIPMENT	74,111	2.38%	4.55%	141,684	67,572
58	39410 GARAGE& REPR SHOP EQP-TRANSP	205,327	3.33%	4.55%	280,552	75,225
59	39420 TOOLS AND WORK SHOP EQUIP	1,178,408	2.94%	4.55%	1,823,727	645,319
60	39500 OTHER LABORATORY EQUIPMENT	548,922	2.50%	4.55%	999,038	450,116
61	39510 CONSERVATION LAB EQUIPMENT	1,106	2.50%	4.55%	2,013	907
62	39600 PWR OP EQUIP-TOOLS & WRK EQP	11,725	7.14%	7.14%	11,725	0
63	39720 Com Equip Radio Genl Amort NY	2,513,862	5.00%	4.55%	2,287,615	-226,248
64	39730 Commun Radio Site Specific NY	203,403	5.00%	4.55%	185,097	-18,306
65	39740 Comm Equip Telephone Site NY	82,835	12.50%	12.50%	82,835	0
66	39740 Comm Equip Telephone Site NY	347,434	12.50%	12.50%	347,434	0
67	39750 Comm Equip Network Amort NY	445,690	6.67%	4.55%	304,031	-141,659
68	39760 Comm Equip Network Site NY	10,600	6.67%	4.55%	7,231	-3,369
69	39760 Comm Equip Network Site NY	740,641	6.67%	4.55%	505,235	-235,406
70	39800 MISC EQUIP PWR & SUP CONTRL	431,362	5.00%	4.55%	392,539	-38,823
71	39810 MISC EQUIP - OTHER	28,400	5.00%	4.55%	25,844	-2,556
72	39855 GENERAL - RTU	24,707	2.86%	4.55%	39,306	14,600
73	39856 EMS CONTRL SYSTM-ENERGY MGMNT	2,622,213	5.00%	4.55%	2,386,214	-235,999
74	39856 EMS CONTRL SYSTM-ENERGY MGMNT	1,372,656	10.00%	4.55%	624,559	-748,098
75		13,112,567			12,966,634	-145,933
76						
77	59000 COMMON STRUCTR & IMPROVEMENTS	18,581	1.82%	2.63%	26,851	8,270
78	59000 COMMON STRUCTR & IMPROVEMENTS	19,700	1.82%	2.63%	28,468	8,768
79	59000 COMMON STRUCTR & IMPROVEMENTS	20,684	1.82%	2.63%	29,890	9,206
80	59000 COMMON STRUCTR & IMPROVEMENTS	26,150	1.82%	2.63%	37,788	11,638
81	59000 COMMON STRUCTR & IMPROVEMENTS	191	1.82%	2.63%	276	85
82	59000 COMMON STRUCTR & IMPROVEMENTS	130,215	1.82%	2.63%	188,168	57,953
83	59000 COMMON STRUCTR & IMPROVEMENTS	926	1.91%	2.63%	1,276	349
84	59000 COMMON STRUCTR & IMPROVEMENTS	262,462	1.91%	2.63%	361,401	98,939
85	59000 COMMON STRUCTR & IMPROVEMENTS	3,071,763	1.91%	2.63%	4,229,705	1,157,942
86	59100 COMMON OFFICE FURN & FIXTURES	542,230	2.38%	4.55%	1,036,616	494,386
87	59110 COMMON OTHER OFFICE EQUIPMENT	334,221	3.33%	4.55%	456,668	122,447

Line No	Account Description	provision	Rate in 2010	Rate in 2011	Provision at New Rate	Change
88	59120 COMMON DATA PROCESSING EQUIP	2,602,377	20.00%	20.00%	2,602,377	0
89	59220 COMMON TRANSPRT-AIRLINE EQUIP	490,836	10.00%	7.50%	368,127	-122,709
90	59300 COMMON STORES EQUIPMENT	129,878	2.50%	4.55%	236,378	106,500
91	59400 COMMON SHOP EQUIPMENT	11,590	2.38%	4.55%	22,157	10,567
92	59410 COMMON GARAGE/REPAIR EQUIP	162,240	2.38%	4.55%	310,165	147,925
93	59420 COMMON NATL GAS REFUEL STATN	9,697	2.38%	4.55%	18,539	8,842
94	59430 COMMON TOOLS&WORK EQUIP-OTHR	76,833	2.94%	4.55%	118,909	42,075
95	59500 COMMON LABORATORY EQUIPMENT	2,704	2.50%	4.55%	4,921	2,217
96	59720 Common Radio Equip Amort NY	692,452	5.00%	4.55%	630,131	-62,321
97	59730 Common Radio Site Specific NY	476,653	5.00%	4.55%	433,754	-42,899
98	59735 Common Telephone Amort NY	127,847	12.50%	12.50%	127,847	0
99	59740 Common Telephone Site NY	1,528,119	12.50%	12.50%	1,528,119	0
100	59750 Common Network Equip Amort NY	1,014,294	6.67%	4.55%	691,909	-322,384
101	59760 Common Network Equip Site NY	1,310,491	6.67%	4.55%	893,963	-416,528
102	59800 COMMON MISCELLANEOUS EQUIP	9,678	5.00%	4.55%	8,807	-871
103	59810 COMMON MISC EQUIP - OTHER	17,565	2.86%	4.55%	27,945	10,379
104		13,090,378			14,421,154	1,330,776.27
105						
106	Total Change to Electric Depreciation					(30,778,766.41)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [X] A Resubmission	09/16/2011	End of 2010/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
NYISO OATT	Various	NYPA NYS Municipal		686,429	686,429	1
136	Various	Niagara Frontier TA	1			2
18	Various	NYPA NYS Municipal	2			3
180	Various	CVJ		57,588	57,588	4
141	Nine Mile 2 Station	Central Hudson Gas	103			5
55	North Catskill	North Catskill				6
142	Fitzpatrick	Consolidated Edison	160			7
142	Nine Mile 2 Station	Consolidated Edison	206			8
165	Various	Various				9
174	Watertown Hydro	Watertown Municipal		10,348	10,348	10
171	Selkirk Station	Consolidated Edison	270			11
178	Sithe Station	Consolidated Edison	853			12
175	Indeck Station	Consolidated Edison	129			13
Various	Various	Various	6			14
178	Various	Various				15
NYISO OATT	Various	Various		511,671	511,671	16
NYISO OATT	N/A	Various		2,119,153	2,119,153	17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			1,730	3,385,189	3,385,189	

NIAGARA MOHAWK POWER CORPORATION
Construction Program Statement

This statement is not applicable as it contains a summary of data and supporting assumptions relating to the economics of any construction program to replace or expand the utility's power supply that shall be filed if the utility is filing for construction work in progress in rate base. Cost support for this filing does not rely on such data.

2011 UPDATE
2010 Data

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Attachment 1 to Attachment H

Schedules

Niagara Mohawk Power Corporation **Attachment 1**
Calculation of RR Pursuant to Attachment H, Section 9.2 **Schedule 1**

Shading denotes an input **2010**

Calculation of RR

9.2 The RR component shall equal the (a) Historical Transmission Revenue Requirement plus (b) the Forecasted Transmission Revenue Requirement plus (c) the Annual True-Up, determined in accordance with the formula below.

Historical Transmission Revenue Requirement (Historical TRR)

Line No.			Reference Section:	2010	
1		**Historical Transmission Revenue Requirement (Historical TRR)**			
2					
3	9.2 (a)	Historical TRR shall equal the sum of NMPC's (A) Return and Associated Income Taxes, (B) Transmission Related Depreciation			
4		Expense, (C) Transmission Related Real Estate Tax Expense, (D) Transmission Related Amortization of Investment Tax Credits,			
5		(E) Transmission Operation and Maintenance Expense, (F) Transmission Related Administrative and General Expenses,			
6		(G) Transmission Related Payroll Tax Expense, (H) Billing Adjustments, and (I) Transmission Related Bad Debt Expense less (J) Revenue			
7		Credits, and (K) Transmission Rents, all determined for the most recently ended calendar year as of the beginning of the update year.			
8					
9					
10		Return and Associated Income Taxes	(A)	$133,829,768	Schedule 8, line 64
11		Transmission-Related Depreciation Expense	(B)	$34,783,085	Schedule 9, Line 6, column 5
12		Transmission-Related Real Estate Taxes	(C)	$38,313,586	Schedule 9, Line 12, column 5
13		Transmission - Related Investment Tax Credit	(D)	($364,943)	Schedule 9, Line 16, column 5
14		Transmission Operation & Maintenance Expense	(E)	$65,484,668	Schedule 9, Line 23, column 5
15		Transmission Related Administrative & General Expense	(F)	$47,417,836	Schedule 9, Line 37, column 5
16		Transmission Related Payroll Tax Expense	(G)	$2,374,562	Schedule 9, Line 43, column 5
17		Sub-Total (sum of Lines 10 - Line 16)		$321,838,562	
18					
19		Plus: Billing Adjustments	(H)	($2,487,006)	Schedule 10, Line 1
20		Plus : Bad Debt Expenses	(I)	($796)	Schedule 10, Line 4
21		Less: Revenue Credits	(J)	($47,222,149)	Schedule 10, Line 7
22		Less: Transmission Rents	(K)	($1,589,444)	Schedule 10, Line 14
23					
24		Total Historical Transmission Revenue Requirement (Sum of Line 17 - Line 22)		$270,539,167	

Niagara Mohawk Power Corporation | **Attachment 1**
Forecasted Transmission Revenue Requirement | **Schedule 2**
Attachment H, Section 9.2

Shading denotes an input | **2010**

Line No.			Period	Reference		Source
1	9.2 (b)	**FORECASTED TRANSMISSION REVENUE REQUIREMENTS**				
2		Forecasted TRR shall equal (1) the Forecasted Transmission Plant Additions (FTPA) multiplied by the Annual FTRRF, plus (2) the Mid-Year Trend				
3		Adjustment (MYTA), plus (3) the Tax Rate Adjustment (TRA), as shown in the following formula:				
4						
5		Forecasted TRR = (FTPA * FTRRF) + MYTA + TRA				
6						
7						
8						
9						
10	(1)	Forecasted Transmission Plant Additions (FTPA)	2010		$94,116,015	Workpaper 8, Section I, Line 16
11		Annual Transmission Revenue Requirement Factor (FTRRF)			11.05%	Line 35
12		Sub-Total (Lines 10*11)			$10,402,423	
13		Plus Mid-Year Trend Adjustment (2) (MYTA)			-$2,155,786	Workpaper 9, line 31, variance column
14		Forecasted Transmission Revenue Requirement (Line 12 + Line 13)			**$8,246,637**	
15						
16	(2)	**MID YEAR TREND ADJUSTMENT (MYTA)**				
17		The Mid-Year Trend Adjustment shall be the difference, whether positive or negative, between				
18		(i) the Historical TRR Component (E) based on actual data for the first three months of the Forecast Period,				
19		and (ii) the Historical TRR Component (E) based on data for the first three months of the year prior to the Forecast Period.				Workpaper 9
20						
21	(3)	**The Tax Rate Adjustment (TRA)**				
22		The Tax Rate Adjustment shall be the amount, if any, required to adjust Historical TRR Component (A) for any change in the Federal Income Tax Rate				
23		and/or the State Income Tax Rate that takes effect during the first five months of the Forecast Period.				
24						
25	9.2 (c)	**ANNUAL TRANSMISSION REVENUE REQUIREMENT FACTOR**				
26		The Annual Forecast Transmission Revenue Requirement Factor (Annual FTRRF) shall equal the sum of Historical TRR components (A) through (C),				
27		divided by the year-end balance of Transmission Plant in Service determined in accordance with Section 9.2 (a), component (A)1(a).				
28						
29						
30		Investment Return and Income Taxes		(A)	$133,829,768	Schedule 1, Line 10
31		Depreciation Expense		(B)	$34,783,085	Schedule 1, Line 11
32		Property Tax Expense		(C)	$38,313,586	Schedule 1, Line 12
33		Total Expenses (Lines 30 thru 32)			$206,926,439	
34		Transmission Plant		(a)	$1,872,168,717	Schedule 6, Page 1, Line 12
35		Annual Transmission Revenue Requirement Factor (Lines 33/ Line 34)			11.05%	

Niagara Mohawk Power Corporation | **Attachment 1**
Annual True-up (ATU) | **Schedule 3**
Attachment H Section 9.2 (c)

Shading denotes an input | **2010**

Line No.				Source:
1				
2	9.2(d)	The Annual True-Up (ATU) shall equal (1) the difference between the Actual Transmission Revenue Requirement and the Prior Year		
3		Transmission Revenue Requirement, plus (2) the difference between the Actual Scheduling, System Control and Dispatch costs		
4		and Prior Year Scheduling, System Control and Dispatch costs, less (3) the difference between the Actual Billing Units and the Prior Year		
5		Billing Units multiplied by the Prior Year Unit Rate, plus (4) Interest on the net differences.		
6				
7	(1)	Revenue Requirement (RR) of rate effective July 1 of prior year	$252,031,733	Schedule 4, Line 1, Col (d)
8		Less: Annual True-up (ATU) from rate effective July 1 of prior year	($8,048,949)	Schedule 4, Line 1, Col (c)
9		Prior Year Transmission Revenue Requirement	$260,080,682	Line 7 - Line 8
10				
11		Actual Transmission Revenue Requirement	$270,539,167	Schedule 4, Line 2, Col (a)
12		Difference	$10,458,485	Line 11 - Line 9
13				
14	(2)	Prior Year Scheduling, System Control and Dispatch costs (CCC)	$6,345,322	Schedule 4, Line 1, Col (e)
15		Actual Scheduling, System Control and Dispatch costs (CCC)	$6,748,771	Schedule 4, Line 2, Col (e)
16		Difference	$403,449	Line 15 - Line 14
17				
18	(3)	Prior Year Billing Units (MWH)	35,134,660	Schedule 4, Line 1, Col (f)
19		Actual Billing Units	37,088,552	Schedule 4, Line 2, Col (f)
20		Difference	(1,953,892)	Line 18 - Line 19
21		Prior Year Indicative Rate	7.35	Schedule 4, Line 1, Col (g)
22		Billing Unit True-Up	($14,368,745)	Line 20 * Line 21
23				
24		Total Annual True-Up before Interest	($3,506,812)	(Line 12 + Line 16 + Line 22)
25				
26		Total Annual True-Up before Interest	($3,506,812)	(Line 24 + Line 25)
27				
28	(4)	Interest	$ (18,995)	Line 59
29				
30		Annual True-up RR Component	($3,525,807)	(Line 24 + Line 26)
31				

Line No.	32 Interest Calculation per 18 CFR Section 35.19a								
33	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
34	Quarters	Annual	Accrued Prin	Monthly	Days			Accrued Prin	Accrued
35		Interest	& Int. @ Beg	(Over)/Under	in	Period		& Int. @ End	Int. @ End
36		Rate	Of Period	Recovery	Period	Days	Multiplier	Of Period	Of Period
37		Updated							
38	3rd QTR '10		0		92	92	1.0000	$0	$0
39	July	3.25%		(292,234)	31	92	1.0082	($294,631)	($2,396)
40	August	3.25%		(292,234)	31	61	1.0054	($293,812)	($1,578)
41	September	3.25%		(292,234)	30	30	1.0027	($293,023)	($789)
42									
43	4th QTR '10		(881,466)		92	92	1.0000	($881,466)	$0
44	October	3.25%		(292,234)	31	92	1.0082	($294,631)	($2,396)
45	November	3.25%		(292,234)	30	61	1.0054	($293,812)	($1,578)
46	December	3.25%		(292,234)	31	31	1.0028	($293,053)	($818)
47									
48	1st QTR '11		(1,762,962)		90	90	1.0000	($1,762,962)	$0
49	January	3.25%		(292,234)	31	90	1.0080	($294,572)	($2,338)
50	February	3.25%		(292,234)	28	59	1.0053	($293,783)	($1,549)
51	March	3.25%		(292,234)	31	31	1.0028	($293,053)	($818)
52									
53	2nd QTR '11		(2,644,370)		91	91	1.0000	($2,644,370)	$0
54	April	3.25%		(292,234)	30	91	1.0081	($294,601)	($2,367)
55	May	3.25%		(292,234)	31	61	1.0054	($293,812)	($1,578)
56	June	3.25%		(292,234)	30	30	1.0027	($293,023)	($789)
57									
58									
59	Total (over)/under Recovery			($3,506,812)	(line 26)				($18,995)

Niagara Mohawk Power Corporation Wholesale TSC Calculation Information
2011 Forecast using 2010 Historical Data and 2011 Forecast

Attachment 1
Schedule 4

Shading denotes an input

		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	**Description**	**Historical Transmission Revenue Requirement (Historical TRR)**	**Forecasted Transmission Revenue Requirement**	**Annual True Up**	**Revenue Requirement (RR)**	**Scheduling System Control and Dispatch Costs (CCC)**	**Annual Billing Units (BU) MWh**	**Rate $/MWh (*)**
1	Current Year Rates Effective July 1, 2010	250,606,591	9,474,091	($8,048,949)	252,031,733	6,345,322	35,134,660	7.35
2	Current Year Rates Effective July 1, 2011	270,539,167	8,246,637	($3,525,807)	275,259,997	6,748,771	37,088,552	7.60
3	Increase/(Decrease)				23,228,264	403,449	1,953,892	0.25
4	Percentage Increase/(Decrease)							3%

1.) Information directly from Niagara Mohawk Prior Year Informational Filing adjusted per the Nov 30, 2009 Filing to reflect changes in the debt rate calculation.
2.)
(a) Schedule 1, Line 24
(b) Schedule 2, Line 14
(c) Schedule 3, Line 30
(d) Attachment H, Section 9.2 The RR Component shall equal Col (a) Historical Transmission Revenue Requirement plus Col (b) the Forecasted Transmission Revenue Requirement plus Col (c) the Annual True-Up
(e) Schedule 11 - Annual Scheduling, System Control and Dispatch Costs. (i.e. the Transmission Component of control center costs) as recorded in FERC Account 561 and its associated sub-accounts from the prior calendar year excluding any NY Independent System Operating (NYISO) system control and load dispatch expenses already recovered under Schedule 1 of the NYISO Tariff.
(f) Schedule 12 - Billing Units shall be the total Niagara Mohawk load as reported to the NYISO for the calendar year prior to the Forecast Period, including the load for customers taking service under Niagara Mohawk's TSC rate. The total Niagara Mohawk load will be adjusted to exclude (i) load associated with wholesale transactions being revenue credited through the WR, CRR, SR, ECR, and Reserved components of Attachment H of the NYISO TSC rate including Niagara Mohawk's external sales, load associated with grandfathered OATT agreements, and any load related to pre-OATT grandfathered agreements; (ii) load associated with transactions being revenue credited under Historical TRR Component J; and (iii) load associated with netted station service.
(g) (Col (d) + Col (e)) / Col (f)

(*) The rate column represents the unit rate prior to adjustments; the actual rate will be determined pursuant to the applicable TSC formula rate.

Niagara Mohawk Power Corporation
Allocation Factors - As calculated pursuant to Section 9.1

Attachment 1
Schedule 5

Shading denotes an input

2010

Line No.		Description	Amount	Source	Defiinition
1	9.1 1	**Electric Wages and Salaries Factor**	**83.5000%**		Fixed per settlement
2					
3	9.1 3	**Transmission Wages and Salaries Allocation Factor**	**13.0000%**		Fixed per settlement
4					
5					
6					
7					
8	9.1 2	**Gross Transmission Plant Allocation Factor**			
9		Transmission Plant in Service	$1,872,168,717	Schedule 6, Page 2, Line 3, Col 5	Gross Transmission Plant Allocation Factor shall equal the total investment in
10		Plus: Transmission Related General	$40,274,055	Schedule 6, Page 2, Line 5, Col 5	Transmission Plant in Service, Transmission Related Electric General Plant,
11		Plus: Transmission Related Common	$34,179,455	Schedule 6, Page 2, Line 10, Col 5	Transmission Related Common Plant and Transmission Related Intangible Plant
12		Plus: Transmission Related Intangible Plant	$10,032,845	Schedule 6, Page 2, Line 15, Col 5	divided by Total Electric Plant plus Electric Common Plant.
13		Gross Transmission Investment	$1,956,655,071	Sum of Lines 9 - 13	
14					
15		Total Electric Plant	$6,765,790,850	FF1 207.104	
16		Plus: Electric Common	$262,918,887	Schedule 6, Page 2, Line 10, Col 3	
17		Gross Electric Plant in Service	$7,028,709,737	Line 15 + Line 16	
18					
19		**Percent Allocation**	**27.84%**	Line 13 / Line 17	
20					
21	9.1 4	**Gross Electric Plant Allocation Factor**			
22					Gross Electric Plant Allocation Factor shall equal
23		Total Electric Plant in Service	$6,765,790,850	Line 15	Gross Electric Plant divided by the sum of Total Gas Plant,
24		Plus: Electric Common Plant	$262,918,887	Schedule 6, Page 2, Line 10, Col 3	Total Electric Plant, and Total Common Plant
25		Gross Electric Plant in Service	$7,028,709,737	Line 23 + Line 24	
26					
27		Total Gas Plant in Service	$1,840,736,258	FF1 201.8d	
28		Total Electric Plant in Service	$6,765,790,850	Line 15	
29		Total Common Plant in Service	$314,872,918	Schedule 6, Page 2, Line 10, Col 1	
30		Gross Plant in Service (Gas & Electric)	$8,921,400,026	Sum of Lines 27-Lines 29	
31					
32		**Percent Allocation**	**78.78%**	Line 25 / Line 30	

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Transmission Investment Base (Part 1 of 2)
Attachment H, section 9.2

Attachment 1
Schedule 6
Page 1 of 2

Line No.		Description	Reference Section:	2010	Reference
1	9.2 (a)	Transmission Investment Base			
2					
3	A.1.	Transmission Investment Base shall be defined as (a) Transmission Plant in Service, plus (b) Transmission Related Electric General Plant, plus			
4		(c) Transmission Related Common Plant, plus (d) Transmission Related Intangible Plant, plus (e) Transmission Related Plant Held for Future Use, less			
5		(f) Transmission Related Depreciation Reserve, less (g) Transmission Related Accumulated Deferred Taxes, plus (h) Transmission Related			
6		Regulatory Assets net of Regulatory Liabilities, plus (i) Transmission Related Prepayments, plus (j) Transmission Related Materials and Supplies,			
7		plus (k) Transmission Related Cash Working Capital.			
8					
9					
10					
11					
12		Transmission Plant in Service	(a)	$1,872,168,717	Schedule 6, page 2, line 3, column 5
13		General Plant	(b)	$40,274,055	Schedule 6, page 2, line 5, column 5
14		Common Plant	(c)	$34,179,455	Schedule 6, page 2, line 10, column 5
15		Intangible Plant	(d)	$10,032,845	Schedule 6, page 2, line 15, column 5
16		Plant Held For Future Use	(e)	$0	Schedule 6, page 2, line 19, column 5
17		Total Plant (Sum of Line 12 - Line 16)		$1,956,655,071	
18					
19		Accumulated Depreciation	(f)	($571,581,816)	Schedule 6, page 2, line 29, column 5
20		Accumulated Deferred Income Taxes	(g)	($304,830,100)	Schedule 7, line 6, column 5
21		Other Regulatory Assets	(h)	$20,074,963	Schedule 7, line 11, column 5
22		Net Investment (Sum of Line 17 -Line 21)		$1,100,318,118	
23					
24		Prepayments	(i)	$10,226,833	Schedule 7, line 15, column 5
25		Materials & Supplies	(j)	$8,449,675	Schedule 7, line 21, column 5
26		Cash Working Capital	(k)	$8,185,583	Schedule 7, line 28, column 5
27					
28		Total Investment Base (Sum of Line 22 - Line 26)		$1,127,180,209	

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Transmission Investment Base (Part 1 of 2)
Attachment H Section 9.2 (a) A. 1.

Attachment 1
Schedule 6
Page 2 of 2

Shading denotes an input

2010

Line No.		(1) Total	(2) Allocation Factor	(3) = (1)*(2) Electric Allocated	(4) Allocation Factor	(5) = (3)*(4) Transmission Allocated	FERC Form 1/PSC Report Reference for col (1)		Definition
1	Transmission Plant					$1,872,079,472	FF1 207.58g	9.2(a)A.1.(a)	Transmission Plant in Service shall equal the
2	Wholesale Meter Plant					$89,245	Workpaper 1, Line 51		balance of total investment in Transmission Plant
3	Total Transmission Plant in Service (Line 1+ Line 2)					$1,872,168,717			plus Wholesale Metering Investment
4									
5	General Plant	$309,800,420	100.00%	$309,800,420	13.00% (c)	$40,274,055	FF1 207.99g	9.2(a)A.1.(b)	Transmission Related Electric General Plant shall
6									equal the balance of investment in Electric General
7									Plant mulitplied by the Transmission Wages and
8									Salaries Allocation Factor
9									
10	Common Plant	$314,872,918	83.50% (a)	$262,918,887	13.00% (c)	$34,179,455	FF1 201. 8h	9.2(a)A.1.(c)	Transmission Related Common Plant shall equal Common
11									Plant multiplied by the Electric Wages and Salaries
12									Allocation Factor and further multiplied by the
13									Transmission Wages and Salaries Allocation Factor.
14									
15	Intangible Plant	$77,175,727	100.00%	77,175,727	13.00% (c)	$10,032,845	FF1 205.5g	9.2(a)A.1.(d)	Transmission Related Intangible Plant shall equal Intangible
16									Electric Plant multiplied by the Transmission Wages and
17									Salaries Allocation Factor.
18									
19	Transmission Plant Held for Future U	$0				$0	Workpaper 10, Line 1	9.2(a)A.1.(e)	Transmission Related Plant Held for Future Use shall equal
20									the balance in Plant Held for Future Use associated with
21									property planned to be used for transmission service within
22									five years
23	Transmission Accumulated Depreciation								
24	Transmission Accum. Depreciation	($526,326,494)				($526,326,494)	FF1 219.25b	9.2(a)A.1.(f)	Transmission Related Depreciation Reserve shall equal the
25	General Plant Accum.Depreciation	($184,594,804)	100.00%	($184,594,804)	13.00% (c)	($23,997,325)	FF1 219.28b		balance of: (i) Transmission Depreciation Reserve, plus (ii)
26	Common Plant Accum Depreciation	($107,880,579)	83.50% (a)	($90,080,283)	13.00% (c)	($11,710,437)	FF1 356.1 end of year balance		the product of Electric General Plant Depreciation Reserve
27	Amortization of Other Utility Plant	($73,292,452)	100.00%	($73,292,452)	13.00% (c)	($9,528,019)	FF1 200.21c		multiplied by the Transmission Wages and Salaries
28	Wholesale Meters	($19,542)				($19,542)	Workpaper 1, Line 52		Allocation Factor, plus (iii) the product of Common Plant
29	Total Depreciation (Sum of line 24 - Line 28)					($571,581,816)			Depreciation Reserve multiplied by the Electric Wages and
									Salaries Allocation Factor and further multiplied by the
									Transmission Wages and Salaries Allocation Factor plus (iv)
									the product of Intangible Electric Plant Depreciation Reserve
									multiplied by the Transmission Wages and Salaries
									Allocation Factor plus (v) depreciation reserve associated with
									the Wholesale Metering Investment

Allocation Factor Reference
(a) Schedule 5, line 1
(b) Schedule 5, line 32 - not used on this Schedule
(c) Schedule 5, line 3
(d) Schedule 5, line 19 - not used on this Schedule

Niagara Mohawk Power Corporation | **Attachment 1**
Annual Revenue Requirements of Transmission Facilities | **Schedule 7**
Transmission Investment Base (Part 2 of 2)
Attachment H Section 9.2 (a) A. 1.

Shading denotes an input

2010

Line No.		(1) Total	(2) Allocation Factor	(3) = (1)*(2) Electric Allocated	(4) Allocation Factor	(5) = (3)*(4) Transmission Allocated	FERC Form 1/PSC Report Reference for col (1)		Definition
1	Transmission Accumulated Deferred Taxes								
2	Accumulated Deferred Taxes (281-282)	($1,162,666,592)	100.00%	($1,162,666,592)	27.84% (d)	($323,663,598)	FF1 275.2k	9.2(a)A.1.(g)	Transmission Related Accumulated Deferred Income Taxes
3	Acumulated Deferred Taxes (283)	($531,168,588)	100.00%	($531,168,588)	27.84% (d)	($147,866,927)	Workpaper 2, Line 5		shall equal the electric balance of Total Accumulated Deferred
4	Accumulated Deferred Taxes (190)	$619,765,506	100.00%	$619,765,506	27.84% (d)	$172,530,573	FF1 234.8c		Income Taxes (FERC Accounts 190, 255,281, 282, and 283 net of
5	Accumulated Deferred Inv. Tax Cr (255)	($20,943,098)	100.00%	($20,943,098)	27.84% (d)	($5,830,148)	FF1 267.8h		stranded costs), multiplied by the Gross Transmission Plant
6	Total (Sum of line 2 - Line 5)			($1,095,012,772)		($304,830,100)			Allocation Factor.
7									
8	Other Regulatory Assets								
9	FAS 109 (Asset Account 182.3)	$121,505,005	100.00%	$121,505,005	27.84% (d)	$33,824,613	FF1 232 lines 1,16,20,29	9.2(a)A.1.(h)	Transmission Related Regulatory Assets shall be Regulatory
10	FAS 109 (Liability Account 254)	($49,391,587)	100.00%	($49,391,587)	27.84% (d)	($13,749,650)	FF1 278.1 lines 1 & 27(f)		Assets net of Regulatory Liabilities multiplied by the Gross
11	Total (line 9 + Line 10)	$72,113,418		$72,113,418		$20,074,963			Transmission Plant Allocation Factor.
12									
13	Transmission Prepayments	$58,577,794					FF1 111.57c	9.2(a)A.1.(i)	Transmission Related Prepayments shall be the product of
14	Less: Prepaid State and Federal Income Tax	($11,948,387)					FF1 263 lines 2 & 9 (h)		Prepayments excluding Federal and State taxes multiplied by
15	Total Prepayments	$46,629,407	78.78% (b)	$36,736,898	27.84% (d)	$10,226,833			the Gross Electric Plant Allocation Factor and further
16									multiplied by the Gross Transmission Plant Allocation Factor.
17									
18	Transmission Material and Supplies							9.2(a)A.1.(j)	Transmission Related Materials and Supplies shall equal: (i)
19	Trans. Specific O&M Materials and Supplies	$3,261,216				$3,261,216	FF1 227.8		the balance of Materials and Supplies assigned to
20	Contruction Materials and Supplies	$23,656,863	78.78% (b)	$18,638,019	27.84% (d)	$5,188,459	FF1 227.5		Transmission plus (ii) the product of Material and Supplies
21	Total (Line 19 + Line 20)					$8,449,675			assigned to Construction multiplied by the Gross Electric
22									Plant Allocation Factor and further multiplied by Gross
23									Transmission Plant Allocation Factor
24									
25	Cash Working Capital							9.2(a)A.1.(k)	Transmission Related Cash Working Capital shall be an
26	Operation & Maintenance Expense					$65,484,668	Schedule 9, Line 23		allowance equal to the product of: (i) 12.5% (45 days/ 360 days = 12.5%)
27						0.1250	x 45 / 360		multiplied by (ii) Transmission Operation and Maintenance Expense
28	Total (line 26 * line 27)					$8,185,583			

Allocation Factor Reference
(a) Schedule 5, line 1 - not used on this Schedule
(b) Schedule 5, line 32
(c) Schedule 5, line 3 - not used on this Schedule
(d) Schedule 5, line 19

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Cost of Capital Rate

Attachment 1
Schedule 8

Shading denotes an input — **2010**

Line No

1 **The Cost of Capital Rate shall equal the proposed Weighted Costs of Capital plus Federal Income Taxes and State Income Taxes.**
2 The Weighted Costs of Capital will be calculated for the Transmission Investment Base using NMPC's actual capital structure and will equal the sum of (i), (ii), and (iii) below:
3
4 (i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of NMPC's long-term debt outstanding during the year and the sum of (a) the ratio of actual long-term debt to total capital at year-end; a
5 (b) the extent, if any, by which the ratio of NMPC's actual common equity to total capital at year en(exceeds fifty percent (50%). Long term debt shall be defined as the average of the beginning of the year and end
6 of the year balances of the following: long term debt less the unamortized Discounts on Long-Term Debt less the unamortized
7 Loss on Reacquired Debt plus Unamortized Gain on Reacquired Debt. Cost to maturity of NMPC's long-term debt shall be defined as the cost of long term debt included in the debt discount expense and any loss or gain on reacquired debt.
8
9 (ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of NMPC's preferred stock then outstanding and the ratio of actual preferred stock to total capital at year-end;
10
11 (iii) the return on equity component shall be the product of the allowed return on equity of 11.5% and the ratio of NMPC's actual common equity to total capital at year-end, provided that such ratio
12 shall not exceed fifty percent (50%).

Line No			CAPITALIZATION	Source:	CAPITALIZATION RATIOS	COST OF CAPITAL		WEIGHTED COST OF CAPITAL	EQUITY PORTION
13									
14									
15									
16									
17	(i)	LONG-TERM DEBT	$2,374,309,846	Workpaper 6, Line 16b	49.55%	4.20%	Workpaper 6, Line 17c	2.08%	
18	(ii)	PREFERRED STOCK	$28,984,700	FF1 112.3c	0.45%	3.66%	Workpaper 6, Line 24d	0.02%	0.02%
19	(iii)	COMMON EQUITY	$3,984,099,488	112.16c - FF1 112.3,12,15c	50.00%	11.50%		5.75%	5.75%
20									
21		TOTAL INVESTMENT RETURN	$6,387,394,034		100.00%			7.85%	5.77%

22
23
24
25
26 9.2.2.(b) Federal Income Tax shall e = (A. + [B / C] X Federal Income Tax Rate)
27 (1 - Federal Income Tax Rate)
28
29 where A is the sum of the preferred stock component and the return on equity component, each as determined in Sections (a)(ii) and for the ROE set forth in (a)(iii) above, B is the Equity AFUDC component of Depreciation Expense for
30 Transmission Plant in Service as defined at Section 9.1.16 (FF1 117.38c), and C is the Transmission Investment Base as shown at Schedule 6, Page 1 of 2, Line 28.
31
32 = (0.0577 +($4,082,548) / $1,127,180,209 X 35%)
33 (1 - 0.35)
34
35 = 0.0330195
36
37
38 9.2.2.(c) State Income Tax shall equ = (A. + [B / C] + Federal Income Tax) X State Income Tax Rate
39 (1 - State Income Tax Rate)
40
41 where A is the sum of the preferred stock component and the return on equity component as determined in (a)(ii) and (a)(iii) above , B is the Equity AFUDC component of Depreciation Expense for Transmission Plant in
42 Service as defined at Section 9.1.16 above, and C is the Transmission Investment Base as shown at Schedule 6, Page 1 of 2, Line 28.
43
44
45
46 = (0.0577 +($4,082,548) / $1,127,180,209 + 0.0330195) X 7.10%
47 (1 - 0.071)
48
49 = 0.0072102
50
51
52
53 (a)+(b)+(c) Cost of Capital Rate = 11.87%
54
55
56 **9.2(a) A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate**
57
58
59

Line No			
60	Transmission Investment Base	$1,127,180,209	Schedule 6, page 1 of 2, Line 28
61			
62	Cost of Capital Rate	0.1187297	Line 53
63			
64	= Investment Return and Income Taxes	$133,829,768	Line 60 X Line 62

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Transmission Expenses
Attachment H Section 9.2

Attachment 1
Schedule 9

Shading denotes an input

2010

Line No.		(1) Total	(2) Allocation Factor	(3) = (1)*(2) Electric Allocated	(4) Allocation Factor	(5) = (3)*(4) Transmission Allocated	FERC Form 1 Reference for col (1)		Definition
	Depreciation Expense								
1	Transmission Depreciation	$31,482,012				$31,482,012	FF1 336.7f	9.2.B.	Transmission Related Depreciation Expense shall equal the sum of:
2	General Depreciation	$13,112,567	100.0000%	$13,112,567	13.0000% (c)	$1,704,634	FF1 336.10f		(i) Depreciation Expense for Transmission Plant in Service, plus (ii)
3	Common Depreciation	$13,090,378	83.5000% (a)	$10,930,466	13.0000% (c)	$1,420,961	FF1 356.1		the product of Electric General Plant Depreciation Expense multiplied
4	Intangible Depreciation	$1,330,750	100.0000%	$1,330,750	13.0000% (c)	$172,998	FF1 336.1f		by the Transmission Wages and Salaries Allocation Factor plus (iii)
5	Wholesale Meters					$2,481	Workpaper 1, Line 53		Common Plant Depreciation Expense multiplied by the Electric
6	Total (line 1+2+3+4+5)					$34,783,085			Wages and Salaries Allocation Factor, further multiplied by the
7									Transmission Wages and Salaries Allocation Factor plus (iv)
8									Intangible Electric Plant Depreciation Expense multiplied by the
9									Transmission Wages and Salaries Factor plus (v) depreciation
10									expense associated with the Wholesale Metering Investment.
11									
12	Real Estate Taxes	$137,630,327	100.0000%	$137,630,327	27.8380% (d)	$38,313,586	FF1 263.25i	9.2.C.	Transmission Related Real Estate Tax Expense shall equal the
13									electric Real Estate Tax Expenses multiplied by the Gross
14									Transmission Plant Allocation Factor.
15									
16	Amortization of Investment Tax Credits	$1,663,964	78.7848% (b)	$1,310,951	27.8380% (d)	$364,943	FF1 117.58c	9.2.D.	Transmission Related Amortization of Investment Tax Credits shall
17									equal the product of Amortization of Investment Tax Credits multiplied
18									by the Gross Electric Plant Allocation Factor and further multiplied by
19									the Gross Transmission Plant Allocation Factor
20	Transmission Operation and Maintenance								
21	Operation and Maintenance	$88,777,237				$88,777,237	FF1 321.112b	9.2.E.	Transmission Operation and Maintenance Expense shall equal
22	less Load Dispatching - #561	$12,349,796				$12,349,796	FF1 321.84-92b		the sum of electric expenses as recorded in
23	less Regional Delivery Venture adjustments	$10,942,773 ***				$10,942,773			
24	O&M (Line 21 - Line 22)	$65,484,668				$65,484,668			FERC Account Nos. 560, 562-574
25									
26	Transmission Administrative and General							9.2.F.	Transmission Related Administrative and General Expenses shall
27	Total Administrative and General	$375,117,556					FF1 323.197b		equal the product of electric Administrative and General Expenses,
28	less Property Insurance (#924)	$64,126					FF1 323.185b		excluding the sum of Electric Property Insurance, Electric Research and
29	less Pensions and Benefits (#926)	$92,041,066					FF1 323.187b		Development Expense and Electric Environmental Remediation Expense,
30	less: Research and Development Expenses (#930)	$2,474,429					Workpaper 12, Line 3		and 50% of the NYPSC Regulatory Expense
31	Less: 50% of NY PSC Regulatory Expense	$4,074,213					FF1 351.1.h, 50% of Workpaper 16, Line 14, Column f		multiplied by the Transmission Wages and Salaries Allocation Factor,
32	Less: 18a Charges (Temporary Assessment)	$80,854,971 **					FF1 351.1.h, Workpaper 16, Line 15, Column f		plus the sum of Electric Property Insurance multiplied by the Gross
33	less: Environmental Remediation Expense	$13,055,876					Workpaper 11, Line 3		Transmission Plant Allocation Factor, plus transmission-specific Electric
34	Subtotal (Line 26-27-28-29-30-31-32)	$182,552,875	100.0000%	$182,552,875	13.0000% (c)	$23,731,874			Research and Development Expense, and transmission-specific
35	PLUS Property Insurance alloc. using Plant Allocatior	$64,126	100.0000%	$64,126	27.8380% (d)	$17,851	Line 28		Electric Environmental Remediation Expense. In addition, Administrative
36	PLUS Pensions and Benefits	$179,778,267	100.0000%	$179,778,267	13.0000% (c)	$23,371,175	Workpaper 3, Line 8		and General Expenses shall exclude the actual Post-Employment
37	PLUS Transmission-related research and development	$296,936				$296,936	Workpaper 12, Line 1		Benefits Other than Pensions ("PBOP") included in FERC Account 926,
38	PLUS Transmission-related Enviromental Expense	$0				$0	Workpaper 11, Line 1		and shall add back in the amounts shown on Workpaper 3, page 1,
39	Total A&G (Line 34+35+36+37+38)	$281,837,232		$362,395,268		$47,417,836			or other amount subsequently approved by FERC under Section 205 or 206.
40								9.2.G.	Transmission Related Payroll Tax Expense shall equal the product of
41	Payroll Tax Expense								electric Payroll Taxes multiplied by the Transmission Wages and
42	Federal Unemployment	$233,681					FF1 263.4i		Salaries Allocation Factor.
43	FICA	$17,502,511					FF1 263.3i		
44	State Unemployment	$529,672					FF1 263.17i		
45	Total (Line 40+41+42)	$18,265,864	100.0000%	$18,265,864	13.0000% (b)	$2,374,562			

Allocation Factor Reference
(a) Schedule 5, line 1
(b) Schedule 5, line 32
(c) Schedule 5, line 3
(d) Schedule 5, line 19

** Per November 18, 2010 Supplemental Information Filing, National Grid has agreed to exclude the costs of section 18-a Temporary Assessmet under NY PSC in any future update.
*** In reviewing it's recent rate filing (Case 10-E-0050) with the NYPSC, the Company has determined that it would be appropriate to exclude certain costs related to it's Regional Delivery Venture.

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Billing Adjustments, Revenue Credits, Rental Income
Attachment H Section 9.2 (a)

Attachment 1
Schedule 10

Shading denotes an input

2010

Line No.	Description	(1) Total	Source		Definition
1	Billing Adjustments *	-$2,487,006	Line 37 (Listed below)	9.2.H.	Billing Adjustments shall be any adjustments made in accordance with Section 9.4(d) below.
2					
3					
4	Bad Debt Expense	-$796	Workpaper 4, Line 4	9.2.I.	Transmission Related Bad Debt Expense shall equal
5					Bad Debt Expense as reported in Account 904 related to NMPC's wholesale transmission billing.
6					
7	Revenue Credits	$47,222,149	Workpaper 5, Line 11	9.2.J.	Revenue Credits shall equal all Transmission revenue recorded in FERC account 456
8					excluding (a) any NMPC revenues already reflected in the WR, CRR, SR, ECR and Reserved
9					components in Attachment H of the NYISO TSC rate; (b) excluding any revenues associated
10					with expenses that have been excluded from NMPC's revenue requirement; and (c) any
11					revenues associated with transmission service provided under this TSC rate, for which the
12					load is reflected in the calculation of BU.
13					
14	Transmission Rents	($1,589,444)	Workpaper 7	9.2.K.	Transmission Rents shall equal all Transmission-related rental income recorded in FERC
15					account 454.615
16					
17				9.4(d)	
18				1	Any changes to the Data Inputs for an Annual Update, including but not limited to
19					revisions resulting from any FERC proceeding to consider the Annual Update, or
20					as a result of the procedures set forth herein, shall take effect as of the beginning
21					of the Update Year and the impact of such changes shall be incorporated into the
22					charges produced by the Formula Rate (with interest determined in accordance
23					with 18 C.F.R. § 38.19(a)) in the Annual Update for the next effective Update
24					Year. This mechanism shall apply in lieu of mid-Update Year adjustments and
25					any refunds or surcharges, except that, if an error in a Data Input is discovered
26					and agreed upon within the Review Period, the impact of such change shall be
27					incorporated prospectively into the charges produced by the Formula Rate during
28					the remainder of the year preceding the next effective Update Year, in which case
29					the impact reflected in subsequent charges shall be reduced accordingly.
30				2	The impact of an error affecting a Data Input on charges collected during the
31					Formula Rate during the five (5) years prior to the Update Year in which the error
32					was first discovered shall be corrected by incorporating the impact of the error on
33					the charges produced by the Formula Rate during the five-year period into the
34					charges produced by the Formula Rate (with interest determined in accordance
35					with 18 C.F.R. § 38.19(a)) in the Annual Update for the next effective Update
36					Year. Charges collected before the five-year period shall not be subject to correction.
37	* Billing Adjustment consists of these 2 amounts:				
	(1). Workpaper 14, Line 30	($2,383,112)			
	(2). Interest credit related to FERC Affliate Transaction Audit Finding	($4,650)			
	(3) 2009 Resubmission of FF1; per settlement Attachment D	($99,244)			

Niagara Mohawk Power Corporation
System, Control, and Load Dispatch Expenses (CCC)
Attachment H, Section 9.5

Attachment 1
Schedule 11
Page 1 of 1

Shading denotes an input

The CCC shall equal the annual Scheduling, System Control and Dispatch Costs (i.e., the transmission component of control center costs) as recorded in FERC Account 561 and its associated sub-accounts using information from the prior calendar year, excluding NYISO system control and load dispatch expense already recovered under Schedule 1 of the NYISO Tariff.

Line No.	Scheduling and Dispatch Expenses			2010	Source
1					
2					
3	Accounts	561	Load Dispatching	$2,862,601	FF1 321.84b
4	Accounts	561.1	Reliability	$0	FF1 321.85b
5	Accounts	561.2	Monitor and Operate Transm. System	$2,572,962	FF1 321.86b
6	Accounts	561.3	Transm. Service and Schedule	$0	FF1 321.87b
7	Accounts	561.4	Scheduling System Control and Dispatch	$4,438,211	FF1 321.88b
8	Accounts	561.5	Reliability, Planning and Standards Developmen	$1,303,697	FF1 321.89b
9	Accounts	561.6	Transm. Service Studies	$0	FF1 321.90b
10	Accounts	561.7	Generation Interconnection Studies	$9,511	FF1 321.91b
11	Accounts	561.8	Reliability, Planning and Standards Dev. Service	$1,162,814	FF1 321.92b
12					
13			Total Load Dispatch Expenses (sum of Lines 3 - 11)	$12,349,796	
14					
15	Less Account 561 directly recovered under Schedule 1 of the NY ISO Tariff				
16					
17	Accounts	561.4	Scheduling System Control and Dispatch	$4,438,211	Line 7
18	Accounts	561.8	Reliability, Planning and Standards Dev. Service	$1,162,814	Line 11
19			Total NYISO Schedule 1	$5,601,025	Line 17 + Line 18
20					
21	Total CCC Component			$6,748,771	Line 13 - Line 19

Niagara Mohawk Power Corporation
Billing Units - MWH
Attachment H, Section 9.6

Attachment 1
Schedule 12
Page 1 of 1

Shading denotes an input

BU shall be the total Niagara Mohawk load as reported to the NYISO for the calendar billing year prior to the Forecast Period, including the load for customers taking service under Niagara Mohawk's TSC Rate. The total Niagara Mohawk load will be adjusted to exclude (i) load associated with wholesale transactions being revenue credited through the WR, CRR, SR, ECR and Reserved components of Workpaper H of the NYISO TSC rate including Niagara Mohawk's external sales, . load associated with grandfathered OATT agreements, and any load related to pre-OATT grandfathered agreements; (ii) load associated with transactions being revenue credited under Historical TRR Component J; and (iii) load associated with netted station service

Line No.		Dec 09- Nov 10	SOURCE	
1	Subzone 1	12,298,985.850	NIMO TOL (transmission owner load)	Workpaper 13
2	Subzone 2	7,249,987.760	NIMO TOL (transmission owner load)	Workpaper 13
3	Subzone 3	4,610,230.930	NIMO TOL (transmission owner load)	Workpaper 13
4	Subzone 4	10,487,089.753	NIMO TOL (transmission owner load)	Workpaper 13
5	Subzone 29	2,056,636.007	NIMO TOL (transmission owner load)	Workpaper 13
6	Subzone 31	641,258.223	NIMO TOL (transmission owner load)	Workpaper 13
7	Total NIMO Load report to NYISO	**37,344,188.523**	sum Lines 1-6	
8	LESS: All non-retail transactions			
9	Watertown	10,348.000	FF1 page 329.10.j	
10	**High Load Factor Fitzpatrick ****	30,763.864	NIMO TOL (transmission owner load)	
11	Disputed Station Service	160,913.641	NIMO TOL (transmission owner load)	
12	Other non-retail transactions	2,859,192.544	All other non-retail transactions (Sum of 300,000 series PTID's from TOL)	
13	Total Deductions	**3,061,218.049**	sum Lines 9 - 12	
14	PLUS: TSC Load			
15	NYMPA Muni's, Misc. Villages, Jamestown (X1)	2,119,153.000	FF1 page 329.17.j	
16	NYPA Niagara Muni's (X2)	686,429.000	FF1 page 329.1.j	
17	Total additions	**2,805,582.000**	sum Lines 15 -17	
18	Total Billing Units	**37,088,552.474**	Line 7 - Line 13 + Line 18	

** High Load Factor Fitzpatrick contract expired 12/31/2009.
The new contract is now retail load.
Line 10 only includes December 2009 load.

Adjusted TSC Rate Components
For the Rate Effective January 1, 2012
Tonawanda, FICA and 2009 R&D Expenses

Attachment 1
Schedule 13

	(a) Historical Transmission Revenue Requirement (Historical TRR)	(b) Forecasted Transmission Revenue Requirement	(c) Annual True Up	(d) Revenue Requirement (RR)	(e) Scheduling System Control and Dispatch Costs (CCC)	(f) Annual Billing Units (BU) MWh	(g) Rate $/MWh
1 As Filed	$276,957,312	$8,250,157	$2,927,103	$288,134,572	$6,748,771	37,088,552	$7.95
2 Revised	270,539,167	8,246,637	(3,525,807)	275,259,997	6,748,771	37,088,552	$7.60
3 Increase/(Decrease)	(6,418,145)	(3,520)	(6,452,910)	(12,874,575)	-	-	($0.35)
							-4.37%

Adjustments indicated by **green fill** made to:
Schedule 9 - Lines 21 and 43
Schedule 10 - Footnote 3

File Name:
EXH NMP-4_2011 Update with Settlement figures.xls

Niagara Mohawk Power Corporation **Workpaper 1**
Wholesale Meters **Page 1 of 1**

Shading denotes an input 2010

Line No.			Quantity	Accumulated Cost	Avg Cost
1	A/C 37030 Large Meter Install - Bare Cost				
2		1996	1,166	$187,298.82	
3		1997	3,499	$611,184.89	
4		1998	1,943	$342,748.54	
5		1999	3,208	$543,890.44	
6		2000	2,128	$355,922.26	
7		2001	23	$4,081.64	
8		2002	549	$119,407.77	
9		2003	1,924	$424,598.99	
10		2004	9,833	$2,444,428.00	
11		2005	2,086	$512,694.81	
12		2006	1,749	$1,201,540.30	
13		2007	858	$261,095.35	
14		2008	2,019	$623,333.32	
15		2009	768	$363,212.76	
16		2010	3,499	$531,057.32	
17	**Total**		**35,252**	**$8,526,495.21**	$241.87
18	Net Plant Ratio (Remaining Life / Average Life) (Line 55 / Line 57)				82.17%
19	Net Bare Costs (Line 17 * Line 18)				$198.74
20					
21	A/C 37035 Large Meter - Installation Cost				
22		1996	1,153	$979,200.14	
23		1997	3,489	$3,224,553.18	
24		1998	1,936	$1,805,377.38	
25		1999	3,188	$2,866,714.52	
26		2000	2,107	$1,871,445.37	
27		2001	17	$17,056.14	
28		2002	543	$626,174.53	
29		2003	1,721	$2,056,266.71	
30		2004	8,535	$11,553,647.07	
31		2005	911	$1,194,470.02	
32		2006	1,166	$2,284,325.35	
33		2007	84	$145,054.34	
34		2008	131	$235,809.55	
35		2009	106	$111,410.88	
36		2010	90	$46,907.19	
37	**Total**		**25,177**	**$29,018,412.37**	$1,152.58
38	Net Plant Ratio (Remaining Life / Average Life) (Line 56 / Line 57)				77.25%
39	Net Installation Costs (Line 37 * Line 38)				$890.37
40	Number of Meters				64
41	Total Gross Asset Value Meters (Line 17 * Line 40)				$15,479.85
42	Estimated Depreciation Reserve (Line 43 - Line 41)				-$2,760.57
43	Net Asset Value on Meters (Line 19 * Line 40)				$12,719.28
44	Annual Depreciation Expense @36 year life or 2.78% (Line 41 * .0278)				$430.34
45					
46	Total Gross Asset Value Installation (Line 37 * Line 40)				$73,764.88
47	Estimated Depreciation Reserve (Line 48 - Line 46)				-$16,781.51
48	Net Asset Value on Meters (Line 39 * Line 40)				$56,983.37
49	Annual Depreciation Expense @36 year life or 2.78% (Line 46 * .0278)				$2,050.66
50					
51	Total Gross Asset Value Meters & Installation (Line 41 + Line 46)				$89,244.73
52	Depreciation Reserve Meters & Installation (Line 42 + Line 47)				-$19,542.08
53	Total Depreciation Expense Meters and Installation (Line 44 + Line 49)				$2,481.00
54					
55	Large Meter Bare Cost Remaining Life				29.58
56	Large Meter Installation Cost Remaining Life				27.81
57	Large Meter Average Life				36.00

Source: PowerPlant

Report 13001
Company: Niagara Mohawk
GL Accounts: 101 & 106
Accounts: 37030 & 37035
Select all requird Eng. Vintage

Report 1501
Company: Niagara Mohawk
GL Accounts: 101 & 106
Accounts: 37030 & 37035

Niagara Mohawk Power Corporation
FERC Account 283 - Accumulated Deferred Income Taxes

Workpaper 2
Page 1 of 1

Shading denotes an input

Line No.	Account	Source	2010		2009 vs 2010 bal
1	Total Acct 283	FF1 277.9k	(733,121,426)		32,596,950
2	Excluding:				
3	Merger Rate Plan Stranded Cost	FF1 277.3 Col b + c - d	201,952,838	*	
4	State: Merger Rate Plan Stranded Cost	FF1 277	N/A		
5	**TOTAL ACCOUNT 283**		**(531,168,588)**		

* Due to a change in FF1 reporting, Line 3 reflects both State and Federal.

Niagara Mohawk **Workpaper 3**
Total Account 926 - Administrative and General Expense **Page 1 of 3**

Shading denotes an input

Line No.	Section I	Source:	2010
1	Employee Pensions & Benefits	FF1 pg 323.187	92,041,066
2	Plus: Deferred FAS087 Pension Costs	Workpaper 3, page 2	23,847,298
3	Total Employee Pension & Benefits	Line 1 + Line 2	115,888,364
4			
5	Less: Actual FAS106 Expense in Acct. 926	Workpaper 3, page 3	(24,754,097)
6	Plus: Fixed FAS106 per Docket ER08-552	Fixed Amount **	88,644,000
7			
8	**Total Account 926**	Line 3 + Line 5+ Line 6	**179,778,267**

* * FERC Docket No. ER08-552, Workpaper Statement BK Page 7, Page 2 of 3

Niagara Mohawk
Total Account 926 - Administrative and General Expense
Deferred FAS 087 Pension Costs
Workpaper 3, page 1, line 2

Workpaper 3
Page 2 of 3

Shading denotes an input

2010

Pension Expense	Activity	Month	Jrnl ID	Account	Amount
FAS087	AG1060	January	6264A-6264C	223020	$2,577,328
FAS087	AG1060	February	6264A-6264C	223020	$2,646,112
FAS087	AG1060	March	6264A-6264C	223020	$2,974,442
FAS087	AG1060	April	6264A-6264C	223020	$2,181,834
FAS087	AG1060	May	6264A-6264C	223020	$1,956,282
FAS087	AG1060	June	6264A-6264C	223020	$2,071,392
FAS087	AG1060	July	6264A-6264C	223020	$1,800,516
FAS087	AG1060	August	6264A-6264C	223020	$2,051,997
FAS087	AG1060	September	6264A-6264C	223020	($135,960)
FAS087	AG1060	October	6264A-6264C	223020	$1,850,627
FAS087	AG1060	November	6264A-6264C	223020	$1,958,911
FAS087	AG1060	December	6264A-6264C	223020	$1,913,817
					23,847,298

Source:
Query
PeopleSoft Financials
Company Niagara Mohawk
Activity AG1060
Expense Type B06
Account 223020

Niagara Mohawk **Workpaper 3**
Total Account 926 - Administrative and General Expense **Page 3 of 3**

Actual FAS 106 Expense in FERC Account 926

Workpaper 3, page 1, line 5

	Shading denotes an input	2010

Activity	Activity Descr	**Total**
AG1070	Post Retirement Benefit FAS106	$ 71,622,120.31
AG1079	Cap Related PostRetire Benefit	$ (46,868,023.37)
Grand Total		**24,754,097**

Source:
PeopleSoft Financials
Company Nagara Mohawk
Regulatory Account 926000
Activities AG1070, AG1079

Niagara Mohawk Power Corporation
Bad Debt Expense
Attachment H, Section 9.2

Workpaper 4
Page 1 of 1

Shading denotes an input

I. Transmission Related Bad Debt Expense shall equal NMPC's Wholesale Transmission Related Bad Debt Expense defined as that reported in FERC account 904 related to NMPC's wholesale transmission billing.

Line No.		Regulatory Account	Segment		2010
1					
2		904000	Dist	$	48,937,525
3		904000	Gas	$	16,420,187
4		904000	Tran	$	(796)
5	Total			$	65,356,916

Query:
PeopleSoft Financials
Company Niagara Mohawk
Regulatory Account 904000
Total by Segment

Niagara Mohawk Power Corporation **Workpaper 5**
Transmission Revenue Credits **Page 1 of 1**
Attachment H, Section 9.2

Shading denotes an input

J. Revenue Credits shall equal all Transmission revenue recorded in FERC account 456 excluding (a) any NMPC revenues already reflected in the WR, CRR, SR, ECR and Reserved components in Workpaper H of the NYISO TSC rate; (b) excluding any revenues associated with expenses that have been excluded from NMPC's revenue requirement; and (c) any revenues associated with transmission service provided under this tariff for which the demand is reflected in the calculation of BU.

Line No.		Source:	2010	
1	Transmission of Electricity for Others (456.1)	FF1 300.22b	$128,808,812	
2	Less: Transmission of Electricity by ISO (ECR, CRR, SR)	FF1 331.40e	$62,608,329	
3	Sub-total Revenue (Line 1 - Line 2)	FF1 330.35n	$66,200,485	
4	Less:			
5	TSC Customers	FF1 330.1,16,17,18n (a)	$19,918,017	*
6	Fitzpatrick Industrials	FF1 330.	$0	**
7	Green Island & Richmondville	FF1 330.14n	$195,203	
8	Sub-total Deductions (Line 5 + Line 6 + Line 7)		$20,113,220	
9	Subtotal Transmission Revenue Credit	Line 3 - Line 8	$46,087,265	
10	Transmission Support Revenue	Line 15	$1,134,884	
11	Total Transmission Revenue Credit	Line 9 + Line 10	$47,222,149	
12	Transmission Support Revenue Detail - Query			
13	Regulatory Account 456010		$876,711	
14	Regulatory Account 456040		$258,173	
15	Total	Line 13 + Line 14	$1,134,884	

Query:
PeopleSoft
Company Niagara Mohawk
Regulatory Accounts 456010 and 456040
Segment TRAN
Account 110034

* This number reflects the TSC Reserve as shown on FF1 pg 330, Ln 18, Col n.

** Line item 6 - Fitzpatrick Industrials contract expired 12/31/2009

Niagara Mohawk Power Corporation
Long Term Debt and Preferred Stock Cost

Shading denotes an input

Line No.	Interest on Long Term Debt	Source:	Beginning Balance (a)	Ending Balance (b)	Average (c)	2010 (d)
1						
2						
3	Total Niagara Mohawk Interest on Long Term Debt	FF1 257.33i				$ 98,020,023
4	Amortization of Debt Discount Expense FERC Account 428	FF1 117.63c				$ 2,434,668
5	Amortization of Loss on Reacquired Debt FERC Account 428.1	FF1 117.64c				$ 6,576,120
6	Less: Amort of Premium on Debt-Credit FERC Account 429	FF1 117.65c				$ -
7	Less: Amort of Gain on Reacquired Debt FERC Account 429.1	FF1 117.66c				$ (60,460)
8	**Interest Costs plus Expense**	Sum of Lines 3-7				**$ 106,970,351**
9						
10	Total Long Term Debt					
11						
12	Total Niagara Mohawk Long Term Outstanding Debt	FF1 256.33b & 257.33h	$ 2,750,065,000	$ 2,400,065,000	$ 2,575,065,000	
13	Less: Unamortized Discount on Long-Term Debt FERC Accoun	FF1 112.23c & d	$ (477,312)	$ (415,359)	$ (446,336)	
14	Less: Unamortized Loss on Reacquired Debt FERC Account 18	FF1 111.81c & d	$ (32,019,130)	$ (25,339,795)	$ (28,679,463)	
15	Plus: Unamortized Gain on Reacquired Debt FERC Account 25	FF1 113.61c & d	$ -	$ -	$ -	
16	**Total Long Term Debt**	Sum of Lines 12-15	**$2,717,568,558**	**$2,374,309,846**	**$2,545,939,202**	
17	**Debt Cost as % of Debt**	Line 8d / Line 16c			**4.20%**	
18						
19						
20	Preferred Stock					
21						
22	Total Niagara Mohawk Dividends Declared FERC account 437	FF1 118.29c				$1,060,498
23	Total Niagara Mohawk Preferred Stock FERC Account 204	FF1 112.3c				$28,984,700
24	**Preferred Stock Cost**	Line 22 / Line 23				**3.66%**

NOTES:
Lines 12-15 use the FERC Form 1 average of the beginning year balance and the end of year balance for each line item.

Niagara Mohawk Power Corporation
TSC Revenue Requirement
RIGHT OF WAY RENTS - ACCT #454615
CY 2010
Attachment H, Section 9.2

Workpaper 7
Page 1 of 1

Shading denotes an input

K. Transmission Rents shall equal all Transmission-related rental income recorded in NMPC's internal account 454.615.

Business Unit	Segment	Activity	Activity Descr	Expense Type	Regulatory Acct	Fiscal Yr	Period	GL Act $
00036	TRAN	454615	Rent from elec. Prop	400	454000	2010	January	($34,701)
00036	TRAN	454615	Rent from elec. Prop	400	454000	2010	February	($52,768)
00036	TRAN	454615	Rent from elec. Prop	400	454000	2010	March	($340,203)
00036	TRAN	454615	Rent from elec. Prop	400	454000	2011	April	($70,521)
00036	TRAN	454615	Rent from elec. Prop	400	454000	2011	May	($78,290)
00036	TRAN	454615	Rent from elec. Prop	400	454000	2011	June	($201,911)
00036	TRAN	454615	Rent from elec. Prop	400	454000	2011	July	($117,560)
00036	TRAN	454615	Rent from elec. Prop	400	454000	2011	August	($122,584)
00036	TRAN	454615	Rent from elec. Prop	400	454000	2011	September	($196,200)
00036	TRAN	454615	Rent from elec. Prop	400	454000	2011	October	($74,005)
00036	TRAN	454615	Rent from elec. Prop	400	454000	2011	November	($134,014)
00036	TRAN	454615	Rent from elec. Prop	400	454000	2011	December	($166,688)
							Sum:	**(1,589,444)**

Source:
PeopleSoft Financials
Company: Niagara Mohawk
Regulatory Account: 454000
Segment: TRAN

Niagara Mohawk Power Corporation
Forecasted Transmission Plant In-Service

Workpaper 8
Page 1 of 1

Shading denotes an input

2010

Forecasted Transmission Plant Additions (FTPA) shall mean the sun
(i) NMPC's actual Transmission Plant Additions during the first
quarter (January 1 through March 31) of the Forecast Period, and
(ii) NMPC's forecasted transmission investment for the Forecast
Period less the amount (i), divided by 2.

	Section I:			**Reference**	**Section II** **Program Breakdown for Transmisison**	**($ m)**	**Section III:** **Program Breakdown for Sub-Transmission**	**($ m)**
1	Current Year Capital Investment							
2	Transmission Capital Investment	$	132,004,301	See Section II	Northeast Region Reinforcement	19.50	Sub Transmission Line Overarching	14.92
3	Sub-Transmission Capital Investment	$	44,000,000	See Section III	Overhead Line Refurbishment Program - Asset Condition	17.04	Inspection & Maintenance	10.00
4	Total	$	176,004,301	Line 2 + Line 3	Other Damage/Failure	16.21	Underground Cable	5.18
5					Station NPCC Compliance Upgrades	15.59	Substation Metal Clad Switchgear	3.71
6	Actual Transmission Plant in Service Quarter 1				Clearance Strategy	9.17	Blanket	2.87
7	Quarter 1 2011 actuals Transmission Plant	$	1,884,307,200	FF1, pg 208 (b) **	Other System Capacity & Performance	9.14	Planning Criteria	1.46
8	2010 year end Transmission Plant	$	1,872,079,472	Schedule 6, page 2, line 1	Physical Security	7.78	Subtransmission Line Overarching	1.46
9	Q1 Transmission Plant increase	$	12,227,728	line 8 - line 7	Shield Wire Strategy	7.59	Sub Transmssion Automation	1.38
10					Other Asset Condition	6.68	Blanket	0.97
11	Total Estimated Transmission Plant in Service				Transformer Replacement Strategy	6.62	Sub Transmission and Distribution T	0.90
12	Total Current Year Capital Investment	$	176,004,301	line 4	Wood Pole Strategy	5.77	Blanket	0.70
13	Less: Q1 Increase	$	12,227,728	line 9	Luther Forest	4.22	Damage/Failure	0.64
14	Balance	$	163,776,573	line 12 - line 13	Steel Tower Strategy	4.10	Blanket	0.64
15	Times 50%	$	81,888,286	line 14 * 50%	Substation Rebuilds	3.95	New Business	0.61
16	Forecasted Plant	$	94,116,015	line 13 + line 15	Reliability Criteria Compliance	2.86	Public Requirements	0.55
17					Other Statutory/Regulatory	2.33	Substation Circuit Breaker / Reclose	0.54
18					RTU Strategy	2.30	Subtransmission Line Removal	0.36
19					Overhead Line Refurbishment Program - System Capacity & Performance	2.25	Substation Indoor Substation	0.25
20					NY Inspection Projects	1.92	Wood Pole	0.21
21					U-Series Relay Strategy	1.66	3rd Party Attachments	0.15
22					Circuit Breaker Replacement Strategy	0.90	Reliability	0.15
23					Clay Station Rebuild	0.90	Subtransmission Line Removal	0.10
24					Digital Fault Recorder Strategy	0.84	Substation Capacitor & Switch	0.07
25					Relay Replacement Strategy	0.71	Substation Power Transformer	0.04
26					Battery Strategy	0.63	Recloser Application	0.01
27					Load	0.79	Reserve	(3.85)
28					Steel Tower Strategy	0.13		
29					3A/3B Tower Strategy	0.04		
30					Reserve	(19.62)		
31					TOTAL	**132.0**		**44.0**

Resource:
Niagara Mohawk's filing, Case 06-M-0878, filed on February 7, 2011 broken down as shown below:

	CY2011 ($m)
Transmission	132.0
Sub-Transmission	44.0
Distribution	233.0
Total	409.0

** Due to timing, this number is an estimate as FF1 has not yet been completed at time of filing. The source of the data is Plant Accounting records.

Mid-Year Trend Adjustment **Workpaper 9**
NMPC Actual Transmission O&M for the Quarter 1 2011 vs 2010 **Page 1 of 1**
FERC Form 1 page 321

Shading denotes an input

Line No.	OPERATING EXPENSES	Reg Account		Jan-2011 (a)	Feb-2011 (b)	Mar-2011 (c)	2011 1st QTR FF1 TOTAL (d)	Jan-2010 (e)	Feb-2010 (f)	Mar-2010 (g)	2010 1st QTR FF1 TOTAL (h)	2011 o/(u) 2010 (i) (d - h)
1	Transmission Expenses-O&M											
2	Trans Oper-Supervision & Eng	560000		163,018.05	(29,346.89)	(78,661.10)	55,010.06	52,840.66	364,125.14	308,032.71	724,998.51	(669,988.45)
3	***Trans Oper-Load Dispatching***	***561000***	*	-	-	-	-	-	-	-	-	-
4	***Ld Disptch-Mon & Oper Tran Sys***	***561200***	*	-	-	-	-	-	-	-	-	-
5	***Schd, Sys Cntrl & Dispatch Srv***	***561400***	*	-	-	-	-	-	-	-	-	-
6	***Reliab, Plan & Standards Dev***	***561500***	*	-	-	-	-	-	-	-	-	-
7	***Transmission Service Studies***	***561600***	*	-	-	-	-	-	-	-	-	-
8	***Gen Interconnection Studies***	***561700***	*	-	-	-	-	-	-	-	-	-
9	***Reliab, Plan & Stndrd Dev Serv***	***561800***	*	-	-	-	-	-	-	-	-	-
10	Trans Oper-Substations	562000		231,483.74	422,083.85	415,158.42	1,068,726.01	340,335.92	275,743.40	273,827.78	889,907.10	178,818.91
11	Trans Oper-Overhead Lines	563000		294,006.75	393,422.96	440,827.12	1,128,256.83	265,720.12	207,920.59	530,299.48	1,003,940.19	124,316.64
12	Trans Oper-Underground Lines	564000		734.66	1,404.97	4,755.13	6,894.76	1,244.05	1,145.62	1,261.25	3,650.92	3,243.84
13	Trans Oper-Wheeling	565000		-	-	1,500.00	1,500.00	15,577.92	16,144.18	17,711.62	49,433.72	(47,933.72)
14	Trans Oper-Misc Expenses	566000		4,831,143.72	(333,984.76)	(1,107,902.22)	3,389,256.74	687,541.47	875,508.22	1,223,695.51	2,786,745.20	602,511.54
15	Trans Oper-Rents	567000		1,150,900.93	854,637.44	862,271.95	2,867,810.32	827,290.55	869,633.65	828,971.11	2,525,895.31	341,915.01
16	Oper Transmission Facilities			6,671,287.85	1,308,217.57	537,949.30	8,517,454.72	2,190,550.69	2,610,220.80	3,183,799.46	7,984,570.95	532,883.77
17	Trans Maint-Supervision & Eng	568000	568000	$84,004	$229,275	$384,516	697,794.92	158,380.59	154,782.13	179,413.06	492,575.78	205,219.14
18	Trans Maint-Buildings	569000	569000	$736	$4,876	$1,057	6,669.18	2,203.01	2,223.43	1,857.05	6,283.49	385.69
19	T Maint of Computer Hardware	569100	569100	$21,347	$13,204	$182,283	216,833.00	16,745.64	-	-	16,745.64	200,087.36
20	T Maint of Computer Software	569200	569200	$136,698	$41,722	$115,387	293,806.80	93,856.46	-	-	93,856.46	199,950.34
21	T Maint of Communication Equip	569300	569300	$1,335	$4,956	$2,200	8,489.85	732.98	-	-	732.98	7,756.87
22	T Maint of Misc Reg Tran Plant	569400		-	-	-	-	-	-	-	-	-
23	Trans Maint-Substations	570000	570000	$290,968	$514,978	$486,717	1,292,663.03	743,309.56	529,769.91	502,215.63	1,775,295.10	(482,632.07)
24	Trans Maint-Substation-Trouble	570010	570010	$166,746	$169,490	$381,146	717,382.52	221,639.73	217,129.38	340,966.80	779,735.91	(62,353.39)
25	Trans Maint-Overhead Lines	571000	571000	$616,605	$756,410	$1,297,357	2,670,371.07	1,115,257.16	1,651,248.84	348,081.07	3,114,587.07	(444,216.00)
26	Trans Maint-Switch-Unplanned	571010	571010	$6,694	$7,481	$19,425	33,599.82	2,283.11	10,549.22	19,830.20	32,662.53	937.29
27	Trans Maint-Right of Way	571020	571020	$670,656	$480,938	$699,593	1,851,186.55	1,753,979.04	1,265,523.66	1,430,425.97	4,449,928.67	(2,598,742.12)
28	Trans Maint-Underground Lines	572000	572000	$59,674	$8,448	$109,694	177,816.46	3,314.41	21,064.99	29,210.48	53,589.88	124,226.58
29	Trans Maint-Misc Expenses	573000	573000	$14,191	$47,209	$160,720	222,119.63	16,158.23	8,391.20	36,860.12	61,409.55	160,710.08
30	Maint Transmission Facilities			2,069,653.30	2,278,985.80	3,840,093.73	8,188,732.83	4,127,859.92	3,860,682.76	2,888,860.38	10,877,403.06	(2,688,670.23)
31	Subtotal Transmission Expenses-O&M			8,740,941.15	3,587,203.37	4,378,043.03	16,706,187.55	6,318,410.61	6,470,903.56	6,072,659.84	18,861,974.01	(2,155,786.46)

* Per the formula, these accounts are excluded from the calculation

Source:
PeopleSoft
Company Niagara Mohawk
Regulatory Accounts 560000 - 574000

Niagara Mohawk Power Corporation **Workpaper 10**
Total FERC Account 105 - Plant Held For Future Use **Page 1 of 1**

Shading denotes an input

Line No.		Source:	2010
1	Transmission Plant Held for Future Use	FF1 pg 214	$0.00

NOTE: The property vintage will be provided for any values shown on this workpaper

Niagara Mohawk Power Corporation **Workpaper 11**
Total NIMO Internal Account 930.200 - Misc. General - Environmental **Page 1 of 1**
Attachment H, Section 9.2

Shading denotes an input

Transmission specific Electric Environmental Remediation Expense
as recorded in NMPC's internal Account 930.200

Line No.		Source:	2010
1	**Transmission related Environmental Costs Claimed**		$0.00
2	Regulatory Account		Amount
3	930200	FF1 335.10b	$ 13,055,876

Query:
PeopleSoft
Company Niagara Mohawk
Regulatory Account 930200
Segments all electric (TRAN and DIST)
Activities AG0100, AG0105, AG0110
A list of all Transmission Related Environmental Expenses claimed shall be provided.

Niagara Mohawk Power Corporation **Workpaper 12**
Total NIMO Internal Account 930.210 - Misc. General - Research and Development **Page 1 of 1**
Attachment H, Section 9.2

Shading denotes an input

Transmission specific Electric Research and Development Expense as recorded
in NMPC internal Account No. 930.210

Line No.		Source:	2010
1	**Transmission Related R&D Expense**		**$296,936**
2	Regulatory Account		Amount
3	930210	FF1 353.8f electric	$ 2,474,429

Query:
PeopleSoft
Company Niagara Mohawk
Regulatory Account 930210
Segments all electric (TRAN and DIST)
Expense Types all
A list of all Transmission Related Research and Development Expenses claimed shall be provided.

Niagara Mohawk Power Corporation **Workpaper 13**
Billing Unit Summary **Page 1 of 2**

Shading denotes an input

Reason Code	Reference Number	2009 Dec	2010 Jan	2010 Feb	2010 Mar	2010 Apr	2010 May	2010 Jun	2010 Jul	2010 Aug	2010 Sep	2010 Oct	2010 Nov	Total Dec - Nov
Zone	1	1,072,488.69	1,078,733.26	990,923.70	1,045,687.03	927,806.49	950,183.85	1,026,209.65	1,141,464.77	1,130,235.04	986,870.42	972,126.38	976,256.57	12,298,985.850
Zone	2	641,531.53	660,798.46	587,798.25	588,842.24	539,330.99	572,952.29	590,259.96	702,602.71	660,240.50	572,209.17	562,755.63	570,666.02	7,249,987.760
Zone	3	418,559.77	429,371.46	386,580.91	358,473.31	322,376.17	367,366.48	377,131.96	443,955.19	431,578.96	376,673.07	345,206.94	352,956.73	4,610,230.930
Zone	4	904,183.59	932,458.27	820,521.33	813,530.14	731,390.83	841,897.81	907,608.80	1,095,466.62	1,003,103.00	861,831.83	779,366.20	795,731.34	10,487,089.753
Zone	29	189,731.55	183,915.85	165,135.79	164,329.05	144,952.97	155,319.16	167,774.48	197,183.18	191,185.27	163,611.73	162,093.02	171,403.95	2,056,636.007
Zone	31	68,660.48	72,477.01	64,696.78	57,481.21	45,259.83	44,185.97	42,780.18	50,356.87	48,646.38	43,881.50	48,447.14	54,384.86	641,258.223
	Total	3,295,155.610	3,357,754.309	3,015,656.756	3,028,342.981	2,711,117.277	2,931,905.564	3,111,765.035	3,631,029.341	3,464,989.157	3,005,077.714	2,869,995.312	2,921,399.467	37,344,188.523
X4	z1 HLFF	7,263.18	8,513.85	2,912.99	3,297.31	2,959.10	3,140.92	3,007.17	3,438.66	3,213.05	2,928.81	2,702.00	2,780.59	46,157.615
X4	z4 HLFF	23,500.69	22,496.88	644.76	589.95	498.28	538.29	618.30	703.96	661.18	548.79	532.75	583.83	51,917.655
	Total HLFF	30,763.864	31,010.729	3,557.749	3,887.265	3,457.383	3,679.201	3,625.463	4,142.621	3,874.229	3,477.594	3,234.754	3,364.418	98,075.270
	LSEs are not paying station service													
X6	SS.1	536.89	513.23	459.13	480.00	411.12	402.07	402.50	401.97	438.74	382.85	378.93	403.44	5,210.86
X6	SS.2	409.06	431.01	390.06	400.38	307.83	294.05	283.49	288.18	292.42	283.06	351.92	347.99	4,079.45
X6	SS.3	14.07	14.31	12.83	14.26	744.05	718.59	13.31	353.67	512.13	13.27	599.19	486.89	3,496.54
X6	SS.4	508.61	576.45	684.46	698.23	881.65	854.21	567.96	537.06	562.46	582.69	516.23	690.24	7,660.24
X6	SS.5	1,006.07	139.98	20.60	560.56	1,010.75	1,056.71	809.11	151.60	105.41	103.46	799.71	668.68	6,432.62
X6	SS.6	118.75	126.88	118.98	96.96	52.76	38.79	22.34	22.64	22.20	26.94	59.60	90.74	797.58
X6	SS.7	277.54	646.05	19.99	318.92	812.21	787.63	470.81	94.21	62.71	174.86	300.91	472.26	4,438.10
X6	SS.8	435.83	467.45	421.79	469.46	412.82	380.95	379.06	378.64	370.95	357.76	375.82	382.76	4,833.31
X6	SS.9	146.80	148.41	143.51	174.73	174.38	184.88	181.78	202.54	177.41	177.32	192.69	175.39	2,079.85
X6	SS.10	1,144.89	1,289.65	1,158.33	1,076.88	885.81	837.59	796.02	858.65	994.33	3,393.39	4,289.61	1,715.25	18,440.38
X6	SS.11	237.10	245.97	265.93	204.90	-	150.39	144.86	34.97	6.49	20.46	97.34	142.54	1,550.94
X6	SS.12	313.16	313.43	301.68	264.53	213.13	192.28	221.72	269.38	237.84	207.47	220.63	241.81	2,997.06
X6	SS.13	1,134.16	1,199.88	1,467.01	1,334.10	1,155.12	1,322.30	984.75	1,053.09	1,749.43	982.06	1,048.42	1,509.18	14,939.50
X6	SS.14	940.80	1,202.85	802.93	764.27	694.51	703.30	1,071.16	1,138.77	730.35	797.11	787.84	664.84	10,298.73
X6	SS.15	2.96	2.98	2.68	2.97	2.93	2.99	2.95	3.01	2.99	2.87	3.00	2.93	35.26
X6	SS.16	82.05	61.38	76.30	76.50	69.42	66.39	65.23	69.91	68.65	65.93	67.99	73.10	842.86
X6	SS.17	-	-	-	-	-	-	-	-	-	-	-	61.22	61.22
X6	SS.18	1,818.43	2,146.12	1,860.43	2,641.79	2,445.52	2,181.05	1,242.34	2,003.96	2,450.06	2,414.06	2,576.01	2,647.71	26,427.47
X6	SS.19	-	-	-	-	-	-	-	-	-	-	-	-	-
X6	SS.20	1,038.79	1,821.93	961.36	923.08	677.85	-	901.20	1,191.30	1,116.97	1,137.43	1,065.09	864.04	11,699.01
X6	SS.21	-	-	-	-	-	-	-	-	0.02	0.09	-	0.07	0.18
X6	SS.22	0.20	-	0.12	0.06	0.08	-	0.04	-	-	-	-	0.49	0.98
X6	SS.23	70.52	71.24	63.31	72.10	64.87	59.90	55.00	59.64	65.30	52.24	55.78	58.60	748.49
X6	SS.24	241.68	249.64	225.40	234.95	213.93	210.91	204.42	200.27	196.07	189.88	209.00	216.93	2,593.08
X6	SS.25	5.77	6.01	6.83	6.48	4.86	3.51	2.63	2.58	2.63	3.01	5.26	6.82	56.38
X6	SS.26	83.34	4.22	63.69	117.26	33.74	105.73	138.96	77.11	73.47	71.99	-	-	769.50
X6	SS.27	63.66	249.37	134.07	101.43	206.29	190.91	24.87	24.30	73.55	114.97	101.89	140.12	1,425.41
X6	SS.28	755.94	1,060.42	975.27	308.62	100.77	656.99	928.47	752.68	807.88	220.19	588.44	947.52	8,103.17
X6	SS.29	1,589.89	986.55	1,300.85	2,447.96	342.74	151.90	117.48	501.05	232.48	605.78	856.48	635.00	9,768.15
X6	SS.30	99.68	106.05	89.77	83.34	74.95	80.31	86.81	74.49	76.66	71.75	79.18	73.47	996.46
X6	SS.31	3,989.98	-	134.00	-	-	-	-	-	-	-	743.45	5,263.41	10,130.85
Total X6		17,066.611	14,081.419	12,161.302	13,874.718	11,994.087	11,634.326	10,119.262	10,745.654	11,429.588	12,452.881	16,370.386	18,983.407	160,913.641

Niagara Mohawk Power Corporation
Billing Unit Summary

Workpaper 13
Page 2 of 2

Shading denotes an input

Reason Code	Reference Number	2009 Dec	2010 Jan	2010 Feb	2010 Mar	2010 Apr	2010 May	2010 Jun	2010 Jul	2010 Aug	2010 Sep	2010 Oct	2010 Nov	Total Dec - Nov
	300000 Series PTIDs													
X1	A.1	3,390.78	3,662.08	3,322.82	2,907.52	2,250.66	2,173.82	2,125.44	2,443.99	2,357.50	2,002.94	2,279.92	2,584.26	31,501.71
X1	A.2	43,463.33	45,392.15	38,971.11	37,431.27	35,046.94	35,279.21	34,352.58	36,671.52	36,215.26	35,286.34	38,121.21	40,715.15	456,946.07
X1	A.3	16,856.43	18,779.08	18,433.83	13,652.65	3,943.91	2,132.47	1,751.80	2,631.73	2,544.35	1,208.94	3,567.47	7,587.11	93,089.76
X1	A.4	36,384.99	39,593.61	36,851.05	39,318.14	34,178.15	34,382.25	37,534.72	36,208.64	34,847.31	34,539.70	38,145.81	37,196.97	439,181.34
X1	B.1	50,005.85	52,728.59	48,238.29	50,615.90	47,395.42	48,757.04	43,481.23	52,517.84	46,686.94	44,430.44	46,990.11	45,461.71	577,309.35
X1	B.2	41,219.32	42,546.08	35,647.97	34,635.79	32,573.26	35,251.97	34,756.65	37,504.11	35,763.90	33,318.41	34,827.46	38,639.82	436,684.75
X1	B.3	11,696.02	13,929.96	13,148.13	7,739.47	234.78	667.53	2,005.75	5,502.33	4,477.20	401.90	-	1,797.69	61,600.74
X1	C.1	6,785.47	7,166.09	6,373.03	6,367.42	5,308.09	5,746.52	5,286.46	6,399.82	6,123.23	5,281.37	5,519.86	5,536.59	71,893.94
X1	C.2	20,086.26	21,088.98	17,878.96	17,361.52	15,319.34	14,718.37	14,314.43	15,822.88	15,011.48	14,042.28	16,111.08	18,411.65	200,167.21
X1	C.3	5,750.73	6,142.10	5,568.93	3,257.66	485.87	351.27	342.52	896.36	789.13	167.38	620.47	1,883.78	26,256.19
X3	C.4	811.19	660.66	657.05	619.46	570.68	526.78	477.02	554.81	571.34	486.94	493.16	525.49	6,954.58
X3	C.5	-	0.01	0.04	23.53	-	0.13	0.18	-	1.64	39.18	0.33	-	65.03
X4	D.1	2,914.75	3,026.17	2,591.09	2,798.60	2,588.32	2,571.00	2,420.78	2,587.50	2,438.83	2,493.36	2,808.12	3,017.97	32,256.48
X4	D.2	2,171.49	2,250.97	2,040.83	1,482.78	811.65	933.32	1,201.08	1,615.54	1,413.78	857.02	704.38	1,033.97	16,516.81
X3	D.3	-	1.73	-	0.10	0.02	-	-	0.08	-	-	6.30	-	8.23
X3	D.4	1.76	7.84	-	-	-	-	-	0.14	0.09	-	8.41	-	18.23
X3	D.5	216.65	228.96	229.60	208.06	110.90	78.37	70.50	79.89	81.39	75.14	100.30	135.41	1,615.18
X5	D.6	397.71	144.68	-	9.82	20.87	116.13	421.79	54.26	81.22	-	315.74	168.86	1,731.07
X5	D.7	821.73	790.64	697.36	709.75	224.60	22.24	-	334.61	76.68	-	-	264.52	3,942.13
X5	D.8	276.00	814.43	613.56	283.56	-	235.74	223.34	91.61	155.08	106.54	133.97	-	2,933.83
X1	E.1	1,310.40	1,423.11	1,181.92	1,169.34	1,098.15	1,221.79	740.29	1,216.50	1,116.50	1,372.92	1,419.34	1,334.92	14,605.18
X1	E.2	8,505.95	8,844.20	7,365.90	7,654.95	7,314.76	7,807.70	7,527.93	8,083.25	7,853.65	7,761.92	8,192.96	8,041.96	94,955.13
X1	E.3	698.04	640.10	645.46	450.68	253.38	315.20	2,665.91	2,741.92	4,535.53	4,093.09	2,609.97	2,346.57	21,995.86
X1	E.4	3,199.19	3,198.67	3,460.97	2,559.17	910.61	562.01	907.34	1,227.76	1,195.65	449.57	630.96	1,692.12	19,994.02
X1	F.1	31,194.54	33,655.10	30,133.28	24,835.56	16,968.26	13,849.91	12,494.89	15,250.84	14,380.60	13,113.10	18,615.50	22,478.18	246,969.76
Total 300000 Series		288,158.554	306,715.982	274,051.172	256,092.680	207,608.598	207,700.761	205,102.625	230,437.944	218,718.261	201,528.471	222,222.830	240,854.666	2,859,192.544

Reason Code Key

X1	included	NYPA, NYMPA, Jamestown and Misc Villages (some of which are NYPA)
X2	no longer applicable - referred to year in which some municipals converted to the TSC rate	
X3	reported not billed	
X4	excluded - in WR	
X5	Athens	
X6	Disputed Station Service	

Reason Code	Dec - Nov Total
X1	2,793,150.989
X2	0.000
X3	8,661.247
X4	48,773.286
X5	8,607.022
X6	160,913.641
Total	3,020,106.185

Niagara Mohawk Power Corporation **Workpaper 14**
Billing Adjustment to be included in 2011 Informational Filing **Page 1 of 1**
Attachment H Section 9.2 (c)

Line No.		2010 UPDATE 2009			Source:
1					
2	9.2(d) The Annual True-Up (ATU) shall equal (1) the difference between the Actual Transmission Revenue Requirement and the Prior Year				
3	Transmission Revenue Requirement, plus (2) the difference between the Actual Scheduling, System Control and Dispatch costs				
4	and Prior Year Scheduling, System Control and Dispatch costs, less (3) the difference between the Actual Billing Units and the Prior Year				
5	Billing Units multiplied by the Prior Year Unit Rate, plus (4) Interest on the net differences.				
6		**ORIGINAL**	**REVISED**	**Billing Adjustment**	
7	(1) Revenue Requirement (RR) of rate effective July 1 of prior year	$274,084,485	$274,084,485		Schedule 4, Line 1, Col (d)
8	Less: Annual True-up (ATU) from rate effective July 1 of prior year	$4,555,970	$4,555,970		Schedule 4, Line 1, Col (c)
9	Prior Year Transmission Revenue Requirement	$269,528,515	$269,528,515		Line 7 - Line 8
10					
11	Actual Transmission Revenue Requirement	$250,606,591	$248,236,337	$2,370,254	Schedule 4, Line 2, Col (a)
12	Difference	($18,921,924)	($21,292,178)	$2,370,254	Line 11 - Line 9
13					
14	(2) Prior Year Scheduling, System Control and Dispatch costs (CCC)	$6,056,721	$6,056,721		Schedule 4, Line 1, Col (e)
15	Actual Scheduling, System Control and Dispatch costs (CCC)	$6,345,322	$6,345,322		Schedule 4, Line 2, Col (e)
16	Difference	$288,601	$288,601		Line 15 - Line 14
17					
18	(3) Prior Year Billing Units (MWH)	36,954,476	36,954,476		Schedule 4, Line 1, Col (f)
19	Actual Billing Units	35,134,660	35,134,660		Schedule 4, Line 2, Col (f)
20	Difference	1,819,816	1,819,816		Line 18 - Line 19
21	Prior Year Indicative Rate	7.58	7.58		Schedule 4, Line 1, Col (g)
22	Billing Unit True-Up	$13,795,496	$13,795,496		Line 20 * Line 21
23					
24	Total Annual True-Up before Interest	($4,837,827)	($7,208,081)	$2,370,254	(Line 12 + Line 16 + Line 22)
25	LTD Rate 6 month phase plus current	($3,167,691)	($3,167,691)		Wkpp 14 - Per Settlement ATU Line 27, Col (a)
26	Total Annual True-Up before Interest	($8,005,519)	($10,375,772)	**$2,370,254**	(Line 24 + Line 25)
27					
28	(4) 2009 Interest	$ (43,430)	$ (56,289)	$ 12,859	Line 57
29	2010 Interest				Included in filing
30	Annual True-up RR Component	($8,048,949)	($10,432,061)	**$2,383,112**	**Billing Adjmt incl in Schedule 10, Line 1**
31					

Line No.	Interest Calculation per 18 CFR Section 35.19a								
32									
33	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
34	Quarters	Annual	Accrued Prin	Monthly	Days			Accrued Prin	Accrued
35		Interest	& Int. @ Beg	(Over)/Under	in	Period		& Int. @ End	Int. @ End
36		Rate	Of Period	Recovery	Period	Days	Multiplier	Of Period	Of Period
37									
38	3rd QTR '09		0		92	92	1.0000	$0	$0
39	July	3.25%		(864,648)	31	92	1.0082	($871,738)	($7,090)
40	August	3.25%		(864,648)	31	61	1.0054	($869,317)	($4,669)
41	September	3.25%		(864,648)	30	30	1.0027	($866,982)	($2,335)
42									
43	4th QTR '09		(2,608,037)		92	92	1.0000	($2,608,037)	$0
44	October	3.25%		(864,648)	31	92	1.0082	($871,738)	($7,090)
45	November	3.25%		(864,648)	30	61	1.0054	($869,317)	($4,669)
46	December	3.25%		(864,648)	31	31	1.0028	($867,069)	($2,421)
47									
48	1st QTR '10		(5,216,160)		91	91	1.0000	($5,216,160)	$0
49	January	3.25%		(864,648)	31	91	1.0081	($871,651)	($7,004)
50	February	3.25%		(864,648)	29	60	1.0053	($869,230)	($4,583)
51	March	3.25%		(864,648)	31	31	1.0028	($867,069)	($2,421)
52									
53	2nd QTR '10		(7,824,110)		91	91	1.0000	($7,824,110)	$0
54	April	3.25%		(864,648)	30	91	1.0081	($871,651)	($7,004)
55	May	3.25%		(864,648)	31	61	1.0054	($869,317)	($4,669)
56	June	3.25%		(864,648)	30	30	1.0027	($866,982)	($2,335)
57									
58									
59	Total (over)/under Recovery			($10,375,772) (line 26)					($56,289)

Niagara Mohawk Power Corporation **Workpaper 15**
Billing Unit Reconciliation **Page 1 of 1**

		2010	
Line No.	**Comment**	**Schedule 12**	**TOL File (X1)**
1	Totals per filing	2,805,582	2,793,151
2	Overages	(3,018)	
3	Unaccounted for Energy (UFE) not billed		10,349
4	Other and Rounding		(936)
5	**Reconciliation**	**2,802,564**	**2,802,564**

Niagara Mohawk Power Corporation **Workpaper 16**
NYPSC §18-a Assessments **Page 1 of 1**
Breakdown of FF1 Page 351, Line 1, Column h

Line No.	Month	General Assessment Expense (a)	Temporary Assessment Expense (b)	Deferrals on Over/Under Collection of the ISAS (c)	Reimburements on Prior Year Assessments (d)	Other (e)	TOTAL (f)
1	Jan-2010	649,806	6,671,561	609,140			7,930,506
2	Feb-2010	649,806	6,671,561	(58,443)			7,262,924
3	Mar-2010	649,806	6,671,561	(296,574)			7,024,793
4	Apr-2010	720,873	6,722,035	(708,489)			6,734,419
5	May-2010	720,873	6,722,035	(900,018)			6,542,890
6	Jun-2010	720,873	6,722,035	(188,820)			7,254,088
7	Jul-2010	720,873	6,722,035	(515,109)			6,927,799
8	Aug-2010	720,873	6,722,035	906,113			8,349,021
9	Sep-2010	720,873	(1,688,757)	10,718,534			9,750,650
10	Oct-2010	623,989	5,320,237	1,054,224			6,998,450
11	Nov-2010	623,989	5,320,237	852,929			6,797,154
12	Dec-2010	623,989	5,320,237	1,484,673		1,805	7,430,704
13	CY2010 Total	8,146,620	67,896,811	12,958,160	-	1,805	89,003,397

14	50% of NY PSC Regulatory Expense	(Line 13, column a + column e)	8,148,425
15	18a Charges (Temporary Assessment)	(Line 13, column b + column c)	80,854,971

Notes:
ISAS = Incremental State Assessment Surcharge (total general + temporary assessement expense above base rate allowance)

1\ agrees to FERC Form 1 page 351 line 1 column h

2011 UPDATE
2010 Data

Table of contents

Attachment 1 to Attachment H

Schedules

Informational Filing - Workpapers

Niagara Mohawk Power Corporation | **Attachment 1**
~~Calculation of RR Pursuant to Attachment H, Section 14.1.9.2~~ | **Schedule 1**

Shading denotes an input | **2010**

Calculation of RR

~~14.1.9.2~~ The RR component shall equal the (a) Historical Transmission Revenue Requirement plus (b) the Forecasted Transmission Revenue Requirement plus (c) the Annual True-Up, determined in accordance with the formula below.

Historical Transmission Revenue Requirement (Historical TRR)

Line No.			Reference Section:	2010	
1		**Historical Transmission Revenue Requirement (Historical TRR)**			
2					
3	~~14.1.9.2 (a~~	Historical TRR shall equal the sum of NMPC's (A) Return and Associated Income Taxes, (B) Transmission Related Depreciation			
4		Expense, (C) Transmission Related Real Estate Tax Expense, (D) Transmission Related Amortization of Investment Tax Credits,			
5		(E) Transmission Operation and Maintenance Expense, (F) Transmission Related Administrative and General Expenses,			
6		(G) Transmission Related Payroll Tax Expense, (H) Billing Adjustments, and (I) Transmission Related Bad Debt Expense less (J) Revenue			
7		Credits, and (K) Transmission Rents, all determined for the most recently ended calendar year as of the beginning of the update year.			
8					
9					
10		Return and Associated Income Taxes	(A)	$133,829,768	Schedule 8, line 64
11		Transmission-Related Depreciation Expense	(B)	$34,783,085	Schedule 9, Line 6, column 5
12		Transmission-Related Real Estate Taxes	(C)	$38,313,586	Schedule 9, Line 12, column 5
13		Transmission - Related Investment Tax Credit	(D)	($364,943)	Schedule 9, Line 16, column 5
14		Transmission Operation & Maintenance Expense	(E)	$65,484,668	Schedule 9, Line 23, column 5
15		Transmission Related Administrative & General Expense	(F)	$47,417,836	Schedule 9, Line 37, column 5
16		Transmission Related Payroll Tax Expense	(G)	$2,374,562	Schedule 9, Line 43, column 5
17		Sub-Total (sum of Lines 10 - Line 16)		$321,838,562	
18					
19		Plus: Billing Adjustments	(H)	($2,487,006)	Schedule 10, Line 1
20		Plus : Bad Debt Expenses	(I)	($796)	Schedule 10, Line 4
21		Less: Revenue Credits	(J)	($47,222,149)	Schedule 10, Line 7
22		Less: Transmission Rents	(K)	($1,589,444)	Schedule 10, Line 14
23					
24		Total Historical Transmission Revenue Requirement (Sum of Line 17 - Line 22)		$270,539,167	

Niagara Mohawk Power Corporation
Forecasted Transmission Revenue Requirement
~~Attachment H, Section 14.1.9.2~~

Attachment 1
Schedule 2

Shading denotes an input

2010

Line No.			Period	Reference		Source
1	~~4.1.9.2 (b~~	**FORECASTED TRANSMISSION REVENUE REQUIREMENTS**				
2		Forecasted TRR shall equal (1) the Forecasted Transmission Plant Additions (FTPA) multiplied by the Annual FTRRF, plus (2) the Mid-Year Trend				
3		Adjustment (MYTA), plus (3) the Tax Rate Adjustment (TRA), as shown in the following formula:				
4						
5		Forecasted TRR = (FTPA * FTRRF) + MYTA + TRA				
6						
7						
8						
9						
10	(1)	Forecasted Transmission Plant Additions (FTPA)	2010		$94,116,015	Workpaper 8, Section I, Line 16
11		Annual Transmission Revenue Requirement Factor (FTRRF)			11.05%	Line 35
12		Sub-Total (Lines 10*11)			$10,402,423	
13		Plus Mid-Year Trend Adjustment (2) (MYTA)			-$2,155,786	Workpaper 9, line 31, variance column
14		Forecasted Transmission Revenue Requirement (Line 12 + Line 13)			**$8,246,637**	
15						
16	(2)	**MID YEAR TREND ADJUSTMENT (MYTA)**				
17		The Mid-Year Trend Adjustment shall be the difference, whether positive or negative, between				
18		(i) the Historical TRR Component (E) based on actual data for the first three months of the Forecast Period,				
19		and (ii) the Historical TRR Component (E) based on data for the first three months of the year prior to the Forecast Period.				Workpaper 9
20						
21	(3)	**The Tax Rate Adjustment (TRA)**				
22		The Tax Rate Adjustment shall be the amount, if any, required to adjust Historical TRR Component (A) for any change in the Federal Income Tax Rate				
23		and/or the State Income Tax Rate that takes effect during the first five months of the Forecast Period.				
24						
25	~~4.1.9.2 (c~~	**ANNUAL TRANSMISSION REVENUE REQUIREMENT FACTOR**				
26		The Annual Forecast Transmission Revenue Requirement Factor (Annual FTRRF) shall equal the sum of Historical TRR components (A) through (C),				
27		~~divided by the year-end balance of Transmission Plant in Service determined in accordance with Section 14.1.9.2 (a), component (A)1(a).~~				
28						
29						
30		Investment Return and Income Taxes		(A)	$133,829,768	Schedule 1, Line 10
31		Depreciation Expense		(B)	$34,783,085	Schedule 1, Line 11
32		Property Tax Expense		(C)	$38,313,586	Schedule 1, Line 12
33		Total Expenses (Lines 30 thru 32)			$206,926,439	
34		Transmission Plant		(a)	$1,872,168,717	Schedule 6, Page 1, Line 12
35		Annual Transmission Revenue Requirement Factor (Lines 33/ Line 34)			11.05%	

Niagara Mohawk Power Corporation
Annual True-up (ATU)
~~Attachment H Section 14.1.9.2 (c)~~

Attachment 1
Schedule 3

Shading denotes an input

2010

Line No.			Source:
1			
2	~~14.1.9.2(~~ The Annual True-Up (ATU) shall equal (1) the difference between the Actual Transmission Revenue Requirement and the Prior Year		
3	Transmission Revenue Requirement, plus (2) the difference between the Actual Scheduling, System Control and Dispatch costs		
4	and Prior Year Scheduling, System Control and Dispatch costs, less (3) the difference between the Actual Billing Units and the Prior Year		
5	Billing Units multiplied by the Prior Year Unit Rate, plus (4) Interest on the net differences.		
6			
7	(1) Revenue Requirement (RR) of rate effective July 1 of prior year	$252,031,733	Schedule 4, Line 1, Col (d)
8	Less: Annual True-up (ATU) from rate effective July 1 of prior year	($8,048,949)	Schedule 4, Line 1, Col (c)
9	Prior Year Transmission Revenue Requirement	$260,080,682	Line 7 - Line 8
10			
11	Actual Transmission Revenue Requirement	$270,539,167	Schedule 4, Line 2, Col (a)
12	Difference	$10,458,485	Line 11 - Line 9
13			
14	(2) Prior Year Scheduling, System Control and Dispatch costs (CCC)	$6,345,322	Schedule 4, Line 1, Col (e)
15	Actual Scheduling, System Control and Dispatch costs (CCC)	$6,748,771	Schedule 4, Line 2, Col (e)
16	Difference	$403,449	Line 15 - Line 14
17			
18	(3) Prior Year Billing Units (MWH)	35,134,660	Schedule 4, Line 1, Col (f)
19	Actual Billing Units	37,088,552	Schedule 4, Line 2, Col (f)
20	Difference	(1,953,892)	Line 18 - Line 19
21	Prior Year Indicative Rate	7.35	Schedule 4, Line 1, Col (g)
22	Billing Unit True-Up	($14,368,745)	Line 20 * Line 21
23			
24	Total Annual True-Up before Interest	($3,506,812)	(Line 12 + Line 16 + Line 22)
25			
26	Total Annual True-Up before Interest	($3,506,812)	(Line 24 + Line 25)
27			
28	(4) Interest	$ (18,995)	Line 59
29			
30	Annual True-up RR Component	($3,525,807)	(Line 24 + Line 26)
31			

Line No.	Interest Calculation per 18 CFR Section 35.19a								
33	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
34	Quarters	Annual	Accrued Prin	Monthly	Days			Accrued Prin	Accrued
35		Interest	& Int. @ Beg	(Over)/Under	in	Period		& Int. @ End	Int. @ End
36		Rate	Of Period	Recovery	Period	Days	Multiplier	Of Period	Of Period
37		**Updated**							
38	3rd QTR '10		0		92	92	1.0000	$0	$0
39	July	3.25%		(292,234)	31	92	1.0082	($294,631)	($2,396)
40	August	3.25%		(292,234)	31	61	1.0054	($293,812)	($1,578)
41	September	3.25%		(292,234)	30	30	1.0027	($293,023)	($789)
42									
43	4th QTR '10		(881,466)		92	92	1.0000	($881,466)	$0
44	October	3.25%		(292,234)	31	92	1.0082	($294,631)	($2,396)
45	November	3.25%		(292,234)	30	61	1.0054	($293,812)	($1,578)
46	December	3.25%		(292,234)	31	31	1.0028	($293,053)	($818)
47									
48	1st QTR '11		(1,762,962)		90	90	1.0000	($1,762,962)	$0
49	January	3.25%		(292,234)	31	90	1.0080	($294,572)	($2,338)
50	February	3.25%		(292,234)	28	59	1.0053	($293,783)	($1,549)
51	March	3.25%		(292,234)	31	31	1.0028	($293,053)	($818)
52									
53	2nd QTR '11		(2,644,370)		91	91	1.0000	($2,644,370)	$0
54	April	3.25%		(292,234)	30	91	1.0081	($294,601)	($2,367)
55	May	3.25%		(292,234)	31	61	1.0054	($293,812)	($1,578)
56	June	3.25%		(292,234)	30	30	1.0027	($293,023)	($789)
57									
58									
59	Total (over)/under Recovery			($3,506,812)	(line 26)				($18,995)

Niagara Mohawk Power Corporation Wholesale TSC Calculation Information
2011 Forecast using 2010 Historical Data and 2011 Forecast

Attachment 1
Schedule 4

Shading denotes an input

		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	**Description**	**Historical Transmission Revenue Requirement (Historical TRR)**	**Forecasted Transmission Revenue Requirement**	**Annual True Up**	**Revenue Requirement (RR)**	**Scheduling System Control and Dispatch Costs (CCC)**	**Annual Billing Units (BU) MWh**	**Rate $/MWh (*)**
1	Current Year Rates Effective July 1, 2010	250,606,591	9,474,091	($8,048,949)	252,031,733	6,345,322	35,134,660	7.35
2	Current Year Rates Effective July 1, 2011	270,539,167	8,246,637	($3,525,807)	275,259,997	6,748,771	37,088,552	7.60
3	Increase/(Decrease)				23,228,264	403,449	1,953,892	0.25
4	Percentage Increase/(Decrease)							3%

1.) Information directly from Niagara Mohawk Prior Year Informational Filing adjusted per the Nov 30, 2009 Filing to reflect changes in the debt rate calculation.
2.)
(a) Schedule 1, Line 24
(b) Schedule 2, Line 14
(c) Schedule 3, Line 30
(d) ~~Attachment H, Section 14.1.9.2 The RR Component shall equal Col (a) Historical Transmission Revenue Requirement plus Col (b) the Forecasted Transmission Revenue Requirement~~ plus Col (c) the Annual True-Up
(e) Schedule 11 - Annual Scheduling, System Control and Dispatch Costs. (i.e. the Transmission Component of control center costs) as recorded in FERC Account 561 and its associated sub-accounts from the prior calendar year excluding any NY Independent System Operating (NYISO) system control and load dispatch expenses already recovered under Schedule 1 of the NYISO Tariff.
(f) Schedule 12 - Billing Units shall be the total Niagara Mohawk load as reported to the NYISO for the calendar year prior to the Forecast Period, including the load for customers taking service under Niagara Mohawk's TSC rate. The total Niagara Mohawk load will be adjusted to exclude (i) load associated with wholesale transactions being revenue credited through the WR, CRR, SR, ECR, and Reserved components of Attachment H of the NYISO TSC rate including Niagara Mohawk's external sales, load associated with grandfathered OATT agreements, and any load related to pre-OATT grandfathered agreements; (ii) load associated with transactions being revenue credited under Historical TRR Component J; and (iii) load associated with netted station service.
(g) (Col (d) + Col (e)) / Col (f)

(*) The rate column represents the unit rate prior to adjustments; the actual rate will be determined pursuant to the applicable TSC formula rate.

Niagara Mohawk Power Corporation **Attachment 1**
~~Allocation Factors - As calculated pursuant to Section 14.1.9.1~~ **Schedule 5**

Shading denotes an input **2010**

Line No.		Description	Amount	Source	Defiinition
1	~~14.1.9.1~~	**Electric Wages and Salaries Factor**	**83.5000%**		Fixed per settlement
2					
3	~~14.1.9.1~~	**Transmission Wages and Salaries Allocation Factor**	**13.0000%**		Fixed per settlement
4					
5					
6					
7					
8	~~14.1.9.1~~	**Gross Transmission Plant Allocation Factor**			
9		Transmission Plant in Service	$1,872,168,717	Schedule 6, Page 2, Line 3, Col 5	Gross Transmission Plant Allocation Factor shall equal the total investment in
10		Plus: Transmission Related General	$40,274,055	Schedule 6, Page 2, Line 5, Col 5	Transmission Plant in Service, Transmission Related Electric General Plant,
11		Plus: Transmission Related Common	$34,179,455	Schedule 6, Page 2, Line 10, Col 5	Transmission Related Common Plant and Transmission Related Intangible Plant
12		Plus: Transmission Related Intangible Plant	$10,032,845	Schedule 6, Page 2, Line 15, Col 5	divided by Total Electric Plant plus Electric Common Plant.
13		Gross Transmission Investment	$1,956,655,071	Sum of Lines 9 - 13	
14					
15		Total Electric Plant	$6,765,790,850	FF1 207.104	
16		Plus: Electric Common	$262,918,887	Schedule 6, Page 2, Line 10, Col 3	
17		Gross Electric Plant in Service	$7,028,709,737	Line 15 + Line 16	
18					
19		**Percent Allocation**	**27.84%**	Line 13 / Line 17	
20					
21	~~14.1.9.1~~	**Gross Electric Plant Allocation Factor**			
22					Gross Electric Plant Allocation Factor shall equal
23		Total Electric Plant in Service	$6,765,790,850	Line 15	Gross Electric Plant divided by the sum of Total Gas Plant,
24		Plus: Electric Common Plant	$262,918,887	Schedule 6, Page 2, Line 10, Col 3	Total Electric Plant, and Total Common Plant
25		Gross Electric Plant in Service	$7,028,709,737	Line 23 + Line 24	
26					
27		Total Gas Plant in Service	$1,840,736,258	FF1 201.8d	
28		Total Electric Plant in Service	$6,765,790,850	Line 15	
29		Total Common Plant in Service	$314,872,918	Schedule 6, Page 2, Line 10, Col 1	
30		Gross Plant in Service (Gas & Electric)	$8,921,400,026	Sum of Lines 27-Lines 29	
31					
32		**Percent Allocation**	**78.78%**	Line 25 / Line 30	

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Transmission Investment Base (Part 1 of 2)
~~Attachment H, section 14.1.9.2~~

Attachment 1
Schedule 6
Page 1 of 2

Line No.		Description	Reference Section:	2010	Reference
1	~~14.1.9.2 (a)~~	Transmission Investment Base			
2					
3	A.1.	Transmission Investment Base shall be defined as (a) Transmission Plant in Service, plus (b) Transmission Related Electric General Plant, plus			
4		(c) Transmission Related Common Plant, plus (d) Transmission Related Intangible Plant, plus (e) Transmission Related Plant Held for Future Use, less			
5		(f) Transmission Related Depreciation Reserve, less (g) Transmission Related Accumulated Deferred Taxes, plus (h) Transmission Related			
6		Regulatory Assets net of Regulatory Liabilities, plus (i) Transmission Related Prepayments, plus (j) Transmission Related Materials and Supplies,			
7		plus (k) Transmission Related Cash Working Capital.			
8					
9					
10					
11					
12		Transmission Plant in Service	(a)	$1,872,168,717	Schedule 6, page 2, line 3, column 5
13		General Plant	(b)	$40,274,055	Schedule 6, page 2, line 5, column 5
14		Common Plant	(c)	$34,179,455	Schedule 6, page 2, line 10, column 5
15		Intangible Plant	(d)	$10,032,845	Schedule 6, page 2, line 15, column 5
16		Plant Held For Future Use	(e)	$0	Schedule 6, page 2, line 19, column 5
17		Total Plant (Sum of Line 12 - Line 16)		$1,956,655,071	
18					
19		Accumulated Depreciation	(f)	($571,581,816)	Schedule 6, page 2, line 29, column 5
20		Accumulated Deferred Income Taxes	(g)	($304,830,100)	Schedule 7, line 6, column 5
21		Other Regulatory Assets	(h)	$20,074,963	Schedule 7, line 11, column 5
22		Net Investment (Sum of Line 17 -Line 21)		$1,100,318,118	
23					
24		Prepayments	(i)	$10,226,833	Schedule 7, line 15, column 5
25		Materials & Supplies	(j)	$8,449,675	Schedule 7, line 21, column 5
26		Cash Working Capital	(k)	$8,185,583	Schedule 7, line 28, column 5
27					
28		Total Investment Base (Sum of Line 22 - Line 26)		$1,127,180,209	

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Transmission Investment Base (Part 1 of 2)
~~Attachment H Section 14.1.9.2 (a) A. 1.~~

Attachment 1
Schedule 6
Page 2 of 2

Shading denotes an input

2010

Line No.		(1) Total	(2) Allocation Factor	(3) = (1)*(2) Electric Allocated	(4) Allocation Factor	(5) = (3)*(4) Transmission Allocated	FERC Form 1/PSC Report Reference for col (1)		Definition
1	Transmission Plant					$1,872,079,472	FF1 207.58g	~~14.1.9.2(a)A.1.(~~	Transmission Plant in Service shall equal the
2	Wholesale Meter Plant					$89,245	Workpaper 1, Line 51		balance of total investment in Transmission Plant
3	Total Transmission Plant in Service (Line 1+ Line 2)					$1,872,168,717			plus Wholesale Metering Investment
4									
5	General Plant	$309,800,420	100.00%	$309,800,420	13.00% (c)	$40,274,055	FF1 207.99g	~~14.1.9.2(a)A.1.(~~	Transmission Related Electric General Plant shall
6									equal the balance of investment in Electric General
7									Plant mulitplied by the Transmission Wages and
8									Salaries Allocation Factor
9									
10	Common Plant	$314,872,918	83.50% (a)	$262,918,887	13.00% (c)	$34,179,455	FF1 201. 8h	~~14.1.9.2(a)A.1.(~~	Transmission Related Common Plant shall equal Common
11									Plant multiplied by the Electric Wages and Salaries
12									Allocation Factor and further multiplied by the
13									Transmission Wages and Salaries Allocation Factor.
14									
15	Intangible Plant	$77,175,727	100.00%	77,175,727	13.00% (c)	$10,032,845	FF1 205.5g	~~14.1.9.2(a)A.1.(~~	Transmission Related Intangible Plant shall equal Intangible
16									Electric Plant multiplied by the Transmission Wages and
17									Salaries Allocation Factor.
18									
19	Transmission Plant Held for Future Us	$0				$0	Workpaper 10, Line 1	~~14.1.9.2(a)A.1.(~~	Transmission Related Plant Held for Future Use shall equal
20									the balance in Plant Held for Future Use associated with
21									property planned to be used for transmission service within
22									five years
23	Transmission Accumulated Depreciation								
24	Transmission Accum. Depreciation	($526,326,494)				($526,326,494)	FF1 219.25b	~~14.1.9.2(a)A.1.(~~	Transmission Related Depreciation Reserve shall equal the
25	General Plant Accum.Depreciation	($184,594,804)	100.00%	($184,594,804)	13.00% (c)	($23,997,325)	FF1 219.28b		balance of: (i) Transmission Depreciation Reserve, plus (ii)
26	Common Plant Accum Depreciation	($107,880,579)	83.50% (a)	($90,080,283)	13.00% (c)	($11,710,437)	FF1 356.1 end of year balance		the product of Electric General Plant Depreciation Reserve
27	Amortization of Other Utility Plant	($73,292,452)	100.00%	($73,292,452)	13.00% (c)	($9,528,019)	FF1 200.21c		multiplied by the Transmission Wages and Salaries
28	Wholesale Meters	($19,542)				($19,542)	Workpaper 1, Line 52		Allocation Factor, plus (iii) the product of Common Plant
29	Total Depreciation (Sum of line 24 - Line 28)					($571,581,816)			Depreciation Reserve multiplied by the Electric Wages and
									Salaries Allocation Factor and further multiplied by the
									Transmission Wages and Salaries Allocation Factor plus (iv)
									the product of Intangible Electric Plant Depreciation Reserve
									multiplied by the Transmission Wages and Salaries
									Allocation Factor plus (v) depreciation reserve associated with
									the Wholesale Metering Investment

Allocation Factor Reference
(a) Schedule 5, line 1
(b) Schedule 5, line 32 - not used on this Schedule
(c) Schedule 5, line 3
(d) Schedule 5, line 19 - not used on this Schedule

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Transmission Investment Base (Part 2 of 2)
~~Attachment H Section 14.1.9.2 (a) A. 1.~~

Attachment 1
Schedule 7

Shading denotes an input

2010

Line No.		(1) Total	(2) Allocation Factor	(3) = (1)*(2) Electric Allocated	(4) Allocation Factor	(5) = (3)*(4) Transmission Allocated	FERC Form 1/PSC Report Reference for col (1)		Definition
1	Transmission Accumulated Deferred Taxes								
2	Accumulated Deferred Taxes (281-282)	($1,162,666,592)	100.00%	($1,162,666,592)	27.84% (d)	($323,663,598)	FF1 275.2k	~~14.1.9.2(a)A.1~~	Transmission Related Accumulated Deferred Income Taxes
3	Acumulated Deferred Taxes (283)	($531,168,588)	100.00%	($531,168,588)	27.84% (d)	($147,866,927)	Workpaper 2, Line 5		shall equal the electric balance of Total Accumulated Deferred
4	Accumulated Deferred Taxes (190)	$619,765,506	100.00%	$619,765,506	27.84% (d)	$172,530,573	FF1 234.8c		Income Taxes (FERC Accounts 190, 255,281, 282, and 283 net of
5	Accumulated Deferred Inv. Tax Cr (255)	($20,943,098)	100.00%	($20,943,098)	27.84% (d)	($5,830,148)	FF1 267.8h		stranded costs), multiplied by the Gross Transmission Plant
6	Total (Sum of line 2 - Line 5)			($1,095,012,772)		($304,830,100)			Allocation Factor.
7									
8	Other Regulatory Assets								
9	FAS 109 (Asset Account 182.3)	$121,505,005	100.00%	$121,505,005	27.84% (d)	$33,824,613	FF1 232 lines 1,16,20,29	~~14.1.9.2(a)A.1~~	Transmission Related Regulatory Assets shall be Regulatory
10	FAS 109 (Liability Account 254)	($49,391,587)	100.00%	($49,391,587)	27.84% (d)	($13,749,650)	FF1 278.1 lines 1 & 27(f)		Assets net of Regulatory Liabilities multiplied by the Gross
11	Total (line 9 + Line 10)	$72,113,418		$72,113,418		$20,074,963			Transmission Plant Allocation Factor.
12									
13	Transmission Prepayments	$58,577,794					FF1 111.57c	~~14.1.9.2(a)A.1~~	Transmission Related Prepayments shall be the product of
14	Less: Prepaid State and Federal Income Tax	($11,948,387)					FF1 263 lines 2 & 9 (h)		Prepayments excluding Federal and State taxes multiplied by
15	Total Prepayments	$46,629,407	78.78% (b)	$36,736,898	27.84% (d)	$10,226,833			the Gross Electric Plant Allocation Factor and further
16									multiplied by the Gross Transmission Plant Allocation Factor.
17									
18	Transmission Material and Supplies							~~14.1.9.2(a)A.1~~	Transmission Related Materials and Supplies shall equal: (i)
19	Trans. Specific O&M Materials and Supplies	$3,261,216				$3,261,216	FF1 227.8		the balance of Materials and Supplies assigned to
20	Contruction Materials and Supplies	$23,656,863	78.78% (b)	$18,638,019	27.84% (d)	$5,188,459	FF1 227.5		Transmission plus (ii) the product of Material and Supplies
21	Total (Line 19 + Line 20)					$8,449,675			assigned to Construction multiplied by the Gross Electric
22									Plant Allocation Factor and further multiplied by Gross
23									Transmission Plant Allocation Factor
24									
25	Cash Working Capital							~~14.1.9.2(a)A.1~~	Transmission Related Cash Working Capital shall be an
26	Operation & Maintenance Expense					$65,484,668	Schedule 9, Line 23		allowance equal to the product of: (i) 12.5% (45 days/ 360 days = 12.5%)
27						0.1250	x 45 / 360		multiplied by (ii) Transmission Operation and Maintenance Expense
28	Total (line 26 * line 27)					$8,185,583			

Allocation Factor Reference
(a) Schedule 5, line 1 - not used on this Schedule
(b) Schedule 5, line 32
(c) Schedule 5, line 3 - not used on this Schedule
(d) Schedule 5, line 19

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Cost of Capital Rate

Attachment 1
Schedule 8

Shading denotes an input — **2010**

Line No

1 **The Cost of Capital Rate shall equal the proposed Weighted Costs of Capital plus Federal Income Taxes and State Income Taxes.**
2 The Weighted Costs of Capital will be calculated for the Transmission Investment Base using NMPC's actual capital structure and will equal the sum of (i), (ii), and (iii) below:
3
4 (i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of NMPC's long-term debt outstanding during the year and the sum of (a) the ratio of actual long-term debt to total capital at year-end; a
5 (b) the extent, if any, by which the ratio of NMPC's actual common equity to total capital at year enc exceeds fifty percent (50%). Long term debt shall be defined as the average of the beginning of the year and end
6 of the year balances of the following: long term debt less the unamortized Discounts on Long-Term Debt less the unamortized
7 Loss on Reacquired Debt plus Unamortized Gain on Reacquired Debt. Cost to maturity of NMPC's long-term debt shall be defined as the cost of long term debt included in the debt discount expense and any loss or gain on reacquired debt.
8
9 (ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of NMPC's preferred stock then outstanding and the ratio of actual preferred stock to total capital at year-end;
10
11 (iii) the return on equity component shall be the product of the allowed return on equity of 11.5% and the ratio of NMPC's actual common equity to total capital at year-end, provided that such ratic
12 shall not exceed fifty percent (50%).

Line No			CAPITALIZATION	Source:	CAPITALIZATION RATIOS	COST OF CAPITAL		WEIGHTED COST OF CAPITAL	EQUITY PORTION
17	(i)	LONG-TERM DEBT	$2,374,309,846	Workpaper 6, Line 16b	49.55%	4.20%	Workpaper 6, Line 17c	2.08%	
18	(ii)	PREFERRED STOCK	$28,984,700	FF1 112.3c	0.45%	3.66%	Workpaper 6, Line 24d	0.02%	0.02%
19	(iii)	COMMON EQUITY	$3,984,099,488	112.16c - FF1 112.3,12,15c	50.00%	11.50%		5.75%	5.75%
20									
21		TOTAL INVESTMENT RETURN	$6,387,394,034		100.00%			7.85%	5.77%

26 ~~14.1.9.2.2.(b) Federal Income Tax s~~ = (A. + [B / C] X Federal Income Tax Rate)
27 (1 - Federal Income Tax Rate)
28
29 where A is the sum of the preferred stock component and the return on equity component, each as determined in Sections (a)(ii) and for the ROE set forth in (a)(iii) above, B is the Equity AFUDC component of Depreciation Expense for
30 ~~Transmission Plant in Service as defined at Section 14.1.9.1.16 (FF1 117.38c), and C is the Transmission Investment Base as shown at Schedule 6, Page 1 of 2, Line 28~~.
31
32 = (0.0577 +($4,082,548) / $1,127,180,209 X 35%)
33 (1 - 0.35)
34
35 = 0.0330195
36
37
38 ~~14.1.9.2.2.(c) State Income Tax sha~~ = (A. + [B / C] + Federal Income Tax) X State Income Tax Rate
39 (1 - State Income Tax Rate)
40
41 where A is the sum of the preferred stock component and the return on equity component as determined in (a)(ii) and (a)(iii) above , B is the Equity AFUDC component of Depreciation Expense for Transmission Plant in
42 ~~Service as defined at Section 14.1.9.1.16 above, and C is the Transmission Investment Base as shown at Schedule 6, Page 1 of 2, Line 28~~.
43
44
45
46 = (0.0577 +($4,082,548) / $1,127,180,209 + 0.0330195) X 7.10%
47 (1 - 0.071)
48
49 = 0.0072102
50
51
52
53 (a)+(b)+(c) Cost of Capital Rate = 11.87%
54
55
56 ~~**14.1.9.2(a) A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate**~~
57
58
59

Line No			
60	Transmission Investment Base	$1,127,180,209	Schedule 6, page 1 of 2, Line 28
61			
62	Cost of Capital Rate	0.1187297	Line 53
63			
64	= Investment Return and Income Taxes	$133,829,768	Line 60 X Line 62

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Transmission Expenses
~~Attachment H Section 14.1.9.2~~

Attachment 1
Schedule 9

Shading denotes an input

2010

Line No.		(1) Total	(2) Allocation Factor	(3) = (1)*(2) Electric Allocated	(4) Allocation Factor	(5) = (3)*(4) Transmission Allocated	FERC Form 1 Reference for col (1)		Definition
	Depreciation Expense								
1	Transmission Depreciation	$31,482,012				$31,482,012	FF1 336.7f	~~14.1.9.2.~~	Transmission Related Depreciation Expense shall equal the sum of:
2	General Depreciation	$13,112,567	100.0000%	$13,112,567	13.0000% (c)	$1,704,634	FF1 336.10f		(i) Depreciation Expense for Transmission Plant in Service, plus (ii)
3	Common Depreciation	$13,090,378	83.5000% (a)	$10,930,466	13.0000% (c)	$1,420,961	FF1 356.1		the product of Electric General Plant Depreciation Expense multiplied
4	Intangible Depreciation	$1,330,750	100.0000%	$1,330,750	13.0000% (c)	$172,998	FF1 336.1f		by the Transmission Wages and Salaries Allocation Factor plus (iii)
5	Wholesale Meters					$2,481	Workpaper 1, Line 53		Common Plant Depreciation Expense multiplied by the Electric
6	Total (line 1+2+3+4+5)					$34,783,085			Wages and Salaries Allocation Factor, further multiplied by the
7									Transmission Wages and Salaries Allocation Factor plus (iv)
8									Intangible Electric Plant Depreciation Expense multiplied by the
9									Transmission Wages and Salaries Factor plus (v) depreciation
10									expense associated with the Wholesale Metering Investment.
11									
12	Real Estate Taxes	$137,630,327	100.0000%	$137,630,327	27.8380% (d)	$38,313,586	FF1 263.25i	~~14.1.9.2.~~	Transmission Related Real Estate Tax Expense shall equal the
13									electric Real Estate Tax Expenses multiplied by the Gross
14									Transmission Plant Allocation Factor.
15									
16	Amortization of Investment Tax Credits	$1,663,964	78.7848% (b)	$1,310,951	27.8380% (d)	$364,943	FF1 117.58c	~~14.1.9.2.~~	Transmission Related Amortization of Investment Tax Credits shall
17									equal the product of Amortization of Investment Tax Credits multiplied
18									by the Gross Electric Plant Allocation Factor and further multiplied by
19									the Gross Transmission Plant Allocation Factor
20	Transmission Operation and Maintenance								
21	Operation and Maintenance	$88,777,237				$88,777,237	FF1 321.112b	~~14.1.9.2.~~	Transmission Operation and Maintenance Expense shall equal
22	less Load Dispatching - #561	$12,349,796				$12,349,796	FF1 321.84-92b		the sum of electric expenses as recorded in
23	less Regional Delivery Venture adjustments	$10,942,773 ***				$10,942,773			
24	O&M (Line 21 - Line 22)	$65,484,668				$65,484,668			FERC Account Nos. 560, 562-574
25									
26	Transmission Administrative and General							~~14.1.9.2.~~	Transmission Related Administrative and General Expenses shall
27	Total Administrative and General	$375,117,556					FF1 323.197b		equal the product of electric Administrative and General Expenses,
28	less Property Insurance (#924)	$64,126					FF1 323.185b		excluding the sum of Electric Property Insurance, Electric Research and
29	less Pensions and Benefits (#926)	$92,041,066					FF1 323.187b		Development Expense and Electric Environmental Remediation Expense,
30	less: Research and Development Expenses (#930)	$2,474,429					Workpaper 12, Line 3		and 50% of the NYPSC Regulatory Expense
31	Less: 50% of NY PSC Regulatory Expense	$4,074,213					FF1 351.1.h, 50% of Workpaper 16, Line 14, Column f		multiplied by the Transmission Wages and Salaries Allocation Factor,
32	Less: 18a Charges (Temporary Assessment)	$80,854,971 **					FF1 351.1.h, Workpaper 16, Line 15, Column f		plus the sum of Electric Property Insurance multiplied by the Gross
33	less: Environmental Remediation Expense	$13,055,876					Workpaper 11, Line 3		Transmission Plant Allocation Factor, plus transmission-specific Electric
34	Subtotal (Line 26-27-28-29-30-31-32)	$182,552,875	100.0000%	$182,552,875	13.0000% (c)	$23,731,874			Research and Development Expense, and transmission-specific
35	PLUS Property Insurance alloc. using Plant Allocatior	$64,126	100.0000%	$64,126	27.8380% (d)	$17,851	Line 28		Electric Environmental Remediation Expense. In addition, Administrative
36	PLUS Pensions and Benefits	$179,778,267	100.0000%	$179,778,267	13.0000% (c)	$23,371,175	Workpaper 3, Line 8		and General Expenses shall exclude the actual Post-Employment
37	PLUS Transmission-related research and development	$296,936				$296,936	Workpaper 12, Line 1		Benefits Other than Pensions ("PBOP") included in FERC Account 926,
38	PLUS Transmission-related Enviromental Expense	$0				$0	Workpaper 11, Line 1		and shall add back in the amounts shown on Workpaper 3, page 1,
39	Total A&G (Line 34+35+36+37+38)	$281,837,232		$362,395,268		$47,417,836			or other amount subsequently approved by FERC under Section 205 or 206.
40								~~14.1.9.2.~~	Transmission Related Payroll Tax Expense shall equal the product of
41	Payroll Tax Expense								electric Payroll Taxes multiplied by the Transmission Wages and
42	Federal Unemployment	$233,681					FF1 263.4i		Salaries Allocation Factor.
43	FICA	$17,502,511					FF1 263.3i		
44	State Unemployment	$529,672					FF1 263.17i		
45	Total (Line 40+41+42)	$18,265,864	100.0000%	$18,265,864	13.0000% (b)	$2,374,562			

Allocation Factor Reference
(a) Schedule 5, line 1
(b) Schedule 5, line 32
(c) Schedule 5, line 3
(d) Schedule 5, line 19

** Per November 18, 2010 Supplemental Information Filing, National Grid has agreed to exclude the costs of section 18-a Temporary Assessmet under NY PSC in any future update.
*** In reviewing it's recent rate filing (Case 10-E-0050) with the NYPSC, the Company has determined that it would be appropriate to exclude certain costs related to it's Regional Delivery Venture.

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Billing Adjustments, Revenue Credits, Rental Income
~~Attachment H Section 14.1.9.2 (a)~~

Attachment 1
Schedule 10

Shading denotes an input

2010

Line No.		Description	(1) Total	Source		Definition
1		Billing Adjustments *	-$2,487,006	Line 37 (Listed below)	~~14.1.9.2.H.~~	~~Billing Adjustments shall be any adjustments made in accordance with Section 14.1.9.4(d) below.~~
2						
3						
4		Bad Debt Expense	-$796	Workpaper 4, Line 4	~~14.1.9.2.I.~~	Transmission Related Bad Debt Expense shall equal
5						Bad Debt Expense as reported in Account 904 related to NMPC's wholesale transmission billing.
6						
7		Revenue Credits	$47,222,149	Workpaper 5, Line 11	~~14.1.9.2.J.~~	Revenue Credits shall equal all Transmission revenue recorded in FERC account 456
8						excluding (a) any NMPC revenues already reflected in the WR, CRR, SR, ECR and Reserved
9						components in Attachment H of the NYISO TSC rate; (b) excluding any revenues associated
10						with expenses that have been excluded from NMPC's revenue requirement; and (c) any
11						revenues associated with transmission service provided under this TSC rate, for which the
12						load is reflected in the calculation of BU.
13						
14		Transmission Rents	($1,589,444)	Workpaper 7	~~14.1.9.2.K.~~	Transmission Rents shall equal all Transmission-related rental income recorded in FERC
15						account 454.615
16						
17					~~14.1.9.4(d)~~	
18					1	Any changes to the Data Inputs for an Annual Update, including but not limited to
19						revisions resulting from any FERC proceeding to consider the Annual Update, or
20						as a result of the procedures set forth herein, shall take effect as of the beginning
21						of the Update Year and the impact of such changes shall be incorporated into the
22						charges produced by the Formula Rate (with interest determined in accordance
23						with 18 C.F.R. § 38.19(a)) in the Annual Update for the next effective Update
24						Year. This mechanism shall apply in lieu of mid-Update Year adjustments and
25						any refunds or surcharges, except that, if an error in a Data Input is discovered
26						and agreed upon within the Review Period, the impact of such change shall be
27						incorporated prospectively into the charges produced by the Formula Rate during
28						the remainder of the year preceding the next effective Update Year, in which case
29						the impact reflected in subsequent charges shall be reduced accordingly.
30					2	The impact of an error affecting a Data Input on charges collected during the
31						Formula Rate during the five (5) years prior to the Update Year in which the error
32						was first discovered shall be corrected by incorporating the impact of the error on
33						the charges produced by the Formula Rate during the five-year period into the
34						charges produced by the Formula Rate (with interest determined in accordance
35						with 18 C.F.R. § 38.19(a)) in the Annual Update for the next effective Update
36						Year. Charges collected before the five-year period shall not be subject to correction.
37	*	Billing Adjustment consists of these 2 amounts:				
		(1). Workpaper 14, Line 30	($2,383,112)			
		(2). Interest credit related to FERC Affliate Transaction Audit Finding	($4,650)			
		(3) 2009 Resubmission of FF1; per settlement Attachment D	($99,244)			

Niagara Mohawk Power Corporation **Attachment 1**
System, Control, and Load Dispatch Expenses (CCC) **Schedule 11**
~~Attachment H, Section 14.1.9.5~~ **Page 1 of 1**

Shading denotes an input

The CCC shall equal the annual Scheduling, System Control and Dispatch Costs (i.e., the transmission component of control center costs) as recorded in FERC Account 561 and its associated sub-accounts using information from the prior calendar year, excluding NYISO system control and load dispatch expense already recovered under Schedule 1 of the NYISO Tariff.

Line No.	Scheduling and Dispatch Expenses			2010	Source
1					
2					
3	Accounts	561	Load Dispatching	$2,862,601	FF1 321.84b
4	Accounts	561.1	Reliability	$0	FF1 321.85b
5	Accounts	561.2	Monitor and Operate Transm. System	$2,572,962	FF1 321.86b
6	Accounts	561.3	Transm. Service and Schedule	$0	FF1 321.87b
7	Accounts	561.4	Scheduling System Control and Dispatch	$4,438,211	FF1 321.88b
8	Accounts	561.5	Reliability, Planning and Standards Developmen	$1,303,697	FF1 321.89b
9	Accounts	561.6	Transm. Service Studies	$0	FF1 321.90b
10	Accounts	561.7	Generation Interconnection Studies	$9,511	FF1 321.91b
11	Accounts	561.8	Reliability, Planning and Standards Dev. Service	$1,162,814	FF1 321.92b
12					
13			Total Load Dispatch Expenses (sum of Lines 3 - 11)	$12,349,796	
14					
15	Less Account 561 directly recovered under Schedule 1 of the NY ISO Tariff				
16					
17	Accounts	561.4	Scheduling System Control and Dispatch	$4,438,211	Line 7
18	Accounts	561.8	Reliability, Planning and Standards Dev. Service	$1,162,814	Line 11
19			Total NYISO Schedule 1	$5,601,025	Line 17 + Line 18
20					
21	Total CCC Component			$6,748,771	Line 13 - Line 19

Niagara Mohawk Power Corporation
Billing Units - MWH
~~Attachment H, Section 14.1.9.6~~

Attachment 1
Schedule 12
Page 1 of 1

Shading denotes an input

BU shall be the total Niagara Mohawk load as reported to the NYISO for the calendar billing year prior to the Forecast Period, including the load for customers taking service under Niagara Mohawk's TSC Rate. The total Niagara Mohawk load will be adjusted to exclude (i) load associated with wholesale transactions being revenue credited through the WR, CRR, SR, ECR and Reserved components of Workpaper H of the NYISO TSC rate including Niagara Mohawk's external sales, . load associated with grandfathered OATT agreements, and any load related to pre-OATT grandfathered agreements; (ii) load associated with transactions being revenue credited under Historical TRR Component J; and (iii) load associated with netted station service

Line No.		Dec 09- Nov 10	SOURCE	
1	Subzone 1	12,298,985.850	NIMO TOL (transmission owner load)	Workpaper 13
2	Subzone 2	7,249,987.760	NIMO TOL (transmission owner load)	Workpaper 13
3	Subzone 3	4,610,230.930	NIMO TOL (transmission owner load)	Workpaper 13
4	Subzone 4	10,487,089.753	NIMO TOL (transmission owner load)	Workpaper 13
5	Subzone 29	2,056,636.007	NIMO TOL (transmission owner load)	Workpaper 13
6	Subzone 31	641,258.223	NIMO TOL (transmission owner load)	Workpaper 13
7	Total NIMO Load report to NYISO	**37,344,188.523**	sum Lines 1-6	
8	LESS: All non-retail transactions			
9	Watertown	10,348.000	FF1 page 329.10.j	
10	**High Load Factor Fitzpatrick ****	30,763.864	NIMO TOL (transmission owner load)	
11	Disputed Station Service	160,913.641	NIMO TOL (transmission owner load)	
12	Other non-retail transactions	2,859,192.544	All other non-retail transactions (Sum of 300,000 series PTID's from TOL)	
13	Total Deductions	**3,061,218.049**	sum Lines 9 - 12	
14	PLUS: TSC Load			
15	NYMPA Muni's, Misc. Villages, Jamestown (X1)	2,119,153.000	FF1 page 329.17.j	
16	NYPA Niagara Muni's (X2)	686,429.000	FF1 page 329.1.j	
17	Total additions	**2,805,582.000**	sum Lines 15 -17	
18	Total Billing Units	**37,088,552.474**	Line 7 - Line 13 + Line 18	

** High Load Factor Fitzpatrick contract expired 12/31/2009.
The new contract is now retail load.
Line 10 only includes December 2009 load.

Adjusted TSC Rate Components
For the Rate Effective January 1, 2012
Tonawanda, FICA and 2009 R&D Expenses

Attachment 1
Schedule 13

	(a) Historical Transmission Revenue Requirement (Historical TRR)	(b) Forecasted Transmission Revenue Requirement	(c) Annual True Up	(d) Revenue Requirement (RR)	(e) Scheduling System Control and Dispatch Costs (CCC)	(f) Annual Billing Units (BU) MWh	(g) Rate $/MWh
1 As Filed	$276,957,312	$8,250,157	$2,927,103	$288,134,572	$6,748,771	37,088,552	$7.95
2 Revised	270,539,167	8,246,637	(3,525,807)	275,259,997	6,748,771	37,088,552	$7.60
3 Increase/(Decrease)	(6,418,145)	(3,520)	(6,452,910)	(12,874,575)	-	-	($0.35)
							-4.37%

Adjustments indicated by **green fill** made to:
Schedule 9 - Lines 21 and 43
Schedule 10 - Footnote 3

File Name:
EXH NMP-5_2011 Update with Settlement figures.xls

Niagara Mohawk Power Corporation **Workpaper 1**
Wholesale Meters **Page 1 of 1**

Shading denotes an input 2010

Line No.			Quantity	Accumulated Cost	Avg Cost
1	A/C 37030 Large Meter Install - Bare Cost				
2		1996	1,166	$187,298.82	
3		1997	3,499	$611,184.89	
4		1998	1,943	$342,748.54	
5		1999	3,208	$543,890.44	
6		2000	2,128	$355,922.26	
7		2001	23	$4,081.64	
8		2002	549	$119,407.77	
9		2003	1,924	$424,598.99	
10		2004	9,833	$2,444,428.00	
11		2005	2,086	$512,694.81	
12		2006	1,749	$1,201,540.30	
13		2007	858	$261,095.35	
14		2008	2,019	$623,333.32	
15		2009	768	$363,212.76	
16		2010	3,499	$531,057.32	
17	**Total**		**35,252**	**$8,526,495.21**	$241.87
18	Net Plant Ratio (Remaining Life / Average Life) (Line 55 / Line 57)				82.17%
19	Net Bare Costs (Line 17 * Line 18)				$198.74
20					
21	A/C 37035 Large Meter - Installation Cost				
22		1996	1,153	$979,200.14	
23		1997	3,489	$3,224,553.18	
24		1998	1,936	$1,805,377.38	
25		1999	3,188	$2,866,714.52	
26		2000	2,107	$1,871,445.37	
27		2001	17	$17,056.14	
28		2002	543	$626,174.53	
29		2003	1,721	$2,056,266.71	
30		2004	8,535	$11,553,647.07	
31		2005	911	$1,194,470.02	
32		2006	1,166	$2,284,325.35	
33		2007	84	$145,054.34	
34		2008	131	$235,809.55	
35		2009	106	$111,410.88	
36		2010	90	$46,907.19	
37	**Total**		**25,177**	**$29,018,412.37**	$1,152.58
38	Net Plant Ratio (Remaining Life / Average Life) (Line 56 / Line 57)				77.25%
39	Net Installation Costs (Line 37 * Line 38)				$890.37
40	Number of Meters				64
41	Total Gross Asset Value Meters (Line 17 * Line 40)				$15,479.85
42	Estimated Depreciation Reserve (Line 43 - Line 41)				-$2,760.57
43	Net Asset Value on Meters (Line 19 * Line 40)				$12,719.28
44	Annual Depreciation Expense @36 year life or 2.78% (Line 41 * .0278)				$430.34
45					
46	Total Gross Asset Value Installation (Line 37 * Line 40)				$73,764.88
47	Estimated Depreciation Reserve (Line 48 - Line 46)				-$16,781.51
48	Net Asset Value on Meters (Line 39 * Line 40)				$56,983.37
49	Annual Depreciation Expense @36 year life or 2.78% (Line 46 * .0278)				$2,050.66
50					
51	Total Gross Asset Value Meters & Installation (Line 41 + Line 46)				$89,244.73
52	Depreciation Reserve Meters & Installation (Line 42 + Line 47)				-$19,542.08
53	Total Depreciation Expense Meters and Installation (Line 44 + Line 49)				$2,481.00
54					
55	Large Meter Bare Cost Remaining Life				29.58
56	Large Meter Installation Cost Remaining Life				27.81
57	Large Meter Average Life				36.00

Source: PowerPlant

Report 13001
Company: Niagara Mohawk
GL Accounts: 101 & 106
Accounts: 37030 & 37035
Select all requird Eng. Vintage

Report 1501
Company: Niagara Mohawk
GL Accounts: 101 & 106
Accounts: 37030 & 37035

Niagara Mohawk Power Corporation
FERC Account 283 - Accumulated Deferred Income Taxes

Workpaper 2
Page 1 of 1

Shading denotes an input

Line No.	Account	Source	2010		2009 vs 2010 bal
1	Total Acct 283	FF1 277.9k	(733,121,426)		32,596,950
2	Excluding:				
3	Merger Rate Plan Stranded Cost	FF1 277.3 Col b + c - d	201,952,838	*	
4	State: Merger Rate Plan Stranded Cost	FF1 277	N/A		
5	**TOTAL ACCOUNT 283**		**(531,168,588)**		

* Due to a change in FF1 reporting, Line 3 reflects both State and Federal.

Niagara Mohawk **Workpaper 3**
Total Account 926 - Administrative and General Expense **Page 1 of 3**

Shading denotes an input

Line No.	Section I	Source:	2010
1	Employee Pensions & Benefits	FF1 pg 323.187	92,041,066
2	Plus: Deferred FAS087 Pension Costs	Workpaper 3, page 2	23,847,298
3	Total Employee Pension & Benefits	Line 1 + Line 2	115,888,364
4			
5	Less: Actual FAS106 Expense in Acct. 926	Workpaper 3, page 3	(24,754,097)
6	Plus: Fixed FAS106 per Docket ER08-552	Fixed Amount **	88,644,000
7			
8	**Total Account 926**	Line 3 + Line 5+ Line 6	**179,778,267**

** FERC Docket No. ER08-552, Workpaper Statement BK Page 7, Page 2 of 3

Niagara Mohawk
Total Account 926 - Administrative and General Expense
Deferred FAS 087 Pension Costs
Workpaper 3, page 1, line 2

Workpaper 3
Page 2 of 3

Shading denotes an input **2010**

Pension Expense	Activity	Month	Jrnl ID	Account	Amount
FAS087	AG1060	January	6264A-6264C	223020	$2,577,328
FAS087	AG1060	February	6264A-6264C	223020	$2,646,112
FAS087	AG1060	March	6264A-6264C	223020	$2,974,442
FAS087	AG1060	April	6264A-6264C	223020	$2,181,834
FAS087	AG1060	May	6264A-6264C	223020	$1,956,282
FAS087	AG1060	June	6264A-6264C	223020	$2,071,392
FAS087	AG1060	July	6264A-6264C	223020	$1,800,516
FAS087	AG1060	August	6264A-6264C	223020	$2,051,997
FAS087	AG1060	September	6264A-6264C	223020	($135,960)
FAS087	AG1060	October	6264A-6264C	223020	$1,850,627
FAS087	AG1060	November	6264A-6264C	223020	$1,958,911
FAS087	AG1060	December	6264A-6264C	223020	$1,913,817
					23,847,298

Source:
Query
PeopleSoft Financials
Company Niagara Mohawk
Activity AG1060
Expense Type B06
Account 223020

Niagara Mohawk **Workpaper 3**
Total Account 926 - Administrative and General Expense **Page 3 of 3**

Actual FAS 106 Expense in FERC Account 926

Workpaper 3, page 1, line 5

	Shading denotes an input	2010
Activity	**Activity Descr**	**Total**
AG1070	Post Retirement Benefit FAS106	$ 71,622,120.31
AG1079	Cap Related PostRetire Benefit	$ (46,868,023.37)
Grand Total		**24,754,097**

Source:
PeopleSoft Financials
Company Nagara Mohawk
Regulatory Account 926000
Activities AG1070, AG1079

Niagara Mohawk Power Corporation **Workpaper 4**
Bad Debt Expense **Page 1 of 1**
~~Attachment H, Section 14.1.9.2~~

Shading denotes an input

I. Transmission Related Bad Debt Expense shall equal NMPC's Wholesale Transmission Related Bad Debt Expense defined as that reported in FERC account 904 related to NMPC's wholesale transmission billing.

Line No.	Regulatory Account	Segment		2010
1				
2	904000	Dist	$	48,937,525
3	904000	Gas	$	16,420,187
4	904000	Tran	$	(796)
5	Total		$	65,356,916

Query:
PeopleSoft Financials
Company Niagara Mohawk
Regulatory Account 904000
Total by Segment

Niagara Mohawk Power Corporation **Workpaper 5**
Transmission Revenue Credits **Page 1 of 1**
~~Attachment H, Section 14.1.9.2~~

Shading denotes an input

J. Revenue Credits shall equal all Transmission revenue recorded in FERC account 456 excluding (a) any NMPC revenues already reflected in the WR, CRR, SR, ECR and Reserved components in Workpaper H of the NYISO TSC rate; (b) excluding any revenues associated with expenses that have been excluded from NMPC's revenue requirement; and (c) any revenues associated with transmission service provided under this tariff for which the demand is reflected in the calculation of BU.

Line No.		Source:	2010	
1	Transmission of Electricity for Others (456.1)	FF1 300.22b	$128,808,812	
2	Less: Transmission of Electricity by ISO (ECR, CRR, SR)	FF1 331.40e	$62,608,329	
3	Sub-total Revenue (Line 1 - Line 2)	FF1 330.35n	$66,200,485	
4	Less:			
5	TSC Customers	FF1 330.1,16,17,18n (a)	$19,918,017	*
6	Fitzpatrick Industrials	FF1 330.	$0	**
7	Green Island & Richmondville	FF1 330.14n	$195,203	
8	Sub-total Deductions (Line 5 + Line 6 + Line 7)		$20,113,220	
9	Subtotal Transmission Revenue Credit	Line 3 - Line 8	$46,087,265	
10	Transmission Support Revenue	Line 15	$1,134,884	
11	Total Transmission Revenue Credit	Line 9 + Line 10	$47,222,149	
12	Transmission Support Revenue Detail - Query			
13	Regulatory Account 456010		$876,711	
14	Regulatory Account 456040		$258,173	
15	Total	Line 13 + Line 14	$1,134,884	

Query:
PeopleSoft
Company Niagara Mohawk
Regulatory Accounts 456010 and 456040
Segment TRAN
Account 110034

* This number reflects the TSC Reserve as shown on FF1 pg 330, Ln 18, Col n.
** Line item 6 - Fitzpatrick Industrials contract expired 12/31/2009

Niagara Mohawk Power Corporation
Long Term Debt and Preferred Stock Cost

Shading denotes an input

Line No.	Interest on Long Term Debt	Source:	Beginning Balance (a)	Ending Balance (b)	Average (c)	2010 (d)
1						
2						
3	Total Niagara Mohawk Interest on Long Term Debt	FF1 257.33i				$ 98,020,023
4	Amortization of Debt Discount Expense FERC Account 428	FF1 117.63c				$ 2,434,668
5	Amortization of Loss on Reacquired Debt FERC Account 428.1	FF1 117.64c				$ 6,576,120
6	Less: Amort of Premium on Debt-Credit FERC Account 429	FF1 117.65c				$ -
7	Less: Amort of Gain on Reacquired Debt FERC Account 429.1	FF1 117.66c				$ (60,460)
8	**Interest Costs plus Expense**	Sum of Lines 3-7				**$ 106,970,351**
9						
10	Total Long Term Debt					
11						
12	Total Niagara Mohawk Long Term Outstanding Debt	FF1 256.33b & 257.33h	$ 2,750,065,000	$ 2,400,065,000	$ 2,575,065,000	
13	Less: Unamortized Discount on Long-Term Debt FERC Accoun	FF1 112.23c & d	$ (477,312)	$ (415,359)	$ (446,336)	
14	Less: Unamortized Loss on Reacquired Debt FERC Account 18	FF1 111.81c & d	$ (32,019,130)	$ (25,339,795)	$ (28,679,463)	
15	Plus: Unamortized Gain on Reacquired Debt FERC Account 25	FF1 113.61c & d	$ -	$ -	$ -	
16	**Total Long Term Debt**	Sum of Lines 12-15	**$2,717,568,558**	**$2,374,309,846**	**$2,545,939,202**	
17	**Debt Cost as % of Debt**	Line 8d / Line 16c			**4.20%**	
18						
19						
20	Preferred Stock					
21						
22	Total Niagara Mohawk Dividends Declared FERC account 437	FF1 118.29c				$1,060,498
23	Total Niagara Mohawk Preferred Stock FERC Account 204	FF1 112.3c				$28,984,700
24	**Preferred Stock Cost**	Line 22 / Line 23				**3.66%**

NOTES:
Lines 12-15 use the FERC Form 1 average of the beginning year balance and the end of year balance for each line item.

Niagara Mohawk Power Corporation
TSC Revenue Requirement
RIGHT OF WAY RENTS - ACCT #454615
CY 2010
~~Attachment H, Section 14.1.9.2~~

Workpaper 7
Page 1 of 1

Shading denotes an input

K. Transmission Rents shall equal all Transmission-related rental income recorded in NMPC's internal account 454.615.

Business Unit	Segment	Activity	Activity Descr	Expense Type	Regulatory Acct	Fiscal Yr	Period	GL Act $
00036	TRAN	454615	Rent from elec. Prop	400	454000	2010	January	($34,701)
00036	TRAN	454615	Rent from elec. Prop	400	454000	2010	February	($52,768)
00036	TRAN	454615	Rent from elec. Prop	400	454000	2010	March	($340,203)
00036	TRAN	454615	Rent from elec. Prop	400	454000	2011	April	($70,521)
00036	TRAN	454615	Rent from elec. Prop	400	454000	2011	May	($78,290)
00036	TRAN	454615	Rent from elec. Prop	400	454000	2011	June	($201,911)
00036	TRAN	454615	Rent from elec. Prop	400	454000	2011	July	($117,560)
00036	TRAN	454615	Rent from elec. Prop	400	454000	2011	August	($122,584)
00036	TRAN	454615	Rent from elec. Prop	400	454000	2011	September	($196,200)
00036	TRAN	454615	Rent from elec. Prop	400	454000	2011	October	($74,005)
00036	TRAN	454615	Rent from elec. Prop	400	454000	2011	November	($134,014)
00036	TRAN	454615	Rent from elec. Prop	400	454000	2011	December	($166,688)
							Sum:	**(1,589,444)**

Source:
PeopleSoft Financials
Company: Niagara Mohawk
Regulatory Account: 454000
Segment: TRAN

Niagara Mohawk Power Corporation
Forecasted Transmission Plant In-Service

Shading denotes an input

2010

Forecasted Transmission Plant Additions (FTPA) shall mean the sum
(i) NMPC's actual Transmission Plant Additions during the first quarter (January 1 through March 31) of the Forecast Period, and
(ii) NMPC's forecasted transmission investment for the Forecast Period less the amount (i), divided by 2.

	Section I:			**Reference**	**Section II** Program Breakdown for Transmisison	($ m)	**Section III:** Program Breakdown for Sub-Transmission	($ m)
1	Current Year Capital Investment							
2	Transmission Capital Investment	$	132,004,301	See Section II	Northeast Region Reinforcement	19.50	Sub Transmission Line Overarching	14.92
3	Sub-Transmission Capital Investment	$	44,000,000	See Section III	Overhead Line Refurbishment Program - Asset Condition	17.04	Inspection & Maintenance	10.00
4	Total	$	176,004,301	Line 2 + Line 3	Other Damage/Failure	16.21	Underground Cable	5.18
5					Station NPCC Compliance Upgrades	15.59	Substation Metal Clad Switchgear	3.71
6	Actual Transmission Plant in Service Quarter 1				Clearance Strategy	9.17	Blanket	2.87
7	Quarter 1 2011 actuals Transmission Plant	$	1,884,307,200	FF1, pg 208 (b) **	Other System Capacity & Performance	9.14	Planning Criteria	1.46
8	2010 year end Transmission Plant	$	1,872,079,472	Schedule 6, page 2, line 1	Physical Security	7.78	Subtransmission Line Overarching	1.46
9	Q1 Transmission Plant increase	$	12,227,728	line 8 - line 7	Shield Wire Strategy	7.59	Sub Transmssion Automation	1.38
10					Other Asset Condition	6.68	Blanket	0.97
11	Total Estimated Transmission Plant in Service				Transformer Replacement Strategy	6.62	Sub Transmission and Distribution T	0.90
12	Total Current Year Capital Investment	$	176,004,301	line 4	Wood Pole Strategy	5.77	Blanket	0.70
13	Less: Q1 Increase	$	12,227,728	line 9	Luther Forest	4.22	Damage/Failure	0.64
14	Balance	$	163,776,573	line 12 - line 13	Steel Tower Strategy	4.10	Blanket	0.64
15	Times 50%	$	81,888,286	line 14 * 50%	Substation Rebuilds	3.95	New Business	0.61
16	Forecasted Plant	$	94,116,015	line 13 + line 15	Reliability Criteria Compliance	2.86	Public Requirements	0.55
17					Other Statutory/Regulatory	2.33	Substation Circuit Breaker / Reclose	0.54
18					RTU Strategy	2.30	Subtransmission Line Removal	0.36
19					Overhead Line Refurbishment Program - System Capacity & Performance	2.25	Substation Indoor Substation	0.25
20					NY Inspection Projects	1.92	Wood Pole	0.21
21					U-Series Relay Strategy	1.66	3rd Party Attachments	0.15
22					Circuit Breaker Replacement Strategy	0.90	Reliability	0.15
23					Clay Station Rebuild	0.90	Subtransmission Line Removal	0.10
24					Digital Fault Recorder Strategy	0.84	Substation Capacitor & Switch	0.07
25					Relay Replacement Strategy	0.71	Substation Power Transformer	0.04
26					Battery Strategy	0.63	Recloser Application	0.01
27					Load	0.79	Reserve	(3.85)
28					Steel Tower Strategy	0.13		
29					3A/3B Tower Strategy	0.04		
30					Reserve	(19.62)		
31					TOTAL	**132.0**		**44.0**

Resource:
Niagara Mohawk's filing, Case 06-M-0878, filed on February 7, 2011 broken down as shown below:

	CY2011 ($m)
Transmission	132.0
Sub-Transmission	44.0
Distribution	233.0
Total	409.0

** Due to timing, this number is an estimate as FF1 has not yet been completed at time of filing. The source of the data is Plant Accounting records.

Mid-Year Trend Adjustment
NMPC Actual Transmission O&M for the Quarter 1 2011 vs 2010
FERC Form 1 page 321

Workpaper 9
Page 1 of 1

Shading denotes an input

Line No.	OPERATING EXPENSES	Reg Account		Jan-2011 (a)	Feb-2011 (b)	Mar-2011 (c)	2011 1st QTR FF1 TOTAL (d)	Jan-2010 (e)	Feb-2010 (f)	Mar-2010 (g)	2010 1st QTR FF1 TOTAL (h)	2011 o/(u) 2010 (i) (d - h)
1	Transmission Expenses-O&M											
2	Trans Oper-Supervision & Eng	560000		163,018.05	(29,346.89)	(78,661.10)	55,010.06	52,840.66	364,125.14	308,032.71	724,998.51	(669,988.45)
3	***Trans Oper-Load Dispatching***	***561000***	*	-	-	-	-	-	-	-	-	-
4	***Ld Disptch-Mon & Oper Tran Sys***	***561200***	*	-	-	-	-	-	-	-	-	-
5	***Schd, Sys Cntrl & Dispatch Srv***	***561400***	*	-	-	-	-	-	-	-	-	-
6	***Reliab, Plan & Standards Dev***	***561500***	*	-	-	-	-	-	-	-	-	-
7	***Transmission Service Studies***	***561600***	*	-	-	-	-	-	-	-	-	-
8	***Gen Interconnection Studies***	***561700***	*	-	-	-	-	-	-	-	-	-
9	***Reliab, Plan & Stndrd Dev Serv***	***561800***	*	-	-	-	-	-	-	-	-	-
10	Trans Oper-Substations	562000		231,483.74	422,083.85	415,158.42	1,068,726.01	340,335.92	275,743.40	273,827.78	889,907.10	178,818.91
11	Trans Oper-Overhead Lines	563000		294,006.75	393,422.96	440,827.12	1,128,256.83	265,720.12	207,920.59	530,299.48	1,003,940.19	124,316.64
12	Trans Oper-Underground Lines	564000		734.66	1,404.97	4,755.13	6,894.76	1,244.05	1,145.62	1,261.25	3,650.92	3,243.84
13	Trans Oper-Wheeling	565000		-	-	1,500.00	1,500.00	15,577.92	16,144.18	17,711.62	49,433.72	(47,933.72)
14	Trans Oper-Misc Expenses	566000		4,831,143.72	(333,984.76)	(1,107,902.22)	3,389,256.74	687,541.47	875,508.22	1,223,695.51	2,786,745.20	602,511.54
15	Trans Oper-Rents	567000		1,150,900.93	854,637.44	862,271.95	2,867,810.32	827,290.55	869,633.65	828,971.11	2,525,895.31	341,915.01
16	Oper Transmission Facilities			6,671,287.85	1,308,217.57	537,949.30	8,517,454.72	2,190,550.69	2,610,220.80	3,183,799.46	7,984,570.95	532,883.77
17	Trans Maint-Supervision & Eng	568000	568000	$84,004	$229,275	$384,516	697,794.92	158,380.59	154,782.13	179,413.06	492,575.78	205,219.14
18	Trans Maint-Buildings	569000	569000	$736	$4,876	$1,057	6,669.18	2,203.01	2,223.43	1,857.05	6,283.49	385.69
19	T Maint of Computer Hardware	569100	569100	$21,347	$13,204	$182,283	216,833.00	16,745.64	-	-	16,745.64	200,087.36
20	T Maint of Computer Software	569200	569200	$136,698	$41,722	$115,387	293,806.80	93,856.46	-	-	93,856.46	199,950.34
21	T Maint of Communication Equip	569300	569300	$1,335	$4,956	$2,200	8,489.85	732.98	-	-	732.98	7,756.87
22	T Maint of Misc Reg Tran Plant	569400		-	-	-	-	-	-	-	-	-
23	Trans Maint-Substations	570000	570000	$290,968	$514,978	$486,717	1,292,663.03	743,309.56	529,769.91	502,215.63	1,775,295.10	(482,632.07)
24	Trans Maint-Substation-Trouble	570010	570010	$166,746	$169,490	$381,146	717,382.52	221,639.73	217,129.38	340,966.80	779,735.91	(62,353.39)
25	Trans Maint-Overhead Lines	571000	571000	$616,605	$756,410	$1,297,357	2,670,371.07	1,115,257.16	1,651,248.84	348,081.07	3,114,587.07	(444,216.00)
26	Trans Maint-Switch-Unplanned	571010	571010	$6,694	$7,481	$19,425	33,599.82	2,283.11	10,549.22	19,830.20	32,662.53	937.29
27	Trans Maint-Right of Way	571020	571020	$670,656	$480,938	$699,593	1,851,186.55	1,753,979.04	1,265,523.66	1,430,425.97	4,449,928.67	(2,598,742.12)
28	Trans Maint-Underground Lines	572000	572000	$59,674	$8,448	$109,694	177,816.46	3,314.41	21,064.99	29,210.48	53,589.88	124,226.58
29	Trans Maint-Misc Expenses	573000	573000	$14,191	$47,209	$160,720	222,119.63	16,158.23	8,391.20	36,860.12	61,409.55	160,710.08
30	Maint Transmission Facilities			2,069,653.30	2,278,985.80	3,840,093.73	8,188,732.83	4,127,859.92	3,860,682.76	2,888,860.38	10,877,403.06	(2,688,670.23)
31	Subtotal Transmission Expenses-O&M			8,740,941.15	3,587,203.37	4,378,043.03	16,706,187.55	6,318,410.61	6,470,903.56	6,072,659.84	18,861,974.01	(2,155,786.46)

* Per the formula, these accounts are excluded from the calculation

Source:
PeopleSoft
Company Niagara Mohawk
Regulatory Accounts 560000 - 574000

Niagara Mohawk Power Corporation **Workpaper 10**
Total FERC Account 105 - Plant Held For Future Use **Page 1 of 1**

Shading denotes an input

Line No.		Source:	2010
1	Transmission Plant Held for Future Use	FF1 pg 214	$0.00

NOTE: The property vintage will be provided for any values shown on this workpaper

Niagara Mohawk Power Corporation **Workpaper 11**
Total NIMO Internal Account 930.200 - Misc. General - Environmental **Page 1 of 1**
~~Attachment H, Section 14.1.9.2~~

Shading denotes an input

Transmission specific Electric Environmental Remediation Expense
as recorded in NMPC's internal Account 930.200

Line No.		Source:	2010
1	**Transmission related Environmental Costs Claimed**		$0.00
2	Regulatory Account		Amount
3	930200	FF1 335.10b	$ 13,055,876

Query:
PeopleSoft
Company Niagara Mohawk
Regulatory Account 930200
Segments all electric (TRAN and DIST)
Activities AG0100, AG0105, AG0110
A list of all Transmission Related Environmental Expenses claimed shall be provided.

Niagara Mohawk Power Corporation **Workpaper 12**
Total NIMO Internal Account 930.210 - Misc. General - Research and Development **Page 1 of 1**
~~Attachment H, Section 14.1.9.2~~

Shading denotes an input

Transmission specific Electric Research and Development Expense as recorded
in NMPC internal Account No. 930.210

Line No.		Source:	2010
1	**Transmission Related R&D Expense**		**$296,936**
2	Regulatory Account		Amount
3	930210	FF1 353.8f electric	$ 2,474,429

Query:
PeopleSoft
Company Niagara Mohawk
Regulatory Account 930210
Segments all electric (TRAN and DIST)
Expense Types all
A list of all Transmission Related Research and Development Expenses claimed shall be provided.

Niagara Mohawk Power Corporation
Billing Unit Summary

Shading denotes an input

Reason Code	Reference Number	2009 Dec	2010 Jan	2010 Feb	2010 Mar	2010 Apr	2010 May	2010 Jun	2010 Jul	2010 Aug	2010 Sep	2010 Oct	2010 Nov	Total Dec - Nov
Zone	1	1,072,488.69	1,078,733.26	990,923.70	1,045,687.03	927,806.49	950,183.85	1,026,209.65	1,141,464.77	1,130,235.04	986,870.42	972,126.38	976,256.57	12,298,985.850
Zone	2	641,531.53	660,798.46	587,798.25	588,842.24	539,330.99	572,952.29	590,259.96	702,602.71	660,240.50	572,209.17	562,755.63	570,666.02	7,249,987.760
Zone	3	418,559.77	429,371.46	386,580.91	358,473.31	322,376.17	367,366.48	377,131.96	443,955.19	431,578.96	376,673.07	345,206.94	352,956.73	4,610,230.930
Zone	4	904,183.59	932,458.27	820,521.33	813,530.14	731,390.83	841,897.81	907,608.80	1,095,466.62	1,003,103.00	861,831.83	779,366.20	795,731.34	10,487,089.753
Zone	29	189,731.55	183,915.85	165,135.79	164,329.05	144,952.97	155,319.16	167,774.48	197,183.18	191,185.27	163,611.73	162,093.02	171,403.95	2,056,636.007
Zone	31	68,660.48	72,477.01	64,696.78	57,481.21	45,259.83	44,185.97	42,780.18	50,356.87	48,646.38	43,881.50	48,447.14	54,384.86	641,258.223
	Total	3,295,155.610	3,357,754.309	3,015,656.756	3,028,342.981	2,711,117.277	2,931,905.564	3,111,765.035	3,631,029.341	3,464,989.157	3,005,077.714	2,869,995.312	2,921,399.467	37,344,188.523
X4	z1 HLFF	7,263.18	8,513.85	2,912.99	3,297.31	2,959.10	3,140.92	3,007.17	3,438.66	3,213.05	2,928.81	2,702.00	2,780.59	46,157.615
X4	z4 HLFF	23,500.69	22,496.88	644.76	589.95	498.28	538.29	618.30	703.96	661.18	548.79	532.75	583.83	51,917.655
	Total HLFF	30,763.864	31,010.729	3,557.749	3,887.265	3,457.383	3,679.201	3,625.463	4,142.621	3,874.229	3,477.594	3,234.754	3,364.418	98,075.270
	LSEs are not paying station service													
X6	SS.1	536.89	513.23	459.13	480.00	411.12	402.07	402.50	401.97	438.74	382.85	378.93	403.44	5,210.86
X6	SS.2	409.06	431.01	390.06	400.38	307.83	294.05	283.49	288.18	292.42	283.06	351.92	347.99	4,079.45
X6	SS.3	14.07	14.31	12.83	14.26	744.05	718.59	13.31	353.67	512.13	13.27	599.19	486.89	3,496.54
X6	SS.4	508.61	576.45	684.46	698.23	881.65	854.21	567.96	537.06	562.46	582.69	516.23	690.24	7,660.24
X6	SS.5	1,006.07	139.98	20.60	560.56	1,010.75	1,056.71	809.11	151.60	105.41	103.46	799.71	668.68	6,432.62
X6	SS.6	118.75	126.88	118.98	96.96	52.76	38.79	22.34	22.64	22.20	26.94	59.60	90.74	797.58
X6	SS.7	277.54	646.05	19.99	318.92	812.21	787.63	470.81	94.21	62.71	174.86	300.91	472.26	4,438.10
X6	SS.8	435.83	467.45	421.79	469.46	412.82	380.95	379.06	378.64	370.95	357.76	375.82	382.76	4,833.31
X6	SS.9	146.80	148.41	143.51	174.73	174.38	184.88	181.78	202.54	177.41	177.32	192.69	175.39	2,079.85
X6	SS.10	1,144.89	1,289.65	1,158.33	1,076.88	885.81	837.59	796.02	858.65	994.33	3,393.39	4,289.61	1,715.25	18,440.38
X6	SS.11	237.10	245.97	265.93	204.90	-	150.39	144.86	34.97	6.49	20.46	97.34	142.54	1,550.94
X6	SS.12	313.16	313.43	301.68	264.53	213.13	192.28	221.72	269.38	237.84	207.47	220.63	241.81	2,997.06
X6	SS.13	1,134.16	1,199.88	1,467.01	1,334.10	1,155.12	1,322.30	984.75	1,053.09	1,749.43	982.06	1,048.42	1,509.18	14,939.50
X6	SS.14	940.80	1,202.85	802.93	764.27	694.51	703.30	1,071.16	1,138.77	730.35	797.11	787.84	664.84	10,298.73
X6	SS.15	2.96	2.98	2.68	2.97	2.93	2.99	2.95	3.01	2.99	2.87	3.00	2.93	35.26
X6	SS.16	82.05	61.38	76.30	76.50	69.42	66.39	65.23	69.91	68.65	65.93	67.99	73.10	842.86
X6	SS.17	-	-	-	-	-	-	-	-	-	-	-	61.22	61.22
X6	SS.18	1,818.43	2,146.12	1,860.43	2,641.79	2,445.52	2,181.05	1,242.34	2,003.96	2,450.06	2,414.06	2,576.01	2,647.71	26,427.47
X6	SS.19	-	-	-	-	-	-	-	-	-	-	-	-	-
X6	SS.20	1,038.79	1,821.93	961.36	923.08	677.85	-	901.20	1,191.30	1,116.97	1,137.43	1,065.09	864.04	11,699.01
X6	SS.21	-	-	-	-	-	-	-	-	0.02	0.09	-	0.07	0.18
X6	SS.22	0.20	-	0.12	0.06	0.08	-	0.04	-	-	-	-	0.49	0.98
X6	SS.23	70.52	71.24	63.31	72.10	64.87	59.90	55.00	59.64	65.30	52.24	55.78	58.60	748.49
X6	SS.24	241.68	249.64	225.40	234.95	213.93	210.91	204.42	200.27	196.07	189.88	209.00	216.93	2,593.08
X6	SS.25	5.77	6.01	6.83	6.48	4.86	3.51	2.63	2.58	2.63	3.01	5.26	6.82	56.38
X6	SS.26	83.34	4.22	63.69	117.26	33.74	105.73	138.96	77.11	73.47	71.99	-	-	769.50
X6	SS.27	63.66	249.37	134.07	101.43	206.29	190.91	24.87	24.30	73.55	114.97	101.89	140.12	1,425.41
X6	SS.28	755.94	1,060.42	975.27	308.62	100.77	656.99	928.47	752.68	807.88	220.19	588.44	947.52	8,103.17
X6	SS.29	1,589.89	986.55	1,300.85	2,447.96	342.74	151.90	117.48	501.05	232.48	605.78	856.48	635.00	9,768.15
X6	SS.30	99.68	106.05	89.77	83.34	74.95	80.31	86.81	74.49	76.66	71.75	79.18	73.47	996.46
X6	SS.31	3,989.98	-	134.00	-	-	-	-	-	-	-	743.45	5,263.41	10,130.85
Total X6		17,066.611	14,081.419	12,161.302	13,874.718	11,994.087	11,634.326	10,119.262	10,745.654	11,429.588	12,452.881	16,370.386	18,983.407	160,913.641

Niagara Mohawk Power Corporation | **Workpaper 13**
Billing Unit Summary | **Page 2 of 2**

Shading denotes an input

Reason Code	Reference Number	2009 Dec	2010 Jan	2010 Feb	2010 Mar	2010 Apr	2010 May	2010 Jun	2010 Jul	2010 Aug	2010 Sep	2010 Oct	2010 Nov	Total Dec - Nov
	300000 Series PTIDs													
X1	A.1	3,390.78	3,662.08	3,322.82	2,907.52	2,250.66	2,173.82	2,125.44	2,443.99	2,357.50	2,002.94	2,279.92	2,584.26	31,501.71
X1	A.2	43,463.33	45,392.15	38,971.11	37,431.27	35,046.94	35,279.21	34,352.58	36,671.52	36,215.26	35,286.34	38,121.21	40,715.15	456,946.07
X1	A.3	16,856.43	18,779.08	18,433.83	13,652.65	3,943.91	2,132.47	1,751.80	2,631.73	2,544.35	1,208.94	3,567.47	7,587.11	93,089.76
X1	A.4	36,384.99	39,593.61	36,851.05	39,318.14	34,178.15	34,382.25	37,534.72	36,208.64	34,847.31	34,539.70	38,145.81	37,196.97	439,181.34
X1	B.1	50,005.85	52,728.59	48,238.29	50,615.90	47,395.42	48,757.04	43,481.23	52,517.84	46,686.94	44,430.44	46,990.11	45,461.71	577,309.35
X1	B.2	41,219.32	42,546.08	35,647.97	34,635.79	32,573.26	35,251.97	34,756.65	37,504.11	35,763.90	33,318.41	34,827.46	38,639.82	436,684.75
X1	B.3	11,696.02	13,929.96	13,148.13	7,739.47	234.78	667.53	2,005.75	5,502.33	4,477.20	401.90	-	1,797.69	61,600.74
X1	C.1	6,785.47	7,166.09	6,373.03	6,367.42	5,308.09	5,746.52	5,286.46	6,399.82	6,123.23	5,281.37	5,519.86	5,536.59	71,893.94
X1	C.2	20,086.26	21,088.98	17,878.96	17,361.52	15,319.34	14,718.37	14,314.43	15,822.88	15,011.48	14,042.28	16,111.08	18,411.65	200,167.21
X1	C.3	5,750.73	6,142.10	5,568.93	3,257.66	485.87	351.27	342.52	896.36	789.13	167.38	620.47	1,883.78	26,256.19
X3	C.4	811.19	660.66	657.05	619.46	570.68	526.78	477.02	554.81	571.34	486.94	493.16	525.49	6,954.58
X3	C.5	-	0.01	0.04	23.53	-	0.13	0.18	-	1.64	39.18	0.33	-	65.03
X4	D.1	2,914.75	3,026.17	2,591.09	2,798.60	2,588.32	2,571.00	2,420.78	2,587.50	2,438.83	2,493.36	2,808.12	3,017.97	32,256.48
X4	D.2	2,171.49	2,250.97	2,040.83	1,482.78	811.65	933.32	1,201.08	1,615.54	1,413.78	857.02	704.38	1,033.97	16,516.81
X3	D.3	-	1.73	-	0.10	0.02	-	-	0.08	-	-	6.30	-	8.23
X3	D.4	1.76	7.84	-	-	-	-	-	0.14	0.09	-	8.41	-	18.23
X3	D.5	216.65	228.96	229.60	208.06	110.90	78.37	70.50	79.89	81.39	75.14	100.30	135.41	1,615.18
X5	D.6	397.71	144.68	-	9.82	20.87	116.13	421.79	54.26	81.22	-	315.74	168.86	1,731.07
X5	D.7	821.73	790.64	697.36	709.75	224.60	22.24	-	334.61	76.68	-	-	264.52	3,942.13
X5	D.8	276.00	814.43	613.56	283.56	-	235.74	223.34	91.61	155.08	106.54	133.97	-	2,933.83
X1	E.1	1,310.40	1,423.11	1,181.92	1,169.34	1,098.15	1,221.79	740.29	1,216.50	1,116.50	1,372.92	1,419.34	1,334.92	14,605.18
X1	E.2	8,505.95	8,844.20	7,365.90	7,654.95	7,314.76	7,807.70	7,527.93	8,083.25	7,853.65	7,761.92	8,192.96	8,041.96	94,955.13
X1	E.3	698.04	640.10	645.46	450.68	253.38	315.20	2,665.91	2,741.92	4,535.53	4,093.09	2,609.97	2,346.57	21,995.86
X1	E.4	3,199.19	3,198.67	3,460.97	2,559.17	910.61	562.01	907.34	1,227.76	1,195.65	449.57	630.96	1,692.12	19,994.02
X1	F.1	31,194.54	33,655.10	30,133.28	24,835.56	16,968.26	13,849.91	12,494.89	15,250.84	14,380.60	13,113.10	18,615.50	22,478.18	246,969.76
Total 300000 Series		288,158.554	306,715.982	274,051.172	256,092.680	207,608.598	207,700.761	205,102.625	230,437.944	218,718.261	201,528.471	222,222.830	240,854.666	2,859,192.544

Reason Code Key

X1	included	NYPA, NYMPA, Jamestown and Misc Villages (some of which are NYPA)
X2	no longer applicable - referred to year in which some municipals converted to the TSC rate	
X3	reported not billed	
X4	excluded - in WR	
X5	Athens	
X6	Disputed Station Service	

Reason Code	Dec - Nov Total
X1	2,793,150.989
X2	0.000
X3	8,661.247
X4	48,773.286
X5	8,607.022
X6	160,913.641
Total	3,020,106.185

Niagara Mohawk Power Corporation **Workpaper 14**
Billing Adjustment to be included in 2011 Informational Filing **Page 1 of 1**
~~Attachment H Section 14.1.9.2 (c)~~

Line No.			2010 UPDATE			
			2009			Source:
1						
2	~~14.1.9.2(d~~	The Annual True-Up (ATU) shall equal (1) the difference between the Actual Transmission Revenue Requirement and the Prior Year				
3		Transmission Revenue Requirement, plus (2) the difference between the Actual Scheduling, System Control and Dispatch costs				
4		and Prior Year Scheduling, System Control and Dispatch costs, less (3) the difference between the Actual Billing Units and the Prior Year				
5		Billing Units multiplied by the Prior Year Unit Rate, plus (4) Interest on the net differences.				
6			**ORIGINAL**	**REVISED**	**Billing Adjustment**	
7	(1)	Revenue Requirement (RR) of rate effective July 1 of prior year	$274,084,485	$274,084,485		Schedule 4, Line 1, Col (d)
8		Less: Annual True-up (ATU) from rate effective July 1 of prior year	$4,555,970	$4,555,970		Schedule 4, Line 1, Col (c)
9		Prior Year Transmission Revenue Requirement	$269,528,515	$269,528,515		Line 7 - Line 8
10						
11		Actual Transmission Revenue Requirement	$250,606,591	$248,236,337	$2,370,254	Schedule 4, Line 2, Col (a)
12		Difference	($18,921,924)	($21,292,178)	$2,370,254	Line 11 - Line 9
13						
14	(2)	Prior Year Scheduling, System Control and Dispatch costs (CCC)	$6,056,721	$6,056,721		Schedule 4, Line 1, Col (e)
15		Actual Scheduling, System Control and Dispatch costs (CCC)	$6,345,322	$6,345,322		Schedule 4, Line 2, Col (e)
16		Difference	$288,601	$288,601		Line 15 - Line 14
17						
18	(3)	Prior Year Billing Units (MWH)	36,954,476	36,954,476		Schedule 4, Line 1, Col (f)
19		Actual Billing Units	35,134,660	35,134,660		Schedule 4, Line 2, Col (f)
20		Difference	1,819,816	1,819,816		Line 18 - Line 19
21		Prior Year Indicative Rate	7.58	7.58		Schedule 4, Line 1, Col (g)
22		Billing Unit True-Up	$13,795,496	$13,795,496		Line 20 * Line 21
23						
24		Total Annual True-Up before Interest	($4,837,827)	($7,208,081)	$2,370,254	(Line 12 + Line 16 + Line 22)
25		LTD Rate 6 month phase plus current	($3,167,691)	($3,167,691)		Wkpp 14 - Per Settlement ATU Line 27, Col (a)
26		Total Annual True-Up before Interest	($8,005,519)	($10,375,772)	**$2,370,254**	(Line 24 + Line 25)
27						
28	(4)	2009 Interest	$ (43,430)	$ (56,289)	$ 12,859	Line 57
29		2010 Interest				Included in filing
30		Annual True-up RR Component	($8,048,949)	($10,432,061)	**$2,383,112**	**Billing Adjmt incl in Schedule 10, Line 1**
31						

32	Interest Calculation per 18 CFR Section 35.19a								
33	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
34	Quarters	Annual	Accrued Prin	Monthly	Days			Accrued Prin	Accrued
35		Interest	& Int. @ Beg	(Over)/Under	in	Period		& Int. @ End	Int. @ End
36		Rate	Of Period	Recovery	Period	Days	Multiplier	Of Period	Of Period
37									
38	3rd QTR '09		0		92	92	1.0000	$0	$0
39	July	3.25%		(864,648)	31	92	1.0082	($871,738)	($7,090)
40	August	3.25%		(864,648)	31	61	1.0054	($869,317)	($4,669)
41	September	3.25%		(864,648)	30	30	1.0027	($866,982)	($2,335)
42									
43	4th QTR '09		(2,608,037)		92	92	1.0000	($2,608,037)	$0
44	October	3.25%		(864,648)	31	92	1.0082	($871,738)	($7,090)
45	November	3.25%		(864,648)	30	61	1.0054	($869,317)	($4,669)
46	December	3.25%		(864,648)	31	31	1.0028	($867,069)	($2,421)
47									
48	1st QTR '10		(5,216,160)		91	91	1.0000	($5,216,160)	$0
49	January	3.25%		(864,648)	31	91	1.0081	($871,651)	($7,004)
50	February	3.25%		(864,648)	29	60	1.0053	($869,230)	($4,583)
51	March	3.25%		(864,648)	31	31	1.0028	($867,069)	($2,421)
52									
53	2nd QTR '10		(7,824,110)		91	91	1.0000	($7,824,110)	$0
54	April	3.25%		(864,648)	30	91	1.0081	($871,651)	($7,004)
55	May	3.25%		(864,648)	31	61	1.0054	($869,317)	($4,669)
56	June	3.25%		(864,648)	30	30	1.0027	($866,982)	($2,335)
57									
58									
59	Total (over)/under Recovery			($10,375,772) (line 26)					($56,289)

Niagara Mohawk Power Corporation **Workpaper 15**
Billing Unit Reconciliation **Page 1 of 1**

Line No.	Comment	2010 Schedule 12	2010 TOL File (X1)
1	Totals per filing	2,805,582	2,793,151
2	Overages	(3,018)	
3	Unaccounted for Energy (UFE) not billed		10,349
4	Other and Rounding		(936)
5	**Reconciliation**	**2,802,564**	**2,802,564**

Niagara Mohawk Power Corporation **Workpaper 16**
NYPSC §18-a Assessments **Page 1 of 1**
Breakdown of FF1 Page 351, Line 1, Column h

Line No.	Month	General Assessment Expense (a)	Temporary Assessment Expense (b)	Deferrals on Over/Under Collection of the ISAS (c)	Reimburements on Prior Year Assessments (d)	Other (e)	TOTAL (f)
1	Jan-2010	649,806	6,671,561	609,140			7,930,506
2	Feb-2010	649,806	6,671,561	(58,443)			7,262,924
3	Mar-2010	649,806	6,671,561	(296,574)			7,024,793
4	Apr-2010	720,873	6,722,035	(708,489)			6,734,419
5	May-2010	720,873	6,722,035	(900,018)			6,542,890
6	Jun-2010	720,873	6,722,035	(188,820)			7,254,088
7	Jul-2010	720,873	6,722,035	(515,109)			6,927,799
8	Aug-2010	720,873	6,722,035	906,113			8,349,021
9	Sep-2010	720,873	(1,688,757)	10,718,534			9,750,650
10	Oct-2010	623,989	5,320,237	1,054,224			6,998,450
11	Nov-2010	623,989	5,320,237	852,929			6,797,154
12	Dec-2010	623,989	5,320,237	1,484,673		1,805	7,430,704
13	CY2010 Total	8,146,620	67,896,811	12,958,160	-	1,805	89,003,397

14	50% of NY PSC Regulatory Expense	(Line 13, column a + column e)	8,148,425
15	18a Charges (Temporary Assessment)	(Line 13, column b + column c)	80,854,971

Notes:
ISAS = Incremental State Assessment Surcharge (total general + temporary assessement expense above base rate allowance)

1\ agrees to FERC Form 1 page 351 line 1 column h

National Grid

Niagara Mohawk Power Corporation

INVESTIGATION AS TO THE PROPRIETY OF PROPOSED ELECTRIC TARIFF CHANGES

Testimony and Exhibits of:

Ronald E. White
Testimony and
Exhibits __ (REW-1) through
(REW-3), Pages 1 - 236

Book 9

January 29, 2010

Submitted to:
New York Public Service Commission
Docket No. 10-E-____

Submitted by:

nationalgrid

Testimony of
Ronald E. White

Before the New York Public Service Commission

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID

Direct Testimony

of

Dr. Ronald E. White

Chairman, Foster Associates, Inc.

Dated: January 29, 2010

Dr. Ronald E. White

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Ronald E. White. My business address is 17595 S. Tamiami Trail, Suite 212, Fort Myers, Florida 33908.

Q. What is your occupation?

A. I am Chairman of the Board and a Senior Consultant of Foster Associates, Inc.

Q. Would you briefly describe your educational training and professional background?

A. I received a B.S. degree in Engineering Operations and an M.S. degree and Ph.D. (1977) in Engineering Valuation from Iowa State University. I have taught graduate and undergraduate courses in industrial engineering, engineering economics, and engineering valuation at Iowa State University and previously served on the faculty for Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. I also conduct courses in depreciation and public utility economics for clients of the firm.

I have prepared and presented a number of papers to professional organizations, committees, and conferences and have published several articles on matters relating to depreciation, valuation and economics. I am a past member of the Board of Directors of the Iowa State Regulatory Conference and an affiliate member of the joint American Gas Association (A.G.A.) – Edison Electric Institute (EEI) Depreciation Accounting Committee, where I previously served as chairman of a standing committee on capital recovery and its effect on corporate economics. I am also a member of the American Economic Association, the Financial Management Association, the Midwest Finance Association, the Electric Cooperatives Accounting Association (ECAA), and a founding member of the Society of Depreciation Professionals.

Q. What is your professional experience?

A. I joined the firm of Foster Associates in 1979, as a specialist in depreciation, the economics of capital investment decisions, and cost of capital studies for ratemaking applications. Before joining Foster Associates, I was employed by Northern States Power Company (1968–1979) in various assignments related to finance and treasury activities. As Manager of the Corporate Economics Department, I was responsible for book depreciation studies, studies involving staff assistance from the Corporate Economics Department in evaluating the economics of capital investment decisions, and the development and execution of innovative forms of project financing. As Assistant Treasurer at Northern States, I was responsible for bank relations, cash requirements planning, and short–term borrowings and investments.

Q. Have you previously testified before a regulatory body?

Dr. Ronald E. White

A. Yes. I have testified in numerous proceedings before administrative and judicial bodies in over thirty jurisdictions. I have also testified before the Federal Energy Regulatory Commission, the Federal Power Commission, the Alberta Energy Board, the Ontario Energy Board, and the Securities and Exchange Commission. I have sponsored position statements before the Federal Communication Commission and numerous local franchising authorities in matters relating to the regulation of telephone and cable television. A more detailed description of my professional qualifications is contained in Exhibit___ (REW–1).

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. Foster Associates was engaged by Niagara Mohawk Power Corporation d/b/a National Grid ("Niagara Mohawk" or "Company") to conduct a depreciation rate study of electric properties owned and operated by Niagara Mohawk. The purpose of my testimony is to sponsor and describe the study conducted by Foster Associates.

Depreciation rates currently used by the Company were approved by the New York State Public Service Commission (the Commission) in Case Nos. 29327 and 29328 (Opinion No. 87–3, issued March 13, 1987). The approved rates were derived from parameters (*i.e.*, projection lives, projection curves and net

Dr. Ronald E. White

salvage rates) estimated in a 1986 depreciation study based on plant and depreciation reserve balances at December 31, 1985.

Q. Do you sponsor any exhibits supporting your direct testimony?

A. Yes, I sponsor Exhibit___(REW–1) which details my professional qualifications, Exhibit___(REW–2) titled "2009 Electric Depreciation Rate Study" and Exhibit___(REW–3) containing workpapers supporting the 2009 depreciation study. These exhibits were prepared under my direction and supervision.

III. DEVELOPMENT OF DEPRECIATION RATES

Q. Please explain why depreciation studies are needed for accounting and ratemaking purposes.

A. The goal of depreciation accounting is to charge to operations a reasonable estimate of the cost of the service potential of an asset (or group of assets) consumed during an accounting interval. A number of depreciation systems have been developed to achieve this objective, most of which employ time as the apportionment base.

Implementation of a time–based (or age–life) system of depreciation accounting requires the estimation of several parameters or statistics related to a plant account. The average service life of a vintage, for example, is a statistic that will not be known with certainty until all units from the original placement have been retired from service. A vintage average service life, therefore, must

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be estimated initially and periodically revised as indications of the eventual average service life becomes more certain. Future net salvage rates and projection curves, which describe the expected distribution of retirements over time, are also estimated parameters of a depreciation system that are subject to future revisions. Depreciation studies should be conducted periodically to assess the continuing reasonableness of parameters and accrual rates derived from prior estimates.

The need for periodic depreciation studies is also a derivative of the ratemaking process which establishes prices for utility services based on costs. Absent regulation, deficient or excessive depreciation rates will produce no adverse consequence other than a systematic over or understatement of the accounting measurement of earnings. While a continuance of such practices may not comport with the goals of depreciation accounting, achievement of capital recovery is not dependent upon either the amount or timing of depreciation expense for an unregulated entity. In the case of a regulated utility, however, recovery of investor–supplied capital is dependent upon allowed revenues, which in turn depend upon approved levels of depreciation expense. Periodic reviews of depreciation rates are, therefore, essential to the achievement of timely capital recovery for a regulated utility.

It is also important to recognize that revenue associated with depreciation is a

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significant source of internally generated funds used to finance plant replacements and new capacity additions. Given the same financing requirements and the same dividend payout ratio, an increase in internal cash generation will accelerate per–share growth in earnings, dividends, and book value over the business life of a firm. Financial theory provides that the marginal cost of external financing will be reduced by these enhanced measurements of financial performance. This is not to suggest that internal cash generation should be substituted for the goals of depreciation accounting. However, the potential for realizing a reduction in the marginal cost of external financing provides an added incentive for adopting appropriate depreciation rates.[1]

Q. What are the principal activities involved in conducting a depreciation study?

A. The first step in conducting a depreciation study is the collection of plant accounting data needed to conduct a statistical analysis of past retirement experience. Data are also collected to permit an analysis of the relationship between retirements and realized gross salvage and cost of removal. The data collection phase should include a reconciliation of the assembled data to the official plant records of the company.

[1] I do not discuss nor have I considered whether other regulatory or public policy goals should influence or be reflected in establishing depreciation rates. Such considerations remain the prerogative of the regulatory agency responsible for determining appropriate depreciation rates.

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The next step in a depreciation study is the estimation of service life statistics from an analysis of past retirement experience. The term *life analysis* is used to describe the activities undertaken in this step to obtain a mathematical description of the forces of retirement acting upon a plant category. The mathematical expressions used to describe these forces are known as survival functions or survivor curves.

Life indications obtained from an analysis of past retirement experience are blended with expectations about the future to obtain an appropriate projection life curve. This step, called *life estimation*, is concerned with predicting the expected remaining life of property units still exposed to the forces of retirement. The amount of weight given to the analysis of historical data will depend upon the extent to which past retirement experience is considered descriptive of the future.

An estimate of the net salvage rate applicable to future retirements is usually obtained from an analysis of the gross salvage and cost of removal realized in the past. An analysis of past experience (including an examination of trends over time) provides a baseline for estimating future salvage and cost of removal. Consideration, however, should be given to events that may cause deviations from net salvage realized in the past. Among the factors that should be considered are the age of plant retirements; the portion of retirements that

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will be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to net salvage observed in the past.

A comprehensive depreciation study will also include an analysis of the adequacy of the recorded depreciation reserve. The purpose of such an analysis is to compare the current balance in the recorded reserve with the balance required to achieve the goals and objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized exactly as predicted. The difference between the required (or theoretical) reserve and the recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to extinguish the reserve imbalance.

Although reserve records are commonly maintained by various account classifications, the total recorded reserve in relation to the sum of account computed reserves is a good indicator of the adequacy (or inadequacy) of recorded reserves. Differences between theoretical and recorded reserves will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. Differences can also arise from plant accounting activity such as transfers and adjustments that may require an identification of reserves at a level lower than maintained in the accounting system. It is appropriate, therefore, and consistent with group depreciation theory, to periodically redistribute recorded reserves among primary accounts based on the most recent estimates of service lives, retirement dispersions and net salvage rates. A redistribution of the recorded reserve will provide an initial reserve balance for each primary account consistent with the estimates of retirement dispersion selected to describe mortality characteristics of the accounts and establish a baseline against which future comparisons can be made.

Finally, parameters estimated from service life and net salvage studies are integrated into an appropriate formulation of an accrual rate based upon a selected depreciation system. Three elements (*i.e.*, method, procedure and technique) are needed to describe a depreciation system. The sub–elements most widely used in constructing a depreciation system are shown in Table 1.

Methods	Procedures	Techniques
Retirement	Total Company	Whole-Life
Compound-Interest	Broad Group	Remaining-Life
Sinking-Fund	Vintage Group	Probable-Life
Straight-Line	Equal-Life Group	
Declining Balance	Unit Summation	
Sum-of-Years'-Digits	Item	
Expensing		
Unit-of-Production		
Net Revenue		

Table 1. Elements of a Depreciation System

The components of a depreciation system can be visualized as three dimensions of a cube in which each face describes a variety of sub–elements that can be combined to form a system. A depreciation system is formed by selecting a sub–element from each face such that the system contains one method, one procedure and one technique. The straight–line method, vintage–group procedure, remaining–life technique is a system widely used by regulated utilities.

IV. 2009 DEPRECIATION RATE STUDY

Q. Did the Company provide Foster Associates plant accounting data for conducting the 2009 depreciation study?

A. Yes. The database used in the 2009 study was assembled by the Company from two sources and provided to Foster Associates in Microsoft Excel spreadsheets. The first source was Corporate Project Accounting System (CPAS), a legacy system that provided plant and reserve transactions over the period January 1, 1996 through April 30, 2004.

The second source was PowerPlant®, an asset management system populated with age distributions of surviving plant at April 30, 2004. Plant and reserve activity for calendar years 2004 through 2008 and age distributions of surviving plant at December 31, 2008 were extracted from the PowerPlant system. The accuracy and completeness of the assembled database was verified for the calendar years available in PowerPlant. Beginning plant balances, additions, retirements, transfers and adjustments, and ending plant balances derived for each activity year were reconciled to the official plant records of the Company. Age distributions of surviving plant at December 31, 2008 were reconciled to the Company's Continuing Property Record (CPR) system.

Q. Did Foster Associates conduct statistical life studies for the Company's plant and equipment?

A. Yes, we did. As discussed in Exhibit___(REW–2) , all plant accounts were analyzed using a technique in which first, second and third degree orthogonal polynomials were fitted to a set of observed retirement ratios. The resulting function was expressed as a survivorship function that was numerically integrated to obtain an estimate of the projection life. The smoothed survivorship function was then fitted by a weighted least–squares procedure to the h–Curve family to obtain a mathematical description or classification of the dispersion characteristics of the data.[2] Service life indications derived from the statistical analyses were blended with informed judgment and expectations about the fu-

[2] The family of h–Curves was used in the current study to comply with a directive in Niagara Mohawk gas Case 08–G–0609 in which the parties agreed in settlement that "When the Company next files for new gas rates, its initial filing will include ... the observed curve and selected h–curve." It remains the opinion of Foster Associates, however, that use of the h–Curves is unduly restrictive as only left–modal distributions are considered as likely candidates for describing forces of retirement acting upon a plant category. Iowa–type curves, which are mathematically described by the Pearson frequency curve family, provide a set of 31 distributions ranging from origin to extreme right–modal density functions. While Foster Associates is unaware of any valid reason for rejecting origin, symmetric and right–modal dispersions as descriptors of forces of mortality, accepting only h–Curves is of no consequence if hazard rates are graduated with integrable functions and broad group, whole–life rates are prescribed.

ture to obtain an appropriate projection life curve for each plant category.

Q. Did Foster Associates conduct a net salvage analysis for the Company's plant and equipment?

A. Yes, we did. A five–year moving average analysis of the ratio of realized salvage and cost of removal to the associated retirements was used in the 2009 study to a) estimate realized net salvage rates; b) detect the emergence of historical trends; and c) establish a basis for estimating future net salvage rates. Cost of removal and salvage opinions obtained from Company personnel were blended with judgment and historical net salvage indications in developing estimates of the future.

Average net salvage rates were estimated using direct–dollar weighting of historical retirements with historical net salvage rates, and future retirements (*i.e.*, surviving plant) with estimated future net salvage rates. The computation of the average net salvage rates is shown on Exhibit___(REW–2), Statement D.

Q. Did Foster Associates conduct an analysis of recorded depreciation reserves?

A. Yes, we did. Statement C of Exhibit___(REW–2) provides a comparison of recorded, computed and rebalanced reserves at December 31, 2008. The total recorded reserve for electric operations was $2,182,984,708 or 36.4 percent of the depreciable plant investment. The corresponding computed reserve is

$2,121,908,850 or 35.4 percent of the depreciable plant investment. A reserve excess of $61,075,857 is therefore indicated for electric plant assets. The total recorded reserve for common operations was $96,736,382 or 32.0 percent of the depreciable plant investment. The corresponding computed reserve is $110,130,928 or 36.5 percent of the depreciable plant investment. A reserve deficiency of $13,394,546 is therefore indicated for Common plant assets.

Q. Is Foster Associates recommending a rebalancing of depreciation reserves for Niagara Mohawk?

A. Yes, we are. While whole–life depreciation rates are not affected by rebalancing depreciation reserves, a redistribution of recorded reserves is considered appropriate for Niagara Mohawk. Reserve imbalances attributable to both the passage of time and parameters adjustments developed in the current study should be realigned among primary accounts to reduce offsetting imbalances and partially mitigate the potential for sustained imbalances created by a continuing use of whole–life rates. Recorded reserves should also be realigned to eliminate reserve imbalances created by the prior implementation of amortization accounting for general amortizable categories.

Recorded reserves for all depreciable plant accounts were rebalanced by multiplying the calculated reserve for each primary account within a function by the ratio of the function total recorded reserve to the function total calculated reserve. The sum of redistributed reserves within a function is, therefore, equal to the function total recorded depreciation reserve before the redistribution. Reserves for general amortizable categories were adjusted by replacing recorded reserves with measured theoretical reserves and distributing any reserve imbalances to depreciable categories within the respective plant functions.

Q. Please describe the depreciation system currently approved by the Commission for the Niagara Mohawk.

A. The Company is currently using depreciation rates developed from a system composed of the straight–line method, broad group procedure, whole–life technique. The formulation of an account accrual rate using the currently approved depreciation system is given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Average Net Salvage Rate}}{\text{Average Service Life}}.$$

Q. Is Foster Associates recommending a change in the depreciation system for the Company?

A. No, we are not. Although Foster Associates is of the opinion that a system composed of the straight–line method, vintage group procedure, remaining–life technique would better achieve the goals and objectives of depreciation accounting, the Commission has historically denied any system other than the straight–line method, broad group procedure, whole–life technique. Accordingly, depreciation rates developed in the 2009 study for all depreciable categories were derived using the currently prescribed system.

Q. How does the vintage–group procedure, remaining–life technique differ from the broad–group procedure, whole–life technique?

A. Unlike the broad group procedure in which each vintage is estimated to have the same average service life, consideration is given to the realized life of each vintage when average service lives and remaining lives are derived using the vintage group procedure. The vintage group procedure distinguishes average service lives among vintages and composite life statistics are computed for each plant account. The formulation of an account accrual rate using the straight–line method, vintage group procedure, remaining–life technique or whole–life technique is identical to the broad group procedure.

The distinction between a whole–life rate and a remaining–life rate is the treatment of depreciation reserve imbalances. The measurement of a reserve imbalance is the difference between a theoretical or computed reserve and the corresponding recorded reserve for a rate category. The remaining-life technique provides a systematic amortization of these differences over the composite weighted average remaining life of a rate category. The whole–life technique does not address reserve imbalances.

Dr. Ronald E. White

Q. Please summarize the depreciation rates and accruals recommended for Niagara Mohawk in the 2009 study?

A. Table 2 provides a summary of the changes in annual rates and accruals resulting from an application of the proposed parameters and depreciation system currently prescribed for the Niagara Mohawk electric operations.

Function	Accrual Rate			2009 Annualized Accrual		
	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Transmission Plant	1.85%	2.29%	0.44%	$29,502,824	$36,484,659	$6,981,835
Distribution Plant	3.01%	2.89%	-0.12%	123,959,704	118,529,821	(5,429,883)
General Plant	4.49%	3.77%	-0.72%	13,055,362	10,976,476	(2,078,886)
Total	2.77%	2.77%	0.00%	$166,517,890	$165,990,956	($526,934)

Table 2. Summary of Current and Proposed Accruals for Electric Plant

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 2.77 percent. Depreciation expense is presently accrued at rates that composite to 2.77 percent. Ignoring rounding differences, the resulting composite rate is equal to the current composite accrual rate.

A continued application of current rates would provide annualized depreciation expense of $166,517,890 compared with an annualized expense of $165,990,956 using the rates developed in this study. The resulting 2009 expense reduction is $526,934. The difference is attributable to adjustments in service life and net salvage statistics recommended in the 2009 study.

Table 3 provides a summary of the changes in annual rates and accruals resulting from an application of the parameters and depreciation system recommended for the Niagara Mohawk Common operations.

Function	Accrual Rate			2009 Annualized Accrual		
	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
General Plant	4.28%	4.04%	-0.24%	$12,924,319	$12,188,293	($736,026)
Total	4.28%	4.04%	-0.24%	$12,924,319	$12,188,293	($736,026)

Table 3. Summary of Current and Proposed Accruals for Common Plant

The composite accrual rate recommended for the common operations is 4.04 percent. The current equivalent rate is 4.28 percent. The recommended change in the composite rate is a reduction of 0.24 percentage points.

A continued application of current rates would provide annualized depreciation expense of $12,924,319 compared with an annualized expense of $12,188,293 using the proposed rates. The resulting 2009 expense reduction is $737,026. The difference is attributable to adjustments in service life and net salvage statistics recommended in the 2009 study.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Exhibits of
Ronald E. White

Dr. Ronald E. White

Index of Attachments

Exhibit __ (REW-1)

Testimony of Ronald E. White

Exhibit __ (REW-1)

Professional Qualifications

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Fax (239) 267-5030
E-mail r.white@fosterfm.com

Ronald E. White, Ph.D.

Education

1961 - 1964 Valparaiso University
Major: Electrical Engineering

1965 Iowa State University
B.S., Engineering Operations

1968 Iowa State University
M.S., Engineering Valuation
Thesis: The Multivariate Normal Distribution and the Simulated Plant Record Method of Life Analysis

1977 Iowa State University
Ph.D., Engineering Valuation
Minor: Economics
Dissertation: A Comparative Analysis of Various Estimates of the Hazard Rate Associated With the Service Life of Industrial Property

Employment

2007 - Present Foster Associates, Inc.
Chairman

1996 - 2007 Foster Associates, Inc.
Executive Vice President

1988 - 1996 Foster Associates, Inc.
Senior Vice President

1979 - 1988 Foster Associates, Inc.
Vice President

1978 - 1979 Northern States Power Company
Assistant Treasurer

1974 - 1978 Northern States Power Company
Manager, Corporate Economics

1972 - 1974 Northern States Power Company
Corporate Economist

1970 - 1972 Iowa State University
Graduate Student and Instructor

1968 - 1970 Northern States Power Company
Valuation Engineer

1965 - 1968 Iowa State University
Graduate Student and Teaching Assistant

Publications

A New Set of Generalized Survivor Tables, Journal of the Society of Depreciation Professionals, October, 1992.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, Journal of the Society of Depreciation Professionals, December, 1989.

Standards for Depreciation Accounting Under Regulated Competition, paper presented at The Institute for Study of Regulation, Rate Symposium, February, 1985.

The Economics of Price-Level Depreciation, paper presented at the Iowa State University Regulatory Conference, May, 1981.

Depreciation and the Discount Rate for Capital Investment Decisions, paper presented at the National Communications Forum - National Electronics Conference, October 1979.

A Computerized Method for Generating a Life Table From the 'h-System' of Survival Functions, paper presented at the American Gas Association - Edison Electric Institute Depreciation Accounting Committee Meeting, December, 1975.

The Problem With AFDC is ..., paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1973.

The Simulated Plant-Record Method of Life Analysis, paper presented at the Missouri Public Service Commission Regulatory Information Systems Conference, May, 1971.

Simulated Plant-Record Survivor Analysis Program (User's Manual), special report published by Engineering Research Institute, Iowa State University, February, 1971.

A Test Procedure for the Simulated Plant-Record Method of Life Analysis, Journal of the American Statistical Association, September, 1970.

Modeling the Behavior of Property Records, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1970.

A Technique for Simulating the Retirement Experience of Limited-Life Industrial Property, paper presented at the National Conference of Electric and Gas Utility Accountants, May, 1969.

How Dependable are Simulated Plant-Record Estimates?, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, April, 1968.

Testifying Witness

Alabama Public Service Commission, Docket No. 18488, General Telephone Company of the Southeast; testimony concerning engineering economy study techniques.

Alabama Public Service Commission, Docket No. 20208, General Telephone Company of the South; testimony concerning the equal-life group procedure and remaining-life technique.

Alberta Energy and Utilities Board, Application No. 1250392, Aquila Networks Canada; rebuttal testimony supporting proposed depreciation rates.

Alberta Energy and Utilities Board, Case No. RE95081, Edmonton Power Inc.; rebuttal evidence concerning appropriate depreciation rates.

Alberta Energy and Utilities Board, 1999/2000 General Tariff Application, Edmonton Power Inc.; direct and rebuttal evidence concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. T-01051B-97-0689, U S West Communications, Inc.; testimony concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. G-1032A-02-0598, Citizens Communications Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–01345A–08–0172, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–0135A–03–0437, Arizona Public

Service Company; rebuttal testimony supporting net salvage rates.

Arizona Corporation Commission, Docket No. E–01345A–05–0816, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. G–04204A–06–0463, UNS Gas, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–04204A–06–0783, UNS Electric, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–04204A–09–0206, UNS Electric, Inc, testimony supporting proposed depreciation rates.

Arizona State Board of Equalization, Docket No. 6302-07-2, Arizona Public Service Company; testimony concerning valuation and assessment of contributions in aid of construction.

California Public Utilities Commission, Case Nos. A.92-06-040, 92-06-042, GTE California Incorporated; rebuttal testimony supporting depreciation study techniques.

California Public Utilities Commission. Docket No. GRC A.05–12–002, Pacific Gas and Electric Company; testimony regarding estimation of net salvage rates.

California Public Utilities Commission. Docket No. GRC A.06–12–009/A.06–12–010, San Diego Gas & Electric Company and Southern California Gas Company; testimony regarding estimation of net salvage rates.

Public Utilities Commission of the State of Colorado, Application No. 36883-Reopened. U S WEST Communications; testimony concerning equal-life group procedure.

State of Connecticut Department of Public Utility Control, Docket No. 05–03–17, The Southern Connecticut Gas Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 06–12PH01, Yankee Gas Services Company; testimony supporting recommended depreciation rates.

Delaware Public Service Commission, Docket No. 81-8, Diamond State Telephone Company; testimony concerning the amortization of inside wiring.

Delaware Public Service Commission, Docket No. 82-32, Diamond State Telephone Company; testimony concerning the equal-life group procedure and remaining-life technique.

Public Service Commission of the District of Columbia, Formal Case No. 842, District of Columbia Natural Gas; testimony concerning depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1016, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1054, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Federal Communications Commission, Prescription of Revised Depreciation Rates for AT&T Communications; statement concerning depreciation, regulation and competition.

Federal Communications Commission, Petition for Modification of FCC Depreciation Prescription Practices for AT&T; statement concerning alignment of depreciation expense used for financial reporting and regulatory purposes.

Federal Communications Commission, Docket No. 99-117, Bell Atlantic; affidavit concerning revenue requirement and capital recovery implications of omitted plant retirements.

Federal Energy Regulatory Commission, Docket No. ER10-185-000, Michigan Electric Transmission Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER09-1530-000, ITC*Transmission*; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER95-267-000, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. RP89-248, Mississippi River Transmission Corporation; rebuttal testimony concerning appropriateness of net salvage component in depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER91-565, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER78-291, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Energy Regulatory Commission, Docket Nos. RP80-97 and RP81-54, Tennessee Gas Pipeline Company; testimony concerning offshore plant depreciation rates.

Federal Power Commission, Docket No. E-8252, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. E-9148, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. ER76-818, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Power Commission, Docket No. RP74-80, *Northern* Natural Gas Company; testimony concerning depreciation expense.

Public Utilities Commission of the State of Hawaii, Docket No. 00-0309, The Gas Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of Hawaii, Docket No. 94-0298, GTE Hawaiian Telephone Company Incorporated; testimony concerning the need for shortened service lives and disclosure of asset impairment losses.

Idaho Public Utilities Commission, Case No. U-1002-59, General Telephone Company of the Northwest, Inc.; testimony concerning the remaining-life technique and the equal-life group procedure.

Illinois Commerce Commission, Case No. 04–0476, Illinois Power Company; testimony supporting proposed depreciation rates.

Illinois Commerce Commission, Docket No. 94-0481, Citizens Utilities Company of Illinois; rebuttal testimony concerning applications of the Simulated Plant-Record method of life analysis.

Iowa State Commerce Commission, Docket No. RPU 82-47, North Central Public Service Company; testimony on depreciation rates.

Iowa State Commerce Commission, Docket No. RPU 84-34, General Telephone

Company of the Midwest; testimony concerning the remaining-life technique and the equal-life group procedure.

Iowa State Utilities Board, Docket No. DPU-86-2, Northwestern Bell Telephone Company; testimony concerning capital recovery in competition.

Iowa State Utilities Board, Docket No. RPU-84-7, Northwestern Bell Telephone Company; testimony concerning the deduction of a reserve deficiency from the rate base.

Iowa State Utilities Board, Docket No. DPU-88-6, U S WEST Communications; testimony concerning depreciation subject to refund.

Iowa State Utilities Board, Docket No. RPU-90-9, Central Telephone Company of Iowa; testimony concerning depreciation rates.

Iowa State Utilities Board, Docket No. RPU-93-9, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. DPU-96-1, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. RPU-05-2, Aquila Networks; testimony supporting recommended depreciation rates.

Kansas Corporation Commission, Docket No. 04–AQLE–1065–RTS, Aquila Networks – WPE (Kansas); testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 03–KGSG–602–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; rebuttal testimony supporting net salvage rates.

Kansas Corporation Commission, Docket No. 06–KGSG–1209–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.

Kentucky Public Service Commission, Case No. 97-224, Jackson Purchase Electric Cooperative Corporation; rebuttal testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 8485, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9096, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 7689, Washington Gas Light Company; testimony concerning life analysis and net salvage.

Maryland Public Service Commission, Case No. 8960, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9103, Washington Gas Light Company; rebuttal testimony supporting proposed depreciation rates.

Commonwealth of Massachusetts Department of Telecommunications and Energy, D.T.E. 06–55, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.

Massachusetts Department of Public Utilities, Case No. DPU 91-52, Massachusetts Electric Company; testimony supporting proposed depreciation rates which include a net salvage component.

Michigan Public Service Commission, Case No. U–16117, The Detroit Edison

Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–15699, Michigan Consolidated Gas Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–13899, Michigan Consolidated Gas Company; testimony concerning service life estimates.

Michigan Public Service Commission, Case No. U-13393, Aquila Networks – MGU; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U-12395, Michigan Gas Utilities; testimony supporting proposed depreciation rates including amortization accounting and redistribution of recorded reserves.

Michigan Public Service Commission, Case No. U-6587, General Telephone Company of Michigan; testimony concerning use of a theoretical depreciation reserve with the remaining-life technique.

Michigan Public Service Commission, Case No. U-7134, General Telephone Company of Michigan; testimony concerning the equal-life group depreciation procedure.

Minnesota Public Service Commission, Docket No. E-611, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Minnesota Public Service Commission, Docket No. E-1086, Northern States Power Company; testimony concerning depreciation rates.

Minnesota Public Service Commission, Docket No. G-1015, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Public Service Commission of the State of Missouri, Case No. ER-2009-0090, KCP&L Greater Missouri Operations, rebuttal testimony concerning depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER-2001-672, Missouri Public Service, a division of Utilicorp United Inc.; surrebuttal testimony regarding computation of income tax expense.

Public Service Commission of the State of Missouri, Case No. TO-82-3, Southwestern Bell Telephone Company; rebuttal testimony concerning the remaining-life technique and the equal-life group procedure.

Public Service Commission of the State of Missouri, Case No. GO-97-79, Laclede Gas Company; rebuttal testimony concerning adequacy of database for conducting depreciation studies.

Public Service Commission of the State of Missouri, Case No. GR-99-315, Laclede Gas Company; rebuttal testimony concerning treatment of net salvage in development of depreciation rates.

Public Service Commission of the State of Missouri, Case No. HR–2004–0024, Aquila Inc. d/b/a/ Aquila Networks–L & P; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER–2004–0034, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. GR–2004–0072, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.

Public Service Commission of the State of Montana, Docket No. 88.2.5, Mountain State Telephone and Telegraph Company; rebuttal testimony concerning the equal-life group procedure and amortization of reserve imbalances.

Montana Public Service Commission, Docket No. D95.9.128, The Montana Power Company; testimony supporting proposed depreciation rates.

Nebraska Public Service Commission, Docket No. NG–0041, Aquila Networks (PNG Nebraska); testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 92-7002, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 91-5054, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

New Hampshire Public Utilities Commission, Docket No. DR95-169, Granite State Electric Company; testimony supporting proposed net salvage rates.

New Jersey Board of Public Utilities, Docket No. GR07110889, New Jersey Natural Gas Company; testimony supporting proposed depreciation rates.

New Jersey Board of Public Utilities, Docket No. GR 87060552, New Jersey Natural Gas Company; testimony concerning depreciation rates.

New Jersey Board of Regulatory Commissioners, Docket No. GR93040114J, New Jersey Natural Gas Company; testimony concerning depreciation rates.

North Carolina Utilities Commission, Docket No. E-7, SUB 487, Duke Power Company; rebuttal testimony concerning proposed depreciation rates.

North Carolina Utilities Commission, Docket No. P-19, SUB 207, General Telephone Company of the South; rebuttal testimony concerning the equal-life group depreciation procedure.

North Dakota Public Service Commission, Case No. 8860, Northern States Power Company; testimony concerning general financial requirements.

North Dakota Public Service Commission, Case No. 9634, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9666, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9741, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Oklahoma Corporation Commission, Cause No. PUD 200900110, Oklahoma Natural Gas Company; testimony supporting revised depreciation rates.

Ontario Energy Board, E.B.R.O. 385, Tecumseh Gas Storage Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 388, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 456, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 476-03, Union Gas Limited; testimony concerning depreciation rates.

Public Utilities Commission of Ohio, Case No. 81-383-TP-AIR, General Telephone Company of Ohio; testimony in support of the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 82-886-TP-AIR, General Telephone Company of Ohio; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 84-1026-TP-AIR, General

Telephone Company of Ohio; testimony in support of the equal-life group procedure and the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 81-1433, The Ohio Bell Telephone Company; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 83-300-TP-AIR, The Ohio Bell Telephone Company; testimony concerning straight-line age-life depreciation.

Public Utilities Commission of Ohio, Case No. 84-1435-TP-AIR, The Ohio Bell Telephone Company; testimony in support of test period depreciation expense.

Public Utilities Commission of Oregon, Docket No. UM 204, GTE of the Northwest; testimony concerning the theory and practice of depreciation accounting under public utility regulation.

Public Utilities Commission of Oregon, Docket No. UM 840, GTE Northwest Incorporated; rebuttal testimony concerning principles of capital recovery.

Pennsylvania Public Utility Commission, Docket No. R-80061235, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811512, General Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811819, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-822109, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique.

Pennsylvania Public Utility Commission, Docket No. R-850229, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique and the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. C-860923, The Bell Telephone Company of Pennsylvania; testimony concerning capital recovery under competition.

Rhode Island Public Utilities Commission, Docket No. 2290, The Narragansett Electric Company; testimony supporting proposed net salvage rates and depreciation rates.

South Carolina Public Service Commission, Docket No. 91-216-E, Duke Power Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of South Dakota, Case No. F-3062, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Public Utilities Commission of the State of South Dakota, Case No. F-3188, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Securities and Exchange Commission, File No. 3-5749, Northern States Power Company; testimony concerning the financial and ratemaking implications of an affiliation with Lake Superior District Power Company.

Tennessee Public Service Commission, Docket No. 89-11041, United Inter-Mountain Telephone Company; testimony concerning depreciation principles and capital recovery under competition.

State of Vermont Public Service Board, Docket No. 6596, Citizens Communications Company – Vermont Electric Division; testimony supporting recommended depreciation rates.

State of Vermont Public Service Board, Docket No. 6946 and 6988, Central Vermont Public Service Corporation; testimony supporting net salvage rates.

Commonwealth of Virginia State Corporation Commission, Case No. PUE-2002-00364, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Public Service Commission of Wisconsin, Docket No. 2180-DT-3, General Telephone Company of Wisconsin; testimony concerning the equal-life group depreciation procedure.

Other Consulting Activities

Moran Towing Corporation. In Re: Barge TEXAS-97 CIV. 2272 (ADS) and Tug HEIDE MORAN – 97 CIV. 1947 (ADS), United States District Court, Southern District of New York.

John Reigle, et al. v. Baltimore Gas & Electric Co., et al., Case No. C-2001-73230-CN, Circuit Court for Anne Arundel County, Maryland.

SR International Business Insurance Co. vs. WTC Properties et. al., 01,CV–9291 (JSM) and other related cases.

BellSouth Telecommunications, Inc. v. Citizens Utilities Company d/b/a/ Louisiana Gas Service Company, CA No. 95-2207, United States District Court, Eastern District of Louisiana.

Affidavit on behalf of Continental Cablevision, Inc. and its operating cable television systems regarding basic broadcast tier and equipment and installation cost-of-service rate justification.

Office of Chief Counsel, Internal Revenue Service. In Re: Kansas City Southern Railway Co., et. al. Docket Nos. 971-72, 974-72, and 4788-73.

Office of Chief Counsel, Internal Revenue Service. In Re: Northern Pacific Railway Co., Docket No. 4489-69.

United States Department of Justice. In Re: Burlington Northern Inc. v. United States, Ct. Cl. No. 30-72.

Minnesota District Court. In Re: Northern States Power Company v. Ronald G. Blank, *et. al.* File No. 394126; testimony concerning depreciation and engineering economics.

Faculty

Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. (1980 - 1999)

United States Telephone Association (USTA), Depreciation Training Seminar, November 1999.

Depreciation Advocacy Workshop, a three-day team-training workshop on preparation, presentation, and defense of contested depreciation issues, sponsored by Gilbert Associates, Inc., October, 1979.

Corporate Economics Course, Employee Education Program, Northern States Power Company. (1968 - 1979)

Perspectives of Top Financial Executives, Course No. 5-300, University of Minnesota, September, 1978.

Depreciation Programs for public utility commissions, companies, and consultants, jointly sponsored by Western Michigan University and Michigan Technological

University, 1973.

Professional Associations

Advisory Committee to the Institute for Study of Regulation, sponsored by the American University and The University of Missouri-Columbia.

American Economic Association.

American Gas Association - Edison Electric Institute Depreciation Accounting Committee.

Board of Directors, Iowa State Regulatory Conference.

Edison Electric Institute, Energy Analysis Division, Economic Advisory Committee, 1976-1980.

Financial Management Association.

The Institute of Electrical and Electronics Engineers, Inc., Power Engineering Society, Engineering and Planning Economics Working Group.

Midwest Finance Association.

Society of Depreciation Professionals (Founding Member and Chairman, Policy Committee.

Moderator

Depreciation Open Forum, Iowa State University Regulatory Conference, May 1991.

The Quantification of Risk and Uncertainty in Engineering Economic Studies, Iowa State University Regulatory Conference, May 1989.

Plant Replacement Decisions with Added Revenue from New Service Offerings, Iowa State University Regulatory Conference, May 1988.

Economic Depreciation, Iowa State University Regulatory Conference, May 1987.

Opposing Views on the Use of Customer Discount Rates in Revenue Requirement Comparisons, Iowa State University Regulatory Conference, May 1986.

Cost of Capital Consequences of Depreciation Policy, Iowa State University Regulatory Conference, May 1985.

Concepts of Economic Depreciation, Iowa State University Regulatory Conference, May 1984.

Ratemaking Treatment of Large Capacity Additions, Iowa State University Regulatory Conference, May 1983.

The Economics of Excess Capacity, Iowa State University Regulatory Conference, May 1982.

New Developments in Engineering Economics, Iowa State University Regulatory Conference, May 1980.

Training in Engineering Economy, Iowa State University Regulatory Conference, May 1979.

The Real Time Problem of Capital Recovery, Missouri Public Service Commission, Regulatory Information Systems Conference, September 1974.

Speaker

Group Depreciation Practices of Regulated Utilities (IAS 16 Property, Plant and Equipment), Hydro One Networks, Inc., November 2008.

Economics, Finance and Engineering Valuation. Florida Gulf Coast University, April 2007.

Depreciation Studies for Regulated Utilities, Hydro One Networks, Inc., April 2006.

Depreciation Studies for Cooperatives and Small Utilities. TELERGEE CFO and Controllers Conference, November, 2004.

Finding the "D" in RCNLD (Valuation Applications of Depreciation), Society of Depreciation Professionals Annual Meeting, September 2001.

Capital Asset and Depreciation Accounting, City of Edmonton Value Engineering Workshop, April 2001.

A Valuation View of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, October 1999.

Capital Recovery in a Changing Regulatory Environment, Pennsylvania Electric Association Financial-Accounting Conference, May 1999.

Depreciation Theory and Practice, Southern Natural Gas Company Accounting and Regulatory Seminar, March 1999.

Depreciation Theory Applied to Special Franchise Property, New York Office of Real Property Services, March 1999.

Capital Recovery in a Changing Regulatory Environment, PowerPlan Consultants Annual Client Forum, November 1998.

Economic Depreciation, AGA Accounting Services Committee and EEI Property Accounting and Valuation Committee, May 1998.

Discontinuation of Application of FASB Statement No. 71, Southern Natural Gas Company Accounting Seminar, April 1998.

Forecasting in Depreciation, Society of Depreciation Professionals Annual Meeting, September 1997.

Economic Depreciation In Response to Competitive Market Pricing, 1997 TELUS Depreciation Conference, June 1997.

Valuation of Special Franchise Property, City of New York, Department of Finance Valuation Seminar, March 1997.

Depreciation Implications of FAS Exposure Draft 158-B, 1996 TLG Decommissioning Conference, October 1996.

Why Economic Depreciation?, American Gas Association Depreciation Accounting Committee Meeting, August 1995.

The Theory of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, November 1994.

Vintage Depreciation Issues, G & T Accounting and Finance Association Conference, June 1994.

Pricing and Depreciation Strategies for Segmented Markets (Regulated and Competitive), Iowa State Regulatory Conference, May 1990.

Principles and Practices of Depreciation Accounting, Canadian Electrical Association and Nova Scotia Power Electric Utility Regulatory Seminar, December 1989.

Principles and Practices of Depreciation Accounting, Duke Power Accounting Seminar, September 1989.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, GTE Capital Recovery Managers Conference, February 1989.

Valuation Methods for Regulated Utilities, GTE Capital Recovery Managers Conference, January 1988.

Depreciation Principles and Practices for REA Borrowers, NRECA 1985 National

Accounting and Finance Conference, September 1985.

Depreciation Principles and Practices for REA Borrowers, Kentucky Association of Electric Cooperatives, Inc., Summer Accountants Association Meeting, June 1985.

Considerations in Conducting a Depreciation Study, NRECA 1984 National Accounting and Finance Conference, October 1984.

Software for Conducting Depreciation Studies on a Personal Computer, United States Independent Telephone Association, September 1984.

Depreciation—An Assessment of Current Practices, NRECA 1983 National Accounting and Finance Conference, September 1983

Depreciation—An Assessment of Current Practices, REA National Field Conference, September 1983.

An Overview of Depreciation Systems, Iowa State Commerce Commission, October 1982.

Depreciation Practices for Gas Utilities, Regulatory Committee of the Canadian Gas Association, September 1981.

Practice, Theory, and Needed Research on Capital Investment Decisions in the Energy Supply Industry, workshop, sponsored by Michigan State University and the Electric Power Research Institute, November 1977.

Depreciation Concepts Under Regulation, Public Utilities Conference, sponsored by The University of Texas at Dallas, July 1976.

Electric Utility Economics, Mid-Continent Area Power Pool, May 1974.

Honors and Awards

The Society of Sigma Xi.

Professional Achievement Citation in Engineering, Iowa State University, 1993.

Exhibit __ (REW-2)

Testimony of Ronald E. White

Exhibit __ (REW-2)

2009 Depreciation Rate Study

2009 Electric Depreciation Rate Study

Niagara Mohawk Power Corporation – d/b/a National Grid

Prepared by
Foster Associates, Inc.

FOSTER ASSOCIATES INCORPORATED
ECONOMIC CONSULTANTS

Dated: November 1, 2009

CONTENTS

ANALYSIS

SECTION V

EXECUTIVE SUMMARY

INTRODUCTION

This report presents findings and recommendations developed in a 2009 Electric Depreciation Rate Study conducted by Foster Associates, Inc. (Foster Associates) for Niagara Mohawk Power Corporation d/b/a National Grid (Niagara Mohawk or Company). Work on the study commenced in May 2008 and was suspended in November 2008. Work resumed in June 2009 and progressed through October 2009, at which time the project was completed.

Foster Associates is a public utility economic consulting firm headquartered in Bethesda, Maryland offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by the firm's Fort Myers office include property service–life forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities, including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer software for conducting depreciation and valuation studies.

Depreciation rates currently used by the Company were approved by the New York State Public Service Commission (the Commission) in Case Nos. 29327 and 29328 (Opinion No. 87–3, issued March 13, 1987). The approved rates were derived from parameters (*i.e.*, projection lives, projection curves and net salvage rates) estimated in a 1986 depreciation study based on plant and depreciation reserve balances at December 31, 1985.

The principal findings and recommendations of the 2009 Niagara Mohawk Depreciation Study are summarized in the Statements section of this report. Statement A provides a comparative summary of current and proposed annual depreciation rates for each rate category. Statement B provides a comparison of current and proposed annual depreciation accruals. Statement C provides a comparison of recorded, computed and redistributed reserves for each rate category. Statement D provides a summary of the components used to obtain a weighted–average net salvage rate for each plant account. Statement E provides a comparative summary of current and proposed parameters and statistics including projection life, projection curve, average service life, average remaining life, and average and future net salvage rates. A set of statements is included in this report for both electric and common operations.

SCOPE OF REVIEW

The principal activities undertaken in conducting the 2009 study included:

- Collection of plant and reserve data;
- Field inspections and discussions with Niagara Mohawk plant accounting and operating personnel;
- Estimation of projection lives and retirement dispersion patterns;
- Analysis of gross salvage and cost of removal;
- Analysis of recorded depreciation reserves; and
- Development of recommended accrual rates for each rate category.

DEPRECIATION SYSTEM

A depreciation rate is formed by combining the elements of a depreciation system. A depreciation system is composed of a method, a procedure and a technique. A depreciation method (*e.g.*, straight–line) describes the component of the system that determines the acceleration or deceleration of depreciation accruals in relation to either time or use. A depreciation procedure (*e.g.*, vintage group) identifies the level of grouping or sub–grouping of assets within a plant category. The level of grouping specifies the weighting used to obtain composite life statistics for an account. A depreciation technique (*e.g.*, remaining–life) describes the life statistic used in the system. Depreciation rates currently approved for Niagara Mohawk were developed from a system composed of the straight–line method, broad group procedure, whole–life technique.

The matching and expense recognition principles of accounting provide that the cost of an asset (or group of assets) should be allocated to operations over an estimate of the economic life of the asset in proportion to the consumption of service potential. It is the opinion of Foster Associates that the objectives of depreciation accounting can be more nearly achieved using the vintage group procedure combined with the remaining–life technique.

Unlike the broad group procedure in which each vintage is estimated to have the same average service life, the vintage group procedure distinguishes average service lives among vintages and provides cost apportionment over the estimated weighted–average remaining life or average life of a rate category.

The level of asset grouping identified in the broad group procedure is the total plant in service from all vintages in an account. Each vintage is estimated to have the same average service life. It is unlikely, therefore, that compensating deviations (*i.e.*, over and underestimates of average service life) will be created among vintages to achieve cost allocation over the average service life of each vintage.

The level of asset grouping identified in the vintage group procedure is the plant in service from each vintage. The average service life (or remaining life) is estimated independently for each vintage and composite life statistics are computed for each plant account. It is more likely that compensating deviations will be created with a vintage group procedure than with a broad group procedure.

Although Foster Associates is of the opinion that a system composed of the straight–line method, vintage group procedure, remaining–life technique would better achieve the goals and objectives of depreciation accounting, the New York State Public Service Commission has consistently rejected systems other than the straight–line method, broad group procedure, whole–life technique. Accordingly, depreciation rates developed in the 2009 study for all depreciable categories were derived using the currently prescribed system.

In addition to revised depreciation rates, revised amortization periods are proposed for several general support asset categories in which the unit cost of equipment is small in relation to the cost of maintaining detailed accounting records or in which individual assets are difficult to track. Although amortization accounting was adopted January 1, 1995, amortization periods were derived from average service lives developed in the previously referenced 1986 depreciation study. Current amortization periods for a number of accounts are relatively long and inconsistent with the periods approved for comparable gas plant accounts. Accordingly, amortization periods proposed in the current study are the same as those recently supported by Staff in Niagara Mohawk gas Case 08–G–0609. Amortization periods would be revised for the electric operations general asset categories as summarized in Table 1 below.

Account Number	Description	Amortization Period (yrs) Current	Proposed
A	B	C	D
391.01	Office Furniture and Fixtures	42	22
391.20	Data Processing Equipment	5	5
393.00	Stores Equipment	40	22
394.01	Tools, Shop and Garage Equipment	42	22
395.00	Laboratory Equipment	40	22
397.01	Communication Equipment - Radio	20	22
397.02	Communication Equipment - Telephone	8	8
397.03	Communication Equipment - Network	15	22
398.01	Miscellaneous Equipment	20	22

Table 2. Commpn Plant Amortization Accounts

Amortization periods would be similarly revised for the common asset categories as summarized in Table 2 below.

Account Number	Description	Amortization Period (yrs) Current	Proposed
A	B	C	D
391.01	Office Furniture and Fixtures	42	22
391.20	Data Processing Equipment	5	5
393.00	Stores Equipment	40	22
394.01	Tools, Shop and Garage Equipment	42	22
395.00	Laboratory Equipment	40	22
397.01	Communication Equipment - Radio	20	22
397.02	Communication Equipment - Telephone	8	8
397.03	Communication Equipment - Network	15	22
398.01	Miscellaneous Equipment	20	22

Table 2. Commpn Plant Amortization Accounts

Upon approval of the proposed change in amortization periods, plant older than the proposed amortization periods will be retired from service and future retirements will be posted as each vintage achieves an age equal to the amortization period.[1]

Recommended Depreciation Rates

Table 3 below provides a summary of the changes in annual rates and accruals resulting from an application of the proposed parameters and depreciation system currently prescribed for the Niagara Mohawk electric operations.

Function	Accrual Rate			2009 Annualized Accrual		
	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Transmission Plant	1.85%	2.29%	0.44%	$29,502,824	$36,484,659	$6,981,835
Distribution Plant	3.01%	2.88%	-0.13%	123,959,704	118,529,821	(5,429,883)
General Plant	4.49%	3.77%	-0.72%	13,055,362	10,976,476	(2,078,886)
Total	2.77%	2.77%	0.00%	$166,517,890	$165,990,956	($526,934)

Table 3. Summary of Current and Proposed Accruals for Electric Plant

The composite accrual rate recommended for electric operations is 2.77 percent. The current equivalent rate is 2.77 percent. Ignoring rounding differences,

[1] Amortization accounting is fully implemented by replacing recorded reserves with measured theoretical reserves and distributing any reserve imbalances to depreciable categories within the general plant function. This treatment of amortization reserves (or any rebalancing of reserves) is ineffective absent adoption of remaining–life accrual rates.

the resulting composite rate is equal to the current composite accrual rate.

A continued application of current rates would provide annualized depreciation expense of $166,517,890 compared with an annualized expense of $165,990,956 using the proposed rates. The resulting 2009 expense reduction is $526,934. The difference is attributable to adjustments in service life and net salvage statistics recommended in the 2009 study.

Of the 41 primary accounts included in the 2009 study, Foster Associates is recommending rate reductions for 23 plant accounts and rate increases for 18 accounts.

Table 4 provides a summary of the changes in annual rates and accruals resulting from an application of the parameters and depreciation system recommended for the Niagara Mohawk common operations.

	Accrual Rate			2008 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
General Plant	4.28%	4.04%	-0.24%	$12,924,319	$12,188,293	($736,026)
Total	4.28%	4.04%	-0.24%	$12,924,319	$12,188,293	($736,026)

Table 4. Summary of Current and Proposed Accruals for Common Plant

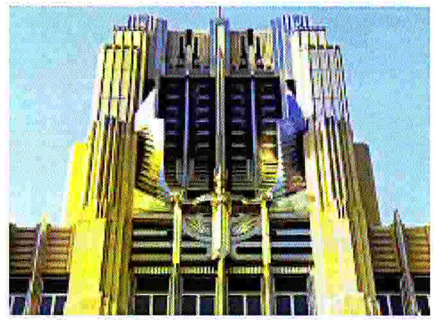
The composite accrual rate recommended for the common operations is 4.04 percent. The current equivalent rate is 4.28 percent. The recommended change in the composite rate is a reduction of 0.24 percentage points.

A continued application of current rates would provide annualized depreciation expense of $12,924,319 compared with an annualized expense of $12,188,293 using the proposed rates. The resulting 2009 expense reduction is $737,026. The difference is attributable to adjustments in service life and net salvage statistics recommended in the 2009 study.

Of the 11 primary accounts included in the 2009 study of common operations, Foster Associates is recommending rate reductions 5 plant accounts and rate increases for 6 accounts.

COMPANY PROFILE

GENERAL

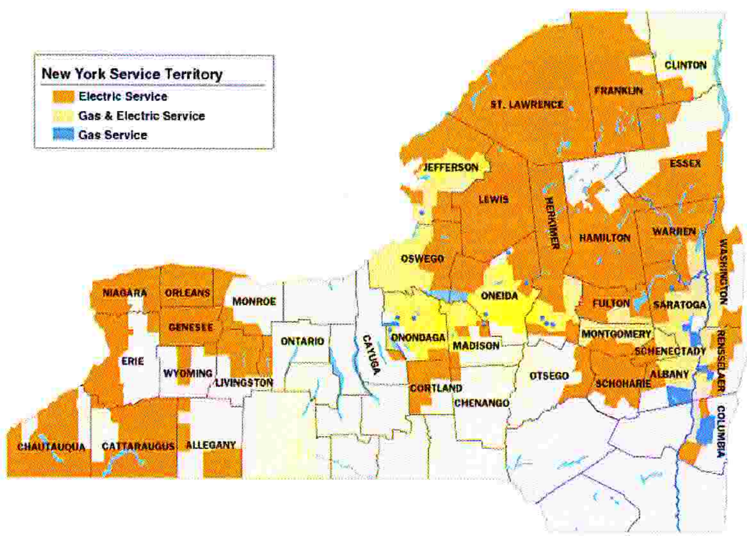


Niagara Mohawk Power Corporation d/b/a National Grid is a wholly–owned electric and gas combination subsidiary of National Grid plc operating in upstate New York based in Syracuse. The Company was incorporated under the laws of the State of New York in 1929 as Niagara Hudson Power Corporation Company. In January 2002, National Grid plc acquired Niagara Mohawk Holdings, Inc. a New York State utility. Niagara Mohawk Holdings is a holding company for utilities providing electricity and gas services. Niagara Mohawk Power Corporation was a subsidiary of Niagara Mohawk Holdings, Inc

The Company's principal business is providing electricity and gas to the upstate New York region. At December 31, 2008, Niagara Mohawk Power Corporation owned 712 substations, 442,828 line transformers, 93,722 pole or conduit miles of distribution lines and 10,595 circuit miles of transmission lines.

SERVICE AREA

Electric service is provided to approximately 1.5 million customers in upstate New York, and natural gas service is provided to thousands of customers in the eastern, central, and northern parts of the state.



Approximately 85 percent of Niagara Mohawk Holdings' revenue comes from electricity sales. The company sold its holdings in nuclear power plants in 2000, prior to the merger with National Grid plc.

STUDY PROCEDURE

INTRODUCTION

The purpose of a depreciation study is to analyze the mortality characteristics, net salvage rates and adequacy of the depreciation accrual and recorded depreciation reserve for each rate category. This study provides the foundation and documentation for recommended changes in depreciation rates used by Niagara Mohawk. The proposed rates are subject to approval by the New York State Public Service Commission.

SCOPE

The steps involved in conducting a depreciation study can be grouped into five major tasks:

- Data Collection;
- Life Analysis and Estimation;
- Net Salvage Analysis;
- Depreciation Reserve Analysis; and
- Development of Accrual Rates.

The scope of the 2009 study undertaken for Niagara Mohawk included a consideration of each of these tasks as described below.

DATA COLLECTION

The minimum database required to conduct a statistical life study consists of a history of vintage year additions and unaged activity year retirements, transfers and adjustments. These data must be appropriately adjusted for transfers, sales and other plant activity that would otherwise bias the measured service life of normal retirements. The age distribution of surviving plant for unaged data can be estimated by distributing plant in service at the beginning of the study year to prior vintages in proportion to the theoretical amount surviving from a projection or survivor curve identified in the life study. The statistical methods of life analysis used to examine unaged plant data are known as *semi–actuarial techniques*.

A far more extensive database is required to apply statistical methods of life analysis known as *actuarial techniques*. Plant data used in an actuarial life study most often include age distributions of surviving plant at the beginning of a study year and the vintage year, activity year, and dollar amounts associated with normal retirements, reimbursed retirements, sales, abnormal retirements, transfers, corrections, and extraordinary adjustments over a series of prior activity years. An actuarial database may include age distributions of surviving plant at the beginning of the earliest activity year, rather than at the beginning of the study year. Plant additions, however, must be included in a database containing an opening age distribution to derive aged survivors at the beginning of the study year. All activity year transactions with vintage year identification are coded and stored in a database. The data are processed by a computer program and transaction summary reports are created in a format reconcilable to the Company's official plant records. The availability of such detailed information is dependent upon an accounting system that supports aged property records. The Continuing Property Record (CPR) system currently used by Niagara Mohawk provides aged transactions since 2006 for all plant accounts.

The database used in the 2009 study was assembled by the Company from two sources and provided to Foster Associates in Microsoft Excel spreadsheets. The first source was a database compiled from plant and reserve records in CPAS (Corporate Project Accounting System), a legacy system that provided accounting transactions over the period January 1, 1996 through April 30, 2004.

The second source was PowerPlant®, an asset management system populated with age distributions of surviving plant at April 30, 2004. Plant and reserve activity for calendar years 2004 through 2008 and age distributions of surviving plant at December 31, 2008 were extracted from the PowerPlant system.

The accuracy and completeness of the assembled database was verified for the calendar years available in PowerPlant. Beginning plant balances, additions, retirements, transfers and adjustments, and ending plant balances derived for each activity year were reconciled to the official plant records of the Company. Age distributions of surviving plant at December 31, 2008 were reconciled to the CPR.

LIFE ANALYSIS AND ESTIMATION

Life analysis and life estimation are terms used to describe a two–step procedure for estimating the mortality characteristics of a plant category. The first step (*i.e.*, life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of the forces of retirement acting upon a plant category and an estimate of the *projection life* of the account. Mathematical expressions used to describe these life characteristics are known as *survival functions* or *survivor curves*.

The second step (*i.e.*, life estimation) is concerned with predicting the expected remaining life of property units still exposed to forces of retirement. It is a process of blending the results of a life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and curve descriptive of the parent population from which a plant account is viewed as a random sample. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future.

The analytical methods used in a life analysis are broadly classified as actuarial and semi–actuarial techniques. Actuarial techniques can be applied to plant accounting records that reveal the age of a plant asset at the time of its retirement from service. Stated differently, each property unit must be identifiable by date of installation and age at retirement. Semi–actuarial techniques can be used to derive service life and dispersion estimates when age identification of retirements is not maintained or readily available. Age identification of retirements was available for all plant accounts contained in the 2009 Niagara Mohawk depreciation study

An actuarial life analysis program designed and developed by Foster Associates was used in the 2009 study. The first step in an actuarial analysis involves a systematic treatment of the available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age–intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age–interval and probability relationships associated with this activity. A life table minimally contains the age of each survivor and the age of each retirement from a group of property units installed in a given accounting year.

A life table can be constructed in any one of at least five methods. The annual–rate or retirement–rate method was used in the 2009 study. The mechanics of the annual–rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. This ratio—called a "retirement ratio"—is an estimator of the hazard rate or conditional probability of retirement during an age interval. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age interval by the proportion of the original group surviving at the beginning of that age interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual–rate method is applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival functions. The functions used in the 2009 study are the so–called h–Curves derived from a truncated normal probability distribution.[2] Observed life tables were smoothed by a weighted least–squares procedure in which first, second and third degree orthogonal polynomials were fitted to the observed retirement ratios. The resulting function was expressed as a survivorship function that was numerically integrated to obtain an estimate of the projection life. The smoothed survivorship function was then fitted by a weighted least–squares procedure to the h–Curve family to obtain a mathematical description or classification of the dispersion characteristics of the data.

The set of computer programs used in the Niagara Mohawk study provides multiple rolling–band, shrinking–band and progressive–band analyses of an account. Observation bands are defined in terms of a "retirement era" that restricts the analysis to the retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling–band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking–band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. A progressive–band analysis adds a year of retirement activity to a previous band without dropping earlier years from the analysis. Rolling, shrinking and progressive band analyses are used to detect the emergence of trends in the behavior of the dispersion and projection life.

Options available in the Foster Associates actuarial life analysis program include the width and location of both placement and observation bands; the interval of years included in a selected band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated. The program also provides both tabular and graphics output to aid in the analysis.

While actuarial and semi–actuarial statistical methods are well–suited to an analysis of plant categories containing a large number of homogeneous units (*e.g.*, poles and conductors), theses methods are not well–suited to plant categories composed of major items of plant that will most likely be retired as a single unit. Property units retired from an integrated system prior to the retirement of the entire facility are more properly viewed as interim retirements that will be replaced in order to maintain the integrity of the system. Plant facilities may also be added to the existing system (*i.e.*, interim additions) to expand or enhance its productive capacity without extending the service life of the present system. A proper depre-

[2] The family of h–Curves was used in the current study to comply with a directive in Niagara Mohawk gas Case 08–G–0609 in which the parties agreed in settlement that "When the Company next files for new gas rates, its initial filing will include ... the observed curve and selected h–curve." It remains the opinion of Foster Associates, however, that use of the h–Curves is unduly restrictive as only left–modal distributions are considered as likely candidates for describing forces of retirement acting upon a plant category. Iowa–type curves, which are mathematically described by the Pearson frequency curve family, provide a set of 31 distributions ranging from origin to extreme right–modal density functions. While Foster Associates is unaware of any valid reason for rejecting origin, symmetric and right–modal dispersions as descriptors of forces of mortality, accepting only h–Curves is of no consequence if hazard rates are graduated with integrable functions and broad group, whole–life rates are prescribed.

ciation rate can be developed for an integrated system using a life–span method. All plant accounts were treated as full mortality categories in the Niagara Mohawk study.

NET SALVAGE ANALYSIS

Depreciation rates designed to achieve the goals and objectives of depreciation accounting will include a parameter for future net salvage and a variable for average net salvage that reflects both realized and future net salvage rates.

Estimates of net salvage rates applicable to future retirements are most often derived from an analysis of gross salvage and cost of removal realized in the past. An analysis of past experience (including an examination of trends over time) provides a basis for estimating future salvage and cost of removal. However, consideration should be given to events that may cause deviations from net salvage realized in the past. Factors that should be considered include the age of plant retirements; the portion of retirements likely to be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to the net salvage rates observed in the past.

Special consideration should also be given to the treatment of insurance proceeds and other forms of third–party reimbursements credited to the depreciation reserve. A properly conducted net salvage study will exclude such activity from the estimate of future parameters and include the activity in the computation of realized and average net salvage rates.

Five–year moving averages of the ratio of realized salvage and cost of removal to the associated retirements were used in the 2009 study to a) estimate realized net salvage rates; b) detect the emergence of historical trends; and c) establish a basis for estimating future net salvage rates. Cost of removal and salvage opinions obtained from Company personnel were blended with judgment and historical net salvage indications in developing estimates of the future.

The average net salvage rate for an account was estimated using direct dollar–weighting of historical retirements with the historical net salvage rate, and future retirements (*i.e.*, surviving plant) with the estimated future net salvage rate. The computation of the estimated average net salvage rate for each rate category is shown in Statement D.

DEPRECIATION RESERVE ANALYSIS

The purpose of a depreciation reserve analysis is to compare the current level of recorded reserves with the level required to achieve the goals or objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized as predicted. The difference between the required (or theoretical) depreciation reserve and the recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to gradually extinguish the reserve imbalance.

Unlike a recorded reserve which represents the net amount of depreciation expense charged to previous periods of operations, a theoretical reserve is a measure of the implied reserve requirement at the beginning of a study year if the timing of future retirements and net salvage is in exact conformance with a survivor curve chosen to predict the probable life of property still exposed to the forces of retirement. Stated differently, a theoretical depreciation reserve is the difference between the recorded cost of plant presently in service and the sum of the depreciation expense and net salvage that will be charged in the future if retirements are distributed over time according to a specified retirement frequency distribution.

The survivor curve used in the calculation of a theoretical depreciation reserve is intended to describe forces of retirement that will be operative in the future. However, retirements caused by forces such as accidents, physical deterioration and changing technology seldom, if ever, remain stable over time. It is unlikely, therefore, that a probability or retirement frequency distribution can be identified that will accurately describe the age of plant retirements over the complete life cycle of multiple vintages. It is for this reason that depreciation rates should be reviewed periodically and adjusted for observed or expected changes in the parameters chosen to describe the underlying forces of mortality.

Although reserve records are commonly maintained by various account classifications, the total recorded reserve in relation to the sum of account computed reserves is a good indicator of the adequacy (or inadequacy) of recorded reserves. If statistical life studies have not been conducted or retirement dispersion has been overlooked in setting depreciation rates, it is likely that some accounts will be over–depreciated and other accounts will be under–depreciated relative to a calculated theoretical reserve. Differences between theoretical and recorded reserves will also arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. Differences can also arise from plant accounting activity such as transfers and adjustments that may require an identification of reserves at a level lower than maintained in the accounting system. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute or rebalance recorded reserves among the various primary accounts based upon the most recent estimates of retirement dispersion and net salvage rates.

While whole–life depreciation rates are not affected by rebalancing depreciation reserves, a redistribution of recorded reserves is considered appropriate for Niagara Mohawk. Reserve imbalances attributable to both the passage of time and parameters adjustments developed in the current study should be realigned among primary accounts to reduce offsetting imbalances and partially mitigate the potential for sustained imbalances created by a continuing use of whole–life rates. Recorded reserves should also be realigned to eliminate reserve imbalances created by the prior implementation of amortization accounting for general amortizable categories.

Recorded reserves for all depreciable plant accounts were rebalanced by multiplying the calculated reserve for each primary account within a function by the ratio of the function total recorded reserve to the function total calculated reserve. The sum of redistributed reserves within a function is, therefore, equal to the function total recorded depreciation reserve before the redistribution. Reserves for general amortizable categories were adjusted by replacing recorded reserves with measured theoretical reserves and distributing any reserve imbalances to depreciable categories within the respective plant functions.

Statement C provides a comparison of recorded, computed and rebalanced reserves at December 31, 2008. The total recorded reserve for electric operations was $2,182,984,708 or 36.4 percent of the depreciable plant investment. The corresponding computed reserve is $2,121,908,850 or 35.4 percent of the depreciable plant investment. A reserve excess of $61,075,857 is therefore indicated for electric plant assets. The total recorded reserve for common operations was $96,736,382 or 32.0 percent of the depreciable plant investment. The corresponding computed reserve is $110,130,928 or 36.5 percent of the depreciable plant investment. A reserve deficiency of $13,394,546 is therefore indicated for common plant assets.

DEVELOPMENT OF ACCRUAL RATES

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non–cash expenses) or cash inflows attributable to the use of that asset alone.

Cost allocation in proportion to the consumption of service potential is often approximated by the use of depreciation methods employing time rather than net revenue as the apportionment base. Examples of time–based methods include sinking–fund, straight–line, declining balance, and sum–of–the–years' digits. The advantage of a time–based method is that it does not require an estimate of the remaining amount of service capacity an asset will provide or the amount of capacity actually consumed during an accounting interval. Using a time–based allocation method, however, does not change the goal of depreciation accounting. If it is reasonable to predict that the net revenue pattern of an asset will either decrease or increase over time, then an accelerated or decelerated time–based method should be used to approximate the rate at which service potential is actually consumed.

The time period over which the cost of an asset will be allocated to operations is determined by the combination of a procedure and a technique. A depreciation procedure describes the level of grouping or sub–grouping of assets within a plant category. The broad group, vintage group, equal–life group, and item (or unit) are a few of the more widely used procedures. A depreciation technique describes the life statistic used in a depreciation system. Whole–life and remaining–life (or expectancy) are the most common techniques.

The first step in the development of an accrual rate, therefore, is the selection of an appropriate method, procedure and technique. Depreciation rates recommended in this study were developed using a system composed of the straight–line method, broad group procedure, whole–life technique. Although Foster Associates is of the opinion that a system composed of the straight–line method, vintage group procedure, remaining–life technique would better achieve the goals and objectives of depreciation accounting, the Commission has historically denied any system other than the straight–line method, broad group procedure, whole–life technique for energy companies. Accordingly, broad group, whole–life rates were developed in the current study. Although the emergence of economic factors such as performance based regulation may ultimately encourage abandonment of the straight–line method, no attempt was made in the current study to address this concern. Page 14

It is also the opinion of Foster Associates that the adoption of revised amortization periods proposed in this study is consistent with the goals and objectives of depreciation accounting derived from the matching and expense recognition principles of accounting. Amortization accounting relieves Niagara Mohawk of the burden to maintain detailed plant records for numerous plant items in which the unit cost is small in relation to the cost of tracking the disposition of the assets.

The treatment of amortization accounts in the current study was designed to produce annualized accruals equivalent to applying a rate equal to the reciprocal of an amortization period to plant balances after retirements have been recorded. Applying a rate equal to the reciprocal of the amortization period to plant balances prior to posting retirements would overstate the annualized amortization expense. Accrual rates contained in Statement A are equal to the reciprocal of the proposed amortizations periods and should be applied to plant balances after retirements have been posted upon approval of the requested amortization periods.

Accrual rates applied to current plant balances shown in Statement B to achieve annualized accruals equivalent to applying a rate equal to the reciprocal of an amortization period after retirements have been recorded are summarized in Table 5 below.

Account Number	Description	Accrual Rate (%) Electric	Accrual Rate (%) Common
A	B	C	D
391.01	Office Furniture and Fixtures	4.55	4.55
391.20	Data Processing Equipment	17.74	17.95
393.00	Stores Equipment	4.55	4.55
394.01	Tools, Shop and Garage Equipment	4.54	4.55
395.00	Laboratory Equipment	--	4.55
395.01	Laboratory Equipment	4.55	--
397.01	Communication Equip. - Radio	4.52	4.31
397.02	Communication Equip. - Telephone	0.21	1.39
397.03	Communication Equip. - Network	--	4.55
397.50	Communication Equip. - Network NY	4.55	--
397.60	Communication Equip. - Network Site NY	4.55	4.55
398.01	Miscellaneous Equipment	4.54	4.55

Table 5. Pre-Retirement Accrual Rates

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded and computed depreciation reserves, and present and proposed service life and net salvage statistics recommended for Niagara Mohawk. The content of these statements is briefly described below.

- Statement A provides a comparative summary of current and proposed annual depreciation rates using the broad group procedure, whole–life technique.
- Statement B provides a comparison of current and proposed annualized 2009 depreciation accruals using the broad group procedure, whole–life technique.
- Statement C provides a comparison of recorded, computed and rebalanced reserves at December 31, 2008.
- Statement D provides a summary of the components used to obtain a weighted average net salvage rate for each rate category.
- Statement E provides a comparative summary of current and proposed parameters including projection life, projection curve, average service life, average remaining life and average and future net salvage rates.

Current depreciation accruals shown on Statement B are the product of the plant investment (Column B) and current depreciation rates (Column D) shown on Statement A. These are the effective rates used by Niagara Mohawk for the mix of investments recorded on December 31, 2008. Proposed depreciation accruals shown on Statement B are the product of the plant investment and proposed depreciation rates (Column H) shown on Statement A. Proposed whole–life accrual rates are given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Average Net Salvage Rate}}{\text{Average Service Life}}.$$

Statements A through E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC Statement A

Comparison of Current and Proposed Accrual Rates
Current: BG Procedure / WL Technique
Proposed: BG Procedure / WL Technique

	Current			Proposed			
Account Description	Average Life	Avg. Net Salvage	Accrual Rate	Curve Shape	Average Life	Avg. Net Salvage	Accrual Rate
A	B	C	D	E	F	G	H
TRANSMISSION PLANT							
350.40 Land Rights - Transmission Lines	75.00		1.33%	H5	75.00	0.5%	1.33%
352.00 Structures and Improvements	65.00	-25.0%	1.92%	H3	65.00	-33.1%	2.05%
353.01 Station Equipment	58.00	-10.0%	1.90%	H0.5	45.00	-13.6%	2.52%
353.55 Station Equipment - EMS RTU	20.00		5.00%	H2	20.00	-0.1%	5.01%
354.00 Towers and Fixtures	68.00		1.47%	H4	70.00	-31.2%	1.87%
355.00 Poles and Fixtures	55.00	-5.0%	1.91%	H4	65.00	-36.6%	2.10%
356.01 Overhead Conductors and Devices	60.00	5.0%	1.51%	H2	75.00	-50.8%	2.01%
357.01 Underground Conduit	62.00	-25.0%	2.02%	H4	75.00		1.33%
358.00 Underground Conductors and Devices	50.00	30.0%	1.40%	H3	50.00	-11.8%	2.24%
359.00 Roads and Trails	75.00		1.33%	H4	75.00		1.33%
Total Transmission Plant			1.85%		53.17	-24.6%	2.29%
DISTRIBUTION PLANT							
360.01 Land Rights	55.00		1.82%	H5	75.00		1.33%
361.00 Structures and Improvements	65.00	-50.0%	2.31%	H2.5	65.00	-32.1%	2.03%
362.01 Station Equipment	52.00	-10.0%	2.12%	H2	60.00	-15.5%	1.93%
362.55 Station Equipment - EMS RTU	20.00		5.00%	H2	20.00	0.1%	5.00%
364.00 Poles, Towers and Fixtures	41.00	-25.0%	2.97%	H2	65.00	-40.9%	2.17%
365.00 Overhead Conductors and Devices	35.00	-30.0%	3.71%	H4	50.00	-102.3%	4.05%
366.01 Underground Conduit	70.00	-20.0%	1.71%	H4	75.00	-1.5%	1.35%
367.10 Underground Conductors and Devices	50.00	10.0%	1.80%	H3	50.00	-10.9%	2.22%
368.01 Line Transformers - Bare Cost	36.00	-15.0%	3.19%	H0.5	35.00	-2.6%	2.93%
368.30 Line Transformers - Install Cost	36.00	-15.0%	3.19%	H2.5	35.00	-24.5%	3.56%
369.10 Overhead Services	40.00	-60.0%	4.00%	H4	50.00	-77.2%	3.54%
369.20 Underground Services - Conduit	50.00	-10.0%	2.20%	H4	75.00	-5.0%	1.40%
369.21 Underground Services - Cable	42.00	20.0%	1.90%	H2.5	75.00	-24.3%	1.66%
370.10 Small Meters - Bare Cost	32.00		3.13%	H0.5	20.00	0.5%	4.98%
370.20 Small Meters - Install Cost	36.00		2.78%	H0.5	20.00	-17.8%	5.89%
370.30 Large Meters - Bare Cost	36.00		2.78%	H3	20.00		5.00%
370.35 Large Meters - Install Cost	36.00		2.78%	H3	20.00	-19.9%	6.00%
371.00 Installations on Customers' Premises	15.00	-10.0%	7.33%	H1.5	40.00	-33.4%	3.34%
373.10 Overhead Street Lighting	30.00	-10.0%	3.80%	H1.5	50.00	-53.6%	3.07%
373.20 Underground Street Lighting	30.00	-10.0%	3.80%	H1	70.00	-24.8%	1.78%
Total Distribution Plant			3.01%		48.50	-40.1%	2.88%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	55.00	-5.0%	1.91%	H0.5	55.00	-3.2%	1.88%
Total Depreciable			1.91%		55.00	-3.2%	1.88%
Amortizable							
391.01 Office Furniture and Equipment	42.00		2.74%	← 22 Year Amortization →			4.55%
391.20 Office Data Processing Equipment	5.00		20.00%	← 5 Year Amortization →			20.00%
393.00 Stores Equipment	40.00		2.50%	← 22 Year Amortization →			4.55%
394.01 Tools, Shop and Garage Equipment	34.00		2.96%	← 22 Year Amortization →			4.55%
395.01 Laboratory Equipment	40.00		2.50%	← 22 Year Amortization →			4.55%
397.01 Communication Equip. - Radio	20.00		5.00%	← 22 Year Amortization →			4.55%
397.02 Communication Equip. - Telephone	8.00		12.50%	← 8 Year Amortization →			12.50%
397.50 Communication Equip. - Network NY	15.00		6.67%	← 22 Year Amortization →			4.55%
397.60 Communication Equip. - Network Site NY	15.00		6.67%	← 22 Year Amortization →			4.55%
398.01 Miscellaneous Equipment	10.00		8.81%	← 22 Year Amortization →			4.55%
Total Amortizable			5.64%		20.55		4.62%
Total General Plant			4.49%		25.48	-0.9%	3.77%
TOTAL ELECTRIC OPERATIONS			2.77%		47.53	-33.5%	2.77%

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Statement B

Comparison of Current and Proposed Accruals
Current: BG Procedure / WL Technique
Proposed: BG Procedure / WL Technique

Account Description	12/31/08 Plant Investment	2009 Annualized Accrual Current	Proposed	Difference
A	B	D	F	
TRANSMISSION PLANT				
350.40 Land Rights - Transmission Lines	$27,123,696	$360,745	$360,745	
352.00 Structures and Improvements	31,004,576	595,288	635,594	40,306
353.01 Station Equipment	623,806,673	11,852,327	15,719,928	3,867,601
353.55 Station Equipment - EMS RTU	42,485,893	2,124,295	2,128,543	4,248
354.00 Towers and Fixtures	133,237,659	1,958,594	2,491,544	532,950
355.00 Poles and Fixtures	365,859,185	6,987,910	7,683,043	695,133
356.01 Overhead Conductors and Devices	236,780,774	3,575,390	4,759,294	1,183,904
357.01 Underground Conduit	29,049,970	586,809	386,365	(200,444)
358.00 Underground Conductors and Devices	102,159,262	1,430,230	2,288,367	858,137
359.00 Roads and Trails	2,348,571	31,236	31,236	
Total Transmission Plant	$1,593,856,259	$29,502,824	$36,484,659	$6,981,835
DISTRIBUTION PLANT				
360.01 Land Rights	$10,113,745	$184,070	$134,513	($49,557)
361.00 Structures and Improvements	35,412,715	818,034	718,878	(99,156)
362.01 Station Equipment	430,797,242	9,132,902	8,314,387	(818,515)
362.55 Station Equipment - EMS RTU	29,492,793	1,474,640	1,474,640	
364.00 Poles, Towers and Fixtures	788,801,034	23,427,391	17,116,982	(6,310,409)
365.00 Overhead Conductors and Devices	875,984,992	32,499,043	35,477,392	2,978,349
366.01 Underground Conduit	134,517,260	2,300,245	1,815,983	(484,262)
367.10 Underground Conductors and Devices	415,936,368	7,486,855	9,233,787	1,746,932
368.01 Line Transformers - Bare Cost	451,751,287	14,410,866	13,236,313	(1,174,553)
368.30 Line Transformers - Install Cost	239,904,970	7,652,969	8,540,617	887,648
369.10 Overhead Services	284,680,583	11,387,223	10,077,693	(1,309,530)
369.20 Underground Services - Conduit	8,035,024	176,771	112,490	(64,281)
369.21 Underground Services - Cable	102,850,405	1,954,158	1,707,317	(246,841)
370.10 Small Meters - Bare Cost	49,724,890	1,556,389	2,476,300	919,911
370.20 Small Meters - Install Cost	26,080,597	725,041	1,536,147	811,106
370.30 Large Meters - Bare Cost	6,871,977	191,041	343,599	152,558
370.35 Large Meters - Install Cost	28,016,510	778,859	1,680,991	902,132
371.00 Installations on Customers' Premises	8,074,220	591,840	269,679	(322,161)
373.10 Overhead Street Lighting	68,539,314	2,604,494	2,104,157	(500,337)
373.20 Underground Street Lighting	121,233,487	4,606,873	2,157,956	(2,448,917)
Total Distribution Plant	$4,116,819,413	$123,959,704	$118,529,821	($5,429,883)
GENERAL PLANT				
Depreciable				
390.00 Structures and Improvements	$89,809,731	$1,715,366	$1,688,423	($26,943)
Total Depreciable	$89,809,731	$1,715,366	$1,688,423	($26,943)
Amortizable				
391.01 Office Furniture and Equipment	$7,409,461	$203,019	$336,794	$133,775
391.20 Office Data Processing Equipment	2,392,757	478,551	424,452	(54,099)
393.00 Stores Equipment	2,143,249	53,581	97,420	43,839
394.01 Tools, Shop and Garage Equipment	41,504,502	1,228,533	1,884,864	656,331
395.01 Laboratory Equipment	20,437,793	510,945	928,991	418,046
397.01 Communication Equip. - Radio	54,408,239	2,720,412	2,461,020	(259,392)
397.02 Communication Equip. - Telephone	3,443,130	430,391	7,100	(423,291)
397.50 Communication Equip. - Network NY	6,824,926	455,223	310,224	(144,999)
397.60 Communication Equip. - Network Site NY	11,247,365	750,199	511,244	(238,955)
398.01 Miscellaneous Equipment	51,182,084	4,509,142	2,325,944	(2,183,198)
Total Amortizable	$200,993,506	$11,339,996	$9,288,053	($2,051,943)
Total General Plant	$290,803,237	$13,055,362	$10,976,476	($2,078,886)
TOTAL ELECTRIC OPERATIONS	$6,001,478,909	$166,517,890	$165,990,956	($526,934)

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Depreciation Reserve Summary
Broad Group Procedure
December 31, 2008

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
TRANSMISSION PLANT							
350.40 Land Rights - Transmission Lines	$27,123,696	$13,069,807	48.19%	$12,539,339	46.23%	$12,505,555	46.11%
352.00 Structures and Improvements	31,004,576	11,287,636	36.41%	12,993,484	41.91%	12,958,476	41.80%
353.01 Station Equipment	623,806,673	181,239,442	29.05%	131,092,556	21.01%	130,739,363	20.96%
353.55 Station Equipment - EMS RTU	42,485,893	30,807,700	72.51%	21,115,383	49.70%	21,058,493	49.57%
354.00 Towers and Fixtures	133,237,659	68,330,989	51.29%	82,184,034	61.68%	81,962,611	61.52%
355.00 Poles and Fixtures	365,859,185	111,143,069	30.38%	131,773,473	36.02%	131,418,445	35.92%
356.01 Overhead Conductors and Devices	236,780,774	77,469,018	32.72%	91,799,717	38.77%	91,552,387	38.67%
357.01 Underground Conduit	29,049,970	14,222,294	48.96%	10,093,896	34.75%	10,066,701	34.65%
358.00 Underground Conductors and Devices	102,159,262	24,750,616	24.23%	40,146,220	39.30%	40,038,057	39.19%
359.00 Roads and Trails	2,348,571	231,855	9.87%	253,019	10.77%	252,338	10.74%
Total Transmission Plant	$1,593,856,259	$532,552,425	33.41%	$533,991,120	33.50%	$532,552,425	33.41%
DISTRIBUTION PLANT							
360.01 Land Rights	$10,113,745	$1,323,743	13.09%	$873,828	8.64%	$876,680	8.67%
361.00 Structures and Improvements	35,412,715	12,178,825	34.39%	12,822,590	36.21%	12,864,442	36.33%
362.01 Station Equipment	430,797,242	115,803,129	26.88%	107,311,593	24.91%	107,661,854	24.99%
362.55 Station Equipment - EMS RTU	29,492,793	20,774,597	70.44%	14,554,900	49.35%	14,602,406	49.51%
364.00 Poles, Towers and Fixtures	788,801,034	286,517,204	36.32%	225,444,190	28.58%	226,180,031	28.67%
365.00 Overhead Conductors and Devices	875,984,992	460,447,571	52.56%	520,348,225	59.40%	522,046,622	59.60%
366.01 Underground Conduit	134,517,260	49,140,823	36.53%	41,036,284	30.51%	41,170,225	30.61%
367.10 Underground Conductors and Devices	415,936,368	98,539,455	23.69%	119,601,088	28.75%	119,991,462	28.85%
368.01 Line Transformers - Bare Cost	451,751,287	169,144,375	37.44%	76,186,435	16.86%	76,435,104	16.92%
368.30 Line Transformers - Install Cost	239,904,970	15,544,011	6.48%	84,014,378	35.02%	84,288,597	35.13%
369.10 Overhead Services	284,680,583	181,592,696	63.79%	170,800,379	60.00%	171,357,865	60.19%
369.20 Underground Services - Conduit	8,035,024	3,669,572	45.67%	2,726,766	33.94%	2,735,666	34.05%
369.21 Underground Services - Cable	102,850,405	24,530,820	23.85%	22,708,958	22.08%	22,783,079	22.15%

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Statement C

Depreciation Reserve Summary
Broad Group Procedure
December 31, 2008

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
370.10 Small Meters - Bare Cost	49,724,890	(41,088,459)	-82.63%	5,740,490	11.54%	5,759,227	11.58%
370.20 Small Meters - Install Cost	26,080,597	(29,670,856)	-113.77%	4,014,743	15.39%	4,027,847	15.44%
370.30 Large Meters - Bare Cost	6,871,977	3,696,845	53.80%	1,810,766	26.35%	1,816,676	26.44%
370.35 Large Meters - Install Cost	28,016,510	2,438,144	8.70%	10,441,473	37.27%	10,475,554	37.39%
371.00 Installations on Customers' Premises	8,074,220	6,216,948	77.00%	2,792,521	34.59%	2,801,636	34.70%
373.10 Overhead Street Lighting	68,539,314	37,286,469	54.40%	23,767,460	34.68%	23,845,036	34.79%
373.20 Underground Street Lighting	121,233,487	54,217,646	44.72%	20,516,585	16.92%	20,583,551	16.98%
Total Distribution Plant	$4,116,819,413	$1,472,303,559	35.76%	$1,467,513,651	35.65%	$1,472,303,559	35.76%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	$89,809,731	$12,912,812	14.38%	$15,755,044	17.54%	$73,479,688	81.82%
Total Depreciable	$89,809,731	$12,912,812	14.38%	$15,755,044	17.54%	$73,479,688	81.82%
Amortizable							
391.01 Office Furniture and Equipment	$7,409,461	$2,623,489	35.41%	$4,422,845	59.69%	$4,422,845	59.69%
391.20 Office Data Processing Equipment	2,392,757	1,317,454	55.06%	1,300,386	54.35%	1,300,386	54.35%
393.00 Stores Equipment	2,143,249	806,037	37.61%	1,397,328	65.20%	1,397,328	65.20%
394.01 Tools, Shop and Garage Equipment	41,504,502	12,515,135	30.15%	19,426,223	46.81%	19,426,223	46.81%
395.01 Laboratory Equipment	20,437,793	5,972,720	29.22%	11,315,257	55.36%	11,315,257	55.36%
397.01 Communication Equip. - Radio	54,408,239	18,508,540	34.02%	18,048,404	33.17%	18,048,404	33.17%
397.02 Communication Equip. - Telephone	3,443,130	6,719,466	195.16%	3,415,145	99.19%	3,415,145	99.19%
397.50 Communication Equip. - Network NY	6,824,926	1,565,296	22.93%	1,461,989	21.42%	1,461,989	21.42%
397.60 Communication Equip. - Network Site NY	11,247,365	19,536,824	173.70%	6,471,582	57.54%	6,471,582	57.54%
398.01 Miscellaneous Equipment	51,182,084	95,650,952	186.88%	37,389,877	73.05%	37,389,877	73.05%
Total Amortizable	$200,993,506	$165,215,913	82.20%	$104,649,036	52.07%	$104,649,036	52.07%
Total General Plant	$290,803,237	$178,128,724	61.25%	$120,404,080	41.40%	$178,128,724	61.25%
TOTAL ELECTRIC OPERATIONS	$6,001,478,909	$2,182,984,708	36.37%	$2,121,908,850	35.36%	$2,182,984,708	36.37%

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Average Net Salvage

Statement D

Account Description	Plant Investment Additions	Plant Investment Retirements	Plant Investment Survivors	Salvage Rate Realized	Salvage Rate Future	Net Salvage Realized	Net Salvage Future	Net Salvage Total	Average Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
TRANSMISSION PLANT									
350.40 Land Rights - Transmission Lines	$27,119,478	($4,218)	$27,123,696	-2990.3%		$126,131		$126,131	0.5%
352.00 Structures and Improvements	33,357,404	2,352,828	31,004,576	-74.6%	-30.0%	(1,755,210)	(9,301,373)	(11,056,582)	-33.1%
353.01 Station Equipment	744,196,204	120,389,531	623,806,673	-6.6%	-15.0%	(7,945,709)	(93,571,001)	(101,516,710)	-13.6%
353.55 Station Equipment - EMS RTU	43,823,790	1,337,897	42,485,893	-3.6%		(48,164)		(48,164)	-0.1%
354.00 Towers and Fixtures	134,104,196	866,537	133,237,659	-223.1%	-30.0%	(1,933,244)	(39,971,298)	(41,904,542)	-31.2%
355.00 Poles and Fixtures	373,521,756	7,662,571	365,859,185	-112.3%	-35.0%	(8,605,067)	(128,050,715)	(136,655,782)	-36.6%
356.01 Overhead Conductors and Devices	242,959,766	6,178,992	236,780,774	-81.6%	-50.0%	(5,042,057)	(118,390,387)	(123,432,444)	-50.8%
357.01 Underground Conduit	29,235,335	185,365	29,049,970	-1.9%		(3,522)		(3,522)	
358.00 Underground Conductors and Devices	104,685,600	2,526,338	102,159,262	-85.8%	-10.0%	(2,167,598)	(10,215,926)	(12,383,524)	-11.8%
359.00 Roads and Trails	2,348,571		2,348,571						
Total Transmission Plant	$1,735,352,100	$141,495,841	$1,593,856,259	-19.3%	-25.1%	($27,374,441)	($399,500,699)	($426,875,140)	-24.6%
DISTRIBUTION PLANT									
360.01 Land Rights	$10,113,745		$10,113,745						
361.00 Structures and Improvements	36,515,914	1,103,199	35,412,715	-98.7%	-30.0%	(1,088,857)	(10,623,815)	(11,712,672)	-32.1%
362.01 Station Equipment	455,876,433	25,079,191	430,797,242	-23.6%	-15.0%	(5,918,689)	(64,619,586)	(70,538,275)	-15.5%
362.55 Station Equipment - EMS RTU	29,516,793	24,000	29,492,793	104.5%		25,080		25,080	0.1%
364.00 Poles, Towers and Fixtures	832,529,131	43,728,097	788,801,034	-57.7%	-40.0%	(25,231,112)	(315,520,414)	(340,751,526)	-40.9%
365.00 Overhead Conductors and Devices	906,315,907	30,330,915	875,984,992	-169.7%	-100.0%	(51,471,563)	(875,984,992)	(927,456,555)	-102.3%
366.01 Underground Conduit	136,627,328	2,110,068	134,517,260	-99.7%		(2,103,738)		(2,103,738)	-1.5%
367.10 Underground Conductors and Devices	421,630,006	5,693,638	415,936,368	-77.8%	-10.0%	(4,429,650)	(41,593,637)	(46,023,287)	-10.9%
368.01 Line Transformers - Bare Cost	563,753,468	112,002,181	451,751,287	-13.0%		(14,560,284)		(14,560,284)	-2.6%
368.30 Line Transformers - Install Cost	258,273,030	18,368,060	239,904,970	-83.5%	-20.0%	(15,337,330)	(47,980,994)	(63,318,324)	-24.5%
369.10 Overhead Services	293,766,717	9,086,134	284,680,583	-147.6%	-75.0%	(13,411,134)	(213,510,437)	(226,921,571)	-77.2%
369.20 Underground Services - Conduit	8,051,653	16,629	8,035,024	-14.7%	-5.0%	(2,444)	(401,751)	(404,196)	-5.0%
369.21 Underground Services - Cable	104,548,377	1,697,972	102,850,405	20.6%	-25.0%	349,782	(25,712,601)	(25,362,819)	-24.3%
370.10 Small Meters - Bare Cost	156,345,408	106,620,518	49,724,890	0.7%		746,344		746,344	0.5%
370.20 Small Meters - Install Cost	75,573,065	49,492,468	26,080,597	-16.7%	-20.0%	(8,265,242)	(5,216,119)	(13,481,362)	-17.8%
370.30 Large Meters - Bare Cost	7,157,271	285,294	6,871,977						
370.35 Large Meters - Install Cost	28,371,930	355,420	28,016,510	-10.2%	-20.0%	(36,253)	(5,603,302)	(5,639,555)	-19.9%
371.00 Installations on Customers' Premises	9,214,234	1,140,014	8,074,220	-57.6%	-30.0%	(656,648)	(2,422,266)	(3,078,914)	-33.4%
373.10 Overhead Street Lighting	76,113,233	7,573,919	68,539,314	-86.2%	-50.0%	(6,528,718)	(34,269,657)	(40,798,375)	-53.6%
373.20 Underground Street Lighting	134,112,166	12,878,679	121,233,487	-22.4%	-25.0%	(2,884,824)	(30,308,372)	(33,193,196)	-24.8%
Total Distribution Plant	$4,544,405,809	$427,586,396	$4,116,819,413	-35.3%	-40.7%	($150,805,281)	($1,673,767,943)	($1,824,573,224)	-40.1%

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
GENERAL PLANT									
Depreciable									
390.00 Structures and Improvements	$124,887,361	$35,077,630	$89,809,731	1.3%	-5.0%	$456,009	($4,490,487)	($4,034,477)	-3.2%
Total Depreciable	$124,887,361	$35,077,630	$89,809,731	1.3%	-5.0%	$456,009	($4,490,487)	($4,034,477)	-3.2%
Amortizable									
391.01 Office Furniture and Equipment	$15,735,031	$8,325,570	$7,409,461						
391.20 Office Data Processing Equipment	88,867,410	86,474,653	2,392,757						
393.00 Stores Equipment	2,512,440	369,191	2,143,249						
394.01 Tools, Shop and Garage Equipment	50,352,666	8,848,164	41,504,502						
395.01 Laboratory Equipment	29,192,114	8,754,321	20,437,793						
397.01 Communication Equip. - Radio	55,727,394	1,319,155	54,408,239						
397.02 Communication Equip. - Telephone	5,864,961	2,421,831	3,443,130						
397.50 Communication Equip. - Network NY	6,824,926		6,824,926						
397.60 Communication Equip. - Network Site NY	18,736,963	7,489,598	11,247,365						
398.01 Miscellaneous Equipment	51,491,536	309,452	51,182,084						
Total Amortizable	$325,305,441	$124,311,935	$200,993,506						
Total General Plant	$450,192,802	$159,389,565	$290,803,237	0.3%	-1.5%	$456,009	($4,490,487)	($4,034,477)	-0.9%
TOTAL ELECTRIC OPERATIONS	$6,729,950,711	$728,471,802	$6,001,478,909	-24.4%	-34.6%	($177,723,712)	($2,077,759,129)	($2,255,482,841)	-33.5%

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Statement E

Current and Proposed Parameters
Broad Group Procedure

	Current Parameters						Proposed Parameters (at December 31, 2008)					
Account Description	P-Life/ AYFR	Curve Shape	Rem. Life	Avg. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
TRANSMISSION PLANT												
350.40 Land Rights - Transmission Lines	75.00	R3		75.00			75.00	H5	75.00	40.53	0.5	
352.00 Structures and Improvements	65.00	R1.5		65.00	-25.0	-25.0	65.00	H3	65.00	43.02	-33.1	-30.0
353.01 Station Equipment	58.00	R2		58.00	-10.0	-10.0	45.00	H0.5	45.00	37.23	-13.6	-15.0
353.55 Station Equipment - EMS RTU	20.00	R2		20.00			20.00	H2	20.00	10.05	-0.1	
354.00 Towers and Fixtures	68.00	R3		68.00			70.00	H4	70.00	36.45	-31.2	-30.0
355.00 Poles and Fixtures	55.00	S2		55.00	-5.0	-5.0	65.00	H4	65.00	47.10	-36.6	-35.0
356.01 Overhead Conductors and Devices	60.00	R2.5		60.00	5.0	5.0	75.00	H2	75.00	55.32	-50.8	-50.0
357.01 Underground Conduit	62.00	R4		62.00	-25.0	-25.0	75.00	H4	75.00	48.94		
358.00 Underground Conductors and Devices	50.00	R1		50.00	30.0	30.0	50.00	H3	50.00	31.62	-11.8	-10.0
359.00 Roads and Trails	75.00	R3		75.00			75.00	H4	75.00	66.92		
Total Transmission Plant									53.17	38.94	-24.6	-25.1
DISTRIBUTION PLANT												
360.01 Land Rights	55.00	R2		55.00			75.00	H5	75.00	68.52		
361.00 Structures and Improvements	65.00	R1.5		65.00	-50.0	-50.0	65.00	H2.5	65.00	46.15	-32.1	-30.0
362.01 Station Equipment	52.00	R1.5		52.00	-10.0	-10.0	60.00	H2	60.00	46.80	-15.5	-15.0
362.55 Station Equipment - EMS RTU	20.00	R1.5		20.00			20.00	H2	20.00	10.14	0.1	
364.00 Poles, Towers and Fixtures	41.00	S-.5		41.00	-25.0	-25.0	65.00	H2	65.00	51.40	-40.9	-40.0
365.00 Overhead Conductors and Devices	35.00	R4		35.00	-30.0	-30.0	50.00	H4	50.00	34.75	-102.3	-100.0
366.01 Underground Conduit	70.00	R1.5		70.00	-20.0	-20.0	75.00	H4	75.00	51.35	-1.5	
367.10 Underground Conductors and Devices	50.00	R1.5		50.00	10.0	10.0	50.00	H3	50.00	36.63	-10.9	-10.0
368.01 Line Transformers - Bare Cost	36.00	L1.5		36.00	-15.0	-15.0	35.00	H0.5	35.00	28.36	-2.6	
368.30 Line Transformers - Install Cost	36.00	L1.5		36.00	-15.0	-15.0	35.00	H2.5	35.00	23.89	-24.5	-20.0
369.10 Overhead Services	40.00	R2		40.00	-60.0	-60.0	50.00	H4	50.00	32.45	-77.2	-75.0
369.20 Underground Services - Conduit	50.00	R1		50.00	-10.0	-10.0	75.00	H4	75.00	50.76	-5.0	-5.0
369.21 Underground Services - Cable	42.00	R1.5		42.00	20.0	20.0	75.00	H2.5	75.00	62.10	-24.3	-25.0

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Current and Proposed Parameters
Broad Group Procedure

Statement E

	Current Parameters						Proposed Parameters (at December 31, 2008)					
Account Description	P-Life/ AYFR	Curve Shape	Rem. Life	Avg. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
370.10 Small Meters - Bare Cost	32.00	S1.5		32.00			20.00	H0.5	20.00	17.78	0.5	
370.20 Small Meters - Install Cost	36.00	S1.5		36.00			20.00	H0.5	20.00	17.76	-17.8	-20.0
370.30 Large Meters - Bare Cost	36.00	R3		36.00			20.00	H3	20.00	14.73		
370.35 Large Meters - Install Cost	36.00	S1.5		36.00			20.00	H3	20.00	13.80	-19.9	-20.0
371.00 Installations on Customers' Premises	15.00	SC		15.00	-10.0	-10.0	40.00	H1.5	40.00	28.61	-33.4	-30.0
373.10 Overhead Street Lighting	30.00	L0.5		30.00	-10.0	-10.0	50.00	H1.5	50.00	37.54	-53.6	-50.0
373.20 Underground Street Lighting	30.00	L0.5		30.00	-10.0	-10.0	70.00	H1	70.00	60.62	-24.8	-25.0
Total Distribution Plant									48.50	36.22	-40.1	-40.7
GENERAL PLANT												
Depreciable												
390.00 Structures and Improvements	55.00	R3		55.00	-5.0	-5.0	55.00	H0.5	55.00	46.61	-3.2	-5.0
Total Depreciable									55.00	46.61	-3.2	-5.0
Amortizable												
391.01 Office Furniture and Equipment	42.00	R2.5		42.00			22.00	SQ	22.00	8.87		
391.20 Office Data Processing Equipment	5.00	R3		5.00			5.00	SQ	5.00	2.28		
393.00 Stores Equipment	40.00	L1.5		40.00			22.00	SQ	22.00	7.66		
394.01 Tools, Shop and Garage Equipment	34.00	L0		34.00			22.00	SQ	22.00	11.71		
395.01 Laboratory Equipment	40.00	L1.5		40.00			22.00	SQ	22.00	9.82		
397.01 Communication Equip. - Radio	20.00	L1		20.00			22.00	SQ	22.00	14.77		
397.02 Communication Equip. - Telephone	8.00	S2		8.00			8.00	SQ	8.00	3.84		
397.50 Communication Equip. - Network NY	15.00	L1		15.00			22.00	SQ	22.00	17.29		
397.60 Communication Equip. - Network Site NY	15.00	L1		15.00			22.00	SQ	22.00	9.34		
398.01 Miscellaneous Equipment	10.00	L0		10.00			22.00	SQ	22.00	5.93		
Total Amortizable									20.55	10.04		
Total General Plant									25.48	15.27	-0.9	-1.5
TOTAL ELECTRIC OPERATIONS									47.53	34.97	-33.5	-34.6

Statements A through E

NIAGARA MOHAWK POWER CORPORATION - COMMON Statement A

Comparison of Current and Proposed Accrual Rates
Current: BG Procedure / WL Technique
Proposed: BG Procedure / WL Technique

	Current			Proposed			
Account Description	Average Life	Avg. Net Salvage	Accrual Rate	Curve Shape	Average Life	Avg. Net Salvage	Accrual Rate
A	B	C	D	E	F	G	H
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	55.00	-5.0%	1.91%	H0.5	40.00	-5.0%	2.63%
392.20 Transportation Equipment - Aircraft	10.00		10.00%	SQ	10.00	25.0%	7.50%
Total Depreciable			1.91%		40.00	-5.0%	2.63%
Amortizable							
391.01 Office Furniture and Equipment	42.00		2.67%	← 22 Year Amortization →			4.55%
391.20 Data Processing Equipment	5.00		20.00%	← 5 Year Amortization →			20.00%
393.00 Stores Equipment	40.00		2.50%	← 22 Year Amortization →			4.55%
394.01 Tools, Shop and Garage Equipment	42.00		2.52%	← 22 Year Amortization →			4.55%
395.00 Laboratory Equipment	40.00		2.50%	← 22 Year Amortization →			4.55%
397.01 Communication Equipment - Radio	20.00		5.00%	← 22 Year Amortization →			4.55%
397.02 Communication Equipment - Telephone	8.00		12.50%	← 8 Year Amortization →			12.50%
397.03 Communication Equipment - Network	15.00		6.67%	← 22 Year Amortization →			4.55%
398.01 Miscellaneous Equipment	20.00		4.17%	← 22 Year Amortization →			4.55%
Total Amortizable			6.89%		14.36		5.58%
Total General Plant			4.28%		9.72	-1.9%	4.04%
TOTAL COMMON OPERATIONS			4.28%		21.61	-1.9%	4.04%

NIAGARA MOHAWK POWER CORPORATION - COMMON

Statement B

Comparison of Current and Proposed Accruals
Current: BG Procedure / WL Technique
Proposed: BG Procedure / WL Technique

Account Description	12/31/08 Plant Investment	2009 Annualized Accrual Current	2009 Annualized Accrual Proposed	2009 Annualized Accrual Difference
A	B	D	F	
GENERAL PLANT				
Depreciable				
390.00 Structures and Improvements	$161,221,380	$3,079,328	$4,240,122	$1,160,794
392.20 Transportation Equipment - Aircraft	4,908,363	490,836	368,127	(122,709)
Total Depreciable	$161,221,380	$3,079,328	$4,240,122	$1,160,794
Amortizable				
391.01 Office Furniture and Equipment	$32,279,330	$861,858	$1,467,242	$605,384
391.20 Data Processing Equipment	14,140,089	2,828,018	2,538,653	(289,365)
393.00 Stores Equipment	5,195,119	129,878	236,142	106,264
394.01 Tools, Shop and Garage Equipment	11,093,198	279,549	504,236	224,687
395.00 Laboratory Equipment	108,149	2,704	4,916	2,212
397.01 Communication Equipment - Radio	22,502,290	1,125,115	970,392	(154,723)
397.02 Communication Equipment - Telephone	13,768,973	1,721,122	191,760	(1,529,362)
397.03 Communication Equipment - Network	35,075,064	2,339,507	1,594,321	(745,186)
398.01 Miscellaneous Equipment	1,592,412	66,404	72,382	5,978
Total Amortizable	$135,754,624	$9,354,155	$7,580,044	($1,774,111)
Total General Plant	$301,884,367	$12,924,319	$12,188,293	($736,026)
TOTAL COMMON OPERATIONS	$301,884,367	$12,924,319	$12,188,293	($736,026)

NIAGARA MOHAWK POWER CORPORATION - COMMON

Statement C

Depreciation Reserve Summary
Broad Group Procedure
December 31, 2008

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	$161,221,380	$12,323,709	7.64%	$30,132,276	18.69%	$17,147,024	10.64%
392.20 Transportation Equipment - Aircraft	4,908,363	998,635	20.35%	949,768	19.35%	540,474	11.01%
Total Depreciable	$161,221,380	$12,323,709	7.64%	$30,132,276	18.69%	$17,147,024	10.64%
Amortizable							
391.01 Office Furniture and Equipment	$32,279,330	$11,052,481	34.24%	$18,958,673	58.73%	$18,958,673	58.73%
391.20 Data Processing Equipment	14,140,089	7,999,867	56.58%	7,968,552	56.35%	7,968,552	56.35%
393.00 Stores Equipment	5,195,119	1,663,725	32.02%	3,095,277	59.58%	3,095,277	59.58%
394.01 Tools, Shop and Garage Equipment	11,093,198	2,998,837	27.03%	5,891,266	53.11%	5,891,266	53.11%
395.00 Laboratory Equipment	108,149	37,527	34.70%	71,278	65.91%	71,278	65.91%
397.01 Communication Equipment - Radio	22,502,290	11,169,571	49.64%	11,358,823	50.48%	11,358,823	50.48%
397.02 Communication Equipment - Telephone	13,768,973	23,240,141	168.79%	13,355,215	96.99%	13,355,215	96.99%
397.03 Communication Equipment - Network	35,075,064	25,482,111	72.65%	17,997,497	51.31%	17,997,497	51.31%
398.01 Miscellaneous Equipment	1,592,412	(230,222)	-14.46%	352,303	22.12%	352,303	22.12%
Total Amortizable	$135,754,624	$83,414,038	61.44%	$79,048,884	58.23%	$79,048,884	58.23%
Total General Plant	$301,884,367	$96,736,382	32.04%	$110,130,928	36.48%	$96,736,382	32.04%
TOTAL COMMON OPERATIONS	$301,884,367	$96,736,382	32.04%	$110,130,928	36.48%	$96,736,382	32.04%

NIAGARA MOHAWK POWER CORPORATION - COMMON
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
GENERAL PLANT									
Depreciable									
390.00 Structures and Improvements	$203,948,432	$42,727,052	$161,221,380	-5.0%	-5.0%	($2,136,353)	($8,061,069)	($10,197,422)	-5.0%
392.20 Transportation Equipment - Aircraft	5,161,488	253,125	4,908,363	25.0%	25.0%	63,281	1,227,091	1,290,372	25.0%
Total Depreciable	$203,948,432	$42,727,052	$161,221,380	-5.0%	-5.0%	($2,136,353)	($8,061,069)	($10,197,422)	-5.0%
Amortizable									
391.01 Office Furniture and Equipment	$33,889,478	$1,610,148	$32,279,330						
391.20 Data Processing Equipment	111,389,083	97,248,994	14,140,089						
393.00 Stores Equipment	5,195,119		5,195,119						
394.01 Tools, Shop and Garage Equipment	11,093,198		11,093,198						
395.00 Laboratory Equipment	108,149		108,149						
397.01 Communication Equipment - Radio	25,897,995	3,395,705	22,502,290						
397.02 Communication Equipment - Telephone	22,210,413	8,441,440	13,768,973						
397.03 Communication Equipment - Network	45,573,917	10,498,853	35,075,064						
398.01 Miscellaneous Equipment	2,504,941	912,529	1,592,412						
Total Amortizable	$257,862,293	$122,107,669	$135,754,624						
Total General Plant	$466,972,213	$165,087,846	$301,884,367	-1.3%	-2.3%	($2,073,071)	($6,833,978)	($8,907,050)	-1.9%
TOTAL COMMON OPERATIONS	$466,972,213	$165,087,846	$301,884,367	-1.3%	-2.3%	($2,073,071)	($6,833,978)	($8,907,050)	-1.9%

NIAGARA MOHAWK POWER CORPORATION - COMMON
Current and Proposed Parameters
Broad Group Procedure

Statement E

	Current Parameters						Proposed Parameters (at December 31, 2008)					
Account Description	P-Life/ AYFR	Curve Shape	Rem. Life	Avg. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
GENERAL PLANT												
Depreciable												
390.00 Structures and Improvements	55.00	S0		55.00	-5.0	-5.0	40.00	H0.5	40.00	32.88	-5.0	-5.0
392.20 Transportation Equipment - Aircraft	10.00	S0		10.00			10.00	SQ	10.00	7.42	25.0	25.0
Total Depreciable									40.00	32.88	-5.0	-5.0
Amortizable												
391.01 Office Furniture and Equipment	42.00	SQ		42.00			22.00	SQ	22.00	9.08		
391.20 Data Processing Equipment	5.00	SQ		5.00			5.00	SQ	5.00	2.18		
393.00 Stores Equipment	40.00	SQ		40.00			22.00	SQ	22.00	8.89		
394.01 Tools, Shop and Garage Equipment	42.00	SQ		42.00			22.00	SQ	22.00	10.32		
395.00 Laboratory Equipment	40.00	SQ		40.00			22.00	SQ	22.00	7.50		
397.01 Communication Equipment - Radio	20.00	SQ		20.00			22.00	SQ	22.00	11.48		
397.02 Communication Equipment - Telephone	8.00	SQ		8.00			8.00	SQ	8.00	1.84		
397.03 Communication Equipment - Network	15.00	SQ		15.00			22.00	SQ	22.00	10.71		
398.01 Miscellaneous Equipment	20.00	SQ		20.00			22.00	SQ	22.00	17.13		
Total Amortizable									14.36	6.35		
Total General Plant									9.72	14.04	-1.9	-2.3
TOTAL COMMON OPERATIONS									21.61	14.04	-1.9	-2.3

ANALYSIS

INTRODUCTION

This section provides an explanation of the supporting schedules developed in the Niagara Mohawk depreciation study to estimate appropriate projection curves, projection lives and net salvage statistics for each rate category. The form and content of the schedules developed for an account depend upon the method of analysis adopted for the category.

This section also includes examples of the supporting schedules developed for distribution Account 368.01 (Line Transformers – Bare Cost). Documentation for all other plant accounts is contained in the study work papers. Supporting schedules developed in the Niagara Mohawk study include:

Schedule A – Generation Arrangement;

Schedule B – Age Distribution;

Schedule C – Plant History;

Schedule D – Actuarial Life Analysis;

Schedule E – Graphics Analysis; and

Schedule F – Historical Net Salvage Analysis.

The format and content of these schedules are briefly described below.

SCHEDULE A – GENERATION ARRANGEMENT

The purpose of this schedule is to obtain appropriate weighted–average life statistics for a rate category. The weighted–average remaining–life is the sum of Column H divided by the sum of Column I. The weighted average life is the sum of Column C divided by the sum of Column I.

It should be noted that the generation arrangement does not include parameters for net salvage. Computed Net Plant (Column H) and Accruals (Column I) must be adjusted for net salvage to obtain a correct measurement of theoretical reserves and annualized depreciation accruals.

The following table provides a description of each column in the generation arrangement.

Column	Title	Description
A	Vintage	Vintage or placement year of surviving plant.
B	Age	Age of surviving plant at beginning of study year.
C	Surviving Plant	Actual dollar amount of surviving plant.
D	Average Life	Estimated average life of each vintage. This statistic is the sum of the realized life and the unrealized life, which is the product of the remaining life (Column E) and the theoretical proportion surviving.
E	Remaining Life	Estimated remaining life of each vintage.
F	Net Plant Ratio	Theoretical net plant ratio of each vintage.
G	Allocation Factor	A pivotal ratio which determines the amortization period of the difference between the recorded and computed reserve.
H	Computed Net Plant	Plant in service less theoretical reserve for each vintage.
I	Accrual	Ratio of computed net plant (Column H) and remaining life (Column E).

Table 6. Generation Arrangement

SCHEDULE B – AGE DISTRIBUTION

This schedule provides the age distribution and realized life of surviving plant shown in Column C of the Generation Arrangement (Schedule A). The format of the schedule depends upon the availability of either aged or unaged data. Derived additions for vintage years older than the earliest activity year in an account for unaged data are obtained from the age distribution of surviving plant at the beginning of the earliest activity year. The amount surviving from these vintages is shown in Column D. The realized life (Column G) is derived from the dollar years of service provided by a vintage over the period of years the vintage has been in service. Plant additions for vintages older than the earliest activity year in an account are represented by the opening balances shown in Column D.

The computed proportion surviving (Column D) for unaged is derived from a computed mortality analysis. The average service life displayed in the title block is the life statistic derived for the most recent activity year, given the derived age distribution at the start of the year and the specified retirement dispersion. The realized life (Column F) is obtained by finding the slope of an SC retirement dispersion, which connects the computed survivors of a vintage (Column E) to the recorded vintage addition (Column B). The realized life is the area bounded by the SC dispersion, the computed proportion surviving and the age of the vintage.

SCHEDULE C – PLANT HISTORY

An Unadjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Activity year totals for unaged data are obtained from a transaction file without vintage identification. Information displayed in the unadjusted plant history is consistent with regulated investments reported internally by the Company.

An Adjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company with sales, transfers, and adjustments appropriately aged for depreciation study purposes. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Ageing of adjusting transactions is achieved using transaction codes that identify an adjusting year associated with the dollar amount of a transaction. Adjusting transactions processed in the adjusted plant history are not aged in the Company's records or in the unadjusted plant history.

SCHEDULE D – ACTUARIAL LIFE ANALYSIS

These schedules provide a summary of the dispersion and life indications obtained from an actuarial life analysis for a specified placement band. The observation band (Column A) is specified to produce a rolling–band, shrinking–band, or progressive–band analysis depending upon the movement of the end points of the band. The degree of censoring (or point of truncation) of the observed life table is shown in Column B for each observation band. The estimated average service life, best fitting Iowa dispersion, and a statistical measure of the goodness of fit are shown for each degree polynomial (First, Second, and Third) fitted to the estimated hazard rates. Options available in the analysis include the width and location of both the placement and observation bands; the interval of years included in a selected rolling, shrinking, or progressive band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated.

Estimated projection lives (Columns C, F, and I) are flagged with an asterisk if negative hazard rates are indicated by the fitted polynomial. All negative hazard rates are set equal to zero in the calculation of the graduated survivor curve. The Conformance Index (Columns E, H, and K) is the square root of the mean sum–

of–squared differences between the graduated survivor curve and the best fitting Iowa curve. A Conformance Index of zero would indicate a perfect fit.

SCHEDULE E – GRAPHICS ANALYSIS

This schedule provides a graphics plot of a) the observed proportion surviving for a selected placement and observation band; b) the statistically best fitting dispersion and derived projection life; and c) the projection curve and projection life selected to describe future forces of mortality.

The graphics analysis also provides a plot of the observed hazard rates and graduated hazard function for a selected placement and observation band. The estimator of the hazard rates and weighting used in fitting orthogonal polynomials to the observed data are displayed in the title block of the displayed graph.

SCHEDULE F – HISTORICAL NET SALVAGE ANALYSIS

This schedule provides a moving average analysis of the ratio of realized net salvage (Column I) to the associated retirements (Column B). The schedule also provides a moving average analysis of the components of net salvage related to retirements. The ratio of gross salvage to retirements is shown in Column D and the ratio of cost of removal to retirements is shown in Column G.

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NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant
Account: 368.01 Line Transformers - Bare Cost

Dispersion: 35 - H0.5
Procedure: Broad Group

Generation Arrangement

Vintage	Age (December 31, 2008)	Surviving Plant (December 31, 2008)	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2008	0.5	26,081,422	35.00	34.76	0.9931	1.0000	25,902,029	745,184
2007	1.5	26,686,753	35.00	34.28	0.9795	1.0000	26,138,529	762,479
2006	2.5	23,154,121	35.00	33.81	0.9660	1.0000	22,366,996	661,546
2005	3.5	25,241,149	35.00	33.35	0.9528	1.0000	24,049,092	721,176
2004	4.5	9,914,750	35.00	32.89	0.9398	1.0000	9,317,533	283,279
2003	5.5	14,486,908	35.00	32.44	0.9270	1.0000	13,428,774	413,912
2002	6.5	16,246,033	35.00	32.00	0.9144	1.0000	14,854,912	464,172
2001	7.5	14,927,864	35.00	31.57	0.9020	1.0000	13,464,753	426,510
2000	8.5	10,277,350	35.00	31.14	0.8898	1.0000	9,144,941	293,639
1999	9.5	3,571,683	35.00	30.72	0.8778	1.0000	3,135,370	102,048
1998	10.5	6,124,660	35.00	30.31	0.8661	1.0000	5,304,327	174,990
1997	11.5	8,605,553	35.00	29.91	0.8545	1.0000	7,353,347	245,873
1996	12.5	5,257,259	35.00	29.51	0.8431	1.0000	4,432,467	150,207
1995	13.5	8,406,660	35.00	29.12	0.8319	1.0000	6,993,725	240,190
1994	14.5	10,968,318	35.00	28.73	0.8209	1.0000	9,004,216	313,381
1993	15.5	14,961,409	35.00	28.35	0.8101	1.0000	12,120,548	427,469
1992	16.5	16,361,683	35.00	27.98	0.7995	1.0000	13,081,037	467,477
1991	17.5	19,690,737	35.00	27.62	0.7891	1.0000	15,537,066	562,593
1990	18.5	11,430,456	35.00	27.26	0.7788	1.0000	8,901,898	326,585
1989	19.5	15,707,710	35.00	26.90	0.7687	1.0000	12,074,578	448,792
1988	20.5	13,108,858	35.00	26.56	0.7588	1.0000	9,946,898	374,539
1987	21.5	11,936,999	35.00	26.22	0.7491	1.0000	8,941,415	341,057
1986	22.5	15,844,397	35.00	25.88	0.7395	1.0000	11,716,436	452,697
1985	23.5	11,826,600	35.00	25.55	0.7301	1.0000	8,634,222	337,903
1984	24.5	8,295,703	35.00	25.23	0.7208	1.0000	5,979,750	237,020
1983	25.5	7,737,115	35.00	24.91	0.7117	1.0000	5,506,774	221,060
1982	26.5	6,345,656	35.00	24.60	0.7028	1.0000	4,459,749	181,305
1981	27.5	7,309,111	35.00	24.29	0.6940	1.0000	5,072,793	208,832
1980	28.5	4,798,978	35.00	23.99	0.6854	1.0000	3,289,261	137,114
1979	29.5	6,807,651	35.00	23.69	0.6769	1.0000	4,608,369	194,504
1978	30.5	5,765,892	35.00	23.40	0.6686	1.0000	3,855,142	164,740
1977	31.5	5,261,029	35.00	23.12	0.6604	1.0000	3,474,574	150,315
1976	32.5	2,816,441	35.00	22.83	0.6524	1.0000	1,837,439	80,470
1975	33.5	1,179,572	35.00	22.56	0.6445	1.0000	760,233	33,702
1974	34.5	4,660,099	35.00	22.29	0.6367	1.0000	2,967,262	133,146
1973	35.5	4,715,569	35.00	22.02	0.6291	1.0000	2,966,627	134,731

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Schedule A
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Distribution Plant
Account: 368.01 Line Transformers - Bare Cost

Dispersion: 35 - H0.5
Procedure: Broad Group

Generation Arrangement

Vintage	December 31, 2008 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1972	36.5	3,776,191	35.00	21.76	0.6216	1.0000	2,347,345	107,891
1971	37.5	3,342,725	35.00	21.50	0.6143	1.0000	2,053,271	95,506
1970	38.5	3,860,882	35.00	21.25	0.6070	1.0000	2,343,589	110,311
1969	39.5	2,903,269	35.00	21.00	0.5999	1.0000	1,741,665	82,951
1968	40.5	3,322,499	35.00	20.75	0.5929	1.0000	1,969,936	94,929
1967	41.5	2,779,068	35.00	20.51	0.5860	1.0000	1,628,641	79,402
1966	42.5	2,080,892	35.00	20.27	0.5793	1.0000	1,205,412	59,454
1965	43.5	1,553,207	35.00	20.04	0.5726	1.0000	889,436	44,377
1964	44.5	1,282,995	35.00	19.81	0.5661	1.0000	726,330	36,657
1963	45.5	1,366,175	35.00	19.59	0.5597	1.0000	764,672	39,034
1962	46.5	1,408,833	35.00	19.37	0.5534	1.0000	779,671	40,252
1961	47.5	1,690,802	35.00	19.15	0.5472	1.0000	925,225	48,309
1960	48.5	1,586,976	35.00	18.94	0.5411	1.0000	858,739	45,342
1959	49.5	1,962,534	35.00	18.73	0.5351	1.0000	1,050,209	56,072
1958	50.5	1,540,462	35.00	18.52	0.5293	1.0000	815,290	44,013
1957	51.5	1,939,160	35.00	18.32	0.5235	1.0000	1,015,085	55,405
1956	52.5	1,532,537	35.00	18.12	0.5178	1.0000	793,525	43,787
1955	53.5	1,231,318	35.00	17.93	0.5122	1.0000	630,666	35,181
1954	54.5	1,096,284	35.00	17.73	0.5067	1.0000	555,455	31,322
1953	55.5	762,903	35.00	17.54	0.5013	1.0000	382,410	21,797
1952	56.5	601,359	35.00	17.36	0.4959	1.0000	298,244	17,182
1951	57.5	702,440	35.00	17.17	0.4907	1.0000	344,694	20,070
1950	58.5	419,197	35.00	17.00	0.4856	1.0000	203,552	11,977
1949	59.5	281,770	35.00	16.82	0.4805	1.0000	135,399	8,051
1948	60.5	303,170	35.00	16.64	0.4755	1.0000	144,170	8,662
1947	61.5	237,309	35.00	16.47	0.4706	1.0000	111,689	6,780
1946	62.5	92,793	35.00	16.30	0.4658	1.0000	43,226	2,651
1945	63.5	44,523	35.00	16.14	0.4611	1.0000	20,529	1,272
1944	64.5	15,404	35.00	15.98	0.4564	1.0000	7,031	440
1943	65.5	11,831	35.00	15.82	0.4519	1.0000	5,346	338
1942	66.5	47,723	35.00	15.66	0.4473	1.0000	21,348	1,364
1941	67.5	102,453	35.00	15.50	0.4429	1.0000	45,376	2,927
1940	68.5	147,053	35.00	15.35	0.4386	1.0000	64,490	4,202
1939	69.5	132,421	35.00	15.20	0.4342	1.0000	57,502	3,783
1938	70.5	37,576	35.00	15.05	0.4300	1.0000	16,158	1,074
1937	71.5	79,494	35.00	14.90	0.4259	1.0000	33,853	2,271

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NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant
Account: 368.01 Line Transformers - Bare Cost

Dispersion: 35 - H0.5
Procedure: Broad Group

Generation Arrangement

Vintage	Age (December 31, 2008)	Surviving Plant (December 31, 2008)	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1936	72.5	90,208	35.00	14.76	0.4218	1.0000	38,046	2,577
1935	73.5	49,860	35.00	14.62	0.4177	1.0000	20,828	1,425
1934	74.5	17,991	35.00	14.48	0.4138	1.0000	7,444	514
1933	75.5	12,535	35.00	14.34	0.4098	1.0000	5,137	358
1932	76.5	25,573	35.00	14.21	0.4060	1.0000	10,383	731
1931	77.5	64,187	35.00	14.08	0.4022	1.0000	25,817	1,834
1930	78.5	105,564	35.00	13.95	0.3985	1.0000	42,066	3,016
1929	79.5	90,884	35.00	13.82	0.3948	1.0000	35,883	2,597
1928	80.5	29,948	35.00	13.69	0.3912	1.0000	11,716	856
1927	81.5	29,782	35.00	13.57	0.3876	1.0000	11,545	851
1926	82.5	39,504	35.00	13.44	0.3841	1.0000	15,175	1,129
1925	83.5	26,564	35.00	13.32	0.3807	1.0000	10,112	759
1924	84.5	21,443	35.00	13.20	0.3773	1.0000	8,090	613
1923	85.5	25,027	35.00	13.09	0.3739	1.0000	9,359	715
1922	86.5	19,713	35.00	12.97	0.3706	1.0000	7,307	563
1921	87.5	17,855	35.00	12.86	0.3674	1.0000	6,560	510
1920	88.5	31,911	35.00	12.75	0.3642	1.0000	11,621	912
1919	89.5	11,801	35.00	12.64	0.3610	1.0000	4,260	337
1918	90.5	15,058	35.00	12.53	0.3579	1.0000	5,389	430
1917	91.5	7,591	35.00	12.42	0.3548	1.0000	2,694	217
1916	92.5	8,195	35.00	12.31	0.3518	1.0000	2,883	234
1915	93.5	5,822	35.00	12.21	0.3489	1.0000	2,031	166
1914	94.5	2,827	35.00	12.11	0.3459	1.0000	978	81
1913	95.5	1,991	35.00	12.01	0.3430	1.0000	683	57
1912	96.5	1,602	35.00	11.91	0.3402	1.0000	545	46
1911	97.5	2,057	35.00	11.81	0.3374	1.0000	694	59
1910	98.5	1,919	35.00	11.71	0.3346	1.0000	642	55
1909	99.5	585	35.00	11.61	0.3318	1.0000	194	17
1908	100.5	12,199	35.00	11.52	0.3292	1.0000	4,015	349
1907	101.5	835	35.00	11.43	0.3265	1.0000	273	24
1906	102.5	1,011	35.00	11.34	0.3239	1.0000	327	29
1905	103.5	2,189	35.00	11.25	0.3213	1.0000	703	63
1904	104.5	70	35.00	11.16	0.3187	1.0000	22	2
1903	105.5	226	35.00	11.07	0.3162	1.0000	71	6
1902	106.5	1,629	35.00	10.98	0.3137	1.0000	511	47
1901	107.5	186,753	35.00	10.90	0.3113	1.0000	58,136	5,336
Total	17.0	$451,751,287	35.00	28.36	0.8102	1.0000	$366,014,403	$12,907,180

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NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 368.01 Line Transformers - Bare Cost

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2008	0.5	26,081,422		26,081,422	1.0000	0.5000
2007	1.5	26,686,753		26,686,753	1.0000	1.5000
2006	2.5	23,154,121		23,154,121	1.0000	2.5000
2005	3.5	25,241,149		25,241,149	1.0000	3.5000
2004	4.5	13,399,360		9,914,750	0.7399	3.5236
2003	5.5	15,594,665		14,486,908	0.9290	5.1809
2002	6.5	16,703,952		16,246,033	0.9726	6.3766
2001	7.5	15,123,291		14,927,864	0.9871	7.4423
2000	8.5	18,466,599		10,277,350	0.5565	6.0703
1999	9.5	16,714,500		3,571,683	0.2137	5.1783
1998	10.5	12,531,090		6,124,660	0.4888	7.6898
1997	11.5	15,155,762		8,605,553	0.5678	8.4184
1996	12.5	6,942,489		5,257,259	0.7573	10.8358
1995	13.5		10,590,506	8,406,660	0.7938	12.0221
1994	14.5		12,685,667	10,968,318	0.8646	13.4625
1993	15.5		18,654,004	14,961,409	0.8020	14.1255
1992	16.5		19,032,089	16,361,683	0.8597	15.4508
1991	17.5		25,764,272	19,690,737	0.7643	15.9278
1990	18.5		15,463,955	11,430,456	0.7392	16.7353
1989	19.5		19,857,626	15,707,710	0.7910	18.0716
1988	20.5		15,601,861	13,108,858	0.8402	19.3738
1987	21.5		14,553,524	11,936,999	0.8202	20.2014
1986	22.5		19,272,209	15,844,397	0.8221	21.2349
1985	23.5		14,559,300	11,826,600	0.8123	22.2084
1984	24.5		10,258,837	8,295,703	0.8086	23.0931
1983	25.5		9,771,387	7,737,115	0.7918	23.9151
1982	26.5		8,085,290	6,345,656	0.7848	24.7964
1981	27.5		9,047,581	7,309,111	0.8079	25.9583
1980	28.5		5,951,790	4,798,978	0.8063	27.0144
1979	29.5		8,243,110	6,807,651	0.8259	28.1356
1978	30.5		7,260,483	5,765,892	0.7941	28.9128
1977	31.5		6,682,451	5,261,029	0.7873	29.8986
1976	32.5		3,499,662	2,816,441	0.8048	30.9469
1975	33.5		1,489,036	1,179,572	0.7922	31.7544
1974	34.5		6,124,507	4,660,099	0.7609	32.3834
1973	35.5		6,011,605	4,715,569	0.7844	33.6002
1972	36.5		4,860,023	3,776,191	0.7770	34.5351

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NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Distribution Plant
Account: 368.01 Line Transformers - Bare Cost

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1971	37.5		4,485,396	3,342,725	0.7452	35.2175
1970	38.5		5,022,290	3,860,882	0.7687	36.4285
1969	39.5		3,816,830	2,903,269	0.7606	37.3984
1968	40.5		4,287,548	3,322,499	0.7749	38.5059
1967	41.5		3,667,911	2,779,068	0.7577	39.3455
1966	42.5		2,792,855	2,080,892	0.7451	40.2885
1965	43.5		2,178,933	1,553,207	0.7128	40.9335
1964	44.5		1,751,221	1,282,995	0.7326	42.0929
1963	45.5		1,932,463	1,366,175	0.7070	42.8529
1962	46.5		2,083,923	1,408,833	0.6760	43.6566
1961	47.5		2,201,811	1,690,802	0.7679	45.4218
1960	48.5		2,157,925	1,586,976	0.7354	46.1656
1959	49.5		2,697,433	1,962,534	0.7276	47.0567
1958	50.5		2,124,258	1,540,462	0.7252	48.0257
1957	51.5		2,704,659	1,939,160	0.7170	48.9724
1956	52.5		2,200,128	1,532,537	0.6966	49.7713
1955	53.5		1,800,486	1,231,318	0.6839	50.7151
1954	54.5		1,573,870	1,096,284	0.6966	51.8025
1953	55.5		1,118,931	762,903	0.6818	52.7788
1952	56.5		959,617	601,359	0.6267	53.3995
1951	57.5		1,056,694	702,440	0.6648	54.5966
1950	58.5		667,818	419,197	0.6277	55.2309
1949	59.5		490,634	281,770	0.5743	55.7246
1948	60.5		570,066	303,170	0.5318	56.4650
1947	61.5		416,153	237,309	0.5702	58.0591
1946	62.5		168,116	92,793	0.5520	58.8729
1945	63.5		75,991	44,523	0.5859	60.0687
1944	64.5		28,259	15,404	0.5451	60.7203
1943	65.5		14,947	11,831	0.7916	63.6925
1942	66.5		77,584	47,723	0.6151	63.1975
1941	67.5		176,594	102,453	0.5802	64.0648
1940	68.5		207,153	147,053	0.7099	65.9780
1939	69.5		228,037	132,421	0.5807	66.1371
1938	70.5		77,090	37,576	0.4874	66.4943
1937	71.5		116,634	79,494	0.6816	68.7054
1936	72.5		169,077	90,208	0.5335	68.4073
1935	73.5		79,231	49,860	0.6293	70.4290

Schedule B
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NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 368.01 Line Transformers - Bare Cost

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1934	74.5		34,868	17,991	0.5160	70.8062
1933	75.5		19,224	12,535	0.6520	72.5106
1932	76.5		39,517	25,573	0.6471	73.6466
1931	77.5		98,710	64,187	0.6503	74.5204
1930	78.5		155,420	105,564	0.6792	75.9564
1929	79.5		135,390	90,884	0.6713	76.5085
1928	80.5		52,332	29,948	0.5723	76.6448
1927	81.5		53,269	29,782	0.5591	77.7167
1926	82.5		171,357	39,504	0.2305	74.2511
1925	83.5		49,029	26,564	0.5418	78.7537
1924	84.5		43,550	21,443	0.4924	79.3181
1923	85.5		51,413	25,027	0.4868	80.2308
1922	86.5		31,228	19,713	0.6313	82.8106
1921	87.5		31,143	17,855	0.5733	83.4323
1920	88.5		52,270	31,911	0.6105	84.8911
1919	89.5		24,861	11,801	0.4747	84.7744
1918	90.5		39,317	15,058	0.3830	85.3770
1917	91.5		13,310	7,591	0.5703	87.2932
1916	92.5		27,545	8,195	0.2975	86.0586
1915	93.5		14,052	5,822	0.4143	87.3662
1914	94.5		5,729	2,827	0.4935	89.7090
1913	95.5		7,293	1,991	0.2730	88.0072
1912	96.5		2,546	1,602	0.6293	92.8853
1911	97.5		3,147	2,057	0.6537	94.6678
1910	98.5		2,119	1,919	0.9057	97.9188
1909	99.5		1,442	585	0.4059	93.1066
1908	100.5		12,289	12,199	0.9927	100.4157
1907	101.5		961	835	0.8686	99.9890
1906	102.5		2,429	1,011	0.4161	95.7854
1905	103.5		4,516	2,189	0.4848	99.5987
1904	104.5		143	70	0.4876	98.6073
1903	105.5		1,371	226	0.1649	99.1337
1902	106.5		1,629	1,629	1.0000	106.5000
1901	107.5		1,275,555	186,753	0.1464	97.9062
Total	17.0	$231,795,152	$331,958,316	$451,751,287	0.8013	

Schedule C
Page 1 of 1

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Distribution Plant
Account: 368.01 Line Transformers - Bare Cost

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996		11,952,535	6,176		11,946,359
1997	11,946,359	334,707,180	11,685,360		334,968,179
1998	334,968,179	15,758,356	7,533,155	(12,409)	343,180,970
1999	343,180,970	20,505,689	5,025,561	(24,329)	358,636,769
2000	358,636,769	18,524,029	11,725,314		365,435,484
2001	365,435,484	15,281,111	543,070		380,173,526
2002	380,173,526	16,635,924	9,089,329		387,720,120
2003	387,720,120	15,403,967	58,641,849	(477)	344,481,762
2004	344,481,762	8,680,892	4,711,501		348,451,153
2005	348,451,153	25,902,918	3,003,324	42,347	371,393,095
2006	371,393,095	27,887,486	17,747	5,677	399,268,511
2007	399,268,511	25,862,917	3,952	39,645	425,167,121
2008	425,167,121	26,611,161	15,843	(11,152)	451,751,287

Schedule C
Page 1 of 1

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 368.01 Line Transformers - Bare Cost

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996	331,898,977	6,942,489	6,176		338,835,289
1997	338,835,289	15,155,762	11,685,360		342,305,691
1998	342,305,691	12,543,499	7,533,155	(12,409)	347,303,626
1999	347,303,626	16,714,500	5,025,561	(24,329)	358,968,236
2000	358,968,236	18,431,024	11,725,314		365,673,946
2001	365,673,946	15,123,768	543,070		380,254,644
2002	380,254,644	16,703,952	9,089,329		387,869,266
2003	387,869,266	15,552,317	58,641,849	(477)	344,779,258
2004	344,779,258	13,399,360	4,711,501		353,467,117
2005	353,467,117	25,250,647	3,003,324	42,347	375,756,787
2006	375,756,787	23,265,495	17,747	5,677	399,010,212
2007	399,010,212	26,650,955	3,952	39,645	425,696,860
2008	425,696,860	26,081,422	15,843	(11,152)	451,751,287

Schedule D
Page 1 of 1

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Distribution Plant

Account: 368.01 Line Transformers - Bare Cost

T-Cut: None
Placement Band: 1901-2008
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2000	0.1	33.4	L1	3.11	33.3	R0.5	2.77	33.2	R0.5	2.76
1997-2001	0.1	33.6	L1 *	3.04	33.3	R0.5	2.26	33.4	R0.5	2.28
1998-2002	1.3	35.3	L1.5 *	2.98	35.3	L1.5 *	2.87	35.5	L1.5 *	2.49
1999-2003	0.6	23.3	O4 *	4.37	20.4	O3	3.76	20.1	O3 *	3.27
2000-2004	0.7	25.9	O4 *	4.87	20.6	O4	4.00	20.4	O4 *	3.52
2001-2005	3.2	52.6	O4 *	10.97	26.4	O4	4.50	27.4	O4 *	3.27
2002-2006	5.8	52.8	O4 *	8.56	28.0	O4	3.65	29.4	O4 *	2.61
2003-2007	15.0	61.9	O4 *	6.03	32.6	O4 *	5.45	36.0	O4 *	3.43
2004-2008	47.4	176.0	R2.5 *	13.88	85.1	R2.5 *	10.05	129.7	SC *	7.09

Schedule D
Page 1 of 1

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Distribution Plant

Account: 368.01 Line Transformers - Bare Cost

T-Cut: None
Placement Band: 1901-2008
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2008	1.0	49.4	O4 *	6.49	35.5	O2	2.64	35.4	O2	2.66
1998-2008	7.2	68.1	O4 *	10.03	37.1	O3	2.96	42.7	O3 *	1.50
2000-2008	6.5	67.5	O4 *	10.74	35.9	O3	3.04	40.5	O3 *	1.72
2002-2008	14.1	78.2	O4 *	10.01	41.8	O4	3.90	42.6	O4	3.18
2004-2008	47.4	176.0	R2.5 *	13.88	85.1	R2.5 *	10.05	129.7	SC *	7.09
2006-2008	62.3	191.8	R5 *	8.31	158.2	R2.5 *	5.36	133.6	S3 *	4.13
2008-2008	53.7	185.2	R4 *	11.30	129.4	S2 *	4.21	111.6	R4 *	2.09

Schedule D
Page 1 of 1

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 368.01 Line Transformers - Bare Cost

T-Cut: None
Placement Band: 1901-2008
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-1997	0.0	36.4	L1	8.27	38.0	R0.5	5.60	40.5	SC	2.20
1996-1999	0.3	39.3	L0	4.73	38.1	SC	5.30	39.8	SC	3.16
1996-2001	0.2	36.4	L1 *	2.62	36.2	S0	2.23	36.0	R1	2.20
1996-2003	0.1	25.6	O3	2.40	24.7	O3	1.69	24.6	O3	1.69
1996-2005	0.3	32.5	O3	3.62	28.2	O3	1.75	27.9	O3	1.84
1996-2007	0.7	43.3	O4	5.42	33.0	O2	2.30	32.9	O2	2.39
1996-2008	1.0	49.4	O4 *	6.49	35.5	O2	2.64	35.4	O2	2.66

Schedule E
Page 1 of 1

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

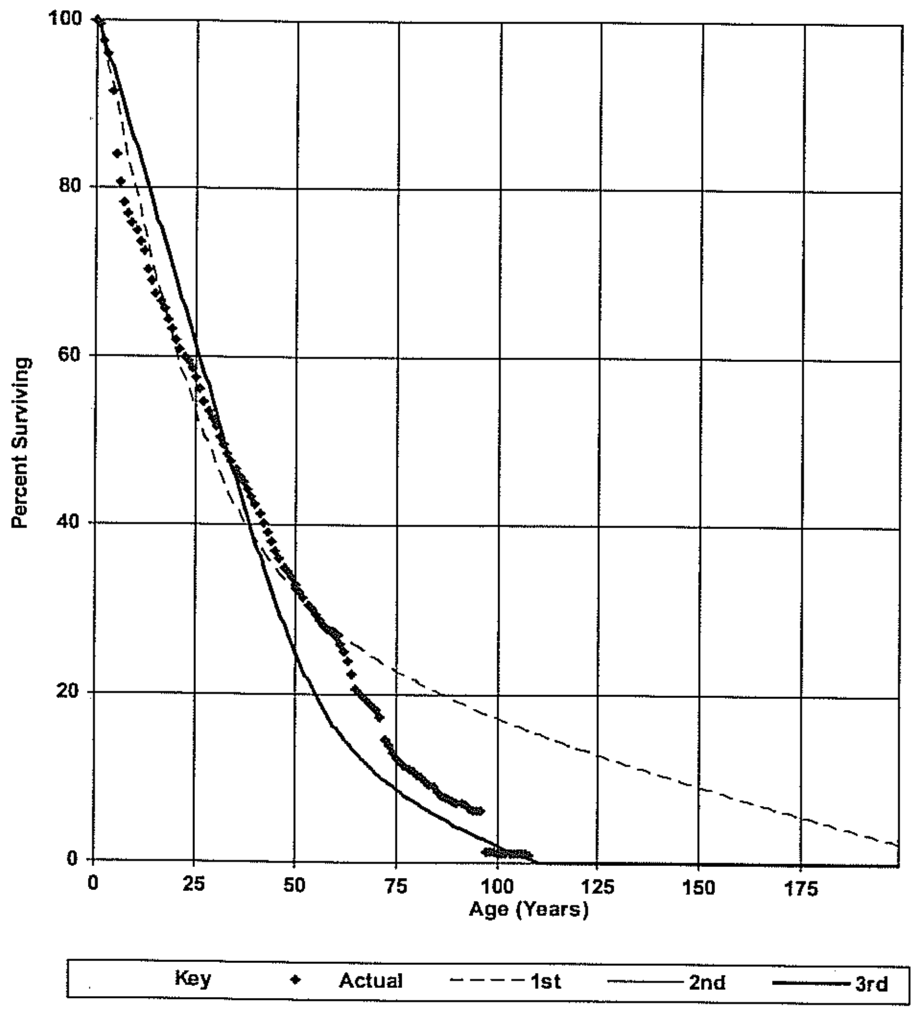
Distribution Plant

Account: 368.01 Line Transformers - Bare Cost

T-Cut: None
Placement Band: 1901-2008 Observation Band: 1996-2008
Hazard Function: Proportion Retired
Weighting: Exposures

Graphics Analysis

1st: 49.4-O4 2nd: 35.5-O2 3rd: 35.4-O2



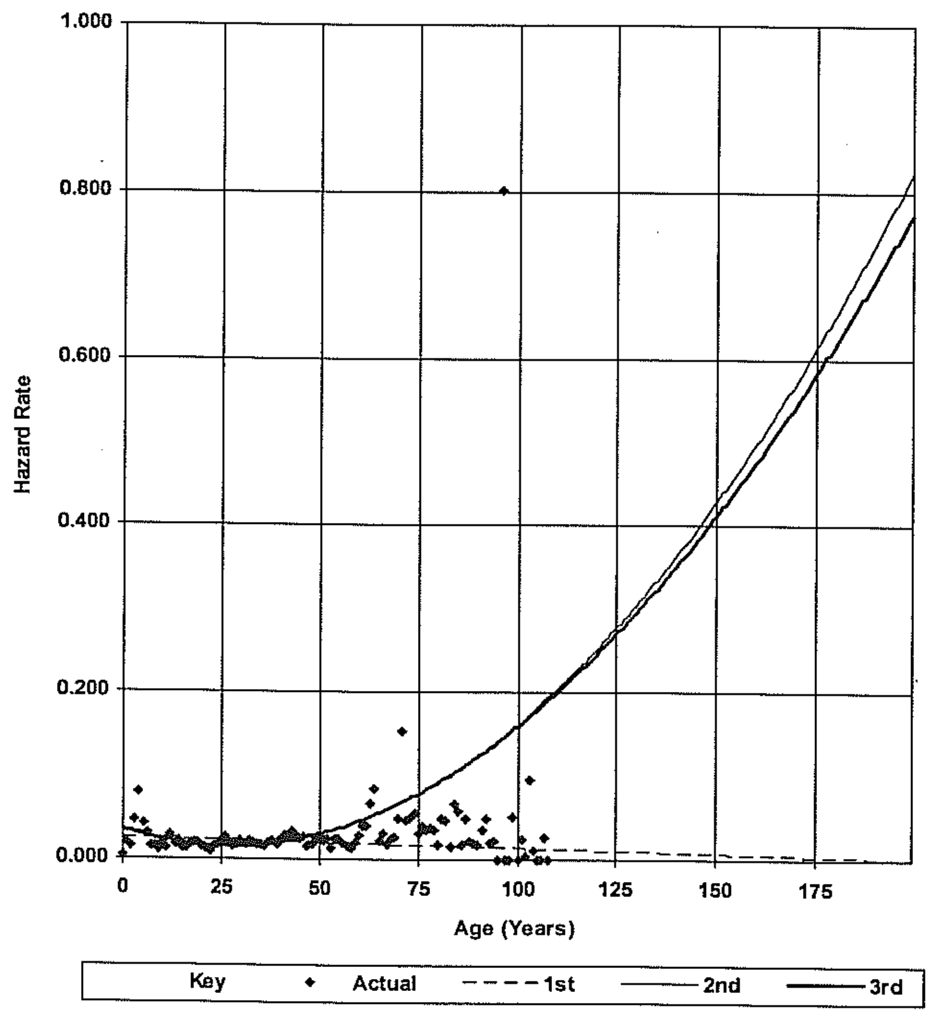
Schedule E
Page 1 of 1

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Distribution Plant
Account: 368.01 Line Transformers - Bare Cost

T-Cut: None
Placement Band: 1901-2008 Observation Band: 1996-2008
Hazard Function: Proportion Retired
Weighting: Exposures

Polynomial Hazard Function

1st: 49.4-O4 2nd: 35.5-O2 3rd: 35.4-O2



Schedule E
Page 1 of 1

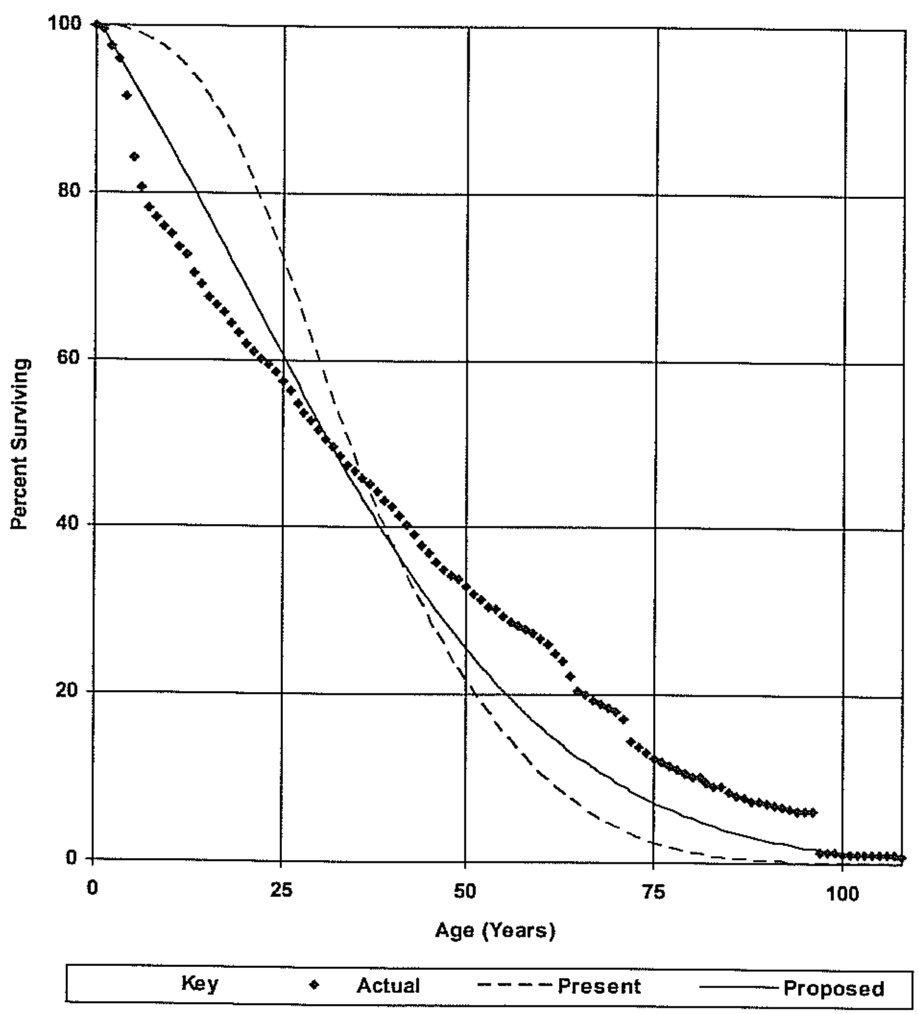
NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 368.01 Line Transformers - Bare Cost

T-Cut: None
Placement Band: 1901-2008
Observation Band: 1996-2008

Present and Proposed Projection Life Curves Present: 36.0-L1.5 Proposed: 35.0-H0.5



Schedule F
Page 1 of 1

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 368.01 Line Transformers

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998	7,533,155	155,179	2.1		1,032,467	13.7		(877,288)	-11.6	
1999	5,025,561	26,435	0.5		2,736,840	54.5		(2,710,404)	-53.9	
2000	11,725,314	83,544	0.7		2,267,445	19.3		(2,183,900)	-18.6	
2001	543,070	164,076	30.2		2,886,372	531.5		(2,722,296)	-501.3	
2002	9,089,329	82,579	0.9	1.5	2,601,115	28.6	34.0	(2,518,537)	-27.7	-32.5
2003	58,641,849	18,252	0.0	0.4	1,273,796	2.2	13.8	(1,255,544)	-2.1	-13.4
2004	4,711,501		0.0	0.4	16,575	0.4	10.7	(16,575)	-0.4	-10.3
2005	3,003,324		0.0	0.3	149,403	5.0	9.1	(149,403)	-5.0	-8.8
2006	17,747		0.0	0.1	307,220	1731.1	5.8	(307,220)	1731.1	-5.6
2007	3,952		0.0	0.0	288,161	7292.2	3.1	(288,161)	7292.2	-3.0
2008	15,843		0.0	0.0		0.0	9.8		0.0	-9.8
Total	100,310,646	530,065	0.5		13,559,394	13.5		(13,029,329)	-13.0	

Schedule F
Page 1 of 1

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Distribution Plant
Account: 368.01 Line Transformers

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998	7,533,155	155,179	2.1		1,032,467	13.7		(877,288)	-11.6	
1999	5,025,561	26,435	0.5		2,736,840	54.5		(2,710,404)	-53.9	
2000	11,725,314	83,544	0.7		2,267,445	19.3		(2,183,900)	-18.6	
2001	543,070	164,076	30.2		2,886,372	531.5		(2,722,296)	-501.3	
2002	9,089,329	82,579	0.9	1.5	2,601,115	28.6	34.0	(2,518,537)	-27.7	-32.5
2003	58,641,849	18,252	0.0	0.4	1,273,796	2.2	13.8	(1,255,544)	-2.1	-13.4
2004	4,711,501		0.0	0.4	16,575	0.4	10.7	(16,575)	-0.4	-10.3
2005	3,003,324		0.0	0.3	149,403	5.0	9.1	(149,403)	-5.0	-8.8
2006	17,747		0.0	0.1	307,220	1731.1	5.8	(307,220)	1731.1	-5.6
2007	3,952		0.0	0.0	288,161	7292.2	3.1	(288,161)	7292.2	-3.0
2008	15,843		0.0	0.0		0.0	9.8		0.0	-9.8
Total	100,310,646	530,065	0.5		13,559,394	13.5		(13,029,329)	-13.0	

Exhibit __ (REW-3)
Wrkpr Pages 1 – 236
Through A/C 366.01, Sch A

Testimony of Ronald E. White

Exhibit __ (REW-3)

Workpapers

Pages 1 – 236

2009 Electric Depreciation Rate Study

Niagara Mohawk Power Corporation – d/b/a National Grid

Work Papers

Prepared by
Foster Associates, Inc.

Schedules A through F

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 350.40 Land Rights - Transmission Lines

Dispersion: 75 - H5
Procedure: Broad Group

Generation Arrangement

Vintage	Age (December 31, 2008)	Surviving Plant (December 31, 2008)	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2008	0.5	396,553	75.00	74.50	0.9933	1.0000	393,909	5,287
2007	1.5	1	75.00	73.50	0.9800	1.0000	1	
2006	2.5	502	75.00	72.50	0.9667	1.0000	485	7
2005	3.5	26,260	75.00	71.50	0.9533	1.0000	25,035	350
2004	4.5	4,366	75.00	70.50	0.9400	1.0000	4,104	58
2003	5.5	290,937	75.00	69.50	0.9267	1.0000	269,602	3,879
2002	6.5	32,995	75.00	68.50	0.9133	1.0000	30,135	440
2001	7.5	66,976	75.00	67.50	0.9000	1.0000	60,278	893
2000	8.5	66,094	75.00	66.50	0.8867	1.0000	58,603	881
1999	9.5	76,524	75.00	65.50	0.8733	1.0000	66,832	1,020
1998	10.5	84,666	75.00	64.50	0.8600	1.0000	72,813	1,129
1997	11.5	2,983	75.00	63.50	0.8467	1.0000	2,525	40
1996	12.5	121,704	75.00	62.50	0.8333	1.0000	101,421	1,623
1995	13.5	554,992	75.00	61.50	0.8200	1.0000	455,103	7,400
1994	14.5	2,756,975	75.00	60.50	0.8067	1.0000	2,224,029	36,760
1993	15.5	208,461	75.00	59.50	0.7934	1.0000	165,386	2,779
1992	16.5	303,175	75.00	58.50	0.7800	1.0000	236,489	4,042
1991	17.5	420,284	75.00	57.50	0.7667	1.0000	322,239	5,604
1990	18.5	324,755	75.00	56.50	0.7534	1.0000	244,670	4,330
1989	19.5	1,072,487	75.00	55.51	0.7401	1.0000	793,733	14,300
1988	20.5	93,939	75.00	54.51	0.7268	1.0000	68,273	1,253
1987	21.5	537,089	75.00	53.51	0.7135	1.0000	383,197	7,161
1986	22.5	1,519,934	75.00	52.51	0.7002	1.0000	1,064,216	20,266
1985	23.5	188,935	75.00	51.52	0.6869	1.0000	129,777	2,519
1984	24.5	182,905	75.00	50.52	0.6736	1.0000	123,206	2,439
1983	25.5	194,020	75.00	49.53	0.6603	1.0000	128,120	2,587
1982	26.5	834,305	75.00	48.53	0.6471	1.0000	539,877	11,124
1981	27.5	382,818	75.00	47.54	0.6339	1.0000	242,656	5,104
1980	28.5	110,611	75.00	46.55	0.6207	1.0000	68,651	1,475
1979	29.5	1,495,178	75.00	45.56	0.6075	1.0000	908,275	19,936
1978	30.5	773,043	75.00	44.57	0.5943	1.0000	459,433	10,307
1977	31.5	283,737	75.00	43.59	0.5812	1.0000	164,905	3,783
1976	32.5	142,870	75.00	42.61	0.5681	1.0000	81,166	1,905
1975	33.5	348,138	75.00	41.63	0.5551	1.0000	193,244	4,642
1974	34.5	326,154	75.00	40.66	0.5421	1.0000	176,805	4,349
1973	35.5	270,642	75.00	39.69	0.5292	1.0000	143,216	3,609

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 350.40 Land Rights - Transmission Lines

Dispersion: 75 - H5
Procedure: Broad Group

Generation Arrangement

Vintage	December 31, 2008 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1972	36.5	248,341	75.00	38.72	0.5163	1.0000	128,222	3,311
1971	37.5	175,252	75.00	37.76	0.5035	1.0000	88,244	2,337
1970	38.5	1,253,496	75.00	36.81	0.4908	1.0000	615,262	16,713
1969	39.5	306,170	75.00	35.87	0.4782	1.0000	146,420	4,082
1968	40.5	358,252	75.00	34.93	0.4657	1.0000	166,848	4,777
1967	41.5	494,155	75.00	34.00	0.4534	1.0000	224,026	6,589
1966	42.5	360,696	75.00	33.08	0.4411	1.0000	159,100	4,809
1965	43.5	273,653	75.00	32.17	0.4290	1.0000	117,385	3,649
1964	44.5	438,658	75.00	31.27	0.4170	1.0000	182,916	5,849
1963	45.5	410,512	75.00	30.39	0.4052	1.0000	166,329	5,473
1962	46.5	480,395	75.00	29.51	0.3935	1.0000	189,040	6,405
1961	47.5	737,917	75.00	28.65	0.3821	1.0000	281,927	9,839
1960	48.5	803,006	75.00	27.81	0.3708	1.0000	297,739	10,707
1959	49.5	347,120	75.00	26.98	0.3597	1.0000	124,856	4,628
1958	50.5	1,055,607	75.00	26.16	0.3488	1.0000	368,239	14,075
1957	51.5	320,468	75.00	25.36	0.3382	1.0000	108,381	4,273
1956	52.5	335,275	75.00	24.58	0.3278	1.0000	109,891	4,470
1955	53.5	98,324	75.00	23.82	0.3176	1.0000	31,228	1,311
1954	54.5	250,748	75.00	23.07	0.3077	1.0000	77,146	3,343
1953	55.5	271,498	75.00	22.35	0.2980	1.0000	80,895	3,620
1952	56.5	251,748	75.00	21.64	0.2885	1.0000	72,640	3,357
1951	57.5	86,798	75.00	20.95	0.2794	1.0000	24,248	1,157
1950	58.5	97,990	75.00	20.28	0.2704	1.0000	26,499	1,307
1949	59.5	135,049	75.00	19.63	0.2618	1.0000	35,354	1,801
1948	60.5	94,279	75.00	19.00	0.2534	1.0000	23,890	1,257
1947	61.5	27,148	75.00	18.39	0.2452	1.0000	6,658	362
1946	62.5	15,147	75.00	17.80	0.2374	1.0000	3,596	202
1945	63.5	32,750	75.00	17.23	0.2298	1.0000	7,526	437
1944	64.5	20,778	75.00	16.68	0.2224	1.0000	4,621	277
1943	65.5	35,495	75.00	16.15	0.2153	1.0000	7,643	473
1942	66.5	100,458	75.00	15.64	0.2085	1.0000	20,944	1,339
1941	67.5	73,581	75.00	15.14	0.2019	1.0000	14,854	981
1940	68.5	31,656	75.00	14.66	0.1955	1.0000	6,190	422
1939	69.5	38,461	75.00	14.21	0.1894	1.0000	7,285	513
1938	70.5	89,701	75.00	13.76	0.1835	1.0000	16,460	1,196
1937	71.5	55,588	75.00	13.34	0.1778	1.0000	9,885	741

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 350.40 Land Rights - Transmission Lines

Dispersion: 75 - H5
Procedure: Broad Group

Generation Arrangement

Vintage	December 31, 2008 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1936	72.5	15,275	75.00	12.93	0.1724	1.0000	2,633	204
1935	73.5	31,307	75.00	12.53	0.1671	1.0000	5,232	417
1934	74.5	34,117	75.00	12.16	0.1621	1.0000	5,530	455
1933	75.5	58,376	75.00	11.79	0.1573	1.0000	9,180	778
1932	76.5	79,149	75.00	11.45	0.1526	1.0000	12,078	1,055
1931	77.5	90,712	75.00	11.11	0.1481	1.0000	13,437	1,209
1930	78.5	143,210	75.00	10.79	0.1438	1.0000	20,599	1,909
1929	79.5	228,047	75.00	10.48	0.1397	1.0000	31,864	3,041
1928	80.5	149,304	75.00	10.18	0.1358	1.0000	20,269	1,991
1927	81.5	285,323	75.00	9.90	0.1320	1.0000	37,650	3,804
1926	82.5	104,598	75.00	9.62	0.1283	1.0000	13,423	1,395
1925	83.5	391,960	75.00	9.36	0.1248	1.0000	48,916	5,226
1924	84.5	127,224	75.00	9.11	0.1214	1.0000	15,449	1,696
1923	85.5	67,117	75.00	8.87	0.1182	1.0000	7,935	895
1922	86.5	137,665	75.00	8.63	0.1151	1.0000	15,844	1,836
1921	87.5	54,000	75.00	8.41	0.1121	1.0000	6,054	720
1920	88.5	62,778	75.00	8.20	0.1093	1.0000	6,860	837
1919	89.5	14,783	75.00	7.99	0.1065	1.0000	1,574	197
1918	90.5	12,926	75.00	7.79	0.1038	1.0000	1,342	172
1917	91.5	15,403	75.00	7.60	0.1013	1.0000	1,561	205
1916	92.5	20,473	75.00	7.41	0.0988	1.0000	2,023	273
1915	93.5	24,822	75.00	7.23	0.0965	1.0000	2,394	331
1914	94.5	7,512	75.00	7.07	0.0942	1.0000	708	100
1913	95.5	35,238	75.00	6.90	0.0920	1.0000	3,242	470
1912	96.5	26,542	75.00	6.74	0.0899	1.0000	2,386	354
1911	97.5	19,442	75.00	6.60	0.0879	1.0000	1,710	259
1910	98.5	22,559	75.00	6.44	0.0859	1.0000	1,938	301
1909	99.5	3,846	75.00	6.30	0.0840	1.0000	323	51
1908	100.5	14,079	75.00	6.17	0.0823	1.0000	1,159	188
1907	101.5	73,146	75.00	6.03	0.0805	1.0000	5,885	975
1906	102.5	12,016	75.00	5.91	0.0788	1.0000	946	160
1905	103.5	21,684	75.00	5.79	0.0772	1.0000	1,674	289
1904	104.5	75	75.00	5.67	0.0756	1.0000	6	1
1903	105.5	48	75.00	5.55	0.0740	1.0000	4	1
1902	106.5	12,777	75.00	5.45	0.0727	1.0000	928	170
1901	107.5	4,531	75.00	5.34	0.0711	1.0000	322	60

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 350.40 Land Rights - Transmission Lines

Dispersion: 75 - H5
Procedure: Broad Group

Generation Arrangement

Vintage	Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
	December 31, 2008							
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1900	108.5	13,089	75.00	5.23	0.0698	1.0000	913	175
1899	109.5	1,710	75.00	5.14	0.0686	1.0000	117	23
1898	110.5	2,181	75.00	5.04	0.0672	1.0000	146	29
1897	111.5	1,229	75.00	4.94	0.0659	1.0000	81	16
1890	118.5	915	75.00	4.37	0.0583	1.0000	53	12
1889	119.5	331	75.00	4.29	0.0572	1.0000	19	4
Total	36.7	$27,123,696	75.00	40.53	0.5405	1.0000	$14,659,206	$361,649

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 350.40 Land Rights - Transmission Lines

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2008	0.5	396,553		396,553	1.0000	0.5000
2007	1.5	1		1	1.0000	1.5000
2006	2.5	502		502	1.0000	2.5000
2005	3.5	26,260		26,260	1.0000	3.5000
2004	4.5	4,366		4,366	1.0000	4.5000
2003	5.5	290,937		290,937	1.0000	5.5000
2002	6.5	32,995		32,995	1.0000	6.5000
2001	7.5	66,976		66,976	1.0000	7.5000
2000	8.5	66,094		66,094	1.0000	8.5000
1999	9.5	76,524		76,524	1.0000	9.5000
1998	10.5	84,666		84,666	1.0000	10.5000
1997	11.5	2,983		2,983	1.0000	11.5000
1996	12.5	121,704		121,704	1.0000	12.5000
1995	13.5		554,992	554,992	1.0000	13.5000
1994	14.5		2,756,975	2,756,975	1.0000	14.5000
1993	15.5		208,461	208,461	1.0000	15.5000
1992	16.5		303,175	303,175	1.0000	16.5000
1991	17.5		420,284	420,284	1.0000	17.5000
1990	18.5		324,755	324,755	1.0000	18.5000
1989	19.5		1,072,487	1,072,487	1.0000	19.5000
1988	20.5		93,939	93,939	1.0000	20.5000
1987	21.5		537,089	537,089	1.0000	21.5000
1986	22.5		1,519,934	1,519,934	1.0000	22.5000
1985	23.5		188,935	188,935	1.0000	23.5000
1984	24.5		182,905	182,905	1.0000	24.5000
1983	25.5		194,020	194,020	1.0000	25.5000
1982	26.5		834,305	834,305	1.0000	26.5000
1981	27.5		382,818	382,818	1.0000	27.5000
1980	28.5		110,611	110,611	1.0000	28.5000
1979	29.5		1,495,178	1,495,178	1.0000	29.5000
1978	30.5		773,043	773,043	1.0000	30.5000
1977	31.5		283,737	283,737	1.0000	31.5000
1976	32.5		142,870	142,870	1.0000	32.5000
1975	33.5		348,138	348,138	1.0000	33.5000
1974	34.5		326,154	326,154	1.0000	34.5000
1973	35.5		270,642	270,642	1.0000	35.5000
1972	36.5		248,341	248,341	1.0000	36.5000

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 350.40 Land Rights - Transmission Lines

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1971	37.5		175,252	175,252	1.0000	37.5000
1970	38.5		1,253,496	1,253,496	1.0000	38.5000
1969	39.5		306,170	306,170	1.0000	39.5000
1968	40.5		358,252	358,252	1.0000	40.5000
1967	41.5		494,309	494,155	0.9997	41.4977
1966	42.5		360,696	360,696	1.0000	42.5000
1965	43.5		273,653	273,653	1.0000	43.5000
1964	44.5		438,658	438,658	1.0000	44.5000
1963	45.5		410,512	410,512	1.0000	45.5000
1962	46.5		480,395	480,395	1.0000	46.5000
1961	47.5		737,917	737,917	1.0000	47.5000
1960	48.5		803,314	803,006	0.9996	48.4960
1959	49.5		347,120	347,120	1.0000	49.5000
1958	50.5		1,055,607	1,055,607	1.0000	50.5000
1957	51.5		320,468	320,468	1.0000	51.5000
1956	52.5		337,275	335,275	0.9941	52.4852
1955	53.5		99,899	98,324	0.9842	53.3187
1954	54.5		251,320	250,748	0.9977	54.4936
1953	55.5		273,708	271,498	0.9919	55.4798
1952	56.5		251,748	251,748	1.0000	56.5000
1951	57.5		86,802	86,798	1.0000	57.4996
1950	58.5		98,077	97,990	0.9991	58.4933
1949	59.5		135,372	135,049	0.9976	59.4797
1948	60.5		79,250	94,279	1.1896	62.1157
1947	61.5		27,148	27,148	1.0000	61.5000
1946	62.5		15,147	15,147	1.0000	62.5000
1945	63.5		32,750	32,750	1.0000	63.5000
1944	64.5		20,778	20,778	1.0000	64.5000
1943	65.5		35,495	35,495	1.0000	65.5000
1942	66.5		100,458	100,458	1.0000	66.5000
1941	67.5		73,581	73,581	1.0000	67.5000
1940	68.5		31,656	31,656	1.0000	68.5000
1939	69.5		38,461	38,461	1.0000	69.5000
1938	70.5		89,701	89,701	1.0000	70.5000
1937	71.5		55,588	55,588	1.0000	71.5000
1936	72.5		15,275	15,275	1.0000	72.5000
1935	73.5		31,307	31,307	1.0000	73.5000

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Transmission Plant
Account: 350.40 Land Rights - Transmission Lines

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1934	74.5		34,117	34,117	1.0000	74.5000
1933	75.5		58,376	58,376	1.0000	75.5000
1932	76.5		79,149	79,149	1.0000	76.5000
1931	77.5		90,712	90,712	1.0000	77.5000
1930	78.5		143,210	143,210	1.0000	78.5000
1929	79.5		228,047	228,047	1.0000	79.5000
1928	80.5		149,304	149,304	1.0000	80.5000
1927	81.5		285,854	285,323	0.9981	81.4991
1926	82.5		104,659	104,598	0.9994	82.4933
1925	83.5		394,497	391,960	0.9936	83.4261
1924	84.5		127,674	127,224	0.9965	84.4595
1923	85.5		67,117	67,117	1.0000	85.5000
1922	86.5		137,665	137,665	1.0000	86.5000
1921	87.5		54,000	54,000	1.0000	87.5000
1920	88.5		62,778	62,778	1.0000	88.5000
1919	89.5		14,783	14,783	1.0000	89.5000
1918	90.5		12,926	12,926	1.0000	90.5000
1917	91.5		15,403	15,403	1.0000	91.5000
1916	92.5		20,473	20,473	1.0000	92.5000
1915	93.5		24,822	24,822	1.0000	93.5000
1914	94.5		7,512	7,512	1.0000	94.5000
1913	95.5		35,238	35,238	1.0000	95.5000
1912	96.5		26,542	26,542	1.0000	96.5000
1911	97.5		19,442	19,442	1.0000	97.5000
1910	98.5		22,559	22,559	1.0000	98.5000
1909	99.5		3,846	3,846	1.0000	99.5000
1908	100.5		14,079	14,079	1.0000	100.5000
1907	101.5		73,146	73,146	1.0000	101.5000
1906	102.5		12,016	12,016	1.0000	102.5000
1905	103.5		21,684	21,684	1.0000	103.5000
1904	104.5		75	75	1.0000	104.5000
1903	105.5		48	48	1.0000	105.5000
1902	106.5		12,777	12,777	1.0000	106.5000
1901	107.5		4,531	4,531	1.0000	107.5000
1900	108.5		13,089	13,089	1.0000	108.5000
1899	109.5		1,710	1,710	1.0000	109.5000
1898	110.5		2,181	2,181	1.0000	110.5000

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Transmission Plant
Account: 350.40 Land Rights - Transmission Lines

Age Distribution

				Experience to 12/31/2008		
Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1897	111.5		1,229	1,229	1.0000	111.5000
1890	118.5		915	915	1.0000	118.5000
1889	119.5		331	331	1.0000	119.5000
Total	36.7	$1,170,560	$25,948,919	$27,123,696	1.0002	

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 350.40 Land Rights - Transmission Lines

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996		26,366,963		(568)	26,366,395
1997	26,366,395	931,626	4,619	(145,656)	27,147,747
1998	27,147,747	457	330	(39,141)	27,108,733
1999	27,108,733	1,339,808	4	(1,221,177)	27,227,360
2000	27,227,360	2,004,014	(15,005)	(2,917,628)	26,328,750
2001	26,328,750	223,263	543	(225,655)	26,325,815
2002	26,325,815	70,543			26,396,358
2003	26,396,358	266,830			26,663,187
2004	26,663,187	20,648			26,683,835
2005	26,683,835	20,255			26,704,090
2006	26,704,090	182,657	4,760		26,881,987
2007	26,881,987	11,191			26,893,178
2008	26,893,178	230,548	531	501	27,123,696

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Transmission Plant
Account: 350.40 Land Rights - Transmission Lines

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996	30,411,600	199,939		(568)	30,610,970
1997	30,610,970	11,499	4,619	(145,656)	30,472,195
1998	30,472,195	84,666	330	(39,141)	30,517,389
1999	30,517,389	76,524	4	(1,221,177)	29,372,733
2000	29,372,733	66,487	(15,005)	(2,917,628)	26,536,596
2001	26,536,596	66,976	543	(225,655)	26,377,373
2002	26,377,373	32,995			26,410,368
2003	26,410,368	290,937			26,701,305
2004	26,701,305	4,366			26,705,671
2005	26,705,671	26,260			26,731,931
2006	26,731,931	2	4,760		26,727,173
2007	26,727,173				26,727,173
2008	26,727,173	396,553	531	501	27,123,696

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 350.40 Land Rights - Transmission Lines

T-Cut: None
Placement Band: 1889-2008
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2000	99.8	195.8	S6 *	6.61	194.1	S6 *	6.64	197.6	S6 *	6.61
1997-2001	99.8	195.7	S6 *	4.04	194.6	S6 *	4.07	197.6	S6 *	4.03
1998-2002	99.9	198.5	SQ *	3.10	198.8	SQ *	3.08	198.8	SQ *	3.10
1999-2003	99.9	198.7	SQ *	2.60	198.9	SQ *	2.59	198.8	SQ *	2.60
2000-2004	99.9	198.7	SQ *	1.71	198.9	SQ *	1.71	198.9	SQ *	1.72
2001-2005	99.9	198.8	SQ *	0.02	198.9	SQ *	0.01	198.9	SQ *	0.01
2002-2006	99.5	197.2	SQ *	0.17	198.3	SQ *	0.09	198.2	SQ *	0.10
2003-2007	99.6	197.3	SQ *	0.17	198.3	SQ *	0.08	198.2	SQ *	0.10
2004-2008	99.6	197.0	SQ *	0.20	198.2	SQ *	0.11	198.1	SQ *	0.14

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 350.40 Land Rights - Transmission Lines

T-Cut: None

Placement Band: 1889-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2008	99.9	197.1	SQ *	0.71	197.4	SQ *	0.70	198.2	SQ *	0.68
1998-2008	99.9	197.9	SQ *	0.67	198.5	SQ *	0.64	198.5	SQ *	0.66
2000-2008	99.9	197.8	SQ *	0.71	198.5	SQ *	0.68	198.4	SQ *	0.70
2002-2008	99.7	197.5	S6 *	0.14	198.4	SQ *	0.07	198.3	SQ *	0.09
2004-2008	99.6	197.0	SQ *	0.20	198.2	SQ *	0.11	198.1	SQ *	0.14
2006-2008	99.4	195.9	S6 *	0.35	197.7	SQ *	0.19	197.6	S6 *	0.26
2008-2008	99.8	197.2	SQ *	0.26	195.4	SQ *	0.35	197.8	SQ *	0.35

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 350.40 Land Rights - Transmission Lines

T-Cut: None

Placement Band: 1889-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-1997	98.8	191.4	R5 *	0.74	185.2	R4 *	1.01	195.1	SQ *	0.81
1996-1999	99.5	195.1	SQ *	0.44	192.6	R5 *	0.55	197.2	SQ *	0.43
1996-2001	99.8	196.2	SQ *	3.74	195.1	S6 *	3.77	197.8	SQ *	3.73
1996-2003	99.9	197.0	SQ *	2.42	196.4	SQ *	2.43	198.1	SQ *	2.41
1996-2005	99.9	197.5	SQ *	1.23	197.1	SQ *	1.24	198.3	SQ *	1.22
1996-2007	99.8	197.1	SQ *	0.85	197.6	S6 *	0.83	198.2	SQ *	0.82
1996-2008	99.9	197.1	SQ *	0.71	197.4	SQ *	0.70	198.2	SQ *	0.68

Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 350.40 Land Rights - Transmission Lines

T-Cut: None

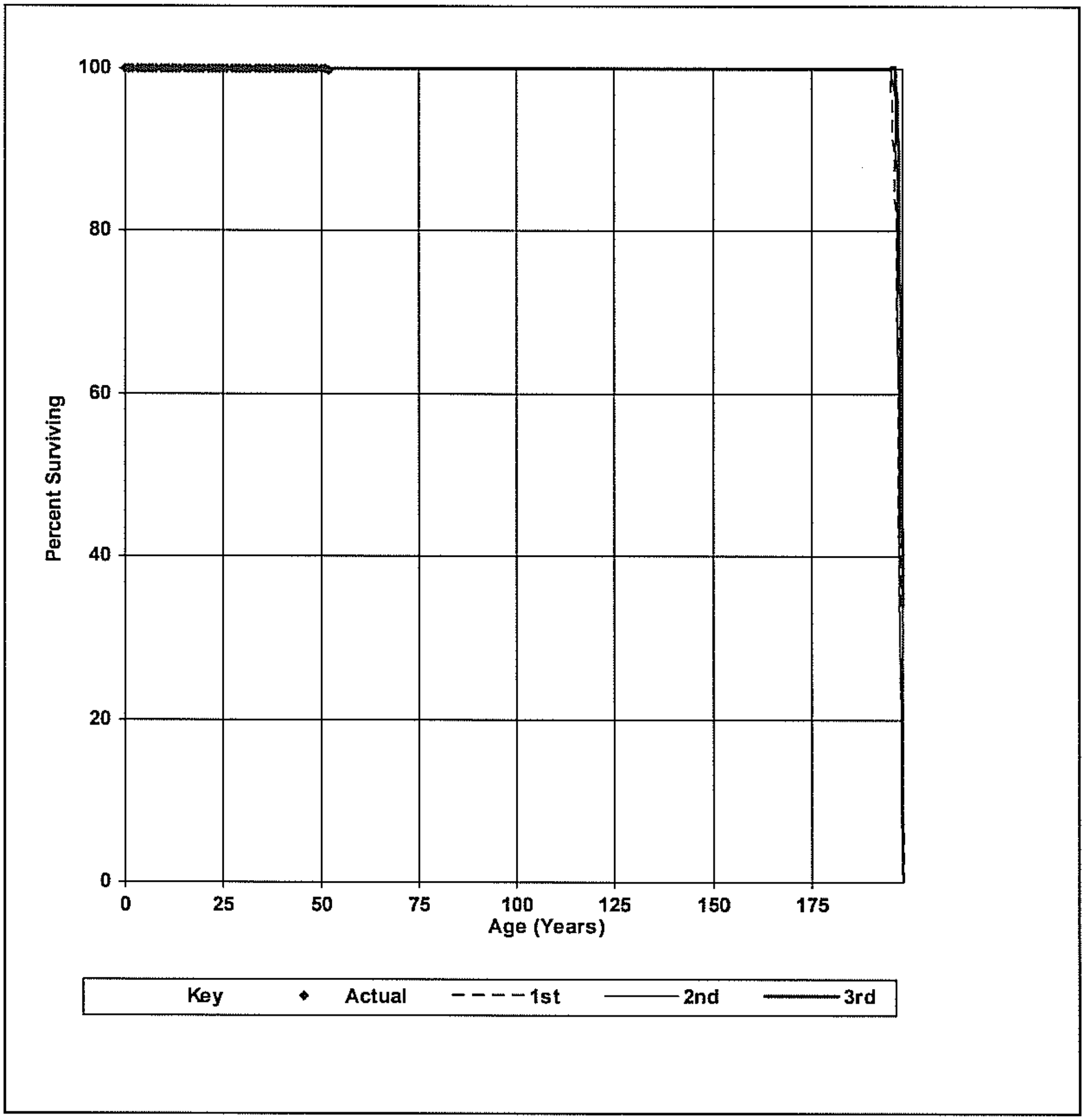
Placement Band: 1889-2008 Observation Band: 1996-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 197.1-SQ 2nd: 197.4-SQ 3rd: 198.2-SQ



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 350.40 Land Rights - Transmission Lines

T-Cut: None

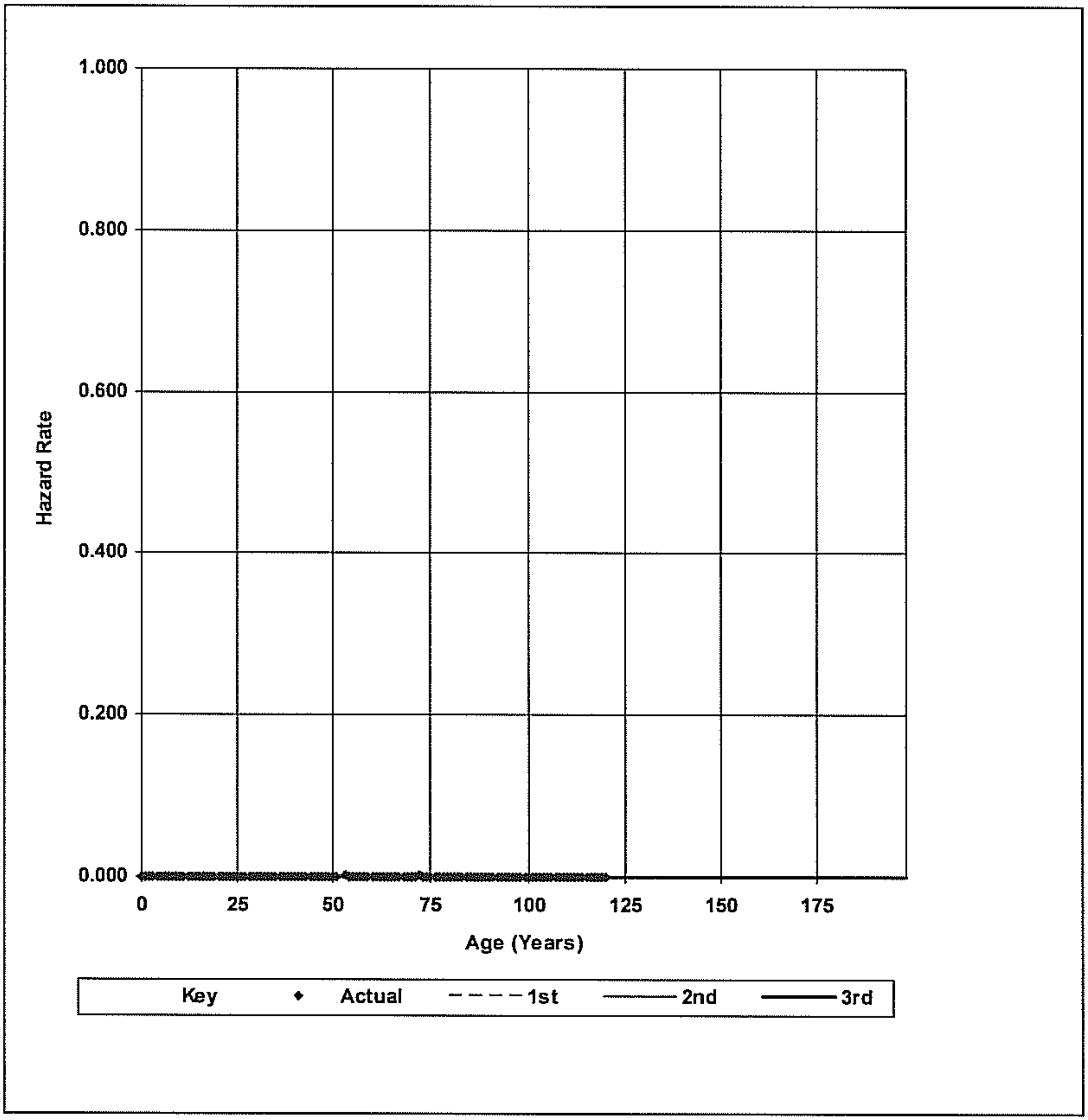
Placement Band: 1889-2008 Observation Band: 1996-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 197.1-SQ 2nd: 197.4-SQ 3rd: 198.2-SQ

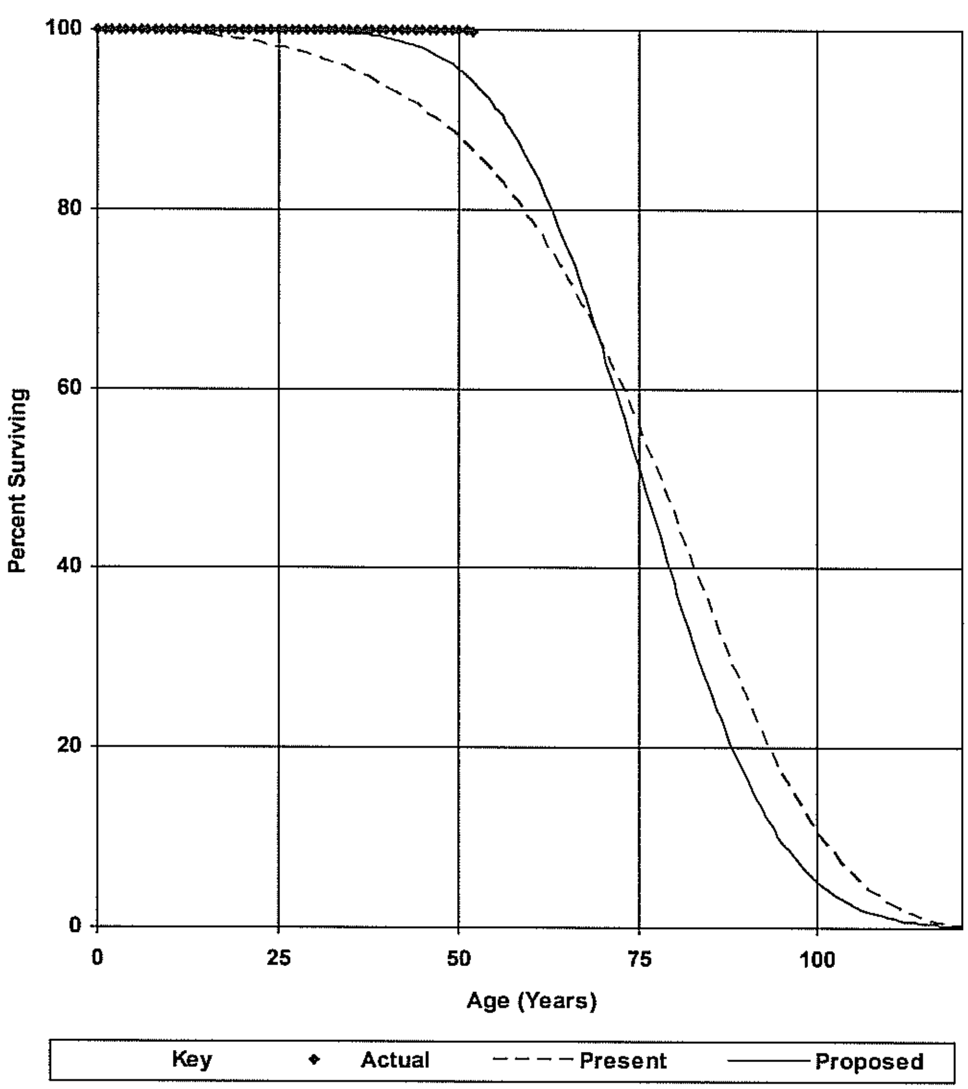


Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Transmission Plant
Account: 350.40 Land Rights - Transmission Lines

T-Cut: None
Placement Band: 1889-2008
Observation Band: 1996-2008

Present and Proposed Projection Life Curves Present: 75.0-R3 Proposed: 75.0-H5



Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 350.40 Land Rights - Transmission Lines

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998	330	30,001	9084.0		1,481	448.3		28,520	8635.7	
1999	4	86,874	3257.6		25,828	3954.5		61,046	9303.1	
2000	(15,005)	48,247	-321.5		8,445	-56.3		39,803	-265.3	
2001	543	23,925	4402.5		5,173	951.8		18,753	3450.7	
2002		60,764	0.0	0.0	16,518	0.0	0.0	44,247	0.0	0.0
2003		70,594	0.0	0.0	17,443	0.0	0.0	53,151	0.0	0.0
2004			0.0	0.0		0.0	0.0		0.0	0.0
2005			0.0	!8573.7	3,627	0.0	7868.3	(3,627)	0.0	0705.3
2006	4,760		0.0	2759.8	(9,404)	-197.6	592.1	9,404	197.6	2167.6
2007			0.0	1483.1		0.0	245.1		0.0	1238.0
2008	531		0.0	0.0	(12,938)	2437.0	-353.7	12,938	2437.0	353.7
Total	(8,836)	320,406	3625.9		56,171	-635.7		264,235	2990.3	

Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 350.40 Land Rights - Transmission Lines

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998	330	30,001	9084.0		1,481	448.3		28,520	8635.7	
1999	4	86,874	3257.6		25,828	3954.5		61,046	9303.1	
2000	(15,005)	48,247	-321.5		8,445	-56.3		39,803	-265.3	
2001	543	23,925	4402.5		5,173	951.8		18,753	3450.7	
2002		60,764	0.0	0.0	16,518	0.0	0.0	44,247	0.0	0.0
2003		70,594	0.0	0.0	17,443	0.0	0.0	53,151	0.0	0.0
2004			0.0	0.0		0.0	0.0		0.0	0.0
2005			0.0	:8573.7	3,627	0.0	7868.3	(3,627)	0.0	0705.3
2006	4,760		0.0	2759.8	(9,404)	-197.6	592.1	9,404	197.6	2167.6
2007			0.0	1483.1		0.0	245.1		0.0	1238.0
2008	531		0.0	0.0	(12,938)	2437.0	-353.7	12,938	2437.0	353.7
Total	(8,836)	320,406	3625.9		56,171	-635.7		264,235	2990.3	

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 352.00 Structrues and Improvements

Dispersion: 65 - H3
Procedure: Broad Group

Generation Arrangement

	December 31, 2008				Net			
Vintage	Age	Surviving Plant	Avg. Life	Rem. Life	Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2008	0.5	168,086	65.00	64.51	0.9924	1.0000	166,811	2,586
2007	1.5	600,199	65.00	63.52	0.9773	1.0000	586,552	9,234
2006	2.5	1,294,580	65.00	62.54	0.9621	1.0000	1,245,566	19,917
2005	3.5	352,635	65.00	61.56	0.9470	1.0000	333,963	5,425
2004	4.5	952,555	65.00	60.58	0.9320	1.0000	887,776	14,655
2003	5.5	57,907	65.00	59.60	0.9170	1.0000	53,100	891
2002	6.5	441,582	65.00	58.63	0.9020	1.0000	398,309	6,794
2001	7.5	600,053	65.00	57.66	0.8871	1.0000	532,298	9,232
2000	8.5	377,652	65.00	56.69	0.8722	1.0000	329,394	5,810
1999	9.5	262,462	65.00	55.73	0.8574	1.0000	225,035	4,038
1998	10.5	204,377	65.00	54.77	0.8426	1.0000	172,216	3,144
1997	11.5	639,110	65.00	53.82	0.8280	1.0000	529,157	9,832
1996	12.5	200,795	65.00	52.87	0.8133	1.0000	163,314	3,089
1995	13.5	618,339	65.00	51.92	0.7988	1.0000	493,930	9,513
1994	14.5	2,120,563	65.00	50.98	0.7843	1.0000	1,663,244	32,624
1993	15.5	2,667,741	65.00	50.05	0.7700	1.0000	2,054,075	41,042
1992	16.5	2,547,556	65.00	49.12	0.7557	1.0000	1,925,161	39,193
1991	17.5	1,154,774	65.00	48.20	0.7415	1.0000	856,274	17,766
1990	18.5	336,939	65.00	47.28	0.7274	1.0000	245,104	5,184
1989	19.5	210,666	65.00	46.38	0.7135	1.0000	150,304	3,241
1988	20.5	1,074,127	65.00	45.48	0.6996	1.0000	751,498	16,525
1987	21.5	1,476,510	65.00	44.58	0.6859	1.0000	1,012,757	22,716
1986	22.5	251,031	65.00	43.70	0.6723	1.0000	168,775	3,862
1985	23.5	96,071	65.00	42.83	0.6589	1.0000	63,298	1,478
1984	24.5	301,654	65.00	41.96	0.6456	1.0000	194,738	4,641
1983	25.5	239,309	65.00	41.11	0.6324	1.0000	151,339	3,682
1982	26.5	516,710	65.00	40.26	0.6194	1.0000	320,049	7,949
1981	27.5	991,503	65.00	39.43	0.6066	1.0000	601,397	15,254
1980	28.5	285,825	65.00	38.60	0.5939	1.0000	169,742	4,397
1979	29.5	1,062,168	65.00	37.79	0.5814	1.0000	617,506	16,341
1978	30.5	315,910	65.00	36.99	0.5690	1.0000	179,759	4,860
1977	31.5	360,486	65.00	36.20	0.5569	1.0000	200,744	5,546
1976	32.5	87,440	65.00	35.42	0.5449	1.0000	47,645	1,345
1975	33.5	112,144	65.00	34.65	0.5331	1.0000	59,787	1,725
1974	34.5	1,175,939	65.00	33.90	0.5215	1.0000	613,287	18,091
1973	35.5	230,567	65.00	33.16	0.5101	1.0000	117,623	3,547

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 352.00 Structrues and Improvements

Dispersion: 65 - H3
Procedure: Broad Group

Generation Arrangement

Vintage	Age (December 31, 2008)	Surviving Plant (December 31, 2008)	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1972	36.5	246,270	65.00	32.43	0.4989	1.0000	122,876	3,789
1971	37.5	343,302	65.00	31.72	0.4880	1.0000	167,518	5,282
1970	38.5	72,378	65.00	31.02	0.4772	1.0000	34,537	1,114
1969	39.5	193,241	65.00	30.33	0.4666	1.0000	90,165	2,973
1968	40.5	417,316	65.00	29.65	0.4562	1.0000	190,390	6,420
1967	41.5	64,034	65.00	28.99	0.4461	1.0000	28,562	985
1966	42.5	75,418	65.00	28.35	0.4361	1.0000	32,890	1,160
1965	43.5	207,232	65.00	27.71	0.4264	1.0000	88,355	3,188
1964	44.5	32,439	65.00	27.09	0.4168	1.0000	13,522	499
1963	45.5	186,083	65.00	26.49	0.4075	1.0000	75,829	2,863
1962	46.5	182,122	65.00	25.90	0.3984	1.0000	72,557	2,802
1961	47.5	568,749	65.00	25.32	0.3895	1.0000	221,520	8,750
1960	48.5	204,987	65.00	24.75	0.3808	1.0000	78,058	3,154
1959	49.5	289,400	65.00	24.20	0.3723	1.0000	107,743	4,452
1958	50.5	471,530	65.00	23.66	0.3640	1.0000	171,643	7,254
1957	51.5	298,527	65.00	23.14	0.3559	1.0000	106,253	4,593
1956	52.5	196,144	65.00	22.62	0.3480	1.0000	68,266	3,018
1955	53.5	59,090	65.00	22.12	0.3404	1.0000	20,111	909
1954	54.5	253,949	65.00	21.64	0.3329	1.0000	84,528	3,907
1953	55.5	61,288	65.00	21.16	0.3256	1.0000	19,953	943
1952	56.5	71,062	65.00	20.70	0.3184	1.0000	22,628	1,093
1951	57.5	31,762	65.00	20.25	0.3115	1.0000	9,894	489
1950	58.5	12,900	65.00	19.81	0.3048	1.0000	3,931	198
1949	59.5	30,481	65.00	19.38	0.2982	1.0000	9,089	469
1948	60.5	39,885	65.00	18.97	0.2918	1.0000	11,638	614
1947	61.5	5,417	65.00	18.56	0.2856	1.0000	1,547	83
1946	62.5	1,609	65.00	18.17	0.2795	1.0000	450	25
1945	63.5	11,326	65.00	17.79	0.2736	1.0000	3,099	174
1944	64.5	18,955	65.00	17.41	0.2679	1.0000	5,078	292
1943	65.5	29,073	65.00	17.05	0.2623	1.0000	7,627	447
1942	66.5	27,173	65.00	16.70	0.2569	1.0000	6,981	418
1941	67.5	41,235	65.00	16.36	0.2516	1.0000	10,376	634
1940	68.5	21,949	65.00	16.02	0.2465	1.0000	5,410	338
1939	69.5	35,780	65.00	15.70	0.2415	1.0000	8,642	550
1938	70.5	167,347	65.00	15.38	0.2367	1.0000	39,605	2,575
1937	71.5	6,184	65.00	15.08	0.2320	1.0000	1,434	95

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 352.00 Structrues and Improvements

Dispersion: 65 - H3
Procedure: Broad Group

Generation Arrangement

Vintage	Age	December 31, 2008 Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1936	72.5	2,160	65.00	14.78	0.2274	1.0000	491	33
1935	73.5	3,146	65.00	14.49	0.2229	1.0000	701	48
1934	74.5	7,856	65.00	14.21	0.2186	1.0000	1,717	121
1933	75.5	101,872	65.00	13.93	0.2144	1.0000	21,839	1,567
1932	76.5	12,229	65.00	13.67	0.2103	1.0000	2,571	188
1931	77.5	41,957	65.00	13.41	0.2063	1.0000	8,655	645
1930	78.5	46,209	65.00	13.16	0.2024	1.0000	9,354	711
1929	79.5	28,052	65.00	12.91	0.1986	1.0000	5,572	432
1928	80.5	143,394	65.00	12.67	0.1950	1.0000	27,960	2,206
1927	81.5	51,865	65.00	12.44	0.1914	1.0000	9,927	798
1926	82.5	269,835	65.00	12.22	0.1880	1.0000	50,718	4,151
1925	83.5	197,510	65.00	12.00	0.1846	1.0000	36,454	3,039
1924	84.5	163,313	65.00	11.79	0.1813	1.0000	29,611	2,513
1923	85.5	43,242	65.00	11.58	0.1781	1.0000	7,702	665
1922	86.5	30,159	65.00	11.38	0.1750	1.0000	5,278	464
1921	87.5	17,187	65.00	11.18	0.1720	1.0000	2,956	264
1920	88.5	234,149	65.00	10.99	0.1690	1.0000	39,581	3,602
1918	90.5	313	65.00	10.62	0.1634	1.0000	51	5
1917	91.5	4,605	65.00	10.44	0.1607	1.0000	740	71
1916	92.5	6,476	65.00	10.27	0.1580	1.0000	1,023	100
1915	93.5	104,689	65.00	10.10	0.1555	1.0000	16,274	1,611
1913	95.5	1,597	65.00	9.78	0.1505	1.0000	240	25
1912	96.5	11,110	65.00	9.63	0.1481	1.0000	1,645	171
1911	97.5	5,862	65.00	9.48	0.1458	1.0000	855	90
1910	98.5	598	65.00	9.33	0.1435	1.0000	86	9
1909	99.5	4,756	65.00	9.19	0.1414	1.0000	672	73
1908	100.5	15,622	65.00	9.05	0.1392	1.0000	2,174	240
1907	101.5	32,814	65.00	8.91	0.1371	1.0000	4,499	505
1906	102.5	37,016	65.00	8.78	0.1350	1.0000	4,998	569
1883	125.5	23,380	65.00	6.45	0.0992	1.0000	2,319	360
Total	25.8	$31,004,576	65.00	43.02	0.6619	1.0000	$20,520,896	$476,993

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 352.00 Structrues and Improvements

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2008	0.5	168,086		168,086	1.0000	0.5000
2007	1.5	600,199		600,199	1.0000	1.5000
2006	2.5	1,294,580		1,294,580	1.0000	2.5000
2005	3.5	352,635		352,635	1.0000	3.5000
2004	4.5	952,555		952,555	1.0000	4.5000
2003	5.5	57,907		57,907	1.0000	5.5000
2002	6.5	441,582		441,582	1.0000	6.5000
2001	7.5	600,053		600,053	1.0000	7.5000
2000	8.5	377,652		377,652	1.0000	8.5000
1999	9.5	262,462		262,462	1.0000	9.5000
1998	10.5	204,377		204,377	1.0000	10.5000
1997	11.5	639,725		639,110	0.9990	11.4938
1996	12.5	201,166		200,795	0.9982	12.4806
1995	13.5		629,437	618,339	0.9824	13.3533
1994	14.5		2,120,563	2,120,563	1.0000	14.5000
1993	15.5		3,209,459	2,667,741	0.8312	14.6158
1992	16.5		2,618,030	2,547,556	0.9731	16.4588
1991	17.5		1,155,157	1,154,774	0.9997	17.4965
1990	18.5		338,439	336,939	0.9956	18.4978
1989	19.5		588,663	210,666	0.3579	17.2429
1988	20.5		1,074,127	1,074,127	1.0000	20.5000
1987	21.5		1,476,510	1,476,510	1.0000	21.5000
1986	22.5		305,864	251,031	0.8207	21.9462
1985	23.5		97,848	96,071	0.9818	23.3093
1984	24.5		337,546	301,654	0.8937	23.2772
1983	25.5		266,577	239,309	0.8977	24.8351
1982	26.5		516,710	516,710	1.0000	26.5000
1981	27.5		995,403	991,503	0.9961	27.4980
1980	28.5		285,825	285,825	1.0000	28.5000
1979	29.5		1,064,173	1,062,168	0.9981	29.4840
1978	30.5		320,910	315,910	0.9844	30.4143
1977	31.5		376,819	360,486	0.9567	31.2579
1976	32.5		136,083	87,440	0.6426	30.1766
1975	33.5		117,257	112,144	0.9564	33.2166
1974	34.5		1,277,182	1,175,939	0.9207	34.0852
1973	35.5		242,998	230,567	0.9488	35.3854
1972	36.5		247,559	246,270	0.9948	36.4609

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 352.00 Structrues and Improvements

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1971	37.5		343,342	343,302	0.9999	37.4990
1970	38.5		76,204	72,378	0.9498	38.0733
1969	39.5		204,323	193,241	0.9458	39.3993
1968	40.5		421,264	417,316	0.9906	40.4277
1967	41.5		66,060	64,034	0.9693	41.2575
1966	42.5		75,418	75,418	1.0000	42.5000
1965	43.5		207,627	207,232	0.9981	43.4835
1964	44.5		34,181	32,439	0.9490	44.1688
1963	45.5		190,552	186,083	0.9765	45.3990
1962	46.5		201,943	182,122	0.9018	45.9264
1961	47.5		931,317	568,749	0.6107	47.1660
1960	48.5		205,394	204,987	0.9980	48.4832
1959	49.5		292,336	289,400	0.9900	49.4642
1958	50.5		480,214	471,530	0.9819	50.3893
1957	51.5		329,919	298,527	0.9048	51.1776
1956	52.5		206,088	196,144	0.9518	52.1377
1955	53.5		60,293	59,090	0.9800	53.4302
1954	54.5		271,934	253,949	0.9339	54.0562
1953	55.5		70,249	61,288	0.8724	55.2518
1952	56.5		72,628	71,062	0.9784	56.3699
1951	57.5		35,037	31,762	0.9065	56.7656
1950	58.5		23,114	12,900	0.5581	55.4206
1949	59.5		32,364	30,481	0.9418	59.0373
1948	60.5		41,298	39,885	0.9658	60.1065
1947	61.5		8,583	5,417	0.6311	59.3807
1946	62.5		1,609	1,609	1.0000	62.5000
1945	63.5		11,539	11,326	0.9816	63.3434
1944	64.5		22,063	18,955	0.8592	63.3026
1943	65.5		38,752	29,073	0.7502	63.3992
1942	66.5		33,645	27,173	0.8076	64.9684
1941	67.5		44,323	41,235	0.9303	67.1617
1940	68.5		28,096	21,949	0.7812	67.6758
1939	69.5		37,284	35,780	0.9597	69.4450
1938	70.5		173,971	167,347	0.9619	70.2751
1937	71.5		6,658	6,184	0.9288	71.2510
1936	72.5		2,236	2,160	0.9659	72.2592
1935	73.5		3,163	3,146	0.9947	73.4974

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 352.00 Structrues and Improvements

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1934	74.5		7,891	7,856	0.9956	74.4713
1933	75.5		106,767	101,872	0.9542	75.1561
1932	76.5		19,695	12,229	0.6209	74.8505
1931	77.5		60,233	41,957	0.6966	75.4685
1930	78.5		50,864	46,209	0.9085	78.2472
1929	79.5		61,531	28,052	0.4559	77.5535
1928	80.5		169,292	143,394	0.8470	79.3613
1927	81.5		88,796	51,865	0.5841	78.7620
1926	82.5		273,538	269,835	0.9865	82.3934
1925	83.5		271,154	197,510	0.7284	82.5503
1924	84.5		230,260	163,313	0.7093	82.0823
1923	85.5		47,355	43,242	0.9132	84.6749
1922	86.5		30,159	30,159	1.0000	86.5000
1921	87.5		17,399	17,187	0.9878	87.3839
1920	88.5		258,446	234,149	0.9060	87.6713
1918	90.5		552	313	0.5673	87.6878
1917	91.5		5,715	4,605	0.8058	89.4610
1916	92.5		36,042	6,476	0.1797	87.1862
1915	93.5		104,815	104,689	0.9988	93.4922
1913	95.5		1,597	1,597	1.0000	95.5000
1912	96.5		11,757	11,110	0.9450	96.4174
1911	97.5		5,912	5,862	0.9915	97.4704
1910	98.5		598	598	1.0000	98.5000
1909	99.5		4,809	4,756	0.9888	99.4275
1908	100.5		27,704	15,622	0.5639	97.6648
1907	101.5		90,572	32,814	0.3623	99.0946
1906	102.5		37,016	37,016	1.0000	102.5000
1903	105.5		2,000		0.0000	104.0000
1896	112.5		74,416		0.0000	103.0000
1883	125.5		23,380	23,380	1.0000	125.5000
Total	25.8	$6,152,981	$27,204,423	$31,004,576	0.9295	

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 352.00 Structrues and Improvements

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996		24,661,198		(514,878)	24,146,320
1997	24,146,320	2,494,933	50,370	(59,495)	26,531,387
1998	26,531,387	5,445	11,377		26,525,456
1999	26,525,456	2,006,103	95,580	(473,704)	27,962,276
2000	27,962,276	590,980	161,359		28,391,896
2001	28,391,896	584,567	16,104		28,960,359
2002	28,960,359	833,589	628,051		29,165,897
2003	29,165,897	(5,853)	25,000		29,135,044
2004	29,135,044	713,105			29,848,149
2005	29,848,149	455,020	819,888	(89,722)	29,393,559
2006	29,393,559	299,949	4,443		29,689,065
2007	29,689,065	899,036	164,110		30,423,991
2008	30,423,991	962,322	376,547	(5,190)	31,004,576

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 352.00 Structrues and Improvements

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996	28,199,235	205,742		(514,878)	27,890,099
1997	27,890,099	639,725	50,370	(59,495)	28,419,959
1998	28,419,959	253,066	11,377		28,661,648
1999	28,661,648	262,462	95,580	(473,704)	28,354,827
2000	28,354,827	377,652	161,359		28,571,120
2001	28,571,120	600,053	16,104		29,155,069
2002	29,155,069	441,582	628,051		28,968,600
2003	28,968,600	57,907	25,000		29,001,507
2004	29,001,507	1,076,030			30,077,537
2005	30,077,537	324,073	819,888	(89,722)	29,492,000
2006	29,492,000	1,294,580	4,443		30,782,137
2007	30,782,137	600,199	164,110		31,218,226
2008	31,218,226	168,086	376,547	(5,190)	31,004,576

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 352.00 Structrues and Improvements

T-Cut: None

Placement Band: 1963-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper- sion	Conf. Index	Average Life	Disper- sion	Conf. Index	Average Life	Disper- sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2000	97.0	171.9	R2.5	0.66	195.2	SQ *	0.62	70.1	R4 *	0.56
1997-2001	97.5	176.8	R3	0.33	195.3	SQ *	0.33	73.5	R4 *	0.29
1998-2002	86.3	101.7	L0	2.89	167.6	R1 *	2.63	53.6	R2.5 *	2.27
1999-2003	87.2	115.2	SC	3.12	167.8	R1 *	2.80	60.8	R2.5	2.52
2000-2004	87.4	137.8	SC	2.91	168.1	R1.5 *	2.59	73.5	R2	2.47
2001-2005	72.4	97.4	O3	4.41	148.5	SC *	1.83	52.6	R1.5 *	1.70
2002-2006	74.6	123.1	SC *	5.21	148.6	SC *	2.52	52.7	R1.5 *	1.73
2003-2007	83.9	134.7	SC *	5.06	163.9	R1 *	3.09	55.6	R2.5 *	2.51
2004-2008	83.5	141.6	SC *	5.58	163.1	R1 *	3.54	54.9	R2.5 *	3.00

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 352.00 Structrues and Improvements

T-Cut: None

Placement Band: 1963-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2008	84.9	112.4	SC	2.08	172.4	R2 *	1.03	59.4	R3 *	0.84
1998-2008	83.6	118.6	SC	2.31	169.9	R1.5 *	1.07	59.2	R2.5 *	0.80
2000-2008	81.9	128.5	SC	3.21	164.9	R1 *	1.62	57.8	R2.5 *	1.10
2002-2008	79.2	135.5	SC *	4.46	157.5	R0.5 *	2.55	54.7	R2 *	1.70
2004-2008	83.5	141.6	SC *	5.58	163.1	R1 *	3.54	54.9	R2.5 *	3.00
2006-2008	93.1	144.4	R1	0.81	187.0	R4 *	0.59	75.5	R3 *	0.62
2008-2008	91.8	144.1	R1 *	2.94	189.9	R5 *	2.81	191.0	R5 *	2.81

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 352.00 Structrues and Improvements

T-Cut: None

Placement Band: 1963-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-1997	93.9	154.8	R1.5	3.04	192.4	SQ *	2.43	63.3	R4 *	2.33
1996-1999	95.7	175.0	R2.5	2.12	195.6	S6 *	1.91	69.9	R4 *	1.88
1996-2001	97.7	177.6	R3	0.33	195.8	SQ *	0.33	75.1	R4 *	0.29
1996-2003	89.3	115.6	S-.5	1.58	178.3	R3 *	1.37	57.8	R3 *	1.30
1996-2005	82.2	91.2	L0	2.24	167.2	R1 *	1.15	56.3	R2.5 *	0.99
1996-2007	84.1	105.3	SC	2.07	170.7	R1.5 *	1.08	57.7	R2.5 *	0.89
1996-2008	84.9	112.4	SC	2.08	172.4	R2 *	1.03	59.4	R3 *	0.84

Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 352.00 Structrues and Improvements

T-Cut: None

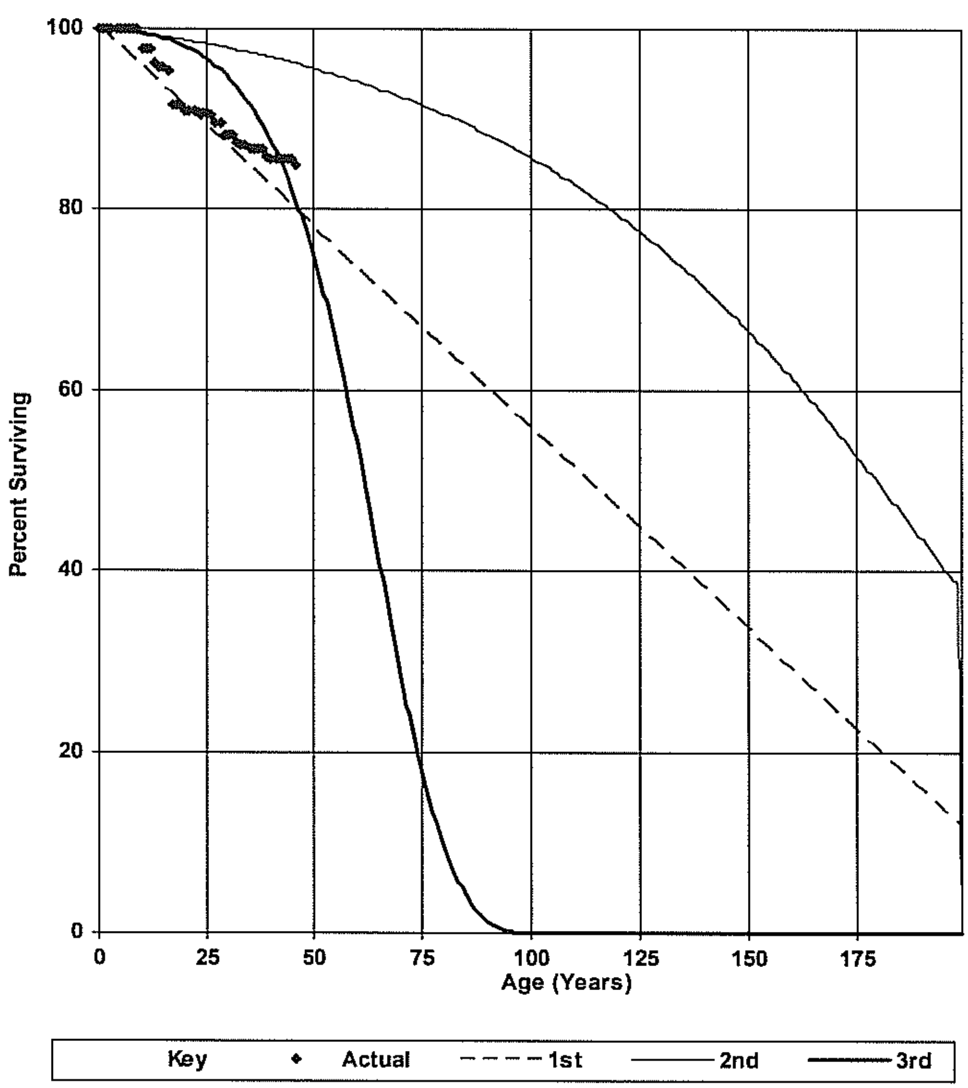
Placement Band: 1963-2008 Observation Band: 1996-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 112.4-SC 2nd: 172.4-R2 3rd: 59.4-R3



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 352.00 Structrues and Improvements

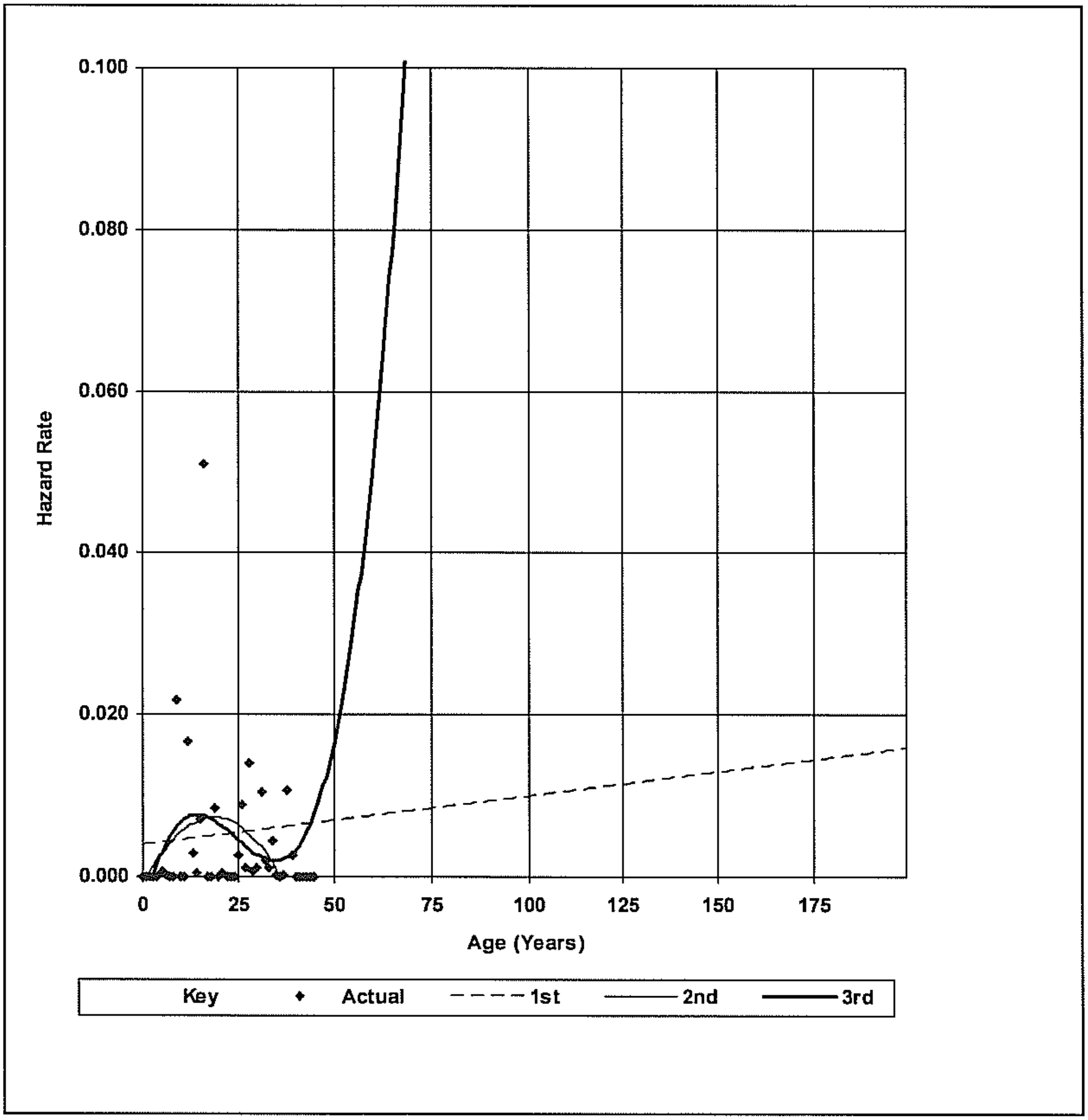
T-Cut: None

Placement Band: 1963-2007 Observation Band: 1996-2007

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function 1st: 105.3-SC 2nd: 170.7-R1.5 3rd: 57.7-R2.5



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

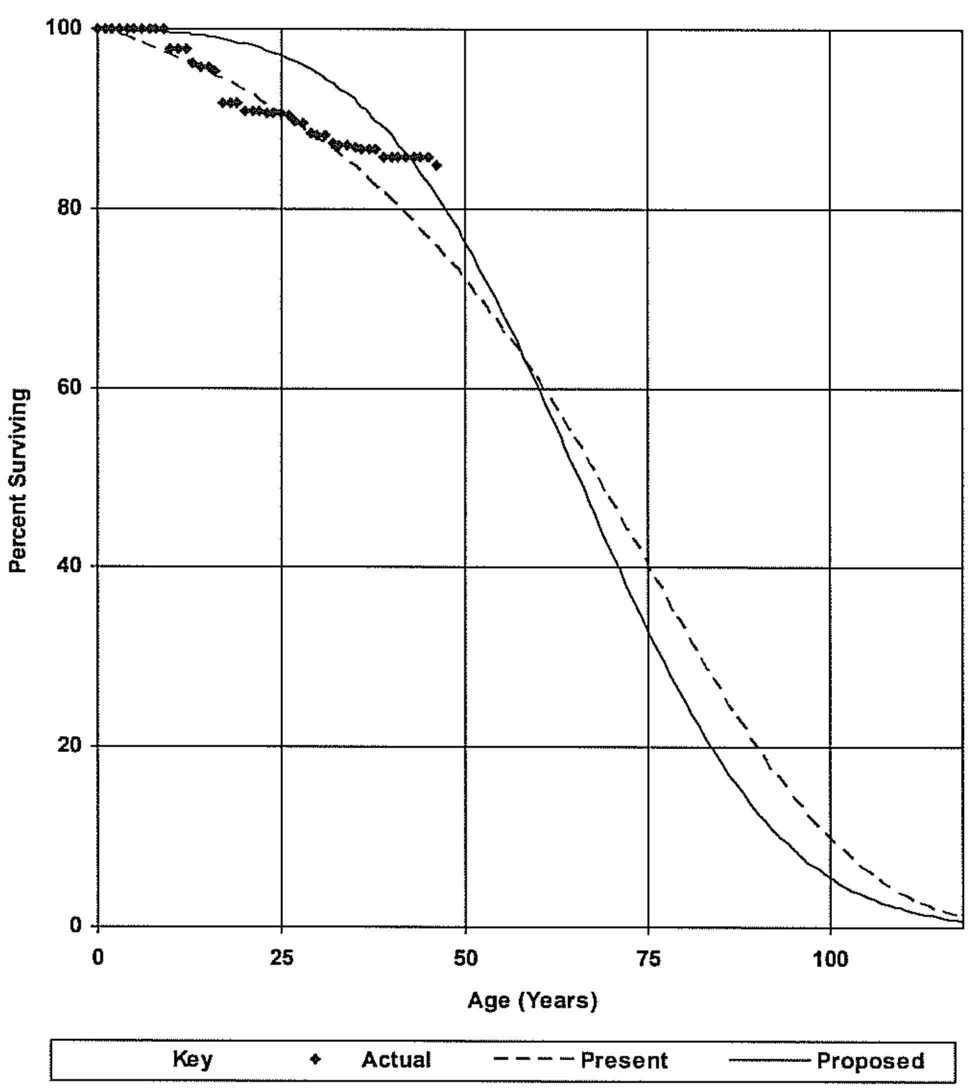
Account: 352.00 Structrues and Improvements

T-Cut: None

Placement Band: 1963-2008

Observation Band: 1996-2008

Present and Proposed Projection Life Curves **Present: 65.0-R1.5** **Proposed: 65.0-H3**



Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 352.00 Structrues and Improvements

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998	11,377		0.0		56,600	497.5		(56,600)	-497.5	
1999	95,580	44,231	46.3		104,161	109.0		(59,930)	-62.7	
2000	161,359	76,311	47.3		34,041	21.1		42,270	26.2	
2001	16,104		0.0		676,457	4200.5		(676,457)	4200.5	
2002	628,051		0.0	13.2	78,813	12.5	104.1	(78,813)	-12.5	-90.9
2003	25,000		0.0	13.0	32,079	128.3	99.9	(32,079)	-128.3	-86.9
2004			0.0	9.2	73,804	0.0	107.8	(73,804)	0.0	-98.6
2005	819,888		0.0	0.0	967	0.1	57.9	(967)	-0.1	-57.9
2006	4,443		0.0	0.0	23,055	518.9	14.1	(23,055)	-518.9	-14.1
2007	164,110		0.0	0.0	169,155	103.1	29.5	(169,155)	-103.1	-29.5
2008	376,547		0.0	0.0	588,646	156.3	62.7	(588,646)	-156.3	-62.7
Total	2,302,459	120,542	5.2		1,837,778	79.8		(1,717,236)	-74.6	

Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 352.00 Structrues and Improvements

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998	11,377		0.0		56,600	497.5		(56,600)	-497.5	
1999	95,580	44,231	46.3		104,161	109.0		(59,930)	-62.7	
2000	161,359	76,311	47.3		34,041	21.1		42,270	26.2	
2001	16,104		0.0		676,457	4200.5		(676,457)	4200.5	
2002	628,051		0.0	13.2	78,813	12.5	104.1	(78,813)	-12.5	-90.9
2003	25,000		0.0	13.0	32,079	128.3	99.9	(32,079)	-128.3	-86.9
2004			0.0	9.2	73,804	0.0	107.8	(73,804)	0.0	-98.6
2005	819,888		0.0	0.0	967	0.1	57.9	(967)	-0.1	-57.9
2006	4,443		0.0	0.0	23,055	518.9	14.1	(23,055)	-518.9	-14.1
2007	164,110		0.0	0.0	169,155	103.1	29.5	(169,155)	-103.1	-29.5
2008	376,547		0.0	0.0	588,646	156.3	62.7	(588,646)	-156.3	-62.7
Total	2,302,459	120,542	5.2		1,837,778	79.8		(1,717,236)	-74.6	

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 353.01 Station Equipment

Dispersion: 45 - H0.5
Procedure: Broad Group

Generation Arrangement

Vintage	Age (December 31, 2008)	Surviving Plant (December 31, 2008)	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2008	0.5	34,960,425	45.00	44.76	0.9946	1.0000	34,772,939	776,898
2007	1.5	30,145,924	45.00	44.28	0.9840	1.0000	29,662,751	669,909
2006	2.5	23,861,035	45.00	43.80	0.9734	1.0000	23,227,190	530,245
2005	3.5	26,639,274	45.00	43.34	0.9630	1.0000	25,654,450	591,984
2004	4.5	26,783,251	45.00	42.87	0.9528	1.0000	25,517,957	595,183
2003	5.5	12,257,548	45.00	42.42	0.9426	1.0000	11,554,244	272,390
2002	6.5	22,307,380	45.00	41.97	0.9326	1.0000	20,804,153	495,720
2001	7.5	16,877,850	45.00	41.52	0.9227	1.0000	15,573,570	375,063
2000	8.5	9,647,603	45.00	41.08	0.9130	1.0000	8,807,938	214,391
1999	9.5	12,874,907	45.00	40.65	0.9033	1.0000	11,630,373	286,109
1998	10.5	9,440,461	45.00	40.22	0.8938	1.0000	8,438,169	209,788
1997	11.5	7,512,900	45.00	39.80	0.8844	1.0000	6,644,783	166,953
1996	12.5	7,428,045	45.00	39.38	0.8752	1.0000	6,500,952	165,068
1995	13.5	17,293,085	45.00	38.97	0.8660	1.0000	14,976,543	384,291
1994	14.5	12,431,494	45.00	38.57	0.8570	1.0000	10,654,161	276,255
1993	15.5	23,330,878	45.00	38.17	0.8481	1.0000	19,787,595	518,464
1992	16.5	17,369,657	45.00	37.77	0.8393	1.0000	14,579,076	385,992
1991	17.5	20,620,467	45.00	37.38	0.8307	1.0000	17,128,936	458,233
1990	18.5	10,046,878	45.00	37.00	0.8221	1.0000	8,259,766	223,264
1989	19.5	10,828,034	45.00	36.62	0.8137	1.0000	8,810,578	240,623
1988	20.5	36,176,528	45.00	36.24	0.8054	1.0000	29,134,942	803,923
1987	21.5	18,957,540	45.00	35.87	0.7971	1.0000	15,111,699	421,279
1986	22.5	5,665,726	45.00	35.51	0.7890	1.0000	4,470,444	125,905
1985	23.5	3,934,272	45.00	35.15	0.7810	1.0000	3,072,788	87,428
1984	24.5	7,698,794	45.00	34.79	0.7731	1.0000	5,952,242	171,084
1983	25.5	10,967,375	45.00	34.44	0.7654	1.0000	8,393,924	243,720
1982	26.5	16,884,627	45.00	34.10	0.7577	1.0000	12,793,124	375,214
1981	27.5	21,918,738	45.00	33.75	0.7501	1.0000	16,441,277	487,083
1980	28.5	7,667,618	45.00	33.42	0.7426	1.0000	5,694,126	170,392
1979	29.5	7,845,893	45.00	33.09	0.7352	1.0000	5,768,667	174,353
1978	30.5	7,974,857	45.00	32.76	0.7280	1.0000	5,805,445	177,219
1977	31.5	8,978,681	45.00	32.44	0.7208	1.0000	6,471,829	199,526
1976	32.5	2,977,593	45.00	32.12	0.7137	1.0000	2,125,145	66,169
1975	33.5	4,047,257	45.00	31.80	0.7067	1.0000	2,860,287	89,939
1974	34.5	9,595,422	45.00	31.49	0.6998	1.0000	6,715,216	213,232
1973	35.5	5,573,419	45.00	31.19	0.6930	1.0000	3,862,635	123,854

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 353.01 Station Equipment

Dispersion: 45 - H0.5
Procedure: Broad Group

Generation Arrangement

Vintage	Age	December 31, 2008 Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1972	36.5	6,596,007	45.00	30.88	0.6863	1.0000	4,527,049	146,578
1971	37.5	4,226,855	45.00	30.59	0.6797	1.0000	2,873,075	93,930
1970	38.5	2,390,400	45.00	30.29	0.6732	1.0000	1,609,194	53,120
1969	39.5	6,231,867	45.00	30.00	0.6668	1.0000	4,155,103	138,486
1968	40.5	7,099,394	45.00	29.72	0.6604	1.0000	4,688,487	157,764
1967	41.5	1,683,679	45.00	29.44	0.6541	1.0000	1,101,363	37,415
1966	42.5	1,771,693	45.00	29.16	0.6480	1.0000	1,147,990	39,371
1965	43.5	5,600,571	45.00	28.88	0.6419	1.0000	3,594,793	124,457
1964	44.5	1,253,095	45.00	28.61	0.6359	1.0000	796,790	27,847
1963	45.5	1,827,058	45.00	28.35	0.6299	1.0000	1,150,914	40,601
1962	46.5	3,675,354	45.00	28.08	0.6241	1.0000	2,293,677	81,675
1961	47.5	11,530,486	45.00	27.82	0.6183	1.0000	7,129,253	256,233
1960	48.5	4,545,670	45.00	27.57	0.6126	1.0000	2,784,677	101,015
1959	49.5	5,307,165	45.00	27.31	0.6070	1.0000	3,221,317	117,937
1958	50.5	7,723,344	45.00	27.06	0.6014	1.0000	4,645,062	171,630
1957	51.5	4,294,746	45.00	26.82	0.5960	1.0000	2,559,531	95,439
1956	52.5	1,407,482	45.00	26.58	0.5906	1.0000	831,205	31,277
1955	53.5	1,968,664	45.00	26.34	0.5853	1.0000	1,152,162	43,748
1954	54.5	3,149,612	45.00	26.10	0.5800	1.0000	1,826,746	69,991
1953	55.5	1,147,545	45.00	25.87	0.5748	1.0000	659,624	25,501
1952	56.5	1,189,389	45.00	25.64	0.5697	1.0000	677,596	26,431
1951	57.5	475,839	45.00	25.41	0.5647	1.0000	268,685	10,574
1950	58.5	1,536,055	45.00	25.19	0.5597	1.0000	859,700	34,135
1949	59.5	1,085,974	45.00	24.96	0.5548	1.0000	602,466	24,133
1948	60.5	567,402	45.00	24.75	0.5499	1.0000	312,022	12,609
1947	61.5	125,257	45.00	24.53	0.5451	1.0000	68,281	2,783
1946	62.5	31,844	45.00	24.32	0.5404	1.0000	17,209	708
1945	63.5	40,064	45.00	24.11	0.5358	1.0000	21,464	890
1944	64.5	32,394	45.00	23.90	0.5312	1.0000	17,206	720
1943	65.5	376,035	45.00	23.70	0.5266	1.0000	198,029	8,356
1942	66.5	159,505	45.00	23.50	0.5221	1.0000	83,285	3,545
1941	67.5	287,574	45.00	23.30	0.5177	1.0000	148,890	6,391
1940	68.5	352,923	45.00	23.10	0.5134	1.0000	181,180	7,843
1939	69.5	120,680	45.00	22.91	0.5091	1.0000	61,434	2,682
1938	70.5	708,216	45.00	22.72	0.5048	1.0000	357,522	15,738
1937	71.5	64,459	45.00	22.53	0.5006	1.0000	32,270	1,432

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 353.01 Station Equipment

Dispersion: 45 - H0.5
Procedure: Broad Group

Generation Arrangement

Vintage	Age	December 31, 2008 Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1936	72.5	60,334	45.00	22.34	0.4965	1.0000	29,955	1,341
1935	73.5	65,856	45.00	22.16	0.4924	1.0000	32,428	1,463
1934	74.5	25,056	45.00	21.98	0.4884	1.0000	12,237	557
1933	75.5	206,741	45.00	21.80	0.4844	1.0000	100,146	4,594
1932	76.5	272,434	45.00	21.62	0.4805	1.0000	130,900	6,054
1931	77.5	346,957	45.00	21.45	0.4766	1.0000	165,354	7,710
1930	78.5	626,821	45.00	21.27	0.4728	1.0000	296,332	13,929
1929	79.5	88,617	45.00	21.10	0.4690	1.0000	41,560	1,969
1928	80.5	249,902	45.00	20.94	0.4653	1.0000	116,272	5,553
1927	81.5	190,225	45.00	20.77	0.4616	1.0000	87,802	4,227
1926	82.5	549,531	45.00	20.61	0.4579	1.0000	251,647	12,212
1925	83.5	294,728	45.00	20.45	0.4543	1.0000	133,909	6,550
1924	84.5	368,396	45.00	20.29	0.4508	1.0000	166,074	8,187
1923	85.5	241,225	45.00	20.13	0.4473	1.0000	107,898	5,361
1922	86.5	56,876	45.00	19.97	0.4438	1.0000	25,244	1,264
1921	87.5	25,375	45.00	19.82	0.4404	1.0000	11,175	564
1920	88.5	43	45.00	19.67	0.4371	1.0000	19	1
1919	89.5	1,673	45.00	19.52	0.4337	1.0000	726	37
1918	90.5	1,340	45.00	19.37	0.4304	1.0000	577	30
1917	91.5	10,746	45.00	19.22	0.4272	1.0000	4,591	239
1915	93.5	5,554	45.00	18.94	0.4208	1.0000	2,337	123
1914	94.5	146	45.00	18.80	0.4177	1.0000	61	3
1913	95.5	909	45.00	18.66	0.4146	1.0000	377	20
1911	97.5	2,280	45.00	18.38	0.4085	1.0000	931	51
1910	98.5	57	45.00	18.25	0.4055	1.0000	23	1
1908	100.5	411	45.00	17.98	0.3997	1.0000	164	9
1907	101.5	8,610	45.00	17.86	0.3968	1.0000	3,416	191
1905	103.5	80	45.00	17.60	0.3912	1.0000	31	2
1900	108.5	20	45.00	16.99	0.3776	1.0000	8	
Total	19.4	$623,806,673	45.00	37.23	0.8272	1.0000	$516,037,356	$13,862,371

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 353.01 Station Equipment

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2008	0.5	34,960,425		34,960,425	1.0000	0.5000
2007	1.5	30,145,924		30,145,924	1.0000	1.5000
2006	2.5	23,868,562		23,861,035	0.9997	2.4995
2005	3.5	26,639,274		26,639,274	1.0000	3.5000
2004	4.5	26,783,251		26,783,251	1.0000	4.5000
2003	5.5	12,292,953		12,257,548	0.9971	5.4932
2002	6.5	22,693,708		22,307,380	0.9830	6.4866
2001	7.5	16,880,226		16,877,850	0.9999	7.4992
2000	8.5	9,794,694		9,647,603	0.9850	8.4058
1999	9.5	12,917,894		12,874,907	0.9967	9.4922
1998	10.5	9,495,866		9,440,461	0.9942	10.4475
1997	11.5	8,497,135		7,512,900	0.8842	10.8559
1996	12.5	7,807,464		7,428,045	0.9514	12.1035
1995	13.5		22,963,375	17,293,085	0.7531	11.2565
1994	14.5		12,692,055	12,431,494	0.9795	14.3323
1993	15.5		30,386,584	23,330,878	0.7678	13.8122
1992	16.5		21,872,583	17,369,657	0.7941	15.3281
1991	17.5		25,859,463	20,620,467	0.7974	15.7418
1990	18.5		10,990,225	10,046,878	0.9142	18.0283
1989	19.5		17,829,421	10,828,034	0.6073	17.4856
1988	20.5		44,587,304	36,176,528	0.8114	19.0694
1987	21.5		32,843,281	18,957,540	0.5772	18.4898
1986	22.5		7,586,422	5,665,726	0.7468	21.0551
1985	23.5		9,879,788	3,934,272	0.3982	19.0178
1984	24.5		8,670,615	7,698,794	0.8879	23.7616
1983	25.5		15,575,715	10,967,375	0.7041	23.2772
1982	26.5		17,652,437	16,884,627	0.9565	26.1197
1981	27.5		23,183,352	21,918,738	0.9455	27.0343
1980	28.5		12,918,976	7,667,618	0.5935	24.7913
1979	29.5		9,019,083	7,845,893	0.8699	28.7332
1978	30.5		9,365,304	7,974,857	0.8515	29.6497
1977	31.5		10,089,340	8,978,681	0.8899	30.6862
1976	32.5		9,978,980	2,977,593	0.2984	27.5926
1975	33.5		4,454,043	4,047,257	0.9087	32.8980
1974	34.5		11,253,840	9,595,422	0.8526	34.0309
1973	35.5		7,130,685	5,573,419	0.7816	34.5604
1972	36.5		8,662,398	6,596,007	0.7615	35.6479

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 353.01 Station Equipment

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1971	37.5		4,588,807	4,226,855	0.9211	37.0808
1970	38.5		6,313,676	2,390,400	0.3786	33.7864
1969	39.5		6,896,521	6,231,867	0.9036	39.1824
1968	40.5		7,698,817	7,099,394	0.9221	40.2421
1967	41.5		2,131,567	1,683,679	0.7899	39.9764
1966	42.5		1,934,721	1,771,693	0.9157	41.8699
1965	43.5		6,873,087	5,600,571	0.8149	42.6605
1964	44.5		1,875,121	1,253,095	0.6683	42.3358
1963	45.5		2,258,921	1,827,058	0.8088	44.1536
1962	46.5		4,373,034	3,675,354	0.8405	45.5135
1961	47.5		13,895,197	11,530,486	0.8298	46.7991
1960	48.5		5,923,017	4,545,670	0.7675	46.5030
1959	49.5		7,397,517	5,307,165	0.7174	47.2756
1958	50.5		8,685,815	7,723,344	0.8892	50.1178
1957	51.5		6,434,875	4,294,746	0.6674	48.8833
1956	52.5		1,899,843	1,407,482	0.7408	50.8899
1955	53.5		2,397,304	1,968,664	0.8212	52.1094
1954	54.5		4,849,361	3,149,612	0.6495	51.8098
1953	55.5		1,926,283	1,147,545	0.5957	52.1077
1952	56.5		1,832,524	1,189,389	0.6490	53.7971
1951	57.5		580,066	475,839	0.8203	55.9164
1950	58.5		2,258,164	1,536,055	0.6802	55.5697
1949	59.5		1,395,335	1,085,974	0.7783	57.7577
1948	60.5		1,289,346	567,402	0.4401	55.3812
1947	61.5		192,330	125,257	0.6513	59.5191
1946	62.5		179,237	31,844	0.1777	55.4207
1945	63.5		87,209	40,064	0.4594	59.1371
1944	64.5		73,586	32,394	0.4402	61.2161
1943	65.5		540,236	376,035	0.6961	62.9879
1942	66.5		580,148	159,505	0.2749	59.8121
1941	67.5		532,624	287,574	0.5399	64.6195
1940	68.5		433,876	352,923	0.8134	67.0590
1939	69.5		195,867	120,680	0.6161	67.5580
1938	70.5		897,230	708,216	0.7893	69.0913
1937	71.5		98,256	64,459	0.6560	69.5649
1936	72.5		67,801	60,334	0.8899	71.7521
1935	73.5		121,919	65,856	0.5402	70.8202

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 353.01 Station Equipment

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1934	74.5		33,228	25,056	0.7541	72.6342
1933	75.5		364,177	206,741	0.5677	73.4643
1932	76.5		311,832	272,434	0.8737	75.7457
1931	77.5		452,409	346,957	0.7669	75.8971
1930	78.5		1,478,345	626,821	0.4240	74.8995
1929	79.5		206,893	88,617	0.4283	76.7813
1928	80.5		306,656	249,902	0.8149	79.4175
1927	81.5		410,856	190,225	0.4630	76.8855
1926	82.5		767,061	549,531	0.7164	79.7098
1925	83.5		517,007	294,728	0.5701	81.4080
1924	84.5		535,913	368,396	0.6874	82.5771
1923	85.5		429,498	241,225	0.5616	82.7872
1922	86.5		174,866	56,876	0.3253	80.6775
1921	87.5		41,307	25,375	0.6143	84.1731
1920	88.5		31,408	43	0.0014	83.1966
1919	89.5		59,888	1,673	0.0279	84.3688
1918	90.5		38,775	1,340	0.0345	81.3455
1917	91.5		10,974	10,746	0.9792	91.4117
1915	93.5		6,124	5,554	0.9069	93.1743
1914	94.5		3,402	146	0.0428	91.0409
1913	95.5		15,145	909	0.0600	92.1364
1912	96.5		71		0.0000	93.0000
1911	97.5		8,167	2,280	0.2792	94.9772
1910	98.5		187	57	0.3039	96.0638
1909	99.5		653		0.0000	90.5067
1908	100.5		411	411	1.0000	100.5000
1907	101.5		58,910	8,610	0.1462	98.5079
1905	103.5		80	80	1.0000	103.5000
1903	105.5		40		0.0000	104.0000
1900	108.5		20	20	1.0000	108.5000
1897	111.5		12		0.0000	106.0000
Total	19.4	$242,777,376	$501,418,828	$623,806,673	0.8382	

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 353.01 Station Equipment

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996	(37,322)	526,662,419		(25,676,477)	500,948,621
1997	500,948,621	25,352,759	2,337,042	(6,093,977)	517,870,360
1998	517,870,360	402,604	1,652,412	(391,057)	516,229,495
1999	516,229,495	57,738,365	39,304,113	(49,172,937)	485,490,810
2000	485,490,810	31,382,242	6,442,494	(13,091,550)	497,339,008
2001	497,339,008	22,791,109	35,134,908	(6,842,362)	478,152,848
2002	478,152,848	25,327,755	4,016,326	(1,551,770)	497,912,507
2003	497,912,507	6,351,258	527,472	50,559	503,786,851
2004	503,786,851	21,715,432	4,607,549		520,894,734
2005	520,894,734	27,645,350	8,396,068	880,202	541,024,218
2006	541,024,218	36,603,454	4,915,789	(825,234)	571,886,649
2007	571,886,649	19,468,016	4,855,286	(377,343)	586,122,036
2008	586,122,036	46,071,544	8,200,071	(186,835)	623,806,673

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Transmission Plant
Account: 353.01 Station Equipment

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996	598,216,464	9,304,074		(25,676,477)	581,844,061
1997	581,844,061	10,904,866	2,337,042	(6,093,977)	584,317,909
1998	584,317,909	10,325,030	1,652,412	(391,057)	592,599,470
1999	592,599,470	12,960,249	39,304,113	(49,172,937)	517,082,668
2000	517,082,668	9,912,217	6,442,494	(13,091,550)	507,460,842
2001	507,460,842	16,806,202	35,134,908	(6,842,362)	482,289,774
2002	482,289,774	24,089,891	4,016,326	(1,551,770)	500,811,570
2003	500,811,570	12,299,928	527,472	50,559	512,634,584
2004	512,634,584	26,674,114	4,607,549		534,701,149
2005	534,701,149	26,984,058	8,396,068	880,202	554,169,341
2006	554,169,341	23,863,792	4,915,789	(825,234)	572,292,110
2007	572,292,110	30,173,765	4,855,286	(377,343)	597,233,246
2008	597,233,246	34,960,334	8,200,071	(186,835)	623,806,673

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 353.01 Station Equipment

T-Cut: None

Placement Band: 1897-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2000	1.1	42.1	O2	5.58	40.4	L0	4.17	40.7	L0 *	3.96
1997-2001	0.9	29.1	O3	3.56	32.0	O3 *	3.47	30.1	O3	3.30
1998-2002	1.2	28.1	O3	3.18	28.5	O3	2.95	28.7	O3	2.96
1999-2003	1.6	28.0	O3	3.57	28.0	O3	3.22	28.3	O3	3.13
2000-2004	13.3	42.7	O3	5.12	66.5	O4 *	6.47	43.7	O2 *	6.77
2001-2005	0.7	44.7	O3	6.93	71.9	O4 *	11.53	44.5	O2 *	4.41
2002-2006	0.4	65.6	L0.5	7.28	67.6	L0	8.00	60.4	R1 *	3.29
2003-2007	0.0	63.5	L0.5	7.22	74.7	O2 *	9.90	60.3	R0.5 *	4.08
2004-2008	0.0	54.7	L0.5	4.94	61.5	O2 *	6.43	53.8	S-.5 *	3.18

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 353.01 Station Equipment

T-Cut: None

Placement Band: 1897-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper- sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper- sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper- sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2008	0.0	45.4	O2	2.99	48.6	O2 *	3.81	44.6	L0	1.63
1998-2008	0.0	41.4	O2	2.64	44.1	O2 *	3.21	41.0	O2	1.58
2000-2008	0.0	47.3	O2	4.40	64.0	O4 *	7.53	47.1	SC *	2.29
2002-2008	0.0	59.4	L1	5.26	59.9	L0.5	5.48	57.0	S0 *	2.58
2004-2008	0.0	54.7	L0.5	4.94	61.5	O2 *	6.43	53.8	S-.5 *	3.18
2006-2008	0.0	55.1	L1	4.99	56.0	L1	5.19	54.9	L1 *	4.71
2008-2008	12.2	47.3	L1	6.59	48.8	L1 *	5.56	48.1	L1 *	5.66

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 353.01 Station Equipment

T-Cut: None

Placement Band: 1897-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-1997	62.1	108.1	L1 *	3.34	86.0	S1.5	8.61	78.9	R3 *	13.59
1996-1999	0.9	41.5	O2	5.91	39.9	O2	4.83	42.2	O2 *	4.73
1996-2001	1.5	33.8	O2	3.38	40.1	O3 *	3.87	34.6	O2	3.69
1996-2003	5.7	40.3	O2	3.07	41.7	O2	3.08	39.7	O2	3.86
1996-2005	0.9	42.9	O2	2.99	47.4	O3 *	3.75	42.1	O2	2.94
1996-2007	0.0	45.6	O2	3.42	48.7	O2 *	4.26	44.4	L0	2.03
1996-2008	0.0	45.4	O2	2.99	48.6	O2 *	3.81	44.6	L0	1.63

Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 353.01 Station Equipment

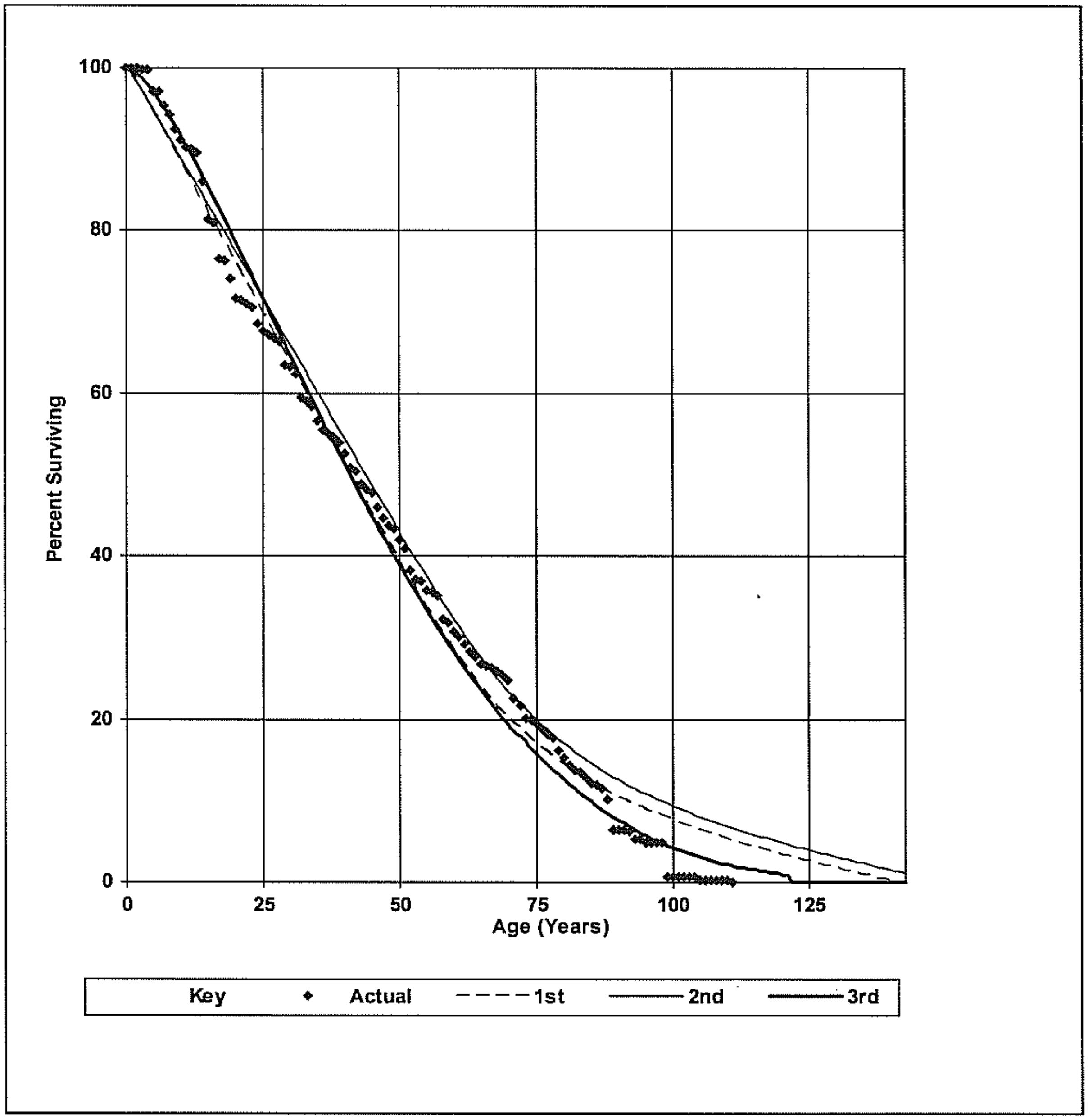
T-Cut: None

Placement Band: 1897-2008 Observation Band: 1996-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis **1st: 45.4-O2 2nd: 48.6-O2 3rd: 44.6-L0**



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 353.01 Station Equipment

T-Cut: None

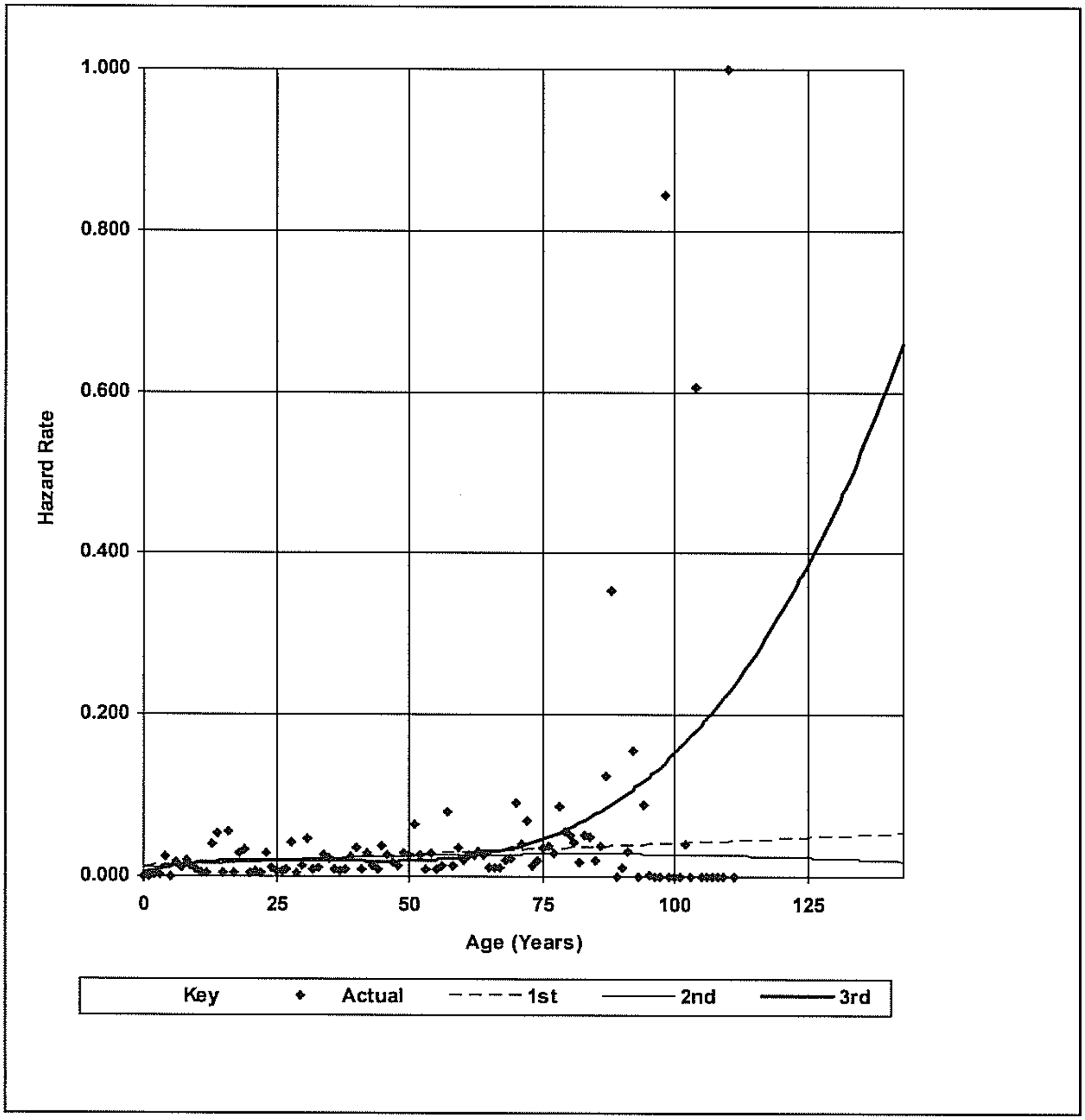
Placement Band: 1897-2008 Observation Band: 1996-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 45.4-O2 2nd: 48.6-O2 3rd: 44.6-L0



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

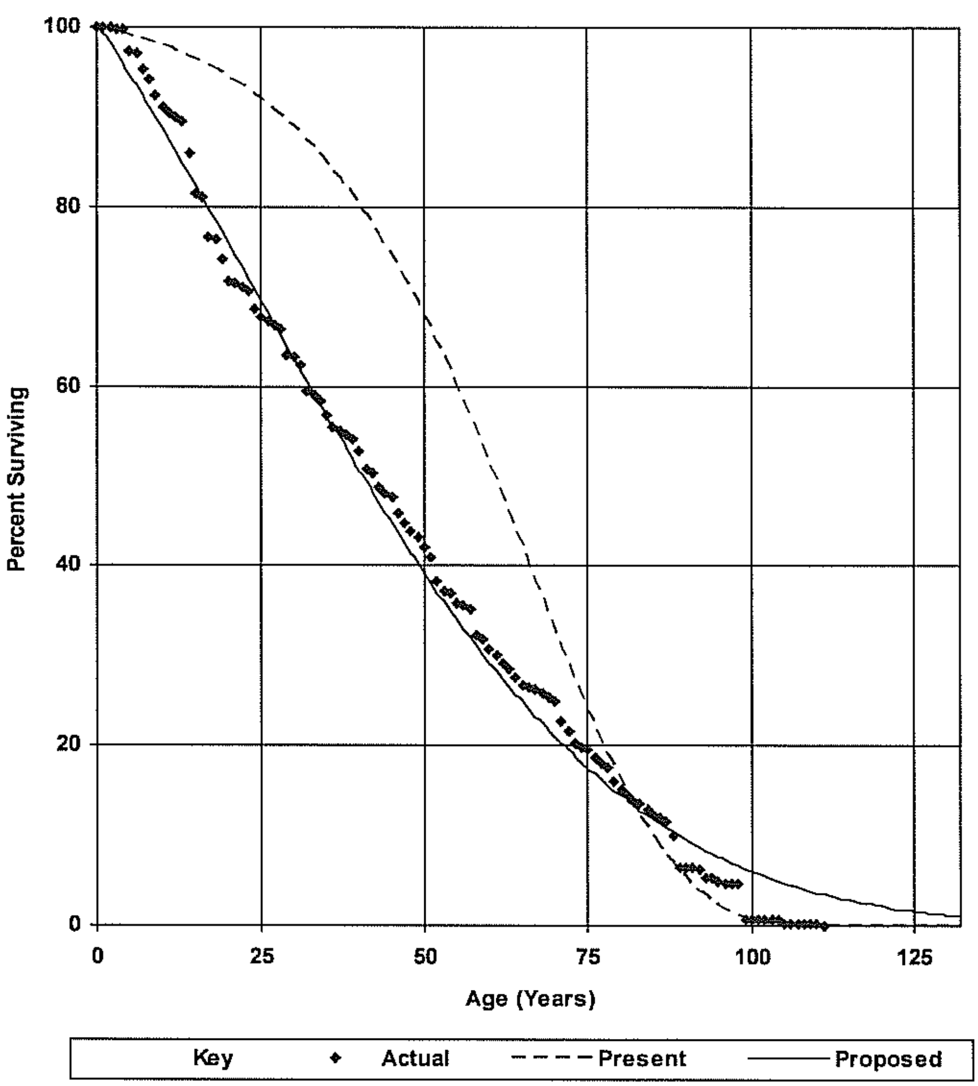
Account: 353.01 Station Equipment

T-Cut: None

Placement Band: 1897-2008

Observation Band: 1996-2008

Present and Proposed Projection Life Curves **Present: 58.0-R2** **Proposed: 45.0-H0.5**



Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Transmission Plant
Account: 353.01 Station Equipment

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998	1,652,412	(41)	0.0		481,496	29.1		(481,537)	-29.1	
1999	39,304,113	31,263	0.1		1,138,358	2.9		(1,107,095)	-2.8	
2000	6,442,494	2,679,436	41.6		1,039,346	16.1		1,640,090	25.5	
2001	35,134,908	782,099	2.2		791,128	2.3		(9,029)	0.0	
2002	4,016,326	(124,549)	-3.1	3.9	1,520,353	37.9	5.7	(1,644,902)	-41.0	-1.9
2003	527,472	(5,614)	-1.1	3.9	944,882	179.1	6.4	(950,495)	-180.2	-2.4
2004	4,607,549	(8,000)	-0.2	6.6	617,249	13.4	9.7	(625,249)	-13.6	-3.1
2005	8,396,068		0.0	1.2	1,833,028	21.8	10.8	(1,833,028)	-21.8	-9.6
2006	4,915,789		0.0	-0.6	687,407	14.0	24.9	(687,407)	-14.0	-25.6
2007	4,855,286		0.0	-0.1	2,142,526	44.1	26.7	(2,142,526)	-44.1	-26.8
2008	8,200,071		0.0	0.0		0.0	17.0		0.0	-17.1
Total	118,052,489	3,354,595	2.8		11,195,774	9.5		(7,841,179)	-6.6	

Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 353.01 Station Equipment

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998	1,652,412	(41)	0.0		481,496	29.1		(481,537)	-29.1	
1999	39,304,113	31,263	0.1		1,138,358	2.9		(1,107,095)	-2.8	
2000	6,442,494	2,679,436	41.6		1,039,346	16.1		1,640,090	25.5	
2001	35,134,908	782,099	2.2		791,128	2.3		(9,029)	0.0	
2002	4,016,326	(124,549)	-3.1	3.9	1,520,353	37.9	5.7	(1,644,902)	-41.0	-1.9
2003	527,472	(5,614)	-1.1	3.9	944,882	179.1	6.4	(950,495)	-180.2	-2.4
2004	4,607,549	(8,000)	-0.2	6.6	617,249	13.4	9.7	(625,249)	-13.6	-3.1
2005	8,396,068		0.0	1.2	1,833,028	21.8	10.8	(1,833,028)	-21.8	-9.6
2006	4,915,789		0.0	-0.6	687,407	14.0	24.9	(687,407)	-14.0	-25.6
2007	4,855,286		0.0	-0.1	2,142,526	44.1	26.7	(2,142,526)	-44.1	-26.8
2008	8,200,071		0.0	0.0		0.0	17.0		0.0	-17.1
Total	118,052,489	3,354,595	2.8		11,195,774	9.5		(7,841,179)	-6.6	

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 353.55 Station Equipment - EMS RTU

Dispersion: 20 - H2
Procedure: Broad Group

Generation Arrangement

Vintage	Age	December 31, 2008 Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2008	0.5	1,506,649	20.00	19.56	0.9780	1.0000	1,473,492	75,332
2007	1.5	796,510	20.00	18.69	0.9347	1.0000	744,480	39,825
2006	2.5	1,509,451	20.00	17.85	0.8925	1.0000	1,347,114	75,473
2005	3.5	176,326	20.00	17.03	0.8514	1.0000	150,127	8,816
2004	4.5	154,473	20.00	16.23	0.8116	1.0000	125,377	7,724
2003	5.5	101,002	20.00	15.46	0.7732	1.0000	78,096	5,050
2002	6.5	32,346	20.00	14.72	0.7362	1.0000	23,813	1,617
2001	7.5	324,009	20.00	14.01	0.7006	1.0000	227,004	16,200
2000	8.5	484,034	20.00	13.33	0.6665	1.0000	322,619	24,202
1999	9.5	270,594	20.00	12.68	0.6339	1.0000	171,542	13,530
1998	10.5	24,075	20.00	12.06	0.6029	1.0000	14,514	1,204
1997	11.5	343,439	20.00	11.47	0.5733	1.0000	196,908	17,172
1996	12.5	1,139,354	20.00	10.91	0.5453	1.0000	621,291	56,968
1995	13.5	1,036,105	20.00	10.37	0.5187	1.0000	537,462	51,805
1994	14.5	3,891,722	20.00	9.87	0.4936	1.0000	1,920,980	194,586
1993	15.5	8,281,160	20.00	9.40	0.4699	1.0000	3,891,099	414,058
1992	16.5	5,703,509	20.00	8.95	0.4475	1.0000	2,552,292	285,176
1991	17.5	8,014,014	20.00	8.53	0.4264	1.0000	3,417,246	400,701
1990	18.5	8,689,546	20.00	8.13	0.4066	1.0000	3,532,831	434,477
1989	19.5	7,574	20.00	7.76	0.3879	1.0000	2,938	379
Total	14.8	$42,485,893	20.00	10.05	0.5025	1.0000	$21,351,227	$2,124,295

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 353.55 Station Equipment - EMS RTU

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2008	0.5	1,506,649		1,506,649	1.0000	0.5000
2007	1.5	796,510		796,510	1.0000	1.5000
2006	2.5	1,509,451		1,509,451	1.0000	2.5000
2005	3.5	176,326		176,326	1.0000	3.5000
2004	4.5	160,834		154,473	0.9604	4.4802
2003	5.5	116,660		101,002	0.8658	5.4329
2002	6.5	32,346		32,346	1.0000	6.5000
2001	7.5	324,009		324,009	1.0000	7.5000
2000	8.5	484,034		484,034	1.0000	8.5000
1999	9.5	270,594		270,594	1.0000	9.5000
1998	10.5	24,075		24,075	1.0000	10.5000
1997	11.5	346,649		343,439	0.9907	11.4768
1996	12.5	1,151,022		1,139,354	0.9899	12.4848
1995	13.5		1,036,105	1,036,105	1.0000	13.5000
1994	14.5		3,891,722	3,891,722	1.0000	14.5000
1993	15.5		8,312,553	8,281,160	0.9962	15.4943
1992	16.5		6,130,458	5,703,509	0.9304	16.4393
1991	17.5		8,727,743	8,014,014	0.9182	17.3259
1990	18.5		8,818,476	8,689,546	0.9854	18.4927
1989	19.5		7,574	7,574	1.0000	19.5000
Total	14.8	$6,899,160	$36,924,630	$42,485,893	0.9695	

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Transmission Plant
Account: 353.55 Station Equipment - EMS RTU

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996		24,307,588			24,307,588
1997	24,307,588	986,290		(82,474)	25,211,403
1998	25,211,403	105,180			25,316,583
1999	25,316,583	511,336			25,827,920
2000	25,827,920	1,152,172		11,330,125	38,310,216
2001	38,310,216	222,330		843,604	39,376,150
2002	39,376,150	98,171			39,474,321
2003	39,474,321	41,073			39,515,394
2004	39,515,394	170,702	203,623		39,482,473
2005	39,482,473	220,452		2,999	39,705,925
2006	39,705,925	385,558	3,210		40,088,273
2007	40,088,273	675,415	549,576		40,214,112
2008	40,214,112	2,853,269	581,488		42,485,893

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 353.55 Station Equipment - EMS RTU

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996	24,860,275	1,205,369			26,065,644
1997	26,065,644	289,477		(82,474)	26,272,647
1998	26,272,647				26,272,647
1999	26,272,647	270,594			26,543,242
2000	26,543,242	484,034		11,330,125	38,357,400
2001	38,357,400	324,009		843,604	39,525,013
2002	39,525,013	32,346			39,557,360
2003	39,557,360	116,660			39,674,020
2004	39,674,020	160,834	203,623		39,631,230
2005	39,631,230	173,327		2,999	39,807,557
2006	39,807,557	1,509,451	3,210		41,313,798
2007	41,313,798	796,510	549,576		41,560,732
2008	41,560,732	1,506,649	581,488		42,485,893

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 353.55 Station Equipment - EMS RTU

T-Cut: None

Placement Band: 1989-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2000	100.0				No Retirements					
1997-2001	100.0				No Retirements					
1998-2002	100.0				No Retirements					
1999-2003	100.0				No Retirements					
2000-2004	98.8	61.0	L1.5 *	0.20	32.7	S2 *	0.75	26.7	R4 *	0.39
2001-2005	99.1	74.1	L1.5 *	0.17	44.8	S2 *	0.19	195.7	SQ *	0.50
2002-2006	99.3	97.9	L1.5 *	0.19	195.4	SQ *	0.19	196.4	SQ *	0.58
2003-2007	96.6	48.1	L2 *	0.41	32.8	S3 *	0.62	31.6	S3 *	0.58
2004-2008	91.9	42.8	L2 *	1.22	30.2	S3 *	0.92	28.1	S3 *	1.07

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 353.55 Station Equipment - EMS RTU

T-Cut: None

Placement Band: 1989-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2008	93.8	48.5	L2 *	0.69	30.8	S3 *	1.19	27.5	R4 *	0.69
1998-2008	93.7	46.4	L2 *	0.56	30.5	S3 *	1.34	27.4	R4 *	0.72
2000-2008	93.3	44.7	L2 *	0.53	30.3	S3 *	1.07	27.4	R4 *	0.66
2002-2008	92.5	43.4	L2 *	1.00	30.1	S3 *	0.67	27.6	R4 *	0.81
2004-2008	91.9	42.8	L2 *	1.22	30.2	S3 *	0.92	28.1	S3 *	1.07
2006-2008	88.4	41.6	L2 *	3.69	29.7	S3 *	3.92	29.4	S3 *	3.93
2008-2008	76.7	38.8	L1.5 *	10.88	29.1	S2 *	11.98	29.3	S2 *	12.01

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 353.55 Station Equipment - EMS RTU

T-Cut: None

Placement Band: 1989-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-1997	100.0				No Retirements					
1996-1999	100.0				No Retirements					
1996-2001	100.0				No Retirements					
1996-2003	100.0				No Retirements					
1996-2005	99.1	88.2	L1.5 *	0.18	44.0	S2 *	0.23	191.7	R5 *	0.32
1996-2007	96.6	57.0	L1.5 *	0.47	33.5	S2 *	0.83	29.1	S3 *	0.54
1996-2008	93.8	48.5	L2 *	0.69	30.8	S3 *	1.19	27.5	R4 *	0.69

Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 353.55 Station Equipment - EMS RTU

T-Cut: None

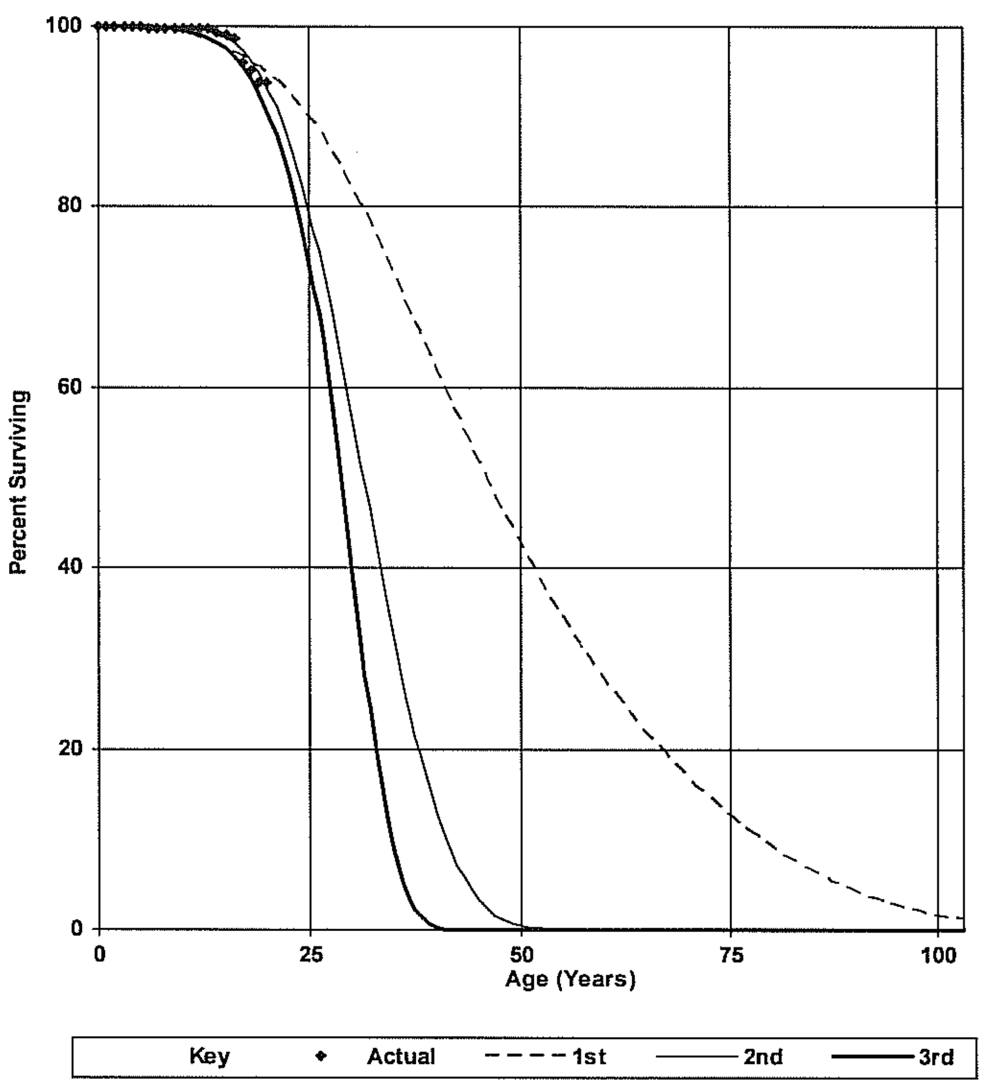
Placement Band: 1989-2008 Observation Band: 1996-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 48.5-L2 2nd: 30.8-S3 3rd: 27.5-R4

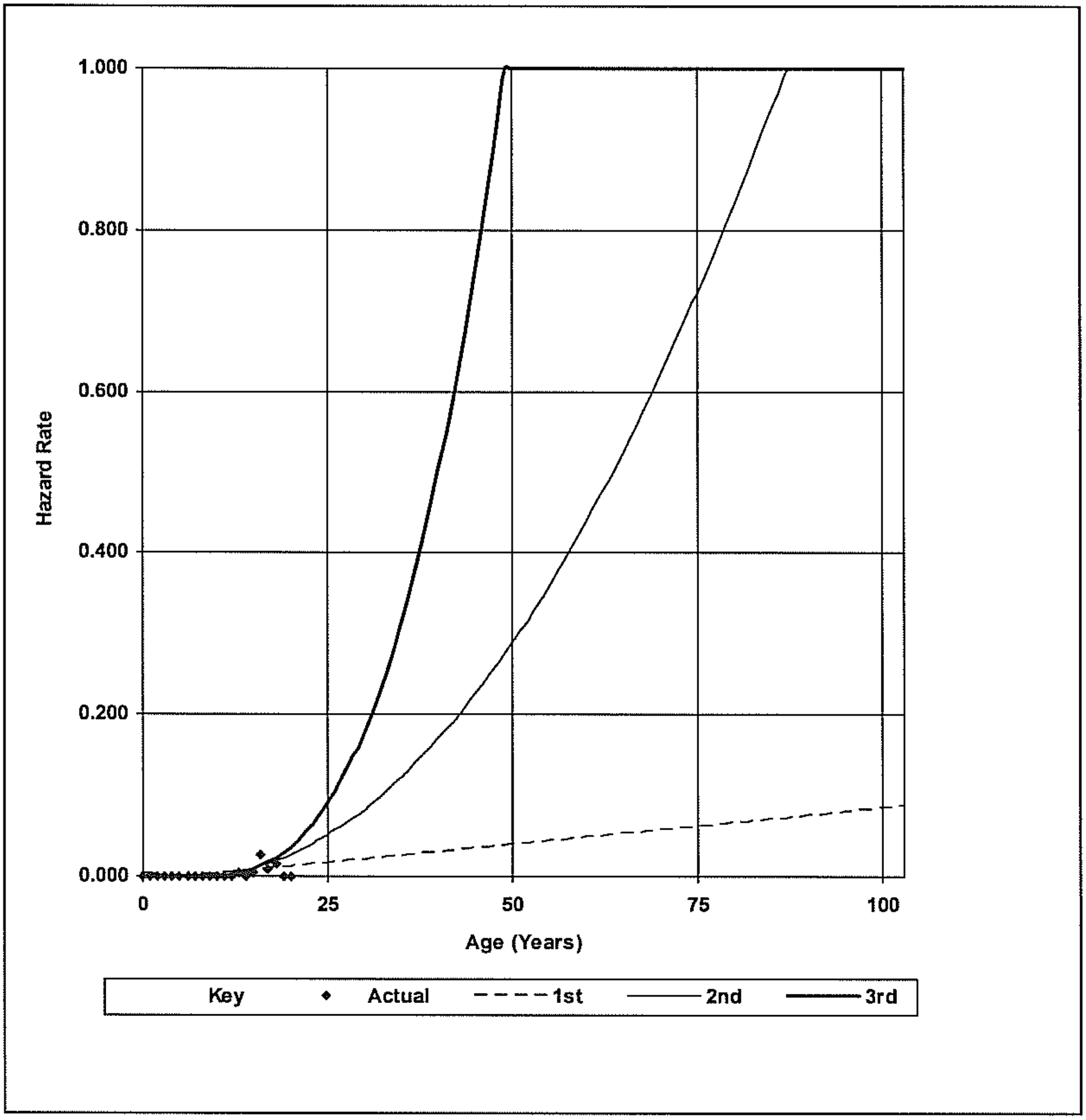


Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Transmission Plant
Account: 353.55 Station Equipment - EMS RTU

T-Cut: None
Placement Band: 1989-2008 Observation Band: 1996-2008
Hazard Function: Proportion Retired
Weighting: Exposures

Polynomial Hazard Function 1st: 48.5-L2 2nd: 30.8-S3 3rd: 27.5-R4



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

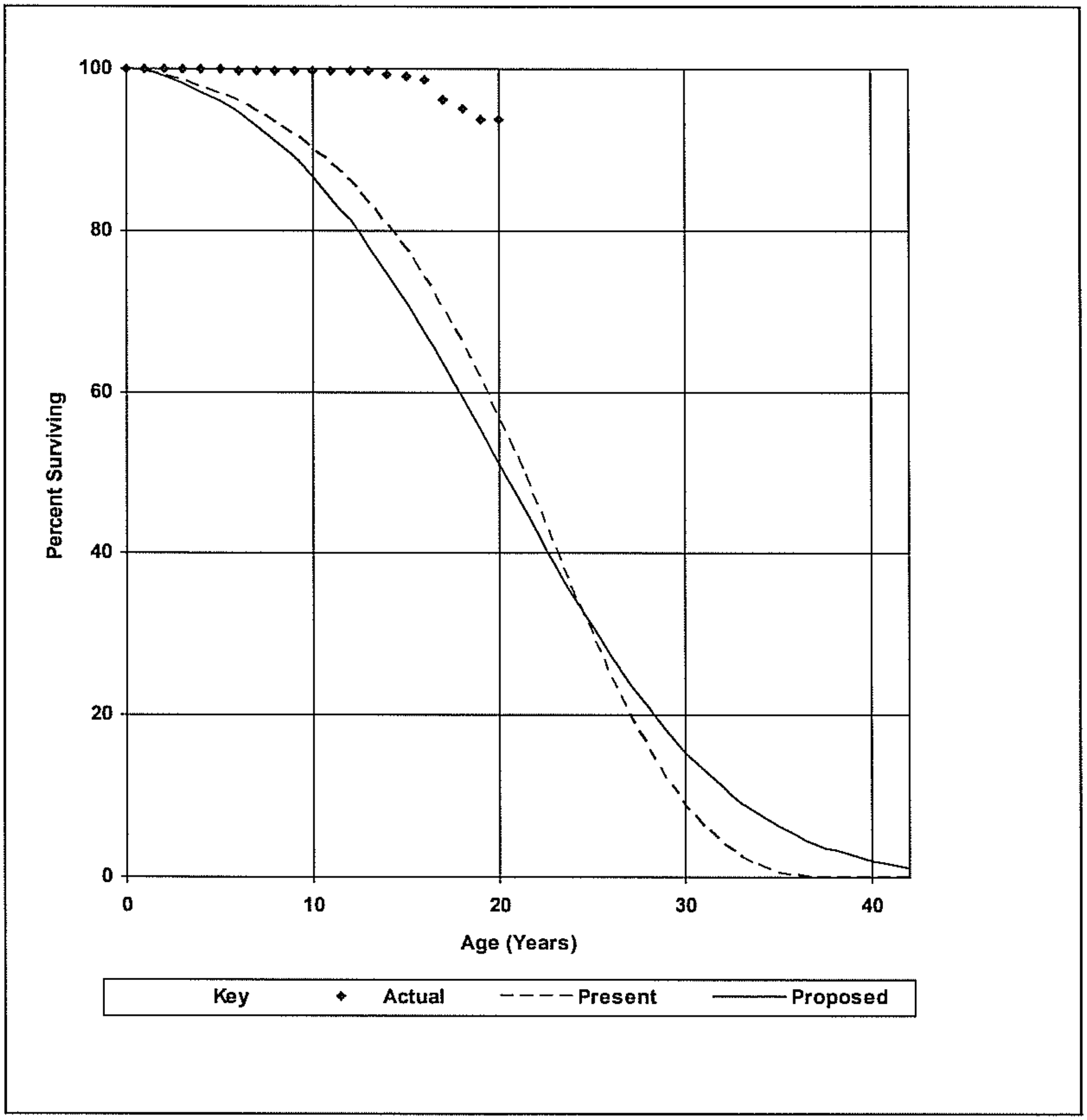
Account: 353.55 Station Equipment - EMS RTU

T-Cut: None

Placement Band: 1989-2008

Observation Band: 1996-2008

Present and Proposed Projection Life Curves **Present: 20.0-R2** **Proposed: 20.0-H2**



Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Transmission Plant
Account: 353.55 Station Equipment - EMS RTU

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998			0.0			0.0			0.0	
1999			0.0			0.0			0.0	
2000		34,783	0.0			0.0		34,783	0.0	
2001			0.0		10,075	0.0		(10,075)	0.0	
2002			0.0	0.0		0.0	0.0		0.0	0.0
2003			0.0	0.0		0.0	0.0		0.0	0.0
2004	203,623		0.0	17.1		0.0	4.9		0.0	12.1
2005			0.0	0.0		0.0	4.9		0.0	-4.9
2006	3,210		0.0	0.0		0.0	0.0		0.0	0.0
2007	549,576		0.0	0.0	19,133	3.5	2.5	(19,133)	-3.5	-2.5
2008	581,488		0.0	0.0	53,249	9.2	5.4	(53,249)	-9.2	-5.4
Total	1,337,896	34,783	2.6		82,457	6.2		(47,675)	-3.6	

Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Transmission Plant
Account: 353.55 Station Equipment - EMS RTU

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998			0.0			0.0			0.0	
1999			0.0			0.0			0.0	
2000		34,783	0.0			0.0		34,783	0.0	
2001			0.0		10,075	0.0		(10,075)	0.0	
2002			0.0	0.0		0.0	0.0		0.0	0.0
2003			0.0	0.0		0.0	0.0		0.0	0.0
2004	203,623		0.0	17.1		0.0	4.9		0.0	12.1
2005			0.0	0.0		0.0	4.9		0.0	-4.9
2006	3,210		0.0	0.0		0.0	0.0		0.0	0.0
2007	549,576		0.0	0.0	19,133	3.5	2.5	(19,133)	-3.5	-2.5
2008	581,488		0.0	0.0	53,249	9.2	5.4	(53,249)	-9.2	-5.4
Total	1,337,896	34,783	2.6		82,457	6.2		(47,675)	-3.6	

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 354.00 Towers and Fixtures

Dispersion: 70 - H4
Procedure: Broad Group

Generation Arrangement

Vintage	Age (December 31, 2008)	Surviving Plant (December 31, 2008)	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2008	0.5	9,707,669	70.00	69.50	0.9929	1.0000	9,638,391	138,681
2007	1.5	631,568	70.00	68.50	0.9786	1.0000	618,042	9,022
2006	2.5	927,114	70.00	67.50	0.9643	1.0000	894,026	13,244
2005	3.5	1,782,711	70.00	66.50	0.9500	1.0000	1,693,643	25,467
2004	4.5	2,662	70.00	65.50	0.9358	1.0000	2,491	38
2003	5.5	16,432	70.00	64.51	0.9215	1.0000	15,142	235
2001	7.5	3,243,667	70.00	62.51	0.8930	1.0000	2,896,565	46,338
2000	8.5	28,434	70.00	61.51	0.8787	1.0000	24,987	406
1999	9.5	502,329	70.00	60.52	0.8645	1.0000	434,266	7,176
1998	10.5	74,158	70.00	59.52	0.8503	1.0000	63,055	1,059
1996	12.5	69,479	70.00	57.53	0.8218	1.0000	57,101	993
1994	14.5	95,270	70.00	55.54	0.7935	1.0000	75,595	1,361
1993	15.5	1,160,426	70.00	54.55	0.7793	1.0000	904,341	16,578
1992	16.5	798,064	70.00	53.56	0.7652	1.0000	610,667	11,401
1991	17.5	217,075	70.00	52.58	0.7511	1.0000	163,040	3,101
1990	18.5	407,576	70.00	51.59	0.7370	1.0000	300,383	5,823
1988	20.5	181,698	70.00	49.63	0.7089	1.0000	128,813	2,596
1987	21.5	182,730	70.00	48.65	0.6950	1.0000	126,993	2,610
1986	22.5	71,593	70.00	47.67	0.6811	1.0000	48,759	1,023
1985	23.5	2,648,048	70.00	46.70	0.6672	1.0000	1,766,749	37,829
1984	24.5	1,896,504	70.00	45.74	0.6534	1.0000	1,239,136	27,093
1983	25.5	1,448,623	70.00	44.77	0.6396	1.0000	926,596	20,695
1982	26.5	6,418,452	70.00	43.82	0.6260	1.0000	4,017,758	91,692
1981	27.5	518,542	70.00	42.87	0.6124	1.0000	317,544	7,408
1980	28.5	298,170	70.00	41.92	0.5989	1.0000	178,567	4,260
1979	29.5	4,779,670	70.00	40.98	0.5855	1.0000	2,798,341	68,281
1978	30.5	1,270,455	70.00	40.05	0.5722	1.0000	726,908	18,149
1977	31.5	2,533,993	70.00	39.13	0.5590	1.0000	1,416,404	36,200
1976	32.5	349,802	70.00	38.21	0.5459	1.0000	190,955	4,997
1975	33.5	3,993,434	70.00	37.31	0.5329	1.0000	2,128,282	57,049
1974	34.5	271,955	70.00	36.41	0.5201	1.0000	141,455	3,885
1973	35.5	539,067	70.00	35.52	0.5075	1.0000	273,564	7,701
1972	36.5	32,381,822	70.00	34.65	0.4950	1.0000	16,027,845	462,598
1971	37.5	5,619,777	70.00	33.78	0.4826	1.0000	2,712,267	80,283
1970	38.5	3,722,507	70.00	32.93	0.4704	1.0000	1,751,237	53,179
1969	39.5	1,080,318	70.00	32.09	0.4585	1.0000	495,288	15,433

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 354.00 Towers and Fixtures

Dispersion: 70 - H4
Procedure: Broad Group

Generation Arrangement

Vintage	Age (December 31, 2008)	Surviving Plant (December 31, 2008)	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1968	40.5	1,705,817	70.00	31.27	0.4467	1.0000	761,916	24,369
1967	41.5	457,157	70.00	30.45	0.4351	1.0000	198,888	6,531
1966	42.5	929,697	70.00	29.66	0.4236	1.0000	393,865	13,281
1965	43.5	630,986	70.00	28.87	0.4124	1.0000	260,248	9,014
1964	44.5	506,601	70.00	28.10	0.4015	1.0000	203,388	7,237
1963	45.5	346,936	70.00	27.35	0.3907	1.0000	135,548	4,956
1962	46.5	12,563,438	70.00	26.61	0.3802	1.0000	4,776,411	179,478
1961	47.5	2,476,669	70.00	25.89	0.3699	1.0000	916,049	35,381
1960	48.5	2,808,467	70.00	25.19	0.3598	1.0000	1,010,498	40,121
1959	49.5	246,808	70.00	24.50	0.3500	1.0000	86,375	3,526
1958	50.5	3,301,988	70.00	23.83	0.3404	1.0000	1,123,892	47,171
1957	51.5	3,513,773	70.00	23.17	0.3310	1.0000	1,163,142	50,197
1956	52.5	167,604	70.00	22.53	0.3219	1.0000	53,951	2,394
1955	53.5	41,103	70.00	21.91	0.3130	1.0000	12,867	587
1954	54.5	1,015,875	70.00	21.31	0.3044	1.0000	309,229	14,513
1953	55.5	666,112	70.00	20.72	0.2960	1.0000	197,176	9,516
1952	56.5	724,864	70.00	20.15	0.2879	1.0000	208,658	10,355
1951	57.5	34,104	70.00	19.60	0.2799	1.0000	9,547	487
1950	58.5	233,015	70.00	19.06	0.2723	1.0000	63,442	3,329
1949	59.5	267,000	70.00	18.54	0.2648	1.0000	70,701	3,814
1948	60.5	137,161	70.00	18.03	0.2576	1.0000	35,331	1,959
1947	61.5	92,409	70.00	17.54	0.2506	1.0000	23,156	1,320
1946	62.5	12,250	70.00	17.07	0.2438	1.0000	2,987	175
1945	63.5	447	70.00	16.61	0.2372	1.0000	106	6
1944	64.5	5,592	70.00	16.16	0.2309	1.0000	1,291	80
1943	65.5	23,505	70.00	15.73	0.2248	1.0000	5,283	336
1942	66.5	240,022	70.00	15.32	0.2188	1.0000	52,518	3,429
1941	67.5	17,285	70.00	14.91	0.2131	1.0000	3,683	247
1940	68.5	79,220	70.00	14.53	0.2075	1.0000	16,439	1,132
1939	69.5	171,755	70.00	14.15	0.2021	1.0000	34,718	2,454
1938	70.5	2,210	70.00	13.79	0.1969	1.0000	435	32
1937	71.5	470,658	70.00	13.44	0.1919	1.0000	90,335	6,724
1935	73.5	3,659	70.00	12.77	0.1824	1.0000	667	52
1934	74.5	27,973	70.00	12.45	0.1779	1.0000	4,976	400
1933	75.5	468,191	70.00	12.15	0.1735	1.0000	81,246	6,688
1932	76.5	479,385	70.00	11.85	0.1693	1.0000	81,164	6,848

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 354.00 Towers and Fixtures

Dispersion: 70 - H4
Procedure: Broad Group

Generation Arrangement

Vintage	December 31, 2008 Age	December 31, 2008 Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1931	77.5	364,496	70.00	11.57	0.1652	1.0000	60,228	5,207
1930	78.5	623,403	70.00	11.29	0.1613	1.0000	100,560	8,906
1929	79.5	413,175	70.00	11.02	0.1575	1.0000	65,075	5,902
1928	80.5	87,968	70.00	10.77	0.1538	1.0000	13,534	1,257
1927	81.5	1,156,134	70.00	10.52	0.1503	1.0000	173,745	16,516
1926	82.5	519,799	70.00	10.28	0.1469	1.0000	76,341	7,426
1925	83.5	733,723	70.00	10.05	0.1435	1.0000	105,326	10,482
1924	84.5	356,009	70.00	9.82	0.1403	1.0000	49,966	5,086
1923	85.5	1,222,322	70.00	9.61	0.1373	1.0000	167,783	17,462
1922	86.5	1,585,891	70.00	9.40	0.1343	1.0000	212,921	22,656
1921	87.5	154,239	70.00	9.20	0.1314	1.0000	20,269	2,203
1920	88.5	123,114	70.00	9.00	0.1286	1.0000	15,830	1,759
1919	89.5	204,955	70.00	8.81	0.1259	1.0000	25,803	2,928
1918	90.5	5,318	70.00	8.63	0.1233	1.0000	655	76
1917	91.5	27,743	70.00	8.45	0.1207	1.0000	3,350	396
1916	92.5	4,382	70.00	8.28	0.1183	1.0000	518	63
1915	93.5	22,668	70.00	8.11	0.1159	1.0000	2,627	324
1914	94.5	149,832	70.00	7.96	0.1137	1.0000	17,032	2,140
1913	95.5	42,881	70.00	7.80	0.1114	1.0000	4,777	613
1912	96.5	27,809	70.00	7.65	0.1093	1.0000	3,039	397
1911	97.5	8,358	70.00	7.50	0.1072	1.0000	896	119
1910	98.5	1,957	70.00	7.36	0.1052	1.0000	206	28
1909	99.5	656	70.00	7.23	0.1032	1.0000	68	9
1908	100.5	29,788	70.00	7.09	0.1013	1.0000	3,017	426
1907	101.5	591,132	70.00	6.97	0.0995	1.0000	58,830	8,445
1906	102.5	32,867	70.00	6.84	0.0977	1.0000	3,210	470
1900	108.5	5,509	70.00	6.17	0.0881	1.0000	485	79
Total	36.8	$133,237,659	70.00	36.45	0.5207	1.0000	$69,381,410	$1,903,395

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 354.00 Towers and Fixtures

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2008	0.5	9,707,669		9,707,669	1.0000	0.5000
2007	1.5	631,568		631,568	1.0000	1.5000
2006	2.5	927,114		927,114	1.0000	2.5000
2005	3.5	1,787,711		1,782,711	0.9972	3.4986
2004	4.5	2,662		2,662	1.0000	4.5000
2003	5.5	16,432		16,432	1.0000	5.5000
2001	7.5	3,243,667		3,243,667	1.0000	7.5000
2000	8.5	28,434		28,434	1.0000	8.5000
1999	9.5	502,329		502,329	1.0000	9.5000
1998	10.5	74,158		74,158	1.0000	10.5000
1996	12.5	69,479		69,479	1.0000	12.5000
1994	14.5		95,270	95,270	1.0000	14.5000
1993	15.5		1,160,426	1,160,426	1.0000	15.5000
1992	16.5		798,064	798,064	1.0000	16.5000
1991	17.5		217,075	217,075	1.0000	17.5000
1990	18.5		407,576	407,576	1.0000	18.5000
1988	20.5		181,698	181,698	1.0000	20.5000
1987	21.5		223,175	182,730	0.8188	20.1408
1986	22.5		71,593	71,593	1.0000	22.5000
1985	23.5		2,648,048	2,648,048	1.0000	23.5000
1984	24.5		1,896,918	1,896,504	0.9998	24.4975
1983	25.5		1,449,588	1,448,623	0.9993	25.4941
1982	26.5		6,418,452	6,418,452	1.0000	26.5000
1981	27.5		518,542	518,542	1.0000	27.5000
1980	28.5		300,428	298,170	0.9925	28.4286
1979	29.5		4,779,670	4,779,670	1.0000	29.5000
1978	30.5		1,270,455	1,270,455	1.0000	30.5000
1977	31.5		2,533,993	2,533,993	1.0000	31.5000
1976	32.5		349,802	349,802	1.0000	32.5000
1975	33.5		4,001,538	3,993,434	0.9980	33.4808
1974	34.5		271,955	271,955	1.0000	34.5000
1973	35.5		539,067	539,067	1.0000	35.5000
1972	36.5		32,381,822	32,381,822	1.0000	36.5000
1971	37.5		5,637,986	5,619,777	0.9968	37.4984
1970	38.5		3,731,787	3,722,507	0.9975	38.4988
1969	39.5		1,080,318	1,080,318	1.0000	39.5000
1968	40.5		1,812,317	1,705,817	0.9412	40.4686

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 354.00 Towers and Fixtures

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1967	41.5		457,157	457,157	1.0000	41.5000
1966	42.5		930,845	929,697	0.9988	42.4858
1965	43.5		640,316	630,986	0.9854	43.4344
1964	44.5		506,601	506,601	1.0000	44.5000
1963	45.5		347,555	346,936	0.9982	45.4831
1962	46.5		12,594,035	12,563,438	0.9976	46.4870
1961	47.5		2,476,684	2,476,669	1.0000	47.4999
1960	48.5		2,831,000	2,808,467	0.9920	48.4514
1959	49.5		246,808	246,808	1.0000	49.5000
1958	50.5		3,372,401	3,301,988	0.9791	50.3430
1957	51.5		3,570,846	3,513,773	0.9840	51.3809
1956	52.5		167,907	167,604	0.9982	52.4847
1955	53.5		50,867	41,103	0.8080	51.6764
1954	54.5		1,015,875	1,015,875	1.0000	54.5000
1953	55.5		666,112	666,112	1.0000	55.5000
1952	56.5		724,864	724,864	1.0000	56.5000
1951	57.5		34,104	34,104	1.0000	57.5000
1950	58.5		233,015	233,015	1.0000	58.5000
1949	59.5		269,140	267,000	0.9920	59.4086
1948	60.5		137,161	137,161	1.0000	60.5000
1947	61.5		92,409	92,409	1.0000	61.5000
1946	62.5		12,250	12,250	1.0000	62.5000
1945	63.5		447	447	1.0000	63.5000
1944	64.5		5,811	5,592	0.9623	64.1795
1943	65.5		23,505	23,505	1.0000	65.5000
1942	66.5		246,239	240,022	0.9748	66.3633
1941	67.5		19,181	17,285	0.9012	66.3913
1940	68.5		79,220	79,220	1.0000	68.5000
1939	69.5		178,915	171,755	0.9600	69.1999
1938	70.5		2,210	2,210	1.0000	70.5000
1937	71.5		473,045	470,658	0.9950	71.4710
1935	73.5		3,669	3,659	0.9973	73.4898
1934	74.5		27,973	27,973	1.0000	74.5000
1933	75.5		469,587	468,191	0.9970	75.4777
1932	76.5		495,371	479,385	0.9677	76.2091
1931	77.5		364,859	364,496	0.9990	77.4906
1930	78.5		628,480	623,403	0.9919	78.4394

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Transmission Plant
Account: 354.00 Towers and Fixtures

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1929	79.5		419,590	413,175	0.9847	79.4435
1928	80.5		96,846	87,968	0.9083	80.1607
1927	81.5		1,173,712	1,156,134	0.9850	81.4424
1926	82.5		537,288	519,799	0.9674	82.3127
1925	83.5		759,259	733,723	0.9664	83.4424
1924	84.5		381,372	356,009	0.9335	83.9141
1923	85.5		1,285,281	1,222,322	0.9510	85.1425
1922	86.5		1,723,353	1,585,891	0.9202	86.1445
1921	87.5		158,532	154,239	0.9729	87.3103
1920	88.5		129,572	123,114	0.9502	88.1370
1919	89.5		208,279	204,955	0.9840	89.3997
1918	90.5		5,318	5,318	1.0000	90.5000
1917	91.5		28,049	27,743	0.9891	91.4072
1916	92.5		7,257	4,382	0.6039	91.4700
1915	93.5		22,668	22,668	1.0000	93.5000
1914	94.5		155,188	149,832	0.9655	94.3720
1913	95.5		56,753	42,881	0.7556	93.7203
1912	96.5		28,270	27,809	0.9837	96.3451
1911	97.5		8,461	8,358	0.9878	97.4696
1910	98.5		1,957	1,957	1.0000	98.5000
1909	99.5		656	656	1.0000	99.5000
1908	100.5		29,788	29,788	1.0000	100.5000
1907	101.5		658,682	591,132	0.8974	101.0082
1906	102.5		57,307	32,867	0.5735	101.0073
1900	108.5		5,509	5,509	1.0000	108.5000
Total	36.8	$16,991,223	$117,112,972	$133,237,659	0.9935	

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 354.00 Towers and Fixtures

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996		117,193,826		(15,283)	117,178,543
1997	117,178,543	459,137	45,106	(460,950)	117,131,624
1998	117,131,624		5,311		117,126,313
1999	117,126,313	171,231	136,668		117,160,877
2000	117,160,877	1,428,207	54,406	(1,022,023)	117,512,655
2001	117,512,655	3,364,429	172,298	(116,188)	120,588,599
2002	120,588,599		5,036		120,583,563
2003	120,583,563	40,144	29,980	(1,375)	120,592,352
2004	120,592,352	3,953	23,928		120,572,377
2005	120,572,377	1,509,992	86,512		121,995,858
2006	121,995,858	981,047	20,713		122,956,192
2007	122,956,192	668,474	22,657		123,602,009
2008	123,602,009	9,899,573	263,924		133,237,659

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 354.00 Towers and Fixtures

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996	118,728,790	69,479		(15,283)	118,782,986
1997	118,782,986		45,106	(460,950)	118,276,931
1998	118,276,931	74,158	5,311		118,345,778
1999	118,345,778	502,329	136,668		118,711,439
2000	118,711,439	28,434	54,406	(1,022,023)	117,663,445
2001	117,663,445	3,243,667	172,298	(116,188)	120,618,626
2002	120,618,626		5,036		120,613,591
2003	120,613,591	16,432	29,980	(1,375)	120,598,668
2004	120,598,668	2,662	23,928		120,577,402
2005	120,577,402	1,787,711	86,512		122,278,601
2006	122,278,601	927,114	20,713		123,185,002
2007	123,185,002	631,568	22,657		123,793,914
2008	123,793,914	9,707,669	263,924		133,237,659

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 354.00 Towers and Fixtures

T-Cut: None
Placement Band: 1960-2008
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2000	99.8	197.6	S6	0.02	196.9	SQ	0.02	127.7	S3 *	0.02
1997-2001	99.1	197.4	SQ *	0.18	145.9	R2.5	0.44	82.8	R4 *	0.13
1998-2002	99.0	197.3	SQ *	0.21	158.1	R2.5	0.32	86.8	R4 *	0.17
1999-2003	97.8	197.0	SQ *	0.61	137.0	S2	0.41	81.0	R4 *	0.27
2000-2004	94.9	196.8	SQ *	3.31	140.2	S2	3.00	84.8	R4 *	2.87
2001-2005	95.8	195.9	SQ	2.79	141.4	S2	2.49	86.6	R4 *	2.32
2002-2006	99.5	188.9	R4 *	0.08	151.3	R2.5 *	0.08	109.5	S3 *	0.08
2003-2007	99.6	190.1	R5 *	0.05	158.4	R2.5 *	0.05	126.1	S3 *	0.05
2004-2008	96.9	179.3	R3 *	0.95	143.6	S2 *	0.96	196.7	SQ *	0.86

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 354.00 Towers and Fixtures

T-Cut: None
Placement Band: 1960-2008
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2008	98.8	186.3	R4 *	0.28	139.8	S2	0.15	119.4	S3	0.14
1998-2008	98.5	185.9	R4 *	0.47	139.1	S2	0.23	120.5	S3	0.23
2000-2008	97.7	185.3	R4 *	1.05	137.9	S2	0.77	127.0	R3	0.77
2002-2008	98.7	180.1	R3 *	0.23	139.5	S2 *	0.22	196.4	SQ *	0.19
2004-2008	96.9	179.3	R3 *	0.95	143.6	S2 *	0.96	196.7	SQ *	0.86
2006-2008	96.1	175.2	R3 *	1.18	143.3	S2	1.21	196.1	SQ *	1.06
2008-2008	93.3	150.4	R1.5 *	1.55	126.9	S1.5 *	1.57	191.0	R5 *	1.50

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 354.00 Towers and Fixtures

T-Cut: None
Placement Band: 1960-2008
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-1997	99.9	198.6	SQ	0.03	196.9	SQ	0.02	198.9	SQ *	0.02
1996-1999	99.8	197.0	SQ	0.02	194.0	S6	0.03	116.2	S3 *	0.03
1996-2001	99.5	197.7	SQ *	0.22	153.0	R2.5	0.45	85.1	R4 *	0.23
1996-2003	98.9	196.6	S6	0.12	144.9	S2	0.32	85.7	R4 *	0.23
1996-2005	99.4	195.2	SQ	0.11	150.1	R2.5	0.23	93.5	R4 *	0.14
1996-2007	99.4	195.8	S6	0.10	161.4	R2.5	0.15	103.9	S3 *	0.10
1996-2008	98.8	186.3	R4 *	0.28	139.8	S2	0.15	119.4	S3	0.14

Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 354.00 Towers and Fixtures

T-Cut: None

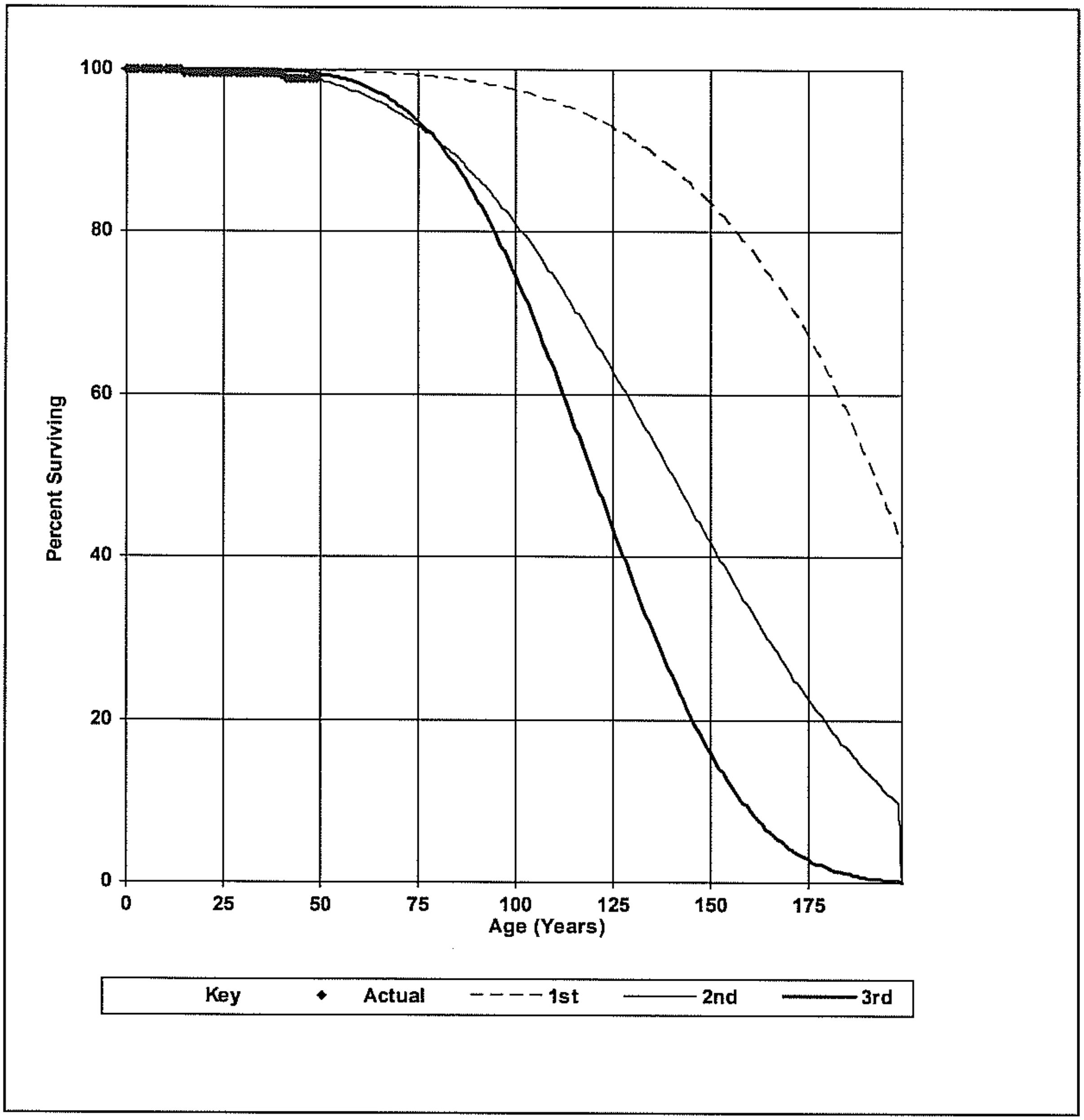
Placement Band: 1960-2008 Observation Band: 1996-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 186.3-R4 2nd: 139.8-S2 3rd: 119.4-S3



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 354.00 Towers and Fixtures

T-Cut: None

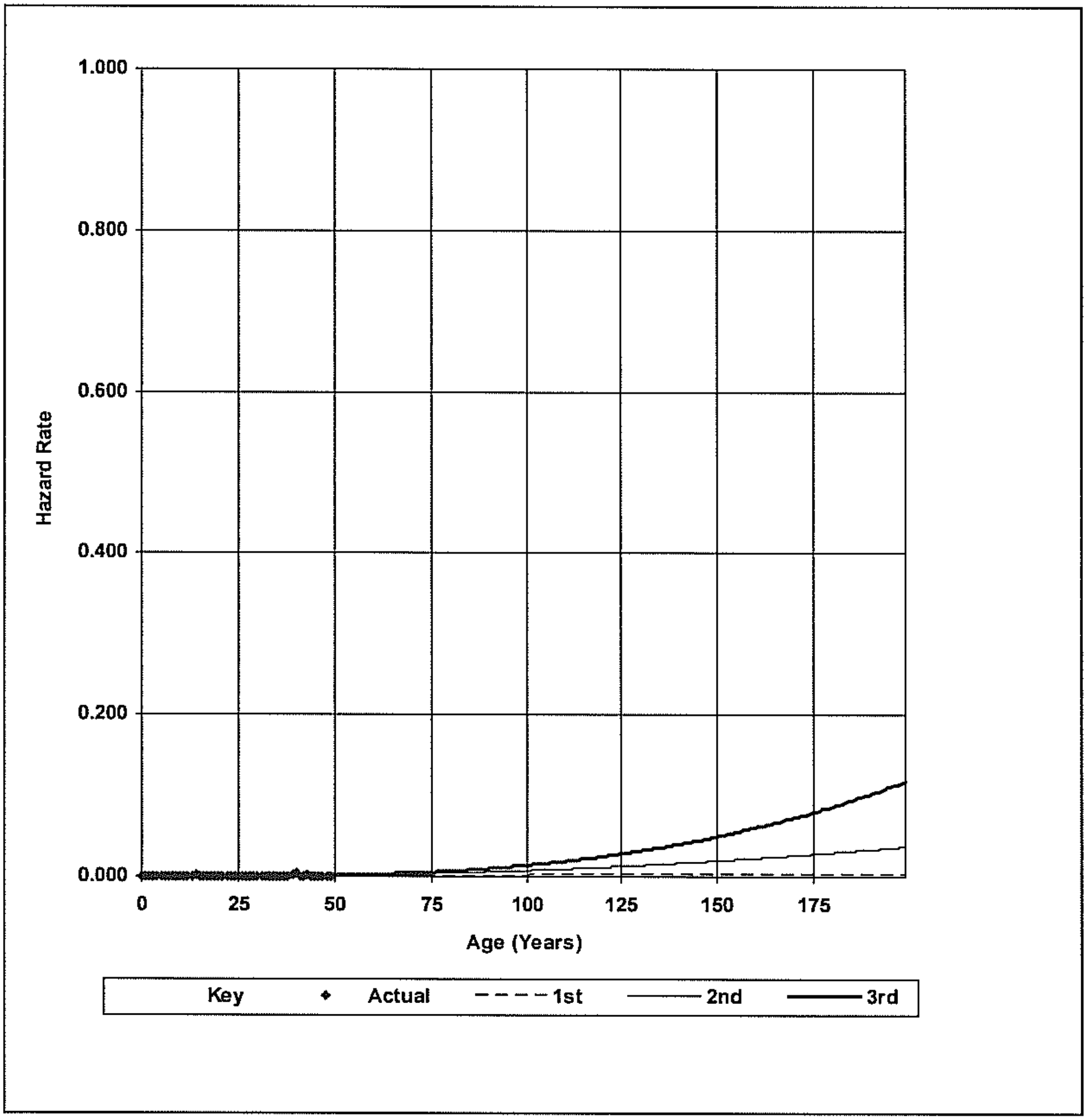
Placement Band: 1960-2008 Observation Band: 1996-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 186.3-R4 2nd: 139.8-S2 3rd: 119.4-S3



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

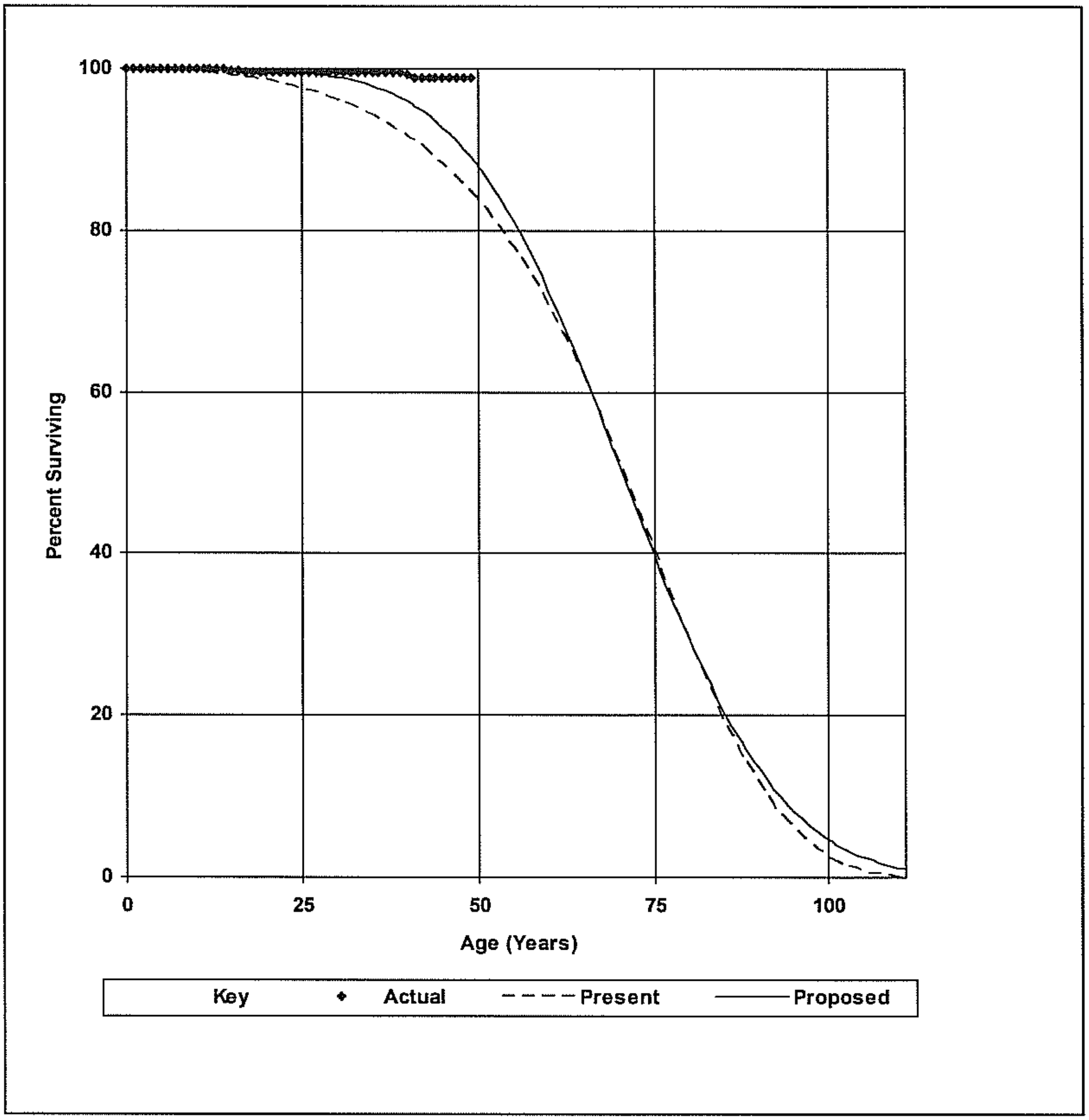
Account: 354.00 Towers and Fixtures

T-Cut: None

Placement Band: 1960-2008

Observation Band: 1996-2008

Present and Proposed Projection Life Curves **Present: 68.0-R3** **Proposed: 70.0-H4**



Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 354.00 Towers and Fixtures

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998	5,311		0.0		4,463	84.0		(4,463)	-84.0	
1999	136,668		0.0		153,200	112.1		(153,200)	-112.1	
2000	54,406	95,970	176.4		24,620	45.3		71,349	131.1	
2001	172,298	116,163	67.4		98,635	57.2		17,528	10.2	
2002	5,036		0.0	56.8	(26,587)	-528.0	68.1	26,587	528.0	-11.3
2003	29,980	(3,487)	-11.6	52.4	34,966	116.6	71.5	(38,453)	-128.3	-19.1
2004	23,928		0.0	73.0	51,201	214.0	64.0	(51,201)	-214.0	9.0
2005	86,512		0.0	35.5	589,981	682.0	235.5	(589,981)	-682.0	-200.0
2006	20,713		0.0	-2.1	181,603	876.8	500.2	(181,603)	-876.8	-502.3
2007	22,657		0.0	-1.9	90,200	398.1	515.8	(90,200)	-398.1	-517.7
2008	263,924		0.0	0.0	838,669	317.8	419.3	(838,669)	-317.8	-419.3
Total	821,431	208,646	25.4		2,040,952	248.5		(1,832,306)	-223.1	

Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 354.00 Towers and Fixtures

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998	5,311		0.0		4,463	84.0		(4,463)	-84.0	
1999	136,668		0.0		153,200	112.1		(153,200)	-112.1	
2000	54,406	95,970	176.4		24,620	45.3		71,349	131.1	
2001	172,298	116,163	67.4		98,635	57.2		17,528	10.2	
2002	5,036		0.0	56.8	(26,587)	-528.0	68.1	26,587	528.0	-11.3
2003	29,980	(3,487)	-11.6	52.4	34,966	116.6	71.5	(38,453)	-128.3	-19.1
2004	23,928		0.0	73.0	51,201	214.0	64.0	(51,201)	-214.0	9.0
2005	86,512		0.0	35.5	589,981	682.0	235.5	(589,981)	-682.0	-200.0
2006	20,713		0.0	-2.1	181,603	876.8	500.2	(181,603)	-876.8	-502.3
2007	22,657		0.0	-1.9	90,200	398.1	515.8	(90,200)	-398.1	-517.7
2008	263,924		0.0	0.0	838,669	317.8	419.3	(838,669)	-317.8	-419.3
Total	821,431	208,646	25.4		2,040,952	248.5		(1,832,306)	-223.1	

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 355.00 Poles and Fixtures

Dispersion: 65 - H4
Procedure: Broad Group

Generation Arrangement

Vintage	December 31, 2008 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2008	0.5	7,351,533	65.00	64.50	0.9923	1.0000	7,295,036	113,101
2007	1.5	35,791,659	65.00	63.50	0.9769	1.0000	34,966,146	550,641
2006	2.5	21,185,439	65.00	62.50	0.9616	1.0000	20,371,196	325,930
2005	3.5	7,247,685	65.00	61.50	0.9462	1.0000	6,857,730	111,503
2004	4.5	6,683,061	65.00	60.50	0.9308	1.0000	6,220,823	102,816
2003	5.5	8,204,165	65.00	59.51	0.9155	1.0000	7,510,658	126,218
2002	6.5	5,045,555	65.00	58.51	0.9001	1.0000	4,541,612	77,624
2001	7.5	24,369,563	65.00	57.51	0.8848	1.0000	21,561,434	374,916
2000	8.5	5,847,232	65.00	56.51	0.8694	1.0000	5,083,785	89,957
1999	9.5	11,820,892	65.00	55.52	0.8541	1.0000	10,096,320	181,860
1998	10.5	1,564,463	65.00	54.52	0.8388	1.0000	1,312,255	24,069
1997	11.5	3,186,994	65.00	53.53	0.8235	1.0000	2,624,451	49,031
1996	12.5	6,497,884	65.00	52.53	0.8082	1.0000	5,251,609	99,967
1995	13.5	10,043,131	65.00	51.54	0.7929	1.0000	7,963,555	154,510
1994	14.5	6,001,266	65.00	50.55	0.7777	1.0000	4,667,107	92,327
1993	15.5	9,171,544	65.00	49.56	0.7625	1.0000	6,993,022	141,101
1992	16.5	9,975,217	65.00	48.57	0.7473	1.0000	7,454,340	153,465
1991	17.5	6,370,498	65.00	47.59	0.7321	1.0000	4,664,044	98,008
1990	18.5	9,420,519	65.00	46.61	0.7170	1.0000	6,754,702	144,931
1989	19.5	17,770,848	65.00	45.63	0.7019	1.0000	12,474,218	273,398
1988	20.5	3,636,644	65.00	44.65	0.6869	1.0000	2,498,154	55,948
1987	21.5	12,873,731	65.00	43.68	0.6720	1.0000	8,650,910	198,057
1986	22.5	6,007,707	65.00	42.71	0.6571	1.0000	3,947,627	92,426
1985	23.5	9,843,716	65.00	41.75	0.6423	1.0000	6,322,374	151,442
1984	24.5	3,116,980	65.00	40.79	0.6275	1.0000	1,956,045	47,954
1983	25.5	5,870,932	65.00	39.84	0.6129	1.0000	3,598,295	90,322
1982	26.5	16,697,902	65.00	38.89	0.5984	1.0000	9,991,294	256,891
1981	27.5	4,699,855	65.00	37.96	0.5839	1.0000	2,744,384	72,305
1980	28.5	1,810,390	65.00	37.02	0.5696	1.0000	1,031,223	27,852
1979	29.5	9,875,093	65.00	36.10	0.5554	1.0000	5,484,998	151,925
1978	30.5	13,870,156	65.00	35.19	0.5414	1.0000	7,509,213	213,387
1977	31.5	4,425,277	65.00	34.29	0.5275	1.0000	2,334,399	68,081
1976	32.5	971,318	65.00	33.40	0.5138	1.0000	499,047	14,943
1975	33.5	15,098,336	65.00	32.52	0.5002	1.0000	7,552,840	232,282
1974	34.5	2,870,387	65.00	31.65	0.4869	1.0000	1,397,519	44,160
1973	35.5	1,281,220	65.00	30.79	0.4737	1.0000	606,937	19,711

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 355.00 Poles and Fixtures

Dispersion: 65 - H4
Procedure: Broad Group

Generation Arrangement

Vintage	December 31, 2008 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1972	36.5	2,093,173	65.00	29.95	0.4608	1.0000	964,434	32,203
1971	37.5	4,077,084	65.00	29.12	0.4480	1.0000	1,826,597	62,724
1970	38.5	5,440,620	65.00	28.31	0.4355	1.0000	2,369,370	83,702
1969	39.5	1,424,338	65.00	27.51	0.4232	1.0000	602,801	21,913
1968	40.5	2,266,739	65.00	26.73	0.4112	1.0000	932,030	34,873
1967	41.5	2,205,186	65.00	25.96	0.3994	1.0000	880,712	33,926
1966	42.5	797,539	65.00	25.21	0.3879	1.0000	309,334	12,270
1965	43.5	834,242	65.00	24.48	0.3766	1.0000	314,158	12,834
1964	44.5	970,322	65.00	23.76	0.3656	1.0000	354,743	14,928
1963	45.5	851,104	65.00	23.06	0.3548	1.0000	302,009	13,094
1962	46.5	3,289,432	65.00	22.39	0.3444	1.0000	1,132,917	50,607
1961	47.5	1,827,290	65.00	21.72	0.3342	1.0000	610,725	28,112
1960	48.5	3,268,426	65.00	21.08	0.3243	1.0000	1,060,090	50,283
1959	49.5	537,831	65.00	20.46	0.3147	1.0000	169,265	8,274
1958	50.5	3,255,127	65.00	19.85	0.3054	1.0000	994,086	50,079
1957	51.5	1,019,342	65.00	19.26	0.2963	1.0000	302,062	15,682
1956	52.5	489,591	65.00	18.69	0.2876	1.0000	140,783	7,532
1955	53.5	368,560	65.00	18.14	0.2790	1.0000	102,846	5,670
1954	54.5	566,086	65.00	17.60	0.2708	1.0000	153,302	8,709
1953	55.5	558,794	65.00	17.09	0.2629	1.0000	146,879	8,597
1952	56.5	539,829	65.00	16.58	0.2551	1.0000	137,731	8,305
1951	57.5	131,863	65.00	16.10	0.2477	1.0000	32,663	2,029
1950	58.5	203,838	65.00	15.63	0.2405	1.0000	49,023	3,136
1949	59.5	431,755	65.00	15.18	0.2336	1.0000	100,843	6,642
1948	60.5	257,286	65.00	14.75	0.2269	1.0000	58,367	3,958
1947	61.5	40,954	65.00	14.33	0.2204	1.0000	9,026	630
1946	62.5	18,328	65.00	13.92	0.2142	1.0000	3,925	282
1945	63.5	14,745	65.00	13.53	0.2081	1.0000	3,069	227
1944	64.5	20,488	65.00	13.15	0.2023	1.0000	4,146	315
1943	65.5	103,468	65.00	12.79	0.1968	1.0000	20,358	1,592
1942	66.5	144,836	65.00	12.44	0.1914	1.0000	27,718	2,228
1941	67.5	155,651	65.00	12.10	0.1862	1.0000	28,980	2,395
1940	68.5	129,021	65.00	11.78	0.1812	1.0000	23,377	1,985
1939	69.5	56,535	65.00	11.46	0.1764	1.0000	9,971	870
1938	70.5	56,843	65.00	11.16	0.1717	1.0000	9,762	875
1937	71.5	18,026	65.00	10.87	0.1673	1.0000	3,015	277

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 355.00 Poles and Fixtures

Dispersion: 65 - H4
Procedure: Broad Group

Generation Arrangement

Vintage	Age	December 31, 2008 Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1936	72.5	26,851	65.00	10.59	0.1630	1.0000	4,376	413
1935	73.5	16,207	65.00	10.32	0.1588	1.0000	2,574	249
1934	74.5	41,789	65.00	10.06	0.1548	1.0000	6,470	643
1933	75.5	16,257	65.00	9.81	0.1510	1.0000	2,454	250
1932	76.5	85,052	65.00	9.57	0.1473	1.0000	12,525	1,308
1931	77.5	102,320	65.00	9.34	0.1437	1.0000	14,703	1,574
1930	78.5	155,256	65.00	9.12	0.1402	1.0000	21,774	2,389
1929	79.5	76,326	65.00	8.90	0.1369	1.0000	10,450	1,174
1928	80.5	43,222	65.00	8.69	0.1337	1.0000	5,780	665
1927	81.5	45,022	65.00	8.49	0.1306	1.0000	5,881	693
1926	82.5	92,672	65.00	8.30	0.1277	1.0000	11,832	1,426
1925	83.5	51,517	65.00	8.11	0.1248	1.0000	6,428	793
1924	84.5	84,031	65.00	7.93	0.1221	1.0000	10,256	1,293
1923	85.5	43,587	65.00	7.76	0.1193	1.0000	5,201	671
1922	86.5	5,473	65.00	7.59	0.1168	1.0000	639	84
1921	87.5	144	65.00	7.43	0.1143	1.0000	16	2
1920	88.5	99	65.00	7.27	0.1119	1.0000	11	2
1919	89.5	59	65.00	7.12	0.1095	1.0000	6	1
1918	90.5	16	65.00	6.97	0.1073	1.0000	2	
1917	91.5	219	65.00	6.83	0.1051	1.0000	23	3
1916	92.5	41	65.00	6.69	0.1030	1.0000	4	1
1915	93.5	403	65.00	6.56	0.1010	1.0000	41	6
1914	94.5	177	65.00	6.43	0.0990	1.0000	18	3
1907	101.5	357	65.00	5.65	0.0869	1.0000	31	5
1900	108.5	9,008	65.00	5.01	0.0771	1.0000	695	139
Total	18.5	$365,859,185	65.00	47.10	0.7246	1.0000	$265,102,614	$5,628,603

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 355.00 Poles and Fixtures

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2008	0.5	7,351,533		7,351,533	1.0000	0.5000
2007	1.5	35,791,659		35,791,659	1.0000	1.5000
2006	2.5	21,190,131		21,185,439	0.9998	2.4997
2005	3.5	7,293,879		7,247,685	0.9937	3.4689
2004	4.5	6,735,447		6,683,061	0.9922	4.4822
2003	5.5	8,297,350		8,204,165	0.9888	5.4856
2002	6.5	5,136,718		5,045,555	0.9823	6.4393
2001	7.5	24,410,316		24,369,563	0.9983	7.4971
2000	8.5	5,969,082		5,847,232	0.9796	8.4233
1999	9.5	12,014,788		11,820,892	0.9839	9.4401
1998	10.5	1,565,288		1,564,463	0.9995	10.4980
1997	11.5	3,190,360		3,186,994	0.9989	11.4917
1996	12.5	6,570,974		6,497,884	0.9889	12.4175
1995	13.5		10,212,031	10,043,131	0.9835	13.3671
1994	14.5		6,081,135	6,001,266	0.9869	14.4192
1993	15.5		9,623,425	9,171,544	0.9530	15.2543
1992	16.5		10,225,805	9,975,217	0.9755	16.3961
1991	17.5		6,434,096	6,370,498	0.9901	17.4621
1990	18.5		9,586,271	9,420,519	0.9827	18.3598
1989	19.5		17,885,220	17,770,848	0.9936	19.4316
1988	20.5		4,748,963	3,636,644	0.7658	18.7554
1987	21.5		13,356,989	12,873,731	0.9638	21.1855
1986	22.5		6,079,605	6,007,707	0.9882	22.3744
1985	23.5		10,022,811	9,843,716	0.9821	23.4068
1984	24.5		3,158,286	3,116,980	0.9869	24.3848
1983	25.5		5,972,509	5,870,932	0.9830	25.3369
1982	26.5		16,774,759	16,697,902	0.9954	26.4645
1981	27.5		4,794,324	4,699,855	0.9803	27.3367
1980	28.5		1,850,664	1,810,390	0.9782	28.3663
1979	29.5		9,917,088	9,875,093	0.9958	29.4741
1978	30.5		14,095,187	13,870,156	0.9840	30.4517
1977	31.5		4,491,181	4,425,277	0.9853	31.4367
1976	32.5		1,001,696	971,318	0.9697	32.2601
1975	33.5		15,196,112	15,098,336	0.9936	33.4601
1974	34.5		3,123,735	2,870,387	0.9189	34.0237
1973	35.5		1,342,019	1,281,220	0.9547	35.1055
1972	36.5		2,219,453	2,093,173	0.9431	36.1924

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 355.00 Poles and Fixtures

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1971	37.5		4,136,565	4,077,084	0.9856	37.4417
1970	38.5		5,560,276	5,440,620	0.9785	38.4219
1969	39.5		1,462,777	1,424,338	0.9737	39.3743
1968	40.5		2,338,661	2,266,739	0.9692	40.3493
1967	41.5		2,249,009	2,205,186	0.9805	41.3981
1966	42.5		827,146	797,539	0.9642	42.3266
1965	43.5		880,161	834,242	0.9478	43.0905
1964	44.5		997,196	970,322	0.9731	44.3310
1963	45.5		955,114	851,104	0.8911	44.8939
1962	46.5		3,425,847	3,289,432	0.9602	46.3677
1961	47.5		1,910,106	1,827,290	0.9566	47.3141
1960	48.5		3,460,616	3,268,426	0.9445	48.1800
1959	49.5		631,679	537,831	0.8514	48.3758
1958	50.5		3,342,675	3,255,127	0.9738	50.3786
1957	51.5		1,057,664	1,019,342	0.9638	51.2731
1956	52.5		576,323	489,591	0.8495	51.6245
1955	53.5		452,569	368,560	0.8144	52.1552
1954	54.5		675,823	566,086	0.8376	53.3316
1953	55.5		646,342	558,794	0.8645	54.8007
1952	56.5		634,460	539,829	0.8508	55.8778
1951	57.5		195,209	131,863	0.6755	55.1475
1950	58.5		285,129	203,838	0.7149	57.0284
1949	59.5		503,296	431,755	0.8579	58.9024
1948	60.5		282,360	257,286	0.9112	60.1091
1947	61.5		54,811	40,954	0.7472	59.9240
1946	62.5		26,688	18,328	0.6868	60.8828
1945	63.5		18,761	14,745	0.7859	62.3982
1944	64.5		25,980	20,488	0.7886	63.8339
1943	65.5		135,850	103,468	0.7616	64.3147
1942	66.5		192,004	144,836	0.7543	65.1840
1941	67.5		211,273	155,651	0.7367	65.7927
1940	68.5		173,277	129,021	0.7446	66.8197
1939	69.5		78,100	56,535	0.7239	67.4446
1938	70.5		79,102	56,843	0.7186	68.9406
1937	71.5		21,929	18,026	0.8220	70.5807
1936	72.5		30,628	26,851	0.8767	71.7925
1935	73.5		23,235	16,207	0.6975	71.5572

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 355.00 Poles and Fixtures

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1934	74.5		64,504	41,789	0.6479	72.6430
1933	75.5		38,454	16,257	0.4228	72.1185
1932	76.5		111,459	85,052	0.7631	75.1123
1931	77.5		135,987	102,320	0.7524	76.0629
1930	78.5		188,493	155,256	0.8237	77.3109
1929	79.5		114,562	76,326	0.6662	77.2230
1928	80.5		67,128	43,222	0.6439	78.5322
1927	81.5		69,317	45,022	0.6495	80.2363
1926	82.5		119,865	92,672	0.7731	81.0763
1925	83.5		101,048	51,517	0.5098	80.6163
1924	84.5		144,538	84,031	0.5814	81.1484
1923	85.5		60,298	43,587	0.7229	84.1733
1922	86.5		10,877	5,473	0.5032	83.9465
1921	87.5		1,058	144	0.1358	81.0391
1920	88.5		127	99	0.7828	86.7623
1919	89.5		168	59	0.3491	85.8964
1918	90.5		5,476	16	0.0029	82.5710
1917	91.5		286	219	0.7659	90.8278
1916	92.5		58	41	0.7089	91.7723
1915	93.5		535	403	0.7524	91.5639
1914	94.5		345	177	0.5132	90.5669
1913	95.5		88		0.0000	90.0000
1908	100.5		224		0.0000	92.5000
1907	101.5		2,734	357	0.1305	97.4018
1900	108.5		14,598	9,008	0.6171	106.0350
Total	18.5	$145,517,526	$228,004,230	$365,859,185	0.9795	

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Transmission Plant
Account: 355.00 Poles and Fixtures

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996		228,969,654		(302,164)	228,667,490
1997	228,667,490	16,197,180	585,599	(6,703,551)	237,575,520
1998	237,575,520	58,090	104,189	(14,220)	237,515,200
1999	237,515,200	15,806,729	1,390,163	(6,256,028)	245,675,739
2000	245,675,739	20,942,336	454,445	(14,396,088)	251,767,542
2001	251,767,542	29,782,998	1,289,855	(5,457,253)	274,803,431
2002	274,803,431	6,892,771	466,072	(182)	281,229,949
2003	281,229,949	4,459,366	135,823		285,553,492
2004	285,553,492	7,282,012	537,861		292,297,643
2005	292,297,643	7,405,783	787,787	(22,449)	298,893,191
2006	298,893,191	17,593,899	883,956	(21,734)	315,581,400
2007	315,581,400	19,013,543	428,567	(36,905)	334,129,471
2008	334,129,471	32,331,547	598,254	(3,580)	365,859,185

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 355.00 Poles and Fixtures

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996	254,218,377	10,461,794		(302,164)	264,378,007
1997	264,378,007	6,143,337	585,599	(6,703,551)	263,232,194
1998	263,232,194	1,597,953	104,189	(14,220)	264,711,737
1999	264,711,737	12,072,487	1,390,163	(6,256,028)	269,138,033
2000	269,138,033	6,003,504	454,445	(14,396,088)	260,291,004
2001	260,291,004	24,410,316	1,289,855	(5,457,253)	277,954,211
2002	277,954,211	5,136,872	466,072	(182)	282,624,829
2003	282,624,829	8,306,536	135,823		290,795,542
2004	290,795,542	6,749,364	537,861		297,007,045
2005	297,007,045	7,301,547	787,787	(22,449)	303,498,357
2006	303,498,357	21,190,631	883,956	(21,734)	323,783,298
2007	323,783,298	35,791,659	428,567	(36,905)	359,109,485
2008	359,109,485	7,351,533	598,254	(3,580)	365,859,185

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 355.00 Poles and Fixtures

T-Cut: None

Placement Band: 1952-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper- sion	Conf. Index	Average Life	Disper- sion	Conf. Index	Average Life	Disper- sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2000	83.8	122.0	S0	1.19	79.2	S1.5	0.70	62.3	R4	0.50
1997-2001	82.6	125.3	S-.5	1.14	93.7	S0.5	1.01	59.9	R4 *	0.94
1998-2002	83.6	130.1	R0.5	1.03	105.5	S0.5	0.94	61.7	R4 *	0.58
1999-2003	84.7	135.1	R0.5	0.96	111.2	R1	0.88	63.2	R3 *	0.61
2000-2004	87.7	159.9	R1	0.97	150.1	R1	0.92	67.5	R4 *	0.48
2001-2005	86.4	172.8	R2 *	1.03	121.3	R1.5	0.89	66.4	R4 *	0.53
2002-2006	80.1	150.4	R1	1.52	88.3	S1.5	0.94	70.4	R3	0.78
2003-2007	81.3	136.7	R1	1.56	85.4	S2	0.80	71.5	R3	0.62
2004-2008	79.8	128.4	S0	1.58	82.4	S2	0.69	69.9	R3	0.40

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 355.00 Poles and Fixtures

T-Cut: None
Placement Band: 1952-2008
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2008	79.4	134.3	R0.5	1.76	88.5	S1.5	0.99	67.9	R3	0.40
1998-2008	79.0	132.5	R0.5	1.70	87.5	S1.5	0.95	67.6	R3	0.41
2000-2008	80.3	137.5	R0.5	1.61	91.3	S1.5	1.03	68.4	R4	0.43
2002-2008	81.0	134.8	R1	1.62	86.2	S1.5	0.81	70.5	R3	0.40
2004-2008	79.8	128.4	S0	1.58	82.4	S2	0.69	69.9	R3	0.40
2006-2008	79.7	117.8	S0 *	1.48	80.6	S2	0.80	70.9	R3	0.67
2008-2008	82.9	116.5	S0 *	1.87	80.8	S2	1.51	69.7	R3	1.57

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 355.00 Poles and Fixtures

T-Cut: None

Placement Band: 1952-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-1997	93.0	164.9	R2	0.53	115.9	S1.5	0.46	70.1	R4	0.57
1996-1999	83.1	122.1	S0	1.36	76.4	S1.5	0.91	59.2	R4 *	0.49
1996-2001	84.3	129.8	R0.5	1.09	99.3	S0.5	0.98	61.2	R4 *	0.81
1996-2003	86.9	140.6	R1	0.83	111.8	S0.5	0.72	65.5	R4 *	0.44
1996-2005	85.0	146.0	R1	1.05	99.7	S1	0.71	66.8	R4	0.43
1996-2007	79.6	136.7	R0.5	1.66	90.8	S1.5	1.05	67.7	R3	0.54
1996-2008	79.4	134.3	R0.5	1.76	88.5	S1.5	0.99	67.9	R3	0.40

Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 355.00 Poles and Fixtures

T-Cut: None

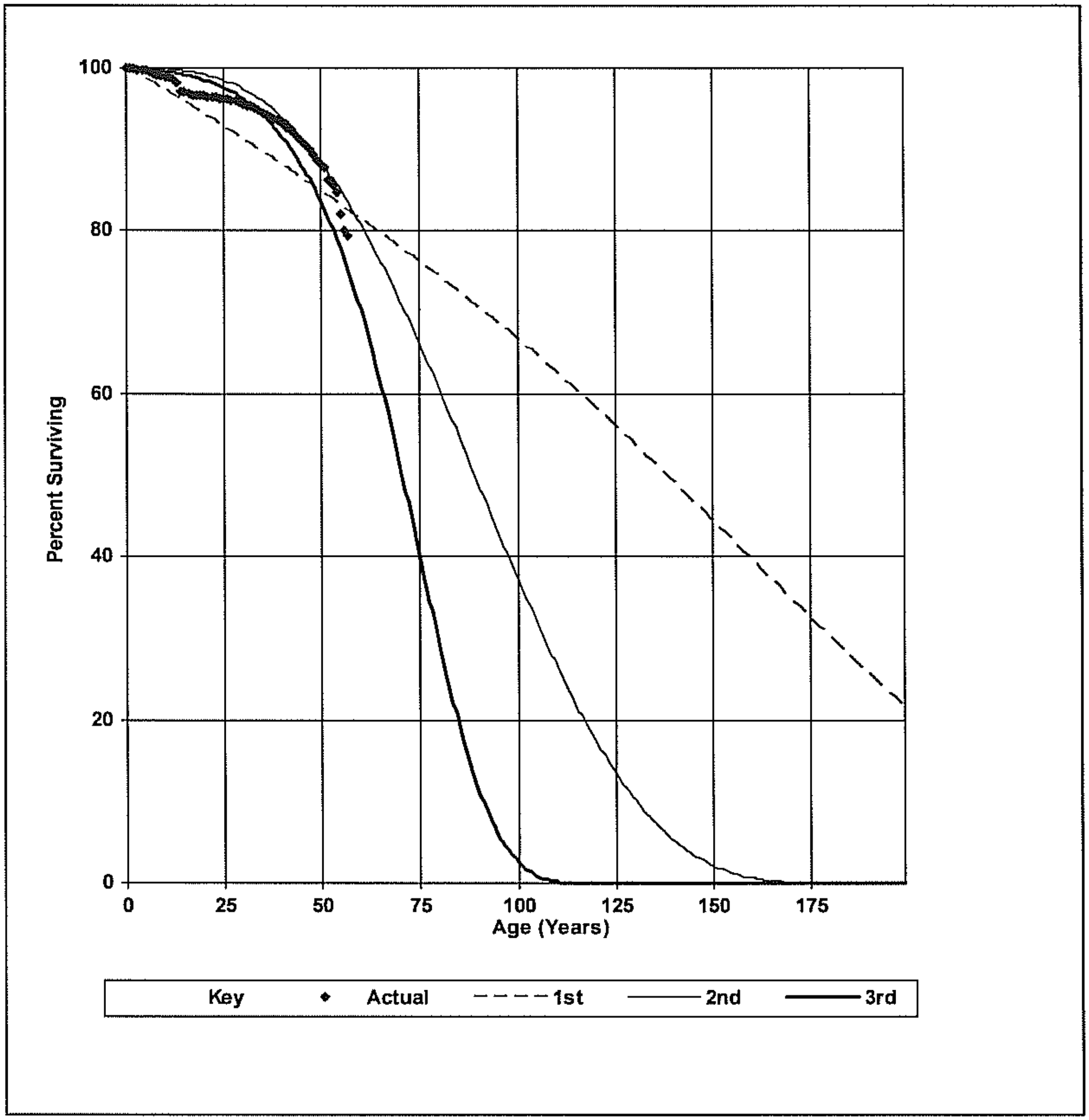
Placement Band: 1952-2008 Observation Band: 1996-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 134.3-R0.5 2nd: 88.5-S1.5 3rd: 67.9-R3



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 355.00 Poles and Fixtures

T-Cut: None

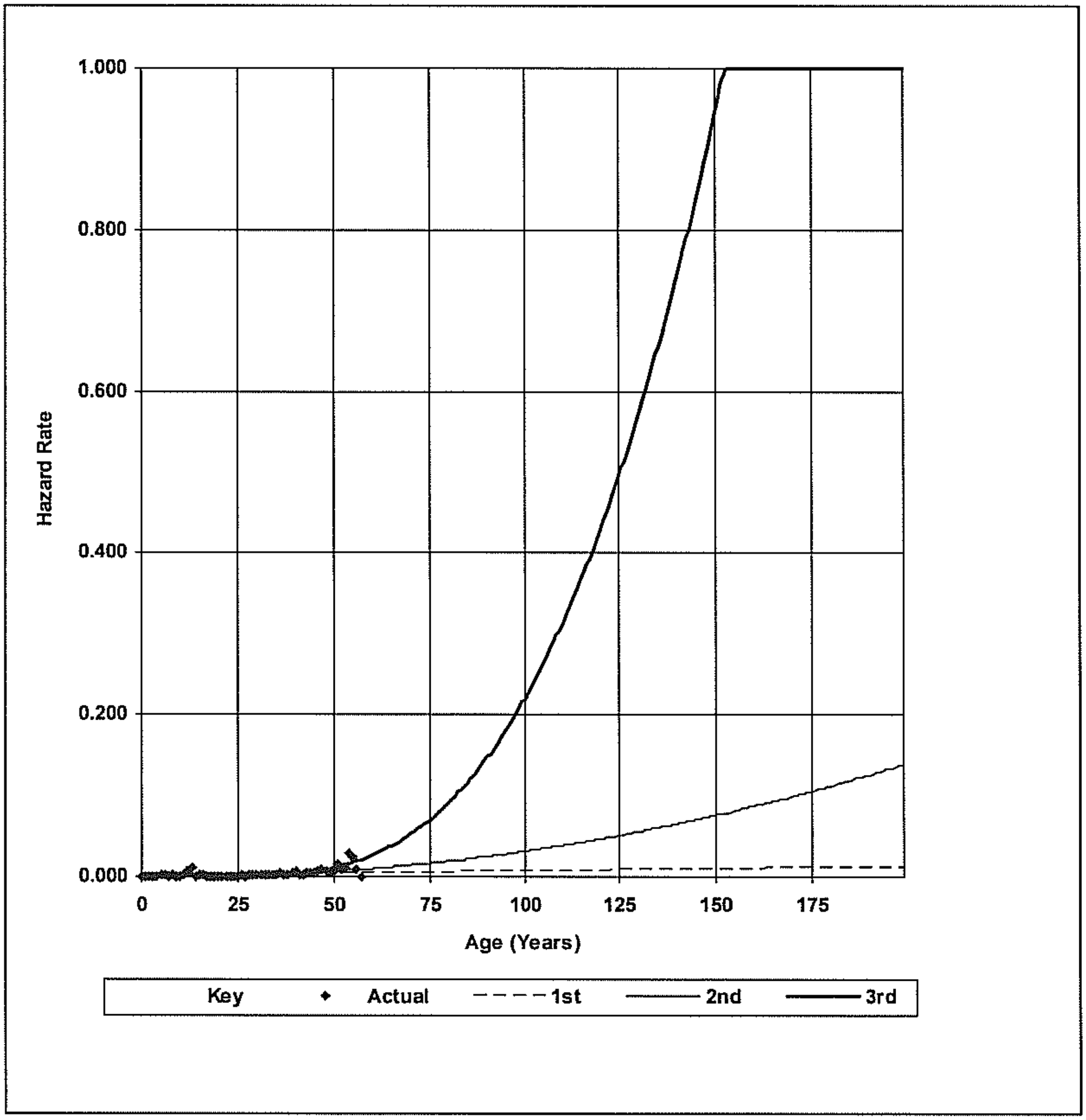
Placement Band: 1952-2008 Observation Band: 1996-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 134.3-R0.5 2nd: 88.5-S1.5 3rd: 67.9-R3



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

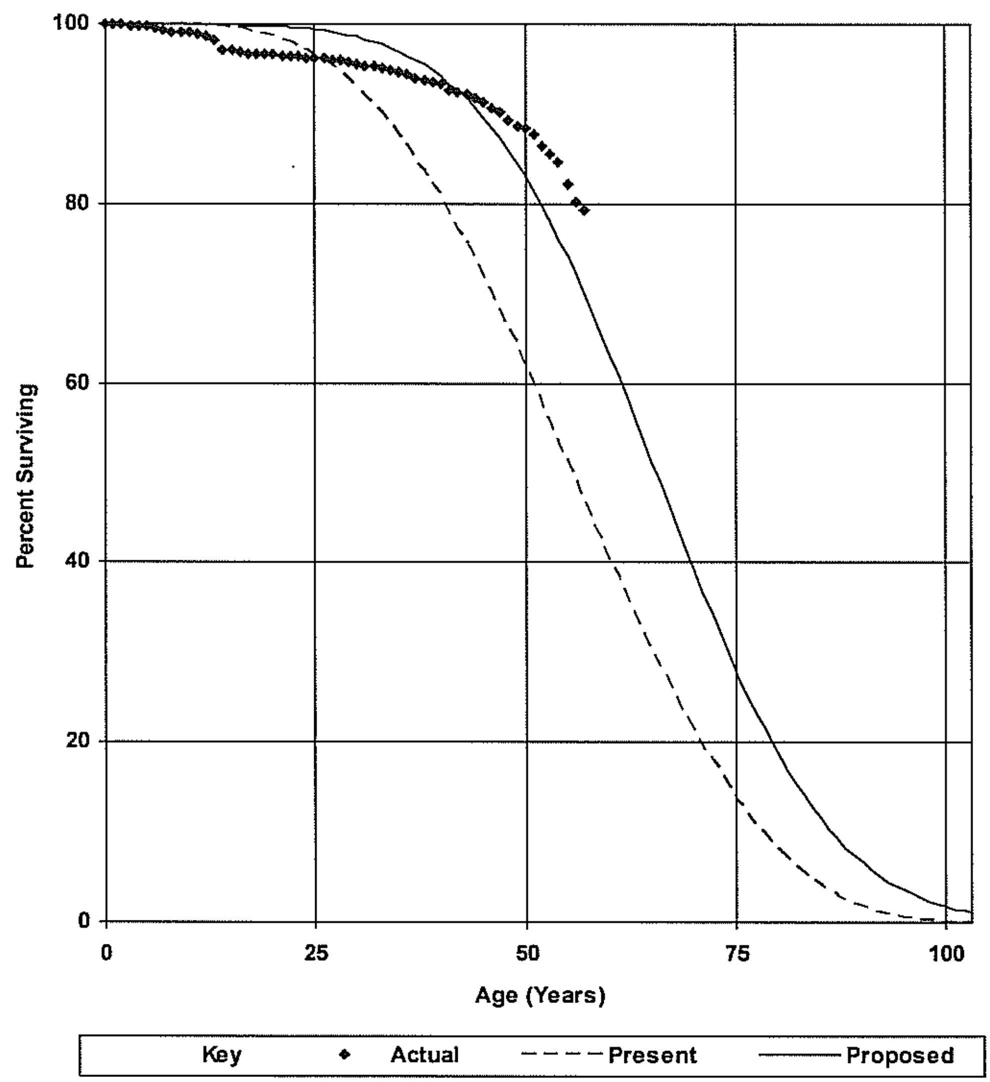
Account: 355.00 Poles and Fixtures

T-Cut: None

Placement Band: 1952-2008

Observation Band: 1996-2008

Present and Proposed Projection Life Curves **Present: 55.0-S2** **Proposed: 65.0-H4**



Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 355.00 Poles and Fixtures

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998	104,189		0.0		(34,495)	-33.1		34,495	33.1	
1999	1,390,163	33,481	2.4		637,570	45.9		(604,089)	-43.5	
2000	454,445	1,713,513	377.1		953,514	209.8		759,998	167.2	
2001	1,289,855	286,058	22.2		765,698	59.4		(479,639)	-37.2	
2002	466,072	16,431	3.5	55.3	326,311	70.0	71.5	(309,880)	-66.5	-16.2
2003	135,823	164,135	120.8	59.2	328,520	241.9	80.6	(164,385)	-121.0	-21.4
2004	537,861	(40,838)	-7.6	74.2	506,466	94.2	99.9	(547,304)	-101.8	-25.7
2005	787,787		0.0	13.2	577,814	73.3	77.9	(577,814)	-73.3	-64.6
2006	883,956		0.0	5.0	1,433,468	162.2	112.8	(1,433,468)	-162.2	-107.9
2007	428,567		0.0	4.4	2,039,831	476.0	176.1	(2,039,831)	-476.0	-171.7
2008	598,254		0.0	-1.3	2,583,391	431.8	220.6	(2,583,391)	-431.8	-221.9
Total	7,076,973	2,172,780	30.7		10,118,088	143.0		(7,945,308)	-112.3	

Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 355.00 Poles and Fixtures

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998	104,189		0.0		(34,495)	-33.1		34,495	33.1	
1999	1,390,163	33,481	2.4		637,570	45.9		(604,089)	-43.5	
2000	454,445	1,713,513	377.1		953,514	209.8		759,998	167.2	
2001	1,289,855	286,058	22.2		765,698	59.4		(479,639)	-37.2	
2002	466,072	16,431	3.5	55.3	326,311	70.0	71.5	(309,880)	-66.5	-16.2
2003	135,823	164,135	120.8	59.2	328,520	241.9	80.6	(164,385)	-121.0	-21.4
2004	537,861	(40,838)	-7.6	74.2	506,466	94.2	99.9	(547,304)	-101.8	-25.7
2005	787,787		0.0	13.2	577,814	73.3	77.9	(577,814)	-73.3	-64.6
2006	883,956		0.0	5.0	1,433,468	162.2	112.8	(1,433,468)	-162.2	-107.9
2007	428,567		0.0	4.4	2,039,831	476.0	176.1	(2,039,831)	-476.0	-171.7
2008	598,254		0.0	-1.3	2,583,391	431.8	220.6	(2,583,391)	-431.8	-221.9
Total	7,076,973	2,172,780	30.7		10,118,088	143.0		(7,945,308)	-112.3	

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 356.01 Overhead Conductors and Device

Dispersion: 75 - H2
Procedure: Broad Group

Generation Arrangement

Vintage	Age	December 31, 2008 Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2008	0.5	7,168,194	75.00	74.56	0.9941	1.0000	7,125,947	95,576
2007	1.5	9,767,300	75.00	73.68	0.9824	1.0000	9,594,940	130,231
2006	2.5	8,975,395	75.00	72.80	0.9707	1.0000	8,712,167	119,672
2005	3.5	9,926,603	75.00	71.93	0.9591	1.0000	9,520,257	132,355
2004	4.5	2,845,178	75.00	71.06	0.9475	1.0000	2,695,891	37,936
2003	5.5	2,821,281	75.00	70.21	0.9361	1.0000	2,640,929	37,617
2002	6.5	3,285,570	75.00	69.35	0.9247	1.0000	3,038,137	43,808
2001	7.5	7,823,846	75.00	68.50	0.9134	1.0000	7,146,127	104,318
2000	8.5	3,626,516	75.00	67.66	0.9022	1.0000	3,271,713	48,354
1999	9.5	5,439,447	75.00	66.83	0.8910	1.0000	4,846,695	72,526
1998	10.5	1,258,059	75.00	66.00	0.8800	1.0000	1,107,047	16,774
1997	11.5	2,409,485	75.00	65.18	0.8690	1.0000	2,093,869	32,126
1996	12.5	2,994,951	75.00	64.36	0.8581	1.0000	2,570,052	39,933
1995	13.5	4,371,290	75.00	63.55	0.8473	1.0000	3,703,901	58,284
1994	14.5	6,162,631	75.00	62.75	0.8366	1.0000	5,155,859	82,168
1993	15.5	5,514,819	75.00	61.95	0.8260	1.0000	4,555,378	73,531
1992	16.5	3,842,516	75.00	61.16	0.8155	1.0000	3,133,570	51,234
1991	17.5	3,784,157	75.00	60.38	0.8051	1.0000	3,046,592	50,455
1990	18.5	6,352,466	75.00	59.61	0.7948	1.0000	5,048,720	84,700
1989	19.5	5,223,426	75.00	58.84	0.7845	1.0000	4,097,926	69,646
1988	20.5	1,706,255	75.00	58.08	0.7744	1.0000	1,321,339	22,750
1987	21.5	4,092,555	75.00	57.33	0.7644	1.0000	3,128,282	54,567
1986	22.5	1,741,865	75.00	56.58	0.7544	1.0000	1,314,137	23,225
1985	23.5	5,962,575	75.00	55.85	0.7446	1.0000	4,439,884	79,501
1984	24.5	2,719,843	75.00	55.12	0.7349	1.0000	1,998,821	36,265
1983	25.5	3,346,745	75.00	54.40	0.7253	1.0000	2,427,309	44,623
1982	26.5	9,751,980	75.00	53.68	0.7158	1.0000	6,980,156	130,026
1981	27.5	2,612,716	75.00	52.98	0.7064	1.0000	1,845,500	34,836
1980	28.5	1,024,152	75.00	52.28	0.6970	1.0000	713,872	13,655
1979	29.5	10,434,338	75.00	51.59	0.6878	1.0000	7,177,216	139,125
1978	30.5	7,216,534	75.00	50.91	0.6788	1.0000	4,898,252	96,220
1977	31.5	2,998,063	75.00	50.23	0.6698	1.0000	2,007,962	39,974
1976	32.5	453,448	75.00	49.57	0.6609	1.0000	299,676	6,046
1975	33.5	6,261,778	75.00	48.91	0.6521	1.0000	4,083,380	83,490
1974	34.5	1,640,536	75.00	48.26	0.6434	1.0000	1,055,587	21,874
1973	35.5	997,990	75.00	47.62	0.6349	1.0000	633,614	13,307

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 356.01 Overhead Conductors and Device

Dispersion: 75 - H2
Procedure: Broad Group

Generation Arrangement

	December 31, 2008				Net			
Vintage	Age	Surviving Plant	Avg. Life	Rem. Life	Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1972	36.5	11,164,409	75.00	46.98	0.6264	1.0000	6,993,848	148,859
1971	37.5	4,206,170	75.00	46.36	0.6181	1.0000	2,599,808	56,082
1970	38.5	3,749,435	75.00	45.74	0.6099	1.0000	2,286,666	49,992
1969	39.5	1,258,560	75.00	45.13	0.6017	1.0000	757,334	16,781
1968	40.5	2,852,205	75.00	44.53	0.5937	1.0000	1,693,408	38,029
1967	41.5	1,795,242	75.00	43.94	0.5858	1.0000	1,051,688	23,937
1966	42.5	972,016	75.00	43.35	0.5780	1.0000	561,842	12,960
1965	43.5	900,990	75.00	42.77	0.5703	1.0000	513,845	12,013
1964	44.5	1,130,923	75.00	42.21	0.5627	1.0000	636,409	15,079
1963	45.5	912,954	75.00	41.64	0.5552	1.0000	506,916	12,173
1962	46.5	10,539,313	75.00	41.09	0.5479	1.0000	5,774,114	140,524
1961	47.5	2,449,207	75.00	40.55	0.5406	1.0000	1,324,049	32,656
1960	48.5	3,917,659	75.00	40.01	0.5334	1.0000	2,089,812	52,235
1959	49.5	732,829	75.00	39.48	0.5264	1.0000	385,736	9,771
1958	50.5	3,521,361	75.00	38.96	0.5194	1.0000	1,829,028	46,951
1957	51.5	2,495,242	75.00	38.44	0.5126	1.0000	1,278,945	33,270
1956	52.5	577,367	75.00	37.93	0.5058	1.0000	292,024	7,698
1955	53.5	518,941	75.00	37.44	0.4991	1.0000	259,024	6,919
1954	54.5	834,187	75.00	36.94	0.4926	1.0000	410,909	11,123
1953	55.5	680,365	75.00	36.46	0.4861	1.0000	330,741	9,072
1952	56.5	671,291	75.00	35.98	0.4798	1.0000	322,066	8,951
1951	57.5	195,303	75.00	35.51	0.4735	1.0000	92,478	2,604
1950	58.5	363,264	75.00	35.05	0.4673	1.0000	169,767	4,844
1949	59.5	671,971	75.00	34.60	0.4613	1.0000	309,966	8,960
1948	60.5	467,672	75.00	34.15	0.4553	1.0000	212,933	6,236
1947	61.5	128,114	75.00	33.71	0.4494	1.0000	57,577	1,708
1946	62.5	101,832	75.00	33.27	0.4436	1.0000	45,176	1,358
1945	63.5	30,728	75.00	32.85	0.4379	1.0000	13,457	410
1944	64.5	19,076	75.00	32.42	0.4323	1.0000	8,247	254
1943	65.5	130,134	75.00	32.01	0.4268	1.0000	55,543	1,735
1942	66.5	455,507	75.00	31.60	0.4214	1.0000	191,946	6,073
1941	67.5	265,051	75.00	31.20	0.4160	1.0000	110,272	3,534
1940	68.5	315,769	75.00	30.81	0.4108	1.0000	129,714	4,210
1939	69.5	251,707	75.00	30.42	0.4056	1.0000	102,097	3,356
1938	70.5	148,494	75.00	30.04	0.4005	1.0000	59,476	1,980
1937	71.5	244,998	75.00	29.66	0.3955	1.0000	96,903	3,267

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 356.01 Overhead Conductors and Device

Dispersion: 75 - H2
Procedure: Broad Group

Generation Arrangement

Vintage	December 31, 2008 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1936	72.5	24,441	75.00	29.29	0.3906	1.0000	9,547	326
1935	73.5	23,959	75.00	28.93	0.3858	1.0000	9,242	319
1934	74.5	44,385	75.00	28.57	0.3810	1.0000	16,910	592
1933	75.5	487,216	75.00	28.22	0.3763	1.0000	183,341	6,496
1932	76.5	917,519	75.00	27.88	0.3717	1.0000	341,038	12,234
1931	77.5	724,755	75.00	27.54	0.3672	1.0000	266,105	9,663
1930	78.5	977,147	75.00	27.20	0.3627	1.0000	354,416	13,029
1929	79.5	593,041	75.00	26.87	0.3583	1.0000	212,498	7,907
1928	80.5	135,163	75.00	26.55	0.3540	1.0000	47,848	1,802
1927	81.5	1,029,294	75.00	26.23	0.3498	1.0000	360,005	13,724
1926	82.5	594,668	75.00	25.92	0.3456	1.0000	205,511	7,929
1925	83.5	731,372	75.00	25.61	0.3415	1.0000	249,751	9,752
1924	84.5	808,238	75.00	25.31	0.3374	1.0000	272,736	10,777
1923	85.5	1,128,050	75.00	25.01	0.3335	1.0000	376,183	15,041
1922	86.5	1,425,779	75.00	24.72	0.3296	1.0000	469,895	19,010
1921	87.5	166,910	75.00	24.43	0.3257	1.0000	54,368	2,225
1920	88.5	154,596	75.00	24.15	0.3220	1.0000	49,774	2,061
1919	89.5	42,444	75.00	23.87	0.3182	1.0000	13,507	566
1918	90.5	34,380	75.00	23.59	0.3146	1.0000	10,815	458
1917	91.5	14,718	75.00	23.32	0.3110	1.0000	4,577	196
1916	92.5	15,502	75.00	23.06	0.3075	1.0000	4,766	207
1915	93.5	55,615	75.00	22.80	0.3040	1.0000	16,906	742
1914	94.5	127,072	75.00	22.54	0.3006	1.0000	38,194	1,694
1913	95.5	10,979	75.00	22.29	0.2972	1.0000	3,263	146
1912	96.5	5,957	75.00	22.04	0.2939	1.0000	1,751	79
1908	100.5	34,643	75.00	21.09	0.2812	1.0000	9,742	462
1907	101.5	222,597	75.00	20.86	0.2782	1.0000	61,916	2,968
1906	102.5	47	75.00	20.64	0.2752	1.0000	13	1
1900	108.5	15,408	75.00	19.36	0.2582	1.0000	3,978	205
1896	112.5	10,091	75.00	18.58	0.2477	1.0000	2,500	135
Total	26.3	$236,780,774	75.00	55.32	0.7375	1.0000	$174,635,565	$3,157,077

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Transmission Plant
Account: 356.01 Overhead Conductors and Device

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2008	0.5	7,168,194		7,168,194	1.0000	0.5000
2007	1.5	9,767,300		9,767,300	1.0000	1.5000
2006	2.5	8,975,395		8,975,395	1.0000	2.5000
2005	3.5	9,926,603		9,926,603	1.0000	3.5000
2004	4.5	2,845,178		2,845,178	1.0000	4.5000
2003	5.5	2,895,172		2,821,281	0.9745	5.4872
2002	6.5	3,346,731		3,285,570	0.9817	6.4085
2001	7.5	9,573,821		7,823,846	0.8172	6.3565
2000	8.5	3,639,264		3,626,516	0.9965	8.4848
1999	9.5	5,448,327		5,439,447	0.9984	9.4890
1998	10.5	1,258,061		1,258,059	1.0000	10.5000
1997	11.5	2,416,132		2,409,485	0.9972	11.4817
1996	12.5	3,042,250		2,994,951	0.9845	12.3682
1995	13.5		4,507,522	4,371,290	0.9698	13.2515
1994	14.5		6,167,871	6,162,631	0.9992	14.4945
1993	15.5		5,568,522	5,514,819	0.9904	15.4728
1992	16.5		3,998,796	3,842,516	0.9609	16.2496
1991	17.5		3,817,921	3,784,157	0.9912	17.4317
1990	18.5		6,501,204	6,352,466	0.9771	18.3947
1989	19.5		5,271,741	5,223,426	0.9908	19.4204
1988	20.5		1,982,147	1,706,255	0.8608	19.4361
1987	21.5		4,250,540	4,092,555	0.9628	21.2118
1986	22.5		1,793,873	1,741,865	0.9710	22.2606
1985	23.5		6,070,252	5,962,575	0.9823	23.4009
1984	24.5		2,720,812	2,719,843	0.9996	24.4975
1983	25.5		3,390,554	3,346,745	0.9871	25.4258
1982	26.5		9,898,244	9,751,980	0.9852	26.3767
1981	27.5		2,683,762	2,612,716	0.9735	27.4196
1980	28.5		1,065,468	1,024,152	0.9612	28.1913
1979	29.5		10,438,236	10,434,338	0.9996	29.4971
1978	30.5		7,289,004	7,216,534	0.9901	30.4817
1977	31.5		3,368,230	2,998,063	0.8901	30.8151
1976	32.5		473,737	453,448	0.9572	32.1479
1975	33.5		6,302,232	6,261,778	0.9936	33.4509
1974	34.5		1,697,038	1,640,536	0.9667	34.2099
1973	35.5		1,051,321	997,990	0.9493	35.0448
1972	36.5		11,226,943	11,164,409	0.9944	36.4492

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 356.01 Overhead Conductors and Device

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1971	37.5		4,268,930	4,206,170	0.9853	37.4082
1970	38.5		3,783,275	3,749,435	0.9911	38.4595
1969	39.5		1,283,608	1,258,560	0.9805	39.4331
1968	40.5		2,861,339	2,852,205	0.9968	40.4806
1967	41.5		1,830,291	1,795,242	0.9809	41.3559
1966	42.5		1,004,904	972,016	0.9673	42.3030
1965	43.5		916,557	900,990	0.9830	43.3449
1964	44.5		1,170,539	1,130,923	0.9662	44.2183
1963	45.5		1,035,081	912,954	0.8820	44.7860
1962	46.5		10,587,919	10,539,313	0.9954	46.4724
1961	47.5		2,480,847	2,449,207	0.9872	47.4014
1960	48.5		4,135,846	3,917,659	0.9472	48.1053
1959	49.5		845,050	732,829	0.8672	48.6354
1958	50.5		3,620,012	3,521,361	0.9727	50.4384
1957	51.5		2,535,687	2,495,242	0.9840	51.3651
1956	52.5		617,497	577,367	0.9350	51.9857
1955	53.5		578,303	518,941	0.8974	52.7366
1954	54.5		912,936	834,187	0.9137	53.7544
1953	55.5		803,927	680,365	0.8463	55.1710
1952	56.5		692,987	671,291	0.9687	56.2553
1951	57.5		230,614	195,303	0.8469	56.1207
1950	58.5		430,851	363,264	0.8431	57.6594
1949	59.5		682,690	671,971	0.9843	59.3765
1948	60.5		475,621	467,672	0.9833	60.4146
1947	61.5		135,409	128,114	0.9461	61.2021
1946	62.5		104,445	101,832	0.9750	62.2820
1945	63.5		32,022	30,728	0.9596	63.3114
1944	64.5		20,464	19,076	0.9322	63.8686
1943	65.5		134,490	130,134	0.9676	65.2673
1942	66.5		482,366	455,507	0.9443	66.0914
1941	67.5		285,236	265,051	0.9292	66.8446
1940	68.5		331,696	315,769	0.9520	68.1647
1939	69.5		265,929	251,707	0.9465	69.1131
1938	70.5		155,139	148,494	0.9572	70.0701
1937	71.5		257,970	244,998	0.9497	71.0947
1936	72.5		24,819	24,441	0.9848	72.4270
1935	73.5		24,981	23,959	0.9591	73.4410

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 356.01 Overhead Conductors and Device

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1934	74.5		47,186	44,385	0.9406	73.9427
1933	75.5		503,942	487,216	0.9668	75.2906
1932	76.5		989,954	917,519	0.9268	75.7273
1931	77.5		752,596	724,755	0.9630	77.3811
1930	78.5		1,009,900	977,147	0.9676	78.2806
1929	79.5		650,986	593,041	0.9110	79.0123
1928	80.5		172,576	135,163	0.7832	79.0545
1927	81.5		1,054,343	1,029,294	0.9762	81.4105
1926	82.5		606,218	594,668	0.9809	82.3759
1925	83.5		810,225	731,372	0.9027	82.7511
1924	84.5		875,000	808,238	0.9237	83.7912
1923	85.5		1,149,631	1,128,050	0.9812	85.3584
1922	86.5		1,462,940	1,425,779	0.9746	86.2754
1921	87.5		168,220	166,910	0.9922	87.4334
1920	88.5		160,129	154,596	0.9654	88.2216
1919	89.5		44,123	42,444	0.9619	89.3309
1918	90.5		63,568	34,380	0.5408	86.6593
1917	91.5		15,193	14,718	0.9688	91.2346
1916	92.5		15,527	15,502	0.9983	92.4876
1915	93.5		83,683	55,615	0.6646	92.3172
1914	94.5		129,375	127,072	0.9822	94.3545
1913	95.5		21,111	10,979	0.5201	91.9000
1912	96.5		5,957	5,957	1.0000	96.5000
1908	100.5		35,348	34,643	0.9800	100.3103
1907	101.5		223,885	222,597	0.9942	101.4858
1906	102.5		47	47	0.9998	102.4993
1900	108.5		19,335	15,408	0.7969	107.0057
1896	112.5		10,091	10,091	1.0000	112.5000
Total	26.3	$70,302,428	$172,657,338	$236,780,774	0.9746	

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 356.01 Overhead Conductors and Device

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996		173,048,444		(125,586)	172,922,858
1997	172,922,858	7,705,879	413,333	(2,388,476)	177,826,928
1998	177,826,928	36,290	105,428	(40,300)	177,717,489
1999	177,717,489	10,142,384	762,270	(6,673,525)	180,424,079
2000	180,424,079	12,429,438	558,213	(7,475,129)	184,820,175
2001	184,820,175	10,350,205	428,139	(1,966,013)	192,776,229
2002	192,776,229	5,809,537	2,256,890		196,328,877
2003	196,328,877	1,955,540	289,331		197,995,086
2004	197,995,086	2,927,970	129,746		200,793,309
2005	200,793,309	9,756,232	251,341		210,298,200
2006	210,298,200	7,941,368	284,136	(16,700)	217,938,733
2007	217,938,733	9,131,520	153,425	342	226,917,169
2008	226,917,169	10,410,347	546,741	(1)	236,780,774

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 356.01 Overhead Conductors and Device

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996	186,935,798	4,587,793		(125,586)	191,398,004
1997	191,398,004	5,183,285	413,333	(2,388,476)	193,779,480
1998	193,779,480	1,287,903	105,428	(40,300)	194,921,655
1999	194,921,655	5,496,627	762,270	(6,673,525)	192,982,487
2000	192,982,487	3,638,995	558,213	(7,475,129)	188,588,140
2001	188,588,140	9,573,821	428,139	(1,966,013)	195,767,810
2002	195,767,810	3,346,731	2,256,890		196,857,651
2003	196,857,651	2,895,172	289,331		199,463,493
2004	199,463,493	2,845,178	129,746		202,178,925
2005	202,178,925	9,942,960	251,341		211,870,544
2006	211,870,544	8,975,395	284,136	(16,700)	220,545,104
2007	220,545,104	9,767,301	153,425	342	230,159,322
2008	230,159,322	7,168,194	546,741	(1)	236,780,774

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 356.01 Overhead Conductors and Device

T-Cut: None

Placement Band: 1896-2008

Hazard Function: Proportion Retired

Rolling Band Life Analysis

Weighting: Exposures

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper- sion	Conf. Index	Average Life	Disper- sion	Conf. Index	Average Life	Disper- sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2000	55.6	129.5	S0	4.25	112.7	S1	2.95	149.5	SC *	3.28
1997-2001	51.0	128.0	S-.5	6.03	111.0	R1.5	4.48	143.2	SC *	4.78
1998-2002	51.9	159.2	R1 *	9.85	92.9	R1.5	3.95	138.2	SC *	4.22
1999-2003	51.9	156.8	R0.5 *	9.26	92.3	R1.5	3.75	135.3	SC *	4.12
2000-2004	73.1	166.0	R1 *	4.54	100.0	R1.5 *	5.92	146.1	SC *	5.10
2001-2005	54.0	168.7	R1.5 *	11.43	104.1	R2 *	4.56	150.9	SC *	6.88
2002-2006	63.1	170.3	R1.5 *	7.79	107.0	R2 *	3.08	152.5	SC *	4.75
2003-2007	69.4	165.4	R2	5.05	156.5	R2	4.42	159.2	R2	4.46
2004-2008	66.9	158.6	R1.5	5.14	145.7	R1.5	4.14	168.2	R1.5 *	4.51

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 356.01 Overhead Conductors and Device

T-Cut: None

Placement Band: 1896-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2008	66.9	161.3	R1	5.09	116.6	R2	2.81	160.9	R1 *	2.57
1998-2008	64.2	163.7	R1 *	6.25	114.5	R2	2.66	158.6	R1 *	3.30
2000-2008	65.1	171.3	R1.5 *	7.64	114.3	R2	2.80	159.3	R1 *	3.54
2002-2008	64.8	173.1	R2 *	7.87	114.7	R2	2.72	159.2	R1 *	3.86
2004-2008	66.9	158.6	R1.5	5.14	145.7	R1.5	4.14	168.2	R1.5 *	4.51
2006-2008	78.4	154.0	R1	2.81	144.6	R1.5	2.95	169.7	R1.5 *	2.13
2008-2008	64.3	133.9	R0.5	4.96	123.2	S0.5	4.79	154.7	R0.5 *	3.85

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 356.01 Overhead Conductors and Device

T-Cut: None
Placement Band: 1896-2008
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-1997	85.2	151.9	R1.5	1.87	128.7	S1.5	3.54	167.9	R1.5 *	2.52
1996-1999	47.9	132.2	S0	8.07	119.0	S1	6.93	158.8	R1 *	8.19
1996-2001	57.1	134.9	R1	4.62	117.7	R1.5	3.23	147.1	SC *	3.51
1996-2003	59.0	162.3	R1 *	7.17	103.6	R2	2.97	151.8	SC *	3.49
1996-2005	56.8	164.8	R1 *	7.95	109.6	R2	2.52	157.4	R0.5 *	4.88
1996-2007	67.7	165.6	R1	5.15	116.0	R2	2.50	161.6	R1 *	2.56
1996-2008	66.9	161.3	R1	5.09	116.6	R2	2.81	160.9	R1 *	2.57

Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 356.01 Overhead Conductors and Device

T-Cut: None

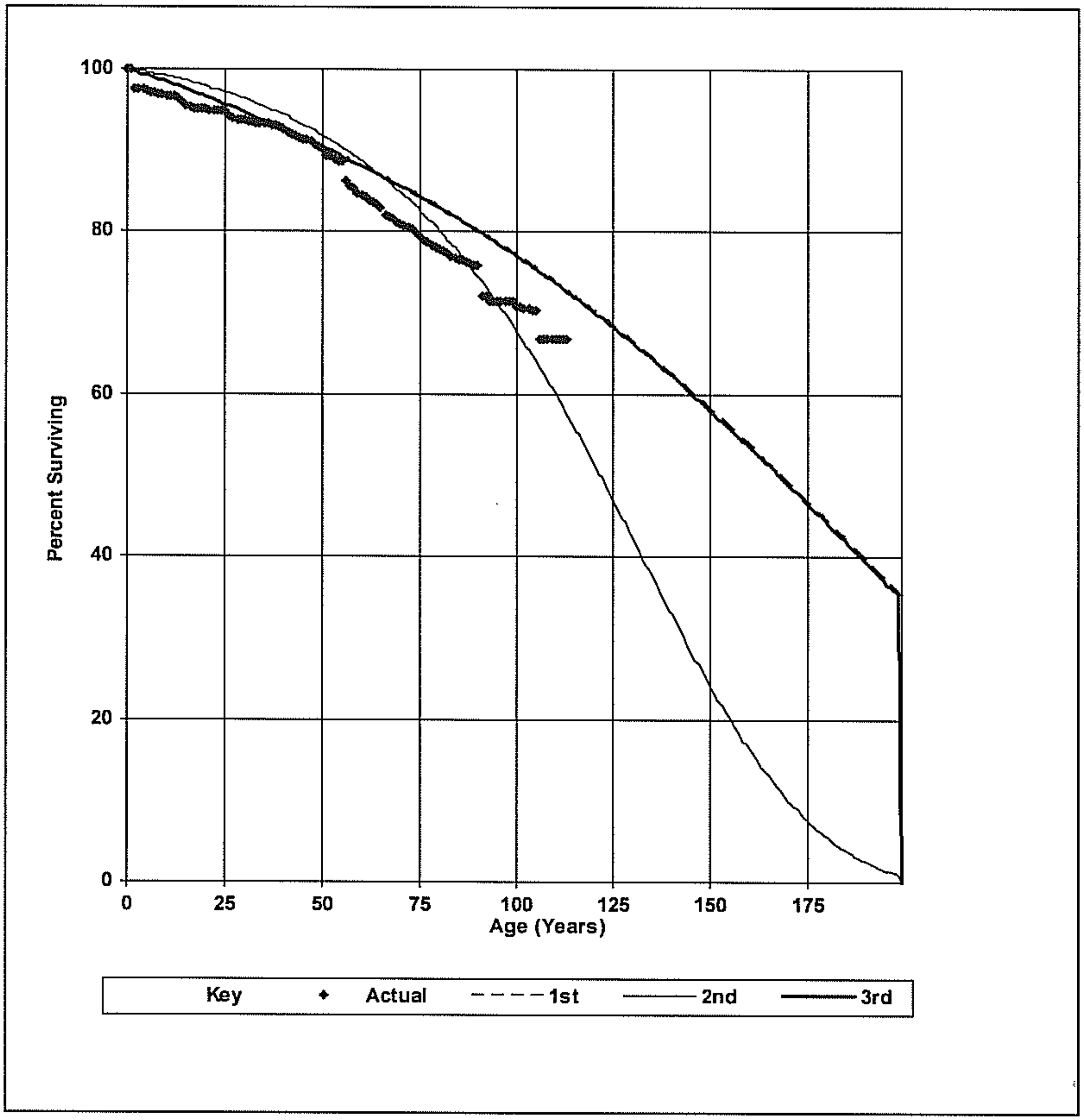
Placement Band: 1896-2008 Observation Band: 1996-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 161.3-R1 2nd: 116.6-R2 3rd: 160.9-R1



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 356.01 Overhead Conductors and Device

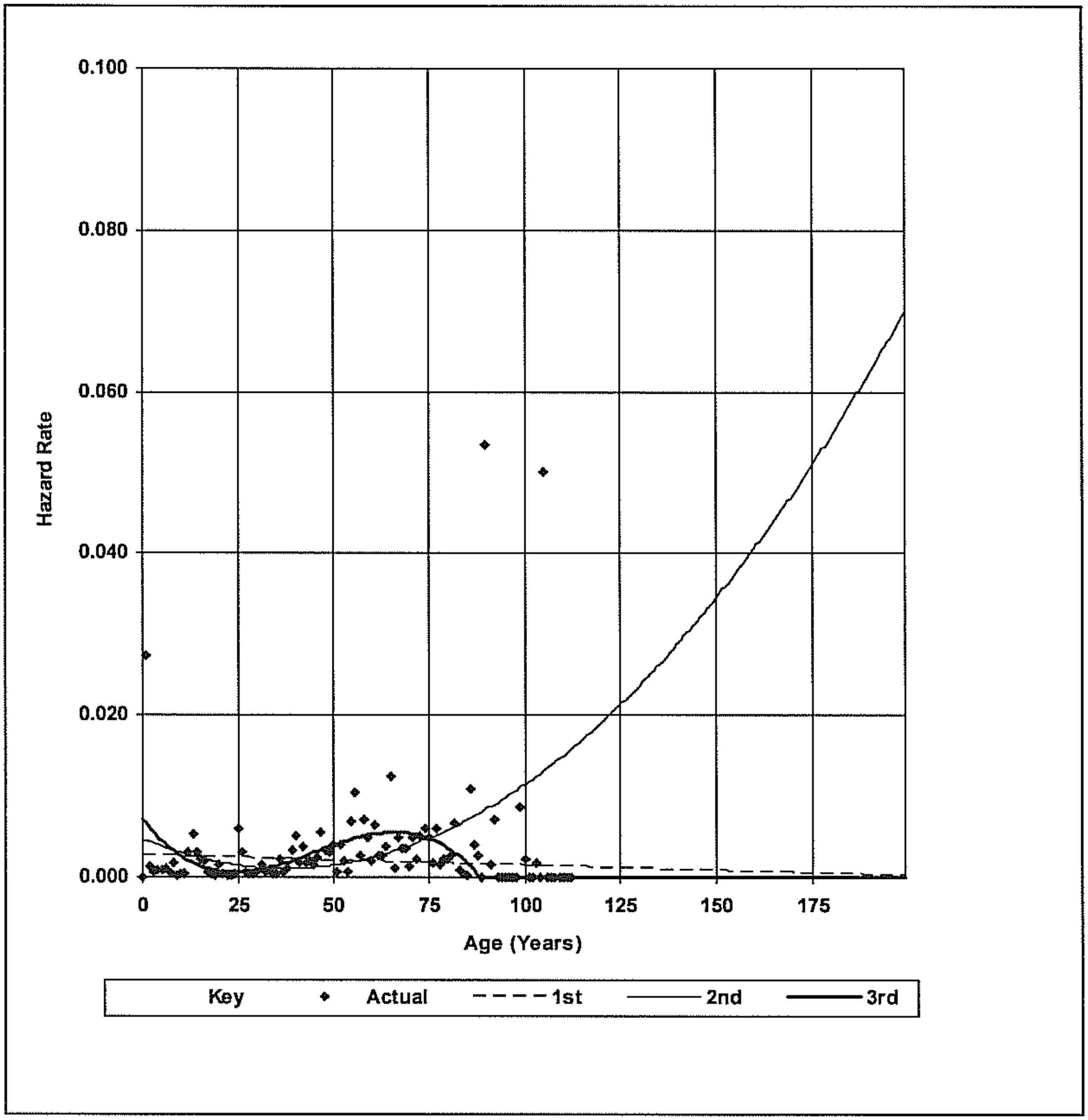
T-Cut: None

Placement Band: 1896-2007 Observation Band: 1996-2007

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function **1st: 165.6-R1 2nd: 116.0-R2 3rd: 161.6-R1**



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

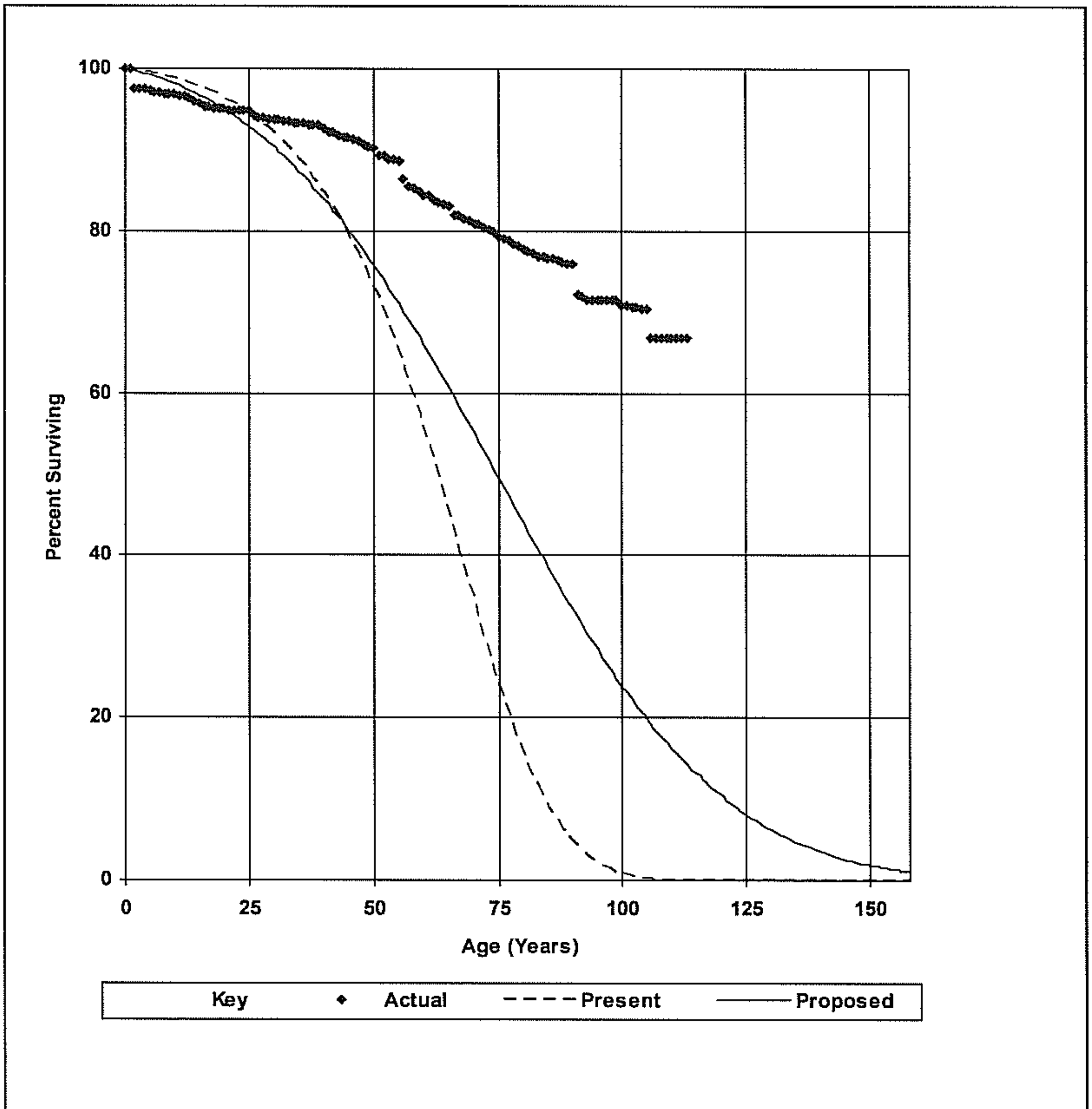
Account: 356.01 Overhead Conductors and Device

T-Cut: None

Placement Band: 1896-2008

Observation Band: 1996-2008

Present and Proposed Projection Life Curves **Present: 60.0-R2.5** **Proposed: 75.0-H2**



Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 356.01 Overhead Conductors and Device

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998	105,428		0.0		91,881	87.2		(91,881)	-87.2	
1999	762,270	1,239	0.2		528,020	69.3		(526,781)	-69.1	
2000	558,213	90,889	16.3		515,742	92.4		(424,852)	-76.1	
2001	428,139	9,841	2.3		424,590	99.2		(414,750)	-96.9	
2002	2,256,890	41,872	1.9	3.5	411,492	18.2	48.0	(369,620)	-16.4	-44.5
2003	289,331	1,448	0.5	3.4	396,184	136.9	53.0	(394,736)	-136.4	-49.6
2004	129,746	(6)	0.0	3.9	124,608	96.0	51.1	(124,613)	-96.0	-47.2
2005	251,341		0.0	1.6	297,214	118.3	49.3	(297,214)	-118.3	-47.7
2006	284,136		0.0	1.3	759,603	267.3	61.9	(759,603)	-267.3	-60.6
2007	153,425		0.0	0.1	1,300,830	847.9	259.8	(1,300,830)	-847.9	-259.7
2008	546,741		0.0	0.0		0.0	181.8		0.0	-181.8
Total	5,765,658	145,283	2.5		4,850,164	84.1		(4,704,881)	-81.6	

Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 356.01 Overhead Conductors and Device

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998	105,428		0.0		91,881	87.2		(91,881)	-87.2	
1999	762,270	1,239	0.2		528,020	69.3		(526,781)	-69.1	
2000	558,213	90,889	16.3		515,742	92.4		(424,852)	-76.1	
2001	428,139	9,841	2.3		424,590	99.2		(414,750)	-96.9	
2002	2,256,890	41,872	1.9	3.5	411,492	18.2	48.0	(369,620)	-16.4	-44.5
2003	289,331	1,448	0.5	3.4	396,184	136.9	53.0	(394,736)	-136.4	-49.6
2004	129,746	(6)	0.0	3.9	124,608	96.0	51.1	(124,613)	-96.0	-47.2
2005	251,341		0.0	1.6	297,214	118.3	49.3	(297,214)	-118.3	-47.7
2006	284,136		0.0	1.3	759,603	267.3	61.9	(759,603)	-267.3	-60.6
2007	153,425		0.0	0.1	1,300,830	847.9	259.8	(1,300,830)	-847.9	-259.7
2008	546,741		0.0	0.0		0.0	181.8		0.0	-181.8
Total	5,765,658	145,283	2.5		4,850,164	84.1		(4,704,881)	-81.6	

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 357.01 Underground Conduit

Dispersion: 75 - H4
Procedure: Broad Group

Generation Arrangement

Vintage	December 31, 2008 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2008	0.5	260,170	75.00	74.50	0.9933	1.0000	258,438	3,469
2007	1.5	204,588	75.00	73.50	0.9800	1.0000	200,499	2,728
2006	2.5	5,466	75.00	72.50	0.9667	1.0000	5,284	73
2005	3.5	209,001	75.00	71.50	0.9534	1.0000	199,255	2,787
2003	5.5	95,924	75.00	69.51	0.9267	1.0000	88,897	1,279
2002	6.5	73,218	75.00	68.51	0.9134	1.0000	66,879	976
2001	7.5	2,751,710	75.00	67.51	0.9001	1.0000	2,476,873	36,689
2000	8.5	35,727	75.00	66.51	0.8868	1.0000	31,683	476
1999	9.5	41,818	75.00	65.51	0.8735	1.0000	36,529	558
1997	11.5	28,096	75.00	63.52	0.8470	1.0000	23,796	375
1996	12.5	84,928	75.00	62.53	0.8337	1.0000	70,804	1,132
1995	13.5	2,343	75.00	61.53	0.8204	1.0000	1,922	31
1994	14.5	772,121	75.00	60.54	0.8072	1.0000	623,244	10,295
1993	15.5	754,410	75.00	59.55	0.7940	1.0000	598,966	10,059
1992	16.5	729,276	75.00	58.55	0.7807	1.0000	569,369	9,724
1991	17.5	2,951,176	75.00	57.57	0.7675	1.0000	2,265,142	39,349
1990	18.5	2,652,859	75.00	56.58	0.7544	1.0000	2,001,232	35,371
1989	19.5	22,704	75.00	55.59	0.7412	1.0000	16,829	303
1988	20.5	87,089	75.00	54.61	0.7281	1.0000	63,409	1,161
1987	21.5	173,866	75.00	53.63	0.7150	1.0000	124,316	2,318
1986	22.5	55,560	75.00	52.65	0.7019	1.0000	39,000	741
1985	23.5	194,860	75.00	51.67	0.6889	1.0000	134,247	2,598
1984	24.5	81,409	75.00	50.70	0.6760	1.0000	55,029	1,085
1983	25.5	37,567	75.00	49.73	0.6630	1.0000	24,908	501
1982	26.5	31,532	75.00	48.76	0.6502	1.0000	20,501	420
1981	27.5	7,412,871	75.00	47.80	0.6374	1.0000	4,724,627	98,838
1980	28.5	199,484	75.00	46.85	0.6246	1.0000	124,599	2,660
1979	29.5	817,824	75.00	45.89	0.6119	1.0000	500,449	10,904
1978	30.5	40,607	75.00	44.95	0.5993	1.0000	24,337	541
1977	31.5	1,799	75.00	44.01	0.5868	1.0000	1,056	24
1976	32.5	233,775	75.00	43.08	0.5744	1.0000	134,274	3,117
1975	33.5	340,314	75.00	42.15	0.5620	1.0000	191,269	4,538
1974	34.5	667,256	75.00	41.23	0.5498	1.0000	366,853	8,897
1973	35.5	1,248,739	75.00	40.33	0.5377	1.0000	671,423	16,650
1972	36.5	12,147	75.00	39.43	0.5257	1.0000	6,385	162
1971	37.5	97,965	75.00	38.53	0.5138	1.0000	50,333	1,306

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 357.01 Underground Conduit

Dispersion: 75 - H4
Procedure: Broad Group

Generation Arrangement

Vintage	Age (December 31, 2008)	Surviving Plant (December 31, 2008)	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1970	38.5	68,404	75.00	37.65	0.5020	1.0000	34,341	912
1969	39.5	28,880	75.00	36.78	0.4904	1.0000	14,164	385
1968	40.5	1,981,521	75.00	35.92	0.4789	1.0000	949,040	26,420
1967	41.5	675,043	75.00	35.07	0.4676	1.0000	315,679	9,001
1966	42.5	59,836	75.00	34.24	0.4565	1.0000	27,314	798
1965	43.5	33,801	75.00	33.41	0.4455	1.0000	15,058	451
1964	44.5	66,795	75.00	32.60	0.4347	1.0000	29,034	891
1963	45.5	9,048	75.00	31.80	0.4240	1.0000	3,837	121
1962	46.5	69,215	75.00	31.02	0.4135	1.0000	28,624	923
1961	47.5	60,347	75.00	30.25	0.4033	1.0000	24,337	805
1960	48.5	7,419	75.00	29.49	0.3932	1.0000	2,917	99
1959	49.5	596,545	75.00	28.75	0.3833	1.0000	228,656	7,954
1958	50.5	13,849	75.00	28.02	0.3736	1.0000	5,174	185
1957	51.5	119,691	75.00	27.31	0.3641	1.0000	43,584	1,596
1956	52.5	51,052	75.00	26.61	0.3548	1.0000	18,115	681
1955	53.5	3,802	75.00	25.93	0.3458	1.0000	1,315	51
1954	54.5	17,288	75.00	25.27	0.3369	1.0000	5,825	231
1953	55.5	15,626	75.00	24.62	0.3282	1.0000	5,129	208
1952	56.5	152,115	75.00	23.99	0.3198	1.0000	48,648	2,028
1951	57.5	109,941	75.00	23.37	0.3116	1.0000	34,255	1,466
1950	58.5	5,890	75.00	22.77	0.3035	1.0000	1,788	79
1949	59.5	195,475	75.00	22.18	0.2957	1.0000	57,808	2,606
1948	60.5	420,640	75.00	21.61	0.2881	1.0000	121,196	5,609
1947	61.5	17,086	75.00	21.05	0.2807	1.0000	4,796	228
1946	62.5	555	75.00	20.51	0.2735	1.0000	152	7
1945	63.5	1,370	75.00	19.99	0.2665	1.0000	365	18
1944	64.5	10,534	75.00	19.48	0.2597	1.0000	2,736	140
1943	65.5	9,125	75.00	18.98	0.2531	1.0000	2,310	122
1942	66.5	45,865	75.00	18.50	0.2467	1.0000	11,316	612
1941	67.5	2,768	75.00	18.04	0.2405	1.0000	666	37
1940	68.5	107,312	75.00	17.58	0.2345	1.0000	25,161	1,431
1939	69.5	4,450	75.00	17.15	0.2286	1.0000	1,017	59
1938	70.5	6,679	75.00	16.72	0.2229	1.0000	1,489	89
1937	71.5	277	75.00	16.31	0.2174	1.0000	60	4
1936	72.5	7,952	75.00	15.91	0.2121	1.0000	1,687	106
1935	73.5	1,156	75.00	15.52	0.2069	1.0000	239	15

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 357.01 Underground Conduit

Dispersion: 75 - H4
Procedure: Broad Group

Generation Arrangement

Vintage	December 31, 2008 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1934	74.5	568	75.00	15.15	0.2020	1.0000	115	8
1932	76.5	8,314	75.00	14.43	0.1924	1.0000	1,600	111
1931	77.5	152,039	75.00	14.09	0.1879	1.0000	28,564	2,027
1930	78.5	30,146	75.00	13.76	0.1835	1.0000	5,531	402
1929	79.5	16,116	75.00	13.44	0.1792	1.0000	2,888	215
1928	80.5	651	75.00	13.13	0.1751	1.0000	114	9
1927	81.5	1,127	75.00	12.83	0.1711	1.0000	193	15
1926	82.5	1,928	75.00	12.54	0.1673	1.0000	323	26
1925	83.5	4,069	75.00	12.26	0.1635	1.0000	665	54
1924	84.5	14,804	75.00	11.99	0.1599	1.0000	2,367	197
1923	85.5	19,025	75.00	11.73	0.1564	1.0000	2,975	254
1922	86.5	7,462	75.00	11.47	0.1530	1.0000	1,142	99
1921	87.5	18,024	75.00	11.23	0.1497	1.0000	2,698	240
1920	88.5	21,826	75.00	10.99	0.1465	1.0000	3,198	291
1917	91.5	17,330	75.00	10.32	0.1376	1.0000	2,384	231
1916	92.5	24,863	75.00	10.11	0.1347	1.0000	3,350	332
1915	93.5	21,931	75.00	9.90	0.1320	1.0000	2,895	292
1914	94.5	1,490	75.00	9.71	0.1294	1.0000	193	20
1913	95.5	2,014	75.00	9.51	0.1268	1.0000	255	27
1912	96.5	1,569	75.00	9.33	0.1244	1.0000	195	21
1911	97.5	59,740	75.00	9.15	0.1220	1.0000	7,289	797
1910	98.5	26,788	75.00	8.97	0.1196	1.0000	3,205	357
1909	99.5	9,135	75.00	8.80	0.1174	1.0000	1,072	122
1908	100.5	829	75.00	8.64	0.1153	1.0000	96	11
1907	101.5	10,736	75.00	8.48	0.1131	1.0000	1,214	143
1906	102.5	3,092	75.00	8.33	0.1110	1.0000	343	41
1905	103.5	5,695	75.00	8.18	0.1091	1.0000	621	76
1904	104.5	56,746	75.00	8.03	0.1071	1.0000	6,076	757
1903	105.5	2,592	75.00	7.89	0.1052	1.0000	273	35
1902	106.5	537	75.00	7.76	0.1034	1.0000	56	7
1901	107.5	91,158	75.00	7.62	0.1016	1.0000	9,260	1,215
1900	108.5	30,070	75.00	7.49	0.0998	1.0000	3,002	401
Total	27.4	$29,049,970	75.00	48.94	0.6525	1.0000	$18,954,639	$387,333

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 357.01 Underground Conduit

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2008	0.5	260,170		260,170	1.0000	0.5000
2007	1.5	204,588		204,588	1.0000	1.5000
2006	2.5	5,466		5,466	1.0000	2.5000
2005	3.5	209,001		209,001	1.0000	3.5000
2003	5.5	95,924		95,924	1.0000	5.5000
2002	6.5	73,218		73,218	1.0000	6.5000
2001	7.5	2,751,710		2,751,710	1.0000	7.5000
2000	8.5	35,727		35,727	1.0000	8.5000
1999	9.5	41,818		41,818	1.0000	9.5000
1997	11.5	28,096		28,096	1.0000	11.5000
1996	12.5	84,928		84,928	1.0000	12.5000
1995	13.5		2,343	2,343	1.0000	13.5000
1994	14.5		772,121	772,121	1.0000	14.5000
1993	15.5		754,410	754,410	1.0000	15.5000
1992	16.5		761,480	729,276	0.9577	16.0982
1991	17.5		3,100,749	2,951,176	0.9518	17.1382
1990	18.5		2,652,859	2,652,859	1.0000	18.5000
1989	19.5		22,704	22,704	1.0000	19.5000
1988	20.5		87,089	87,089	1.0000	20.5000
1987	21.5		173,866	173,866	1.0000	21.5000
1986	22.5		55,560	55,560	1.0000	22.5000
1985	23.5		194,860	194,860	1.0000	23.5000
1984	24.5		81,409	81,409	1.0000	24.5000
1983	25.5		37,567	37,567	1.0000	25.5000
1982	26.5		31,532	31,532	1.0000	26.5000
1981	27.5		7,412,871	7,412,871	1.0000	27.5000
1980	28.5		199,484	199,484	1.0000	28.5000
1979	29.5		817,824	817,824	1.0000	29.5000
1978	30.5		40,607	40,607	1.0000	30.5000
1977	31.5		1,799	1,799	1.0000	31.5000
1976	32.5		233,775	233,775	1.0000	32.5000
1975	33.5		340,314	340,314	1.0000	33.5000
1974	34.5		667,256	667,256	1.0000	34.5000
1973	35.5		1,248,739	1,248,739	1.0000	35.5000
1972	36.5		12,147	12,147	1.0000	36.5000
1971	37.5		97,965	97,965	1.0000	37.5000
1970	38.5		68,404	68,404	1.0000	38.5000

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Transmission Plant
Account: 357.01 Underground Conduit

Age Distribution

				Experience to 12/31/2008		
Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1969	39.5		28,880	28,880	1.0000	39.5000
1968	40.5		1,981,521	1,981,521	1.0000	40.5000
1967	41.5		675,043	675,043	1.0000	41.5000
1966	42.5		59,836	59,836	1.0000	42.5000
1965	43.5		33,801	33,801	1.0000	43.5000
1964	44.5		66,795	66,795	1.0000	44.5000
1963	45.5		9,048	9,048	1.0000	45.5000
1962	46.5		69,215	69,215	1.0000	46.5000
1961	47.5		60,347	60,347	1.0000	47.5000
1960	48.5		7,419	7,419	1.0000	48.5000
1959	49.5		596,545	596,545	1.0000	49.5000
1958	50.5		13,849	13,849	1.0000	50.5000
1957	51.5		119,691	119,691	1.0000	51.5000
1956	52.5		51,052	51,052	1.0000	52.5000
1955	53.5		3,802	3,802	1.0000	53.5000
1954	54.5		17,288	17,288	1.0000	54.5000
1953	55.5		15,626	15,626	1.0000	55.5000
1952	56.5		152,115	152,115	1.0000	56.5000
1951	57.5		109,941	109,941	1.0000	57.5000
1950	58.5		5,890	5,890	1.0000	58.5000
1949	59.5		195,475	195,475	1.0000	59.5000
1948	60.5		420,640	420,640	1.0000	60.5000
1947	61.5		17,086	17,086	1.0000	61.5000
1946	62.5		555	555	1.0000	62.5000
1945	63.5		1,370	1,370	1.0000	63.5000
1944	64.5		10,534	10,534	1.0000	64.5000
1943	65.5		9,125	9,125	1.0000	65.5000
1942	66.5		45,865	45,865	1.0000	66.5000
1941	67.5		2,768	2,768	1.0000	67.5000
1940	68.5		107,312	107,312	1.0000	68.5000
1939	69.5		4,450	4,450	1.0000	69.5000
1938	70.5		6,679	6,679	1.0000	70.5000
1937	71.5		277	277	1.0000	71.5000
1936	72.5		7,952	7,952	1.0000	72.5000
1935	73.5		1,156	1,156	1.0000	73.5000
1934	74.5		568	568	1.0000	74.5000
1932	76.5		8,314	8,314	1.0000	76.5000

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Transmission Plant
Account: 357.01 Underground Conduit

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1931	77.5		155,627	152,039	0.9769	77.3962
1930	78.5		30,146	30,146	1.0000	78.5000
1929	79.5		16,116	16,116	1.0000	79.5000
1928	80.5		651	651	1.0000	80.5000
1927	81.5		1,127	1,127	1.0000	81.5000
1926	82.5		1,928	1,928	1.0000	82.5000
1925	83.5		4,069	4,069	1.0000	83.5000
1924	84.5		14,804	14,804	1.0000	84.5000
1923	85.5		19,025	19,025	1.0000	85.5000
1922	86.5		7,462	7,462	1.0000	86.5000
1921	87.5		18,024	18,024	1.0000	87.5000
1920	88.5		21,826	21,826	1.0000	88.5000
1917	91.5		17,330	17,330	1.0000	91.5000
1916	92.5		24,863	24,863	1.0000	92.5000
1915	93.5		21,931	21,931	1.0000	93.5000
1914	94.5		1,490	1,490	1.0000	94.5000
1913	95.5		2,014	2,014	1.0000	95.5000
1912	96.5		1,569	1,569	1.0000	96.5000
1911	97.5		59,740	59,740	1.0000	97.5000
1910	98.5		26,788	26,788	1.0000	98.5000
1909	99.5		9,135	9,135	1.0000	99.5000
1908	100.5		829	829	1.0000	100.5000
1907	101.5		10,736	10,736	1.0000	101.5000
1906	102.5		3,092	3,092	1.0000	102.5000
1905	103.5		5,695	5,695	1.0000	103.5000
1904	104.5		56,746	56,746	1.0000	104.5000
1903	105.5		2,592	2,592	1.0000	105.5000
1902	106.5		537	537	1.0000	106.5000
1901	107.5		91,158	91,158	1.0000	107.5000
1900	108.5		30,070	30,070	1.0000	108.5000
Total	27.4	$3,790,648	$25,444,687	$29,049,970	0.9937	

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 357.01 Underground Conduit

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996		25,529,615			25,529,615
1997	25,529,615	28,389		(275)	25,557,729
1998	25,557,729			(18)	25,557,711
1999	25,557,711	37,103	32,204		25,562,610
2000	25,562,610	21,767			25,584,377
2001	25,584,377	1,403,168	149,572		26,837,973
2002	26,837,973	1,427,926			28,265,899
2003	28,265,899	40,789			28,306,688
2004	28,306,688	55,131	3,588		28,358,231
2005	28,358,231	199,018			28,557,249
2006	28,557,249	34,042			28,591,291
2007	28,591,291	293,962			28,885,253
2008	28,885,253	164,717			29,049,970

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Transmission Plant
Account: 357.01 Underground Conduit

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996	25,444,687	84,928			25,529,615
1997	25,529,615	28,389		(275)	25,557,729
1998	25,557,729			(18)	25,557,711
1999	25,557,711	41,818	32,204		25,567,325
2000	25,567,325	35,727			25,603,052
2001	25,603,052	2,751,710	149,572		28,205,190
2002	28,205,190	73,218			28,278,408
2003	28,278,408	95,924			28,374,332
2004	28,374,332		3,588		28,370,744
2005	28,370,744	209,001			28,579,745
2006	28,579,745	5,466			28,585,211
2007	28,585,211	204,588			28,789,800
2008	28,789,800	260,170			29,049,970

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 357.01 Underground Conduit

T-Cut: None
Placement Band: 1900-2008
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2000	99.6	197.1	SQ *	0.52	185.0	R4 *	0.58	196.2	SQ *	0.77
1997-2001	97.1	188.0	R5 *	2.66	155.0	R3 *	2.77	187.2	R4 *	2.85
1998-2002	97.1	188.0	R5 *	2.71	155.5	R3 *	2.89	187.0	R4 *	2.92
1999-2003	96.6	187.9	R5 *	2.26	156.2	R3 *	2.48	186.7	R4 *	2.47
2000-2004	96.4	189.7	R5 *	2.31	161.3	R3 *	2.49	185.3	R4 *	2.53
2001-2005	95.6	189.6	R5 *	1.56	162.3	R3 *	1.75	184.2	R4 *	1.76
2002-2006	98.3	194.4	S6 *	0.39	191.2	R5 *	0.38	195.6	S6 *	0.49
2003-2007	98.2	194.5	S6 *	0.46	191.7	R5 *	0.43	195.7	S6 *	0.45
2004-2008	97.8	194.7	S6 *	0.63	192.2	R5 *	0.59	195.8	S6 *	0.43

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 357.01 Underground Conduit

T-Cut: None
Placement Band: 1900-2008
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2008	96.6	194.5	S6 *	0.68	177.7	R4 *	0.57	193.4	SQ *	0.48
1998-2008	96.2	193.6	S6 *	0.71	173.0	R4 *	0.71	191.8	R5 *	0.68
2000-2008	96.5	193.5	SQ *	0.81	173.9	R4 *	0.94	191.7	R5 *	0.96
2002-2008	98.3	195.8	S6 *	0.51	193.7	S6 *	0.47	196.6	S6 *	0.33
2004-2008	97.8	194.7	S6 *	0.63	192.2	R5 *	0.59	195.8	S6 *	0.43
2006-2008	100.0				No Retirements					
2008-2008	100.0				No Retirements					

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 357.01 Underground Conduit

T-Cut: None

Placement Band: 1900-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-1997	100.0				No Retirements					
1996-1999	99.5	196.7	S6 *	0.67	182.9	R4 *	0.70	196.0	SQ *	0.84
1996-2001	97.2	190.0	R5 *	1.74	163.6	R3 *	1.67	188.7	R5 *	1.64
1996-2003	97.6	192.3	SQ *	1.11	172.5	R4 *	1.07	185.6	R4 *	1.04
1996-2005	96.4	193.4	SQ *	0.66	173.5	R4 *	0.62	191.7	R5 *	0.58
1996-2007	96.5	194.2	SQ *	0.66	176.6	R4 *	0.56	193.0	SQ *	0.49
1996-2008	96.6	194.5	S6 *	0.68	177.7	R4 *	0.57	193.4	SQ *	0.48

Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 357.01 Underground Conduit

T-Cut: None

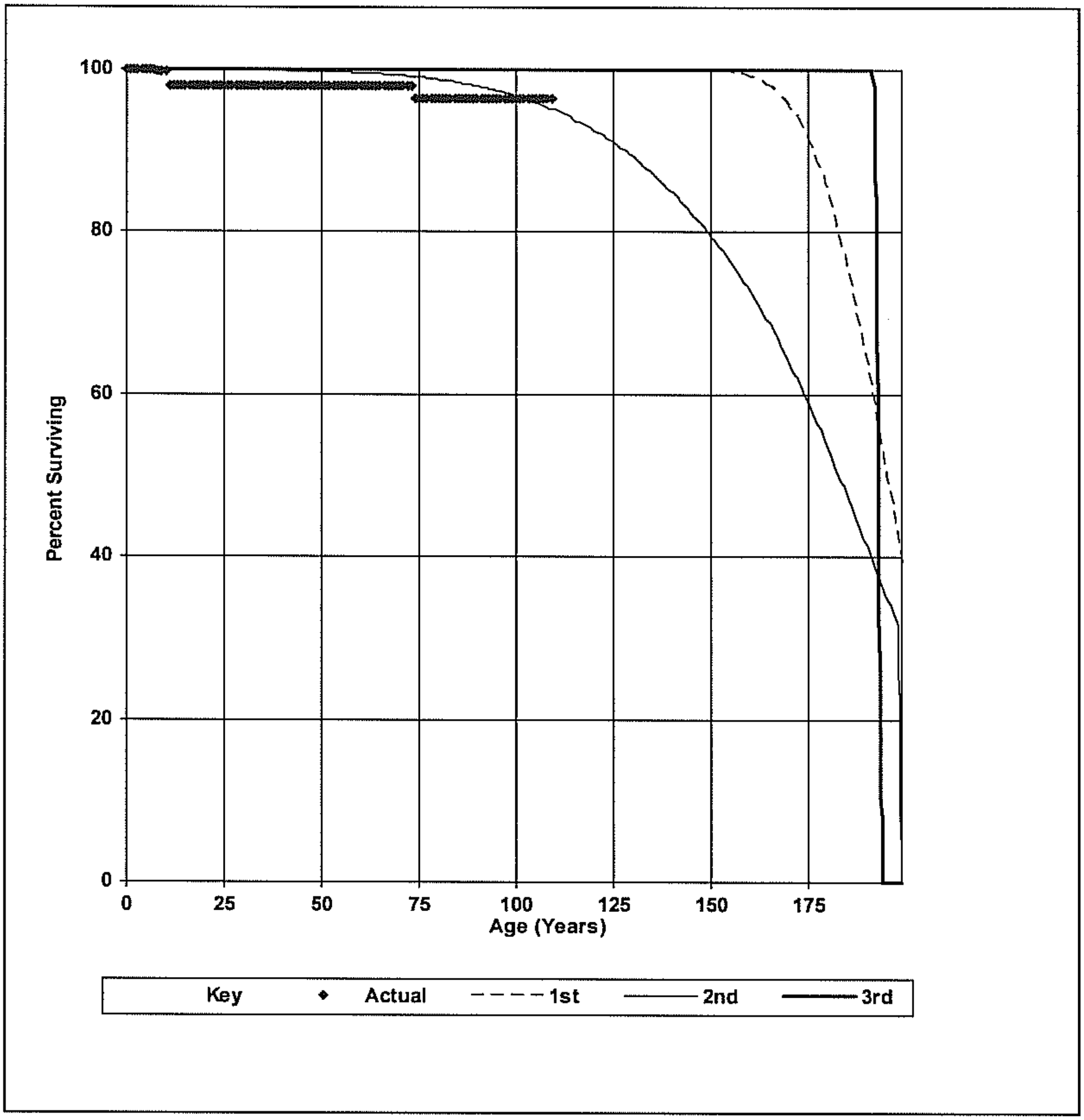
Placement Band: 1900-2008 Observation Band: 1996-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 194.5-S6 2nd: 177.7-R4 3rd: 193.4-SQ



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 357.01 Underground Conduit

T-Cut: None

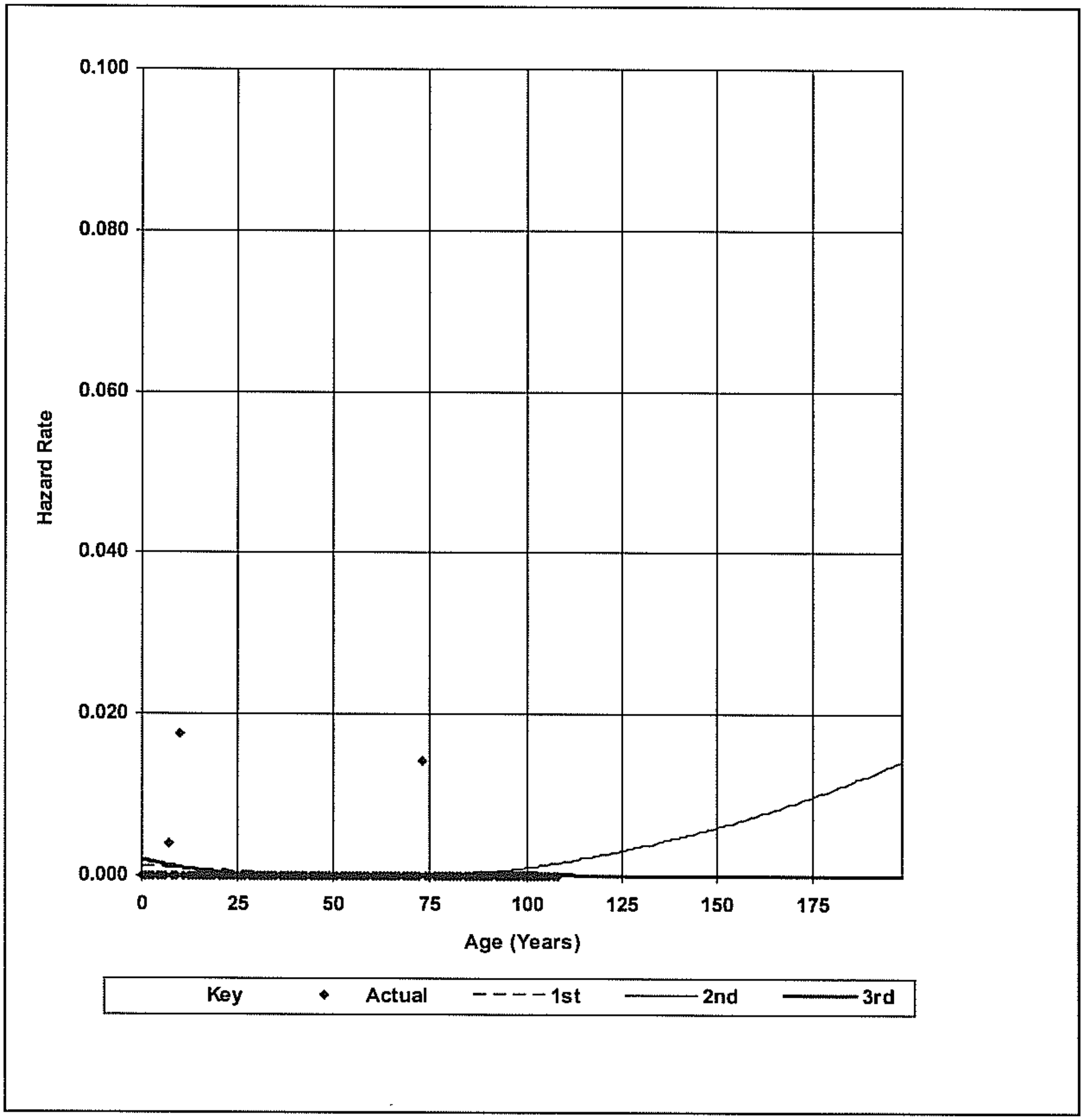
Placement Band: 1900-2007 Observation Band: 1996-2007

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 194.2-SQ 2nd: 176.6-R4 3rd: 193.0-SQ

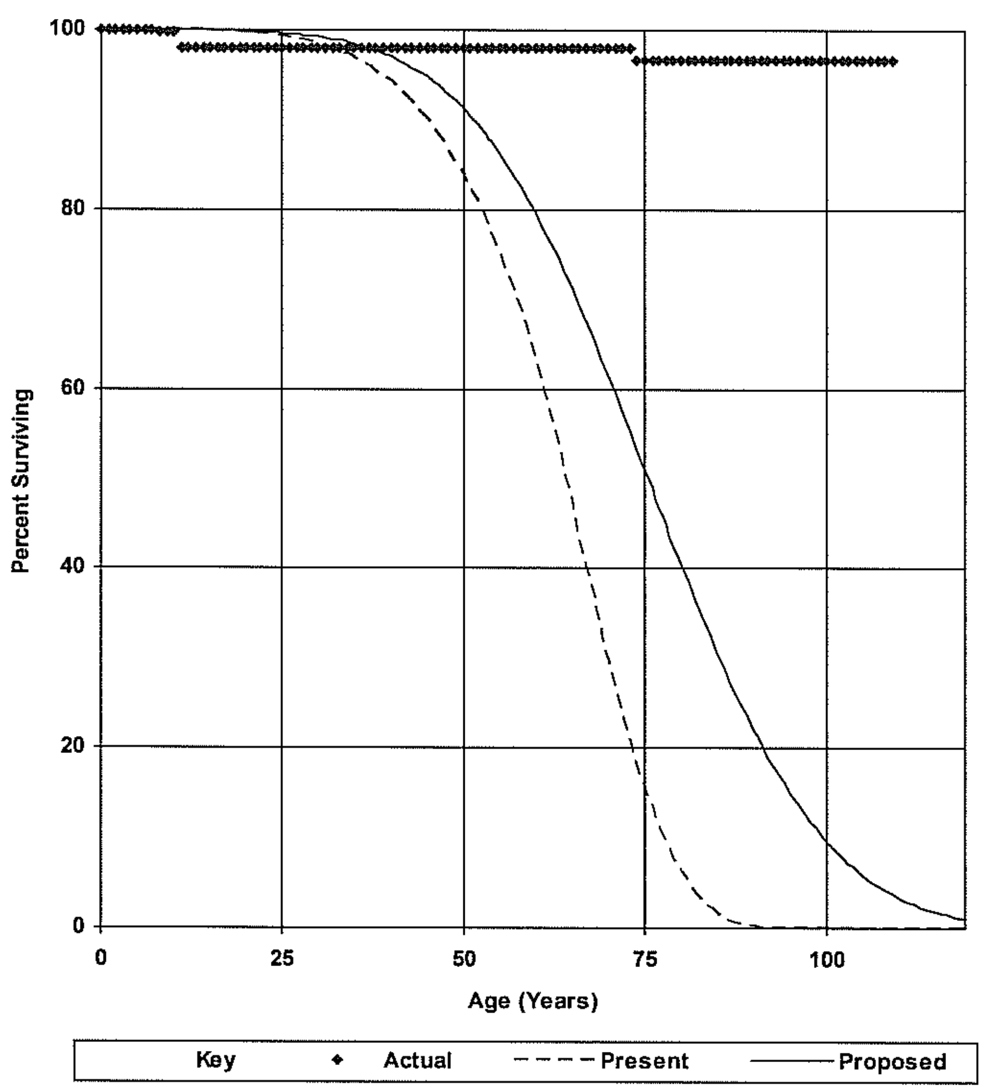


Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Transmission Plant
Account: 357.01 Underground Conduit

T-Cut: None
Placement Band: 1900-2008
Observation Band: 1996-2008

Present and Proposed Projection Life Curves **Present: 62.0-R4** **Proposed: 75.0-H4**



Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 357.01 Underground Conduit

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998			0.0			0.0			0.0	
1999	32,204		0.0		2,587	8.0		(2,587)	-8.0	
2000			0.0		43	0.0		(43)	0.0	
2001	149,572		0.0		1	0.0		(1)	0.0	
2002			0.0	0.0		0.0	1.4		0.0	-1.4
2003			0.0	0.0		0.0	1.4		0.0	-1.4
2004	3,588		0.0	0.0	833	23.2	0.6	(833)	-23.2	-0.6
2005			0.0	0.0		0.0	0.5		0.0	-0.5
2006			0.0	0.0		0.0	23.2		0.0	-23.2
2007			0.0	0.0		0.0	23.2		0.0	-23.2
2008			0.0	0.0		0.0	23.2		0.0	-23.2
Total	185,365		0.0		3,464	1.9		(3,464)	-1.9	

Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 357.01 Underground Conduit

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998			0.0			0.0			0.0	
1999	32,204		0.0		2,587	8.0		(2,587)	-8.0	
2000			0.0		43	0.0		(43)	0.0	
2001	149,572		0.0		1	0.0		(1)	0.0	
2002			0.0	0.0		0.0	1.4		0.0	-1.4
2003			0.0	0.0		0.0	1.4		0.0	-1.4
2004	3,588		0.0	0.0	833	23.2	0.6	(833)	-23.2	-0.6
2005			0.0	0.0		0.0	0.5		0.0	-0.5
2006			0.0	0.0		0.0	23.2		0.0	-23.2
2007			0.0	0.0		0.0	23.2		0.0	-23.2
2008			0.0	0.0		0.0	23.2		0.0	-23.2
Total	185,365		0.0		3,464	1.9		(3,464)	-1.9	

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 358.00 Underground Conductors and Devices

Dispersion: 50 - H3
Procedure: Broad Group

Generation Arrangement

Vintage	December 31, 2008 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2008	0.5	2,993,559	50.00	49.51	0.9901	1.0000	2,964,041	59,871
2007	1.5	3,013,581	50.00	48.52	0.9705	1.0000	2,924,540	60,272
2006	2.5	1,395,670	50.00	47.54	0.9508	1.0000	1,327,029	27,913
2005	3.5	2,682,886	50.00	46.56	0.9312	1.0000	2,498,418	53,658
2004	4.5	1,113,380	50.00	45.59	0.9117	1.0000	1,015,104	22,268
2003	5.5	3,208,858	50.00	44.62	0.8923	1.0000	2,863,267	64,177
2002	6.5	2,367,515	50.00	43.65	0.8730	1.0000	2,066,737	47,350
2001	7.5	3,424,172	50.00	42.69	0.8537	1.0000	2,923,220	68,483
2000	8.5	3,588,118	50.00	41.73	0.8346	1.0000	2,994,491	71,762
1999	9.5	2,482,654	50.00	40.78	0.8155	1.0000	2,024,654	49,653
1998	10.5	391,320	50.00	39.83	0.7966	1.0000	311,735	7,826
1997	11.5	1,909,481	50.00	38.89	0.7779	1.0000	1,485,298	38,190
1996	12.5	9,167,054	50.00	37.96	0.7592	1.0000	6,960,033	183,341
1995	13.5	2,237,630	50.00	37.04	0.7408	1.0000	1,657,637	44,753
1994	14.5	3,185,014	50.00	36.13	0.7225	1.0000	2,301,291	63,700
1993	15.5	3,307,731	50.00	35.22	0.7045	1.0000	2,330,164	66,155
1992	16.5	5,482,751	50.00	34.33	0.6866	1.0000	3,764,428	109,655
1991	17.5	4,668,741	50.00	33.45	0.6689	1.0000	3,123,135	93,375
1990	18.5	1,807,455	50.00	32.58	0.6515	1.0000	1,177,609	36,149
1989	19.5	1,289,659	50.00	31.72	0.6344	1.0000	818,108	25,793
1988	20.5	1,616,297	50.00	30.87	0.6175	1.0000	997,988	32,326
1987	21.5	1,186,638	50.00	30.04	0.6008	1.0000	712,951	23,733
1986	22.5	1,123,472	50.00	29.22	0.5845	1.0000	656,632	22,469
1985	23.5	1,445,099	50.00	28.42	0.5684	1.0000	821,402	28,902
1984	24.5	1,179,394	50.00	27.63	0.5526	1.0000	651,792	23,588
1983	25.5	1,383,484	50.00	26.86	0.5372	1.0000	743,232	27,670
1982	26.5	1,267,098	50.00	26.11	0.5221	1.0000	661,556	25,342
1981	27.5	4,083,262	50.00	25.37	0.5073	1.0000	2,071,511	81,665
1980	28.5	1,242,917	50.00	24.64	0.4929	1.0000	612,601	24,858
1979	29.5	2,258,223	50.00	23.94	0.4788	1.0000	1,081,176	45,164
1978	30.5	397,264	50.00	23.25	0.4650	1.0000	184,735	7,945
1977	31.5	563,871	50.00	22.58	0.4516	1.0000	254,653	11,277
1976	32.5	1,306,113	50.00	21.93	0.4386	1.0000	572,819	26,122
1975	33.5	818,532	50.00	21.29	0.4259	1.0000	348,592	16,371
1974	34.5	1,078,791	50.00	20.68	0.4135	1.0000	446,123	21,576
1973	35.5	2,163,154	50.00	20.08	0.4016	1.0000	868,625	43,263

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 358.00 Underground Conductors and Devices

Dispersion: 50 - H3
Procedure: Broad Group

Generation Arrangement

Vintage	Age (December 31, 2008)	Surviving Plant (December 31, 2008)	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1972	36.5	1,513,377	50.00	19.50	0.3899	1.0000	590,109	30,268
1971	37.5	428,316	50.00	18.93	0.3786	1.0000	162,181	8,566
1970	38.5	345,867	50.00	18.39	0.3677	1.0000	127,181	6,917
1969	39.5	1,012,416	50.00	17.86	0.3571	1.0000	361,557	20,248
1968	40.5	3,373,304	50.00	17.34	0.3469	1.0000	1,170,118	67,466
1967	41.5	975,059	50.00	16.85	0.3370	1.0000	328,550	19,501
1966	42.5	520,723	50.00	16.37	0.3274	1.0000	170,465	10,414
1965	43.5	725,775	50.00	15.90	0.3181	1.0000	230,860	14,515
1964	44.5	460,759	50.00	15.46	0.3091	1.0000	142,434	9,215
1963	45.5	548,900	50.00	15.02	0.3005	1.0000	164,930	10,978
1962	46.5	534,247	50.00	14.61	0.2921	1.0000	156,065	10,685
1961	47.5	204,868	50.00	14.20	0.2841	1.0000	58,193	4,097
1960	48.5	269,053	50.00	13.81	0.2763	1.0000	74,331	5,381
1959	49.5	968,180	50.00	13.44	0.2688	1.0000	260,208	19,364
1958	50.5	489,603	50.00	13.08	0.2615	1.0000	128,038	9,792
1957	51.5	471,267	50.00	12.73	0.2545	1.0000	119,950	9,425
1956	52.5	660,583	50.00	12.39	0.2478	1.0000	163,683	13,212
1955	53.5	367,167	50.00	12.06	0.2413	1.0000	88,594	7,343
1954	54.5	359,390	50.00	11.75	0.2350	1.0000	84,465	7,188
1953	55.5	224,523	50.00	11.45	0.2290	1.0000	51,413	4,490
1952	56.5	240,583	50.00	11.16	0.2232	1.0000	53,688	4,812
1951	57.5	155,299	50.00	10.88	0.2175	1.0000	33,785	3,106
1950	58.5	85,639	50.00	10.61	0.2121	1.0000	18,167	1,713
1949	59.5	265,177	50.00	10.35	0.2069	1.0000	54,867	5,304
1948	60.5	136,399	50.00	10.09	0.2019	1.0000	27,536	2,728
1947	61.5	60,309	50.00	9.85	0.1970	1.0000	11,882	1,206
1946	62.5	60,345	50.00	9.62	0.1923	1.0000	11,606	1,207
1945	63.5	58,136	50.00	9.39	0.1878	1.0000	10,919	1,163
1944	64.5	124,110	50.00	9.17	0.1835	1.0000	22,770	2,482
1943	65.5	60,622	50.00	8.96	0.1793	1.0000	10,867	1,212
1942	66.5	68,459	50.00	8.76	0.1752	1.0000	11,994	1,369
1941	67.5	113,032	50.00	8.56	0.1713	1.0000	19,361	2,261
1940	68.5	189,746	50.00	8.38	0.1675	1.0000	31,784	3,795
1939	69.5	191,778	50.00	8.19	0.1638	1.0000	31,422	3,836
1938	70.5	265,446	50.00	8.02	0.1603	1.0000	42,556	5,309
1937	71.5	69,531	50.00	7.85	0.1569	1.0000	10,910	1,391

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 358.00 Underground Conductors and Devices

Dispersion: 50 - H3
Procedure: Broad Group

Generation Arrangement

Vintage	Age (December 31, 2008)	Surviving Plant (December 31, 2008)	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1936	72.5	62,460	50.00	7.68	0.1536	1.0000	9,595	1,249
1935	73.5	19,917	50.00	7.52	0.1504	1.0000	2,996	398
1934	74.5	13,929	50.00	7.37	0.1474	1.0000	2,053	279
1933	75.5	7,988	50.00	7.22	0.1444	1.0000	1,153	160
1932	76.5	52,192	50.00	7.08	0.1415	1.0000	7,386	1,044
1931	77.5	816,856	50.00	6.94	0.1387	1.0000	113,316	16,337
1930	78.5	811,113	50.00	6.80	0.1360	1.0000	110,334	16,222
1929	79.5	27,255	50.00	6.67	0.1334	1.0000	3,636	545
1928	80.5	62,545	50.00	6.54	0.1309	1.0000	8,187	1,251
1927	81.5	58,149	50.00	6.42	0.1284	1.0000	7,469	1,163
1926	82.5	175,403	50.00	6.30	0.1261	1.0000	22,114	3,508
1925	83.5	155,815	50.00	6.19	0.1238	1.0000	19,286	3,116
1924	84.5	111,854	50.00	6.08	0.1215	1.0000	13,596	2,237
1923	85.5	145,090	50.00	5.97	0.1194	1.0000	17,322	2,902
1922	86.5	6,688	50.00	5.86	0.1173	1.0000	784	134
1921	87.5	4,400	50.00	5.76	0.1153	1.0000	507	88
1920	88.5	9,124	50.00	5.66	0.1133	1.0000	1,034	182
1919	89.5	383	50.00	5.57	0.1114	1.0000	43	8
1918	90.5	19,340	50.00	5.48	0.1095	1.0000	2,118	387
1917	91.5	6,542	50.00	5.38	0.1077	1.0000	705	131
1916	92.5	10,861	50.00	5.30	0.1059	1.0000	1,151	217
1914	94.5	6,902	50.00	5.13	0.1026	1.0000	708	138
1909	99.5	5,138	50.00	4.74	0.0948	1.0000	487	103
1907	101.5	110,108	50.00	4.60	0.0919	1.0000	10,121	2,202
1904	104.5	6,749	50.00	4.39	0.0877	1.0000	592	135
1901	107.5	23,163	50.00	4.17	0.0835	1.0000	1,934	463
1900	108.5	477	50.00	4.10	0.0820	1.0000	39	10
Total	22.2	$102,159,262	50.00	31.62	0.6325	1.0000	$64,613,431	$2,043,185

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 358.00 Underground Conductors and Devices

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2008	0.5	2,993,559		2,993,559	1.0000	0.5000
2007	1.5	3,013,581		3,013,581	1.0000	1.5000
2006	2.5	1,395,670		1,395,670	1.0000	2.5000
2005	3.5	2,682,886		2,682,886	1.0000	3.5000
2004	4.5	1,113,380		1,113,380	1.0000	4.5000
2003	5.5	3,233,507		3,208,858	0.9924	5.4906
2002	6.5	2,367,515		2,367,515	1.0000	6.5000
2001	7.5	3,424,172		3,424,172	1.0000	7.5000
2000	8.5	3,667,083		3,588,118	0.9785	8.4466
1999	9.5	2,578,201		2,482,654	0.9629	9.2221
1998	10.5	391,320		391,320	1.0000	10.5000
1997	11.5	1,958,972		1,909,481	0.9747	11.3358
1996	12.5	9,273,154		9,167,054	0.9886	12.4256
1995	13.5		2,237,630	2,237,630	1.0000	13.5000
1994	14.5		3,227,634	3,185,014	0.9868	14.4154
1993	15.5		3,451,796	3,307,731	0.9583	15.2817
1992	16.5		5,653,441	5,482,751	0.9698	16.3031
1991	17.5		4,702,707	4,668,741	0.9928	17.4550
1990	18.5		1,905,382	1,807,455	0.9486	18.0742
1989	19.5		1,319,221	1,289,659	0.9776	19.3573
1988	20.5		1,849,118	1,616,297	0.8741	19.5560
1987	21.5		1,192,216	1,186,638	0.9953	21.4602
1986	22.5		1,135,896	1,123,472	0.9891	22.3852
1985	23.5		1,464,023	1,445,099	0.9871	23.3585
1984	24.5		1,262,056	1,179,394	0.9345	24.1489
1983	25.5		1,383,484	1,383,484	1.0000	25.5000
1982	26.5		1,372,440	1,267,098	0.9232	25.9546
1981	27.5		4,095,372	4,083,262	0.9970	27.4690
1980	28.5		1,274,273	1,242,917	0.9754	28.3943
1979	29.5		2,280,977	2,258,223	0.9900	29.4512
1978	30.5		401,950	397,264	0.9883	30.4046
1977	31.5		584,931	563,871	0.9640	31.3415
1976	32.5		1,348,150	1,306,113	0.9688	32.2687
1975	33.5		823,592	818,532	0.9939	33.4752
1974	34.5		1,087,088	1,078,791	0.9924	34.4529
1973	35.5		2,188,933	2,163,154	0.9882	35.4339
1972	36.5		1,516,275	1,513,377	0.9981	36.4896

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 358.00 Underground Conductors and Devices

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1971	37.5		442,781	428,316	0.9673	37.4388
1970	38.5		353,203	345,867	0.9792	38.4540
1969	39.5		1,021,013	1,012,416	0.9916	39.4485
1968	40.5		3,380,506	3,373,304	0.9979	40.4898
1967	41.5		990,453	975,059	0.9845	41.4207
1966	42.5		592,107	520,723	0.8794	41.4209
1965	43.5		752,666	725,775	0.9643	43.3274
1964	44.5		474,254	460,759	0.9715	44.4054
1963	45.5		548,900	548,900	1.0000	45.5000
1962	46.5		557,945	534,247	0.9575	46.1991
1961	47.5		217,090	204,868	0.9437	47.2121
1960	48.5		320,384	269,053	0.8398	48.0338
1959	49.5		991,578	968,180	0.9764	49.3636
1958	50.5		506,813	489,603	0.9660	50.3742
1957	51.5		471,288	471,267	1.0000	51.5000
1956	52.5		672,211	660,583	0.9827	52.4588
1955	53.5		375,999	367,167	0.9765	53.3329
1954	54.5		388,143	359,390	0.9259	54.0400
1953	55.5		227,539	224,523	0.9867	55.4564
1952	56.5		244,044	240,583	0.9858	56.3877
1951	57.5		172,933	155,299	0.8980	56.5560
1950	58.5		88,781	85,639	0.9646	58.3256
1949	59.5		273,053	265,177	0.9712	59.3030
1948	60.5		147,184	136,399	0.9267	60.1203
1947	61.5		63,731	60,309	0.9463	61.1718
1946	62.5		62,515	60,345	0.9653	62.3752
1945	63.5		60,136	58,136	0.9667	63.2424
1944	64.5		139,187	124,110	0.8917	64.0498
1943	65.5		69,431	60,622	0.8731	64.6165
1942	66.5		73,008	68,459	0.9377	66.0300
1941	67.5		128,576	113,032	0.8791	66.9791
1940	68.5		207,403	189,746	0.9149	68.0374
1939	69.5		205,667	191,778	0.9325	69.0085
1938	70.5		286,457	265,446	0.9267	69.9868
1937	71.5		94,448	69,531	0.7362	70.1988
1936	72.5		67,457	62,460	0.9259	72.0731
1935	73.5		19,955	19,917	0.9981	73.4970

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 358.00 Underground Conductors and Devices

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1934	74.5		13,929	13,929	1.0000	74.5000
1933	75.5		9,053	7,988	0.8824	75.1547
1932	76.5		54,433	52,192	0.9588	76.2630
1931	77.5		919,781	816,856	0.8881	76.7727
1930	78.5		960,497	811,113	0.8445	77.6479
1929	79.5		47,793	27,255	0.5703	76.9655
1928	80.5		64,145	62,545	0.9751	80.3527
1927	81.5		81,439	58,149	0.7140	79.9435
1926	82.5		233,265	175,403	0.7519	80.5138
1925	83.5		239,752	155,815	0.6499	81.8685
1924	84.5		114,322	111,854	0.9784	84.3337
1923	85.5		196,276	145,090	0.7392	83.6809
1922	86.5		6,688	6,688	1.0000	86.5000
1921	87.5		4,400	4,400	1.0000	87.5000
1920	88.5		9,577	9,124	0.9527	88.0978
1919	89.5		383	383	1.0000	89.5000
1918	90.5		19,340	19,340	1.0000	90.5000
1917	91.5		6,542	6,542	1.0000	91.5000
1916	92.5		10,861	10,861	1.0000	92.5000
1914	94.5		6,902	6,902	1.0000	94.5000
1909	99.5		5,138	5,138	1.0000	99.5000
1907	101.5		110,108	110,108	1.0000	101.5000
1904	104.5		6,749	6,749	1.0000	104.5000
1901	107.5		23,163	23,163	1.0000	107.5000
1900	108.5		639	477	0.7465	106.1109
Total	22.2	$38,093,002	$66,592,598	$102,159,262	0.9759	

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 358.00 Underground Conductors and Devices

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996		76,043,387			76,043,387
1997	76,043,387	1,500,180	82,249	(241,315)	77,220,002
1998	77,220,002	23,253	100,054	(339,272)	76,803,929
1999	76,803,929	2,120,465	215,254	(47,628)	78,661,513
2000	78,661,513	3,983,166	360,729	(2,379)	82,281,570
2001	82,281,570	4,579,577	318,804	(184,754)	86,357,590
2002	86,357,590	2,021,793	523,049	12,873	87,869,207
2003	87,869,207	2,571,611	118,002		90,322,816
2004	90,322,816	1,885,282	179,126		92,028,973
2005	92,028,973	2,893,967	218,295	(42,347)	94,662,298
2006	94,662,298	2,077,637	102,736		96,637,199
2007	96,637,199	3,129,593	105,231	7,441	99,669,002
2008	99,669,002	2,693,068	202,808		102,159,262

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 358.00 Underground Conductors and Devices

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996	66,778,416	9,273,154			76,051,570
1997	76,051,570	2,587,187	82,249	(241,315)	78,315,193
1998	78,315,193	391,320	100,054	(339,272)	78,267,187
1999	78,267,187	2,566,643	215,254	(47,628)	80,570,948
2000	80,570,948	3,667,083	360,729	(2,379)	83,874,923
2001	83,874,923	3,424,172	318,804	(184,754)	86,795,538
2002	86,795,538	2,367,515	523,049	12,873	88,652,877
2003	88,652,877	3,275,854	118,002		91,810,729
2004	91,810,729	1,105,939	179,126		92,737,543
2005	92,737,543	2,682,886	218,295	(42,347)	95,159,786
2006	95,159,786	1,395,670	102,736		96,452,720
2007	96,452,720	3,013,581	105,231	7,441	99,368,511
2008	99,368,511	2,993,559	202,808		102,159,262

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 358.00 Underground Conductors and Devices

T-Cut: None

Placement Band: 1919-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2000	63.4	122.9	S0	2.98	98.1	S1.5	2.18	85.9	R4 *	2.25
1997-2001	63.3	113.5	S-.5	3.42	90.3	R2	2.60	82.4	R3	1.24
1998-2002	60.6	110.7	S-.5	3.26	86.2	R1.5	1.78	79.7	R2.5	1.67
1999-2003	60.0	105.8	L0.5	4.42	82.8	R2	3.20	78.9	R3	1.81
2000-2004	44.1	97.9	L1	6.66	78.8	R2.5	3.03	77.5	R3 *	2.39
2001-2005	50.3	100.7	L1	4.28	81.8	R2.5	1.45	79.9	R3	1.35
2002-2006	56.2	106.4	L1 *	3.49	86.4	R2.5	1.51	83.6	R3	1.56
2003-2007	61.1	109.7	L1.5 *	3.49	91.4	S2	2.18	88.5	R3	1.64
2004-2008	63.3	114.6	L1.5 *	2.47	95.7	S2	1.42	92.2	R3	1.38

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 358.00 Underground Conductors and Devices

T-Cut: None

Placement Band: 1919-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2008	62.8	118.2	S0	3.17	93.3	S1.5	1.80	87.6	R3	1.65
1998-2008	60.9	114.0	S0	3.31	90.7	R2	1.98	86.2	R3	1.71
2000-2008	58.9	110.8	L1	3.57	88.2	R2.5	2.06	85.2	R3	1.80
2002-2008	62.9	116.4	S0	2.77	92.6	S1.5	1.58	88.9	R3	1.53
2004-2008	63.3	114.6	L1.5 *	2.47	95.7	S2	1.42	92.2	R3	1.38
2006-2008	85.0	150.1	R1	1.49	128.1	S1	2.04	109.5	R3	1.75
2008-2008	83.8	148.3	R1	2.02	121.6	R1.5	2.73	103.2	R3	2.35

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 358.00 Underground Conductors and Devices

T-Cut: None

Placement Band: 1919-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-1997	92.2	169.0	R2	0.62	149.3	R2	0.84	151.5	R2	0.83
1996-1999	84.5	152.5	R1	1.07	152.2	R1	1.10	114.6	R2.5	1.41
1996-2001	66.1	120.9	S-.5	3.17	94.8	S1.5	2.36	84.9	R3	1.22
1996-2003	65.7	120.3	S-.5	3.31	92.0	R2	2.06	83.8	R3	1.55
1996-2005	54.9	109.0	L1	4.24	87.0	R2.5	2.12	82.3	R3	1.32
1996-2007	61.0	115.7	S0	3.51	91.6	S1.5	1.86	86.2	R3	1.48
1996-2008	62.8	118.2	S0	3.17	93.3	S1.5	1.80	87.6	R3	1.65

Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 358.00 Underground Conductors and Devices

T-Cut: None

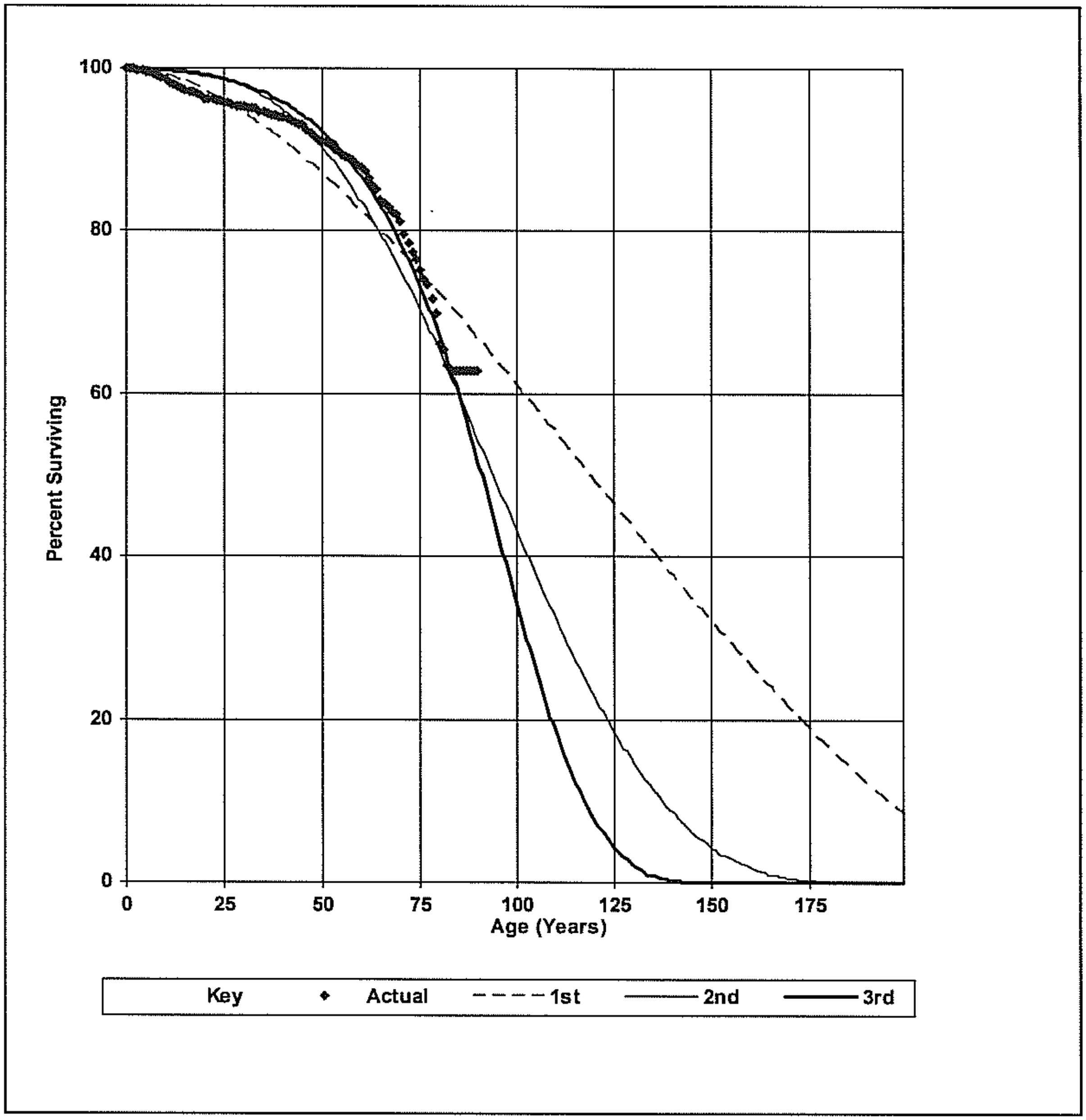
Placement Band: 1919-2008 Observation Band: 1996-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 118.2-S0 2nd: 93.3-S1.5 3rd: 87.6-R3



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 358.00 Underground Conductors and Devices

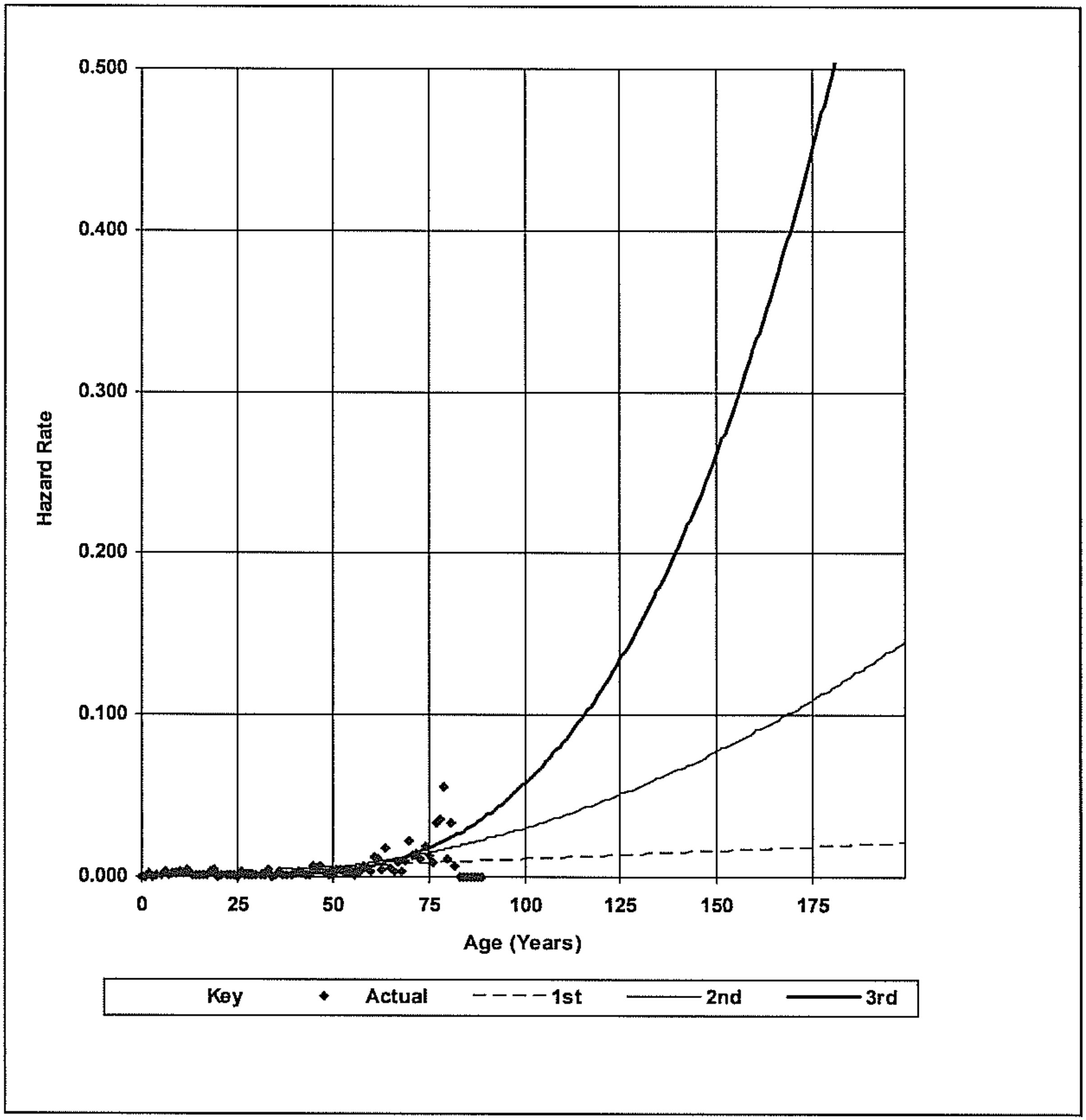
T-Cut: None

Placement Band: 1919-2007 Observation Band: 1996-2007

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function **1st: 115.7-S0 2nd: 91.6-S1.5 3rd: 86.2-R3**



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 358.00 Underground Conductors and Devices

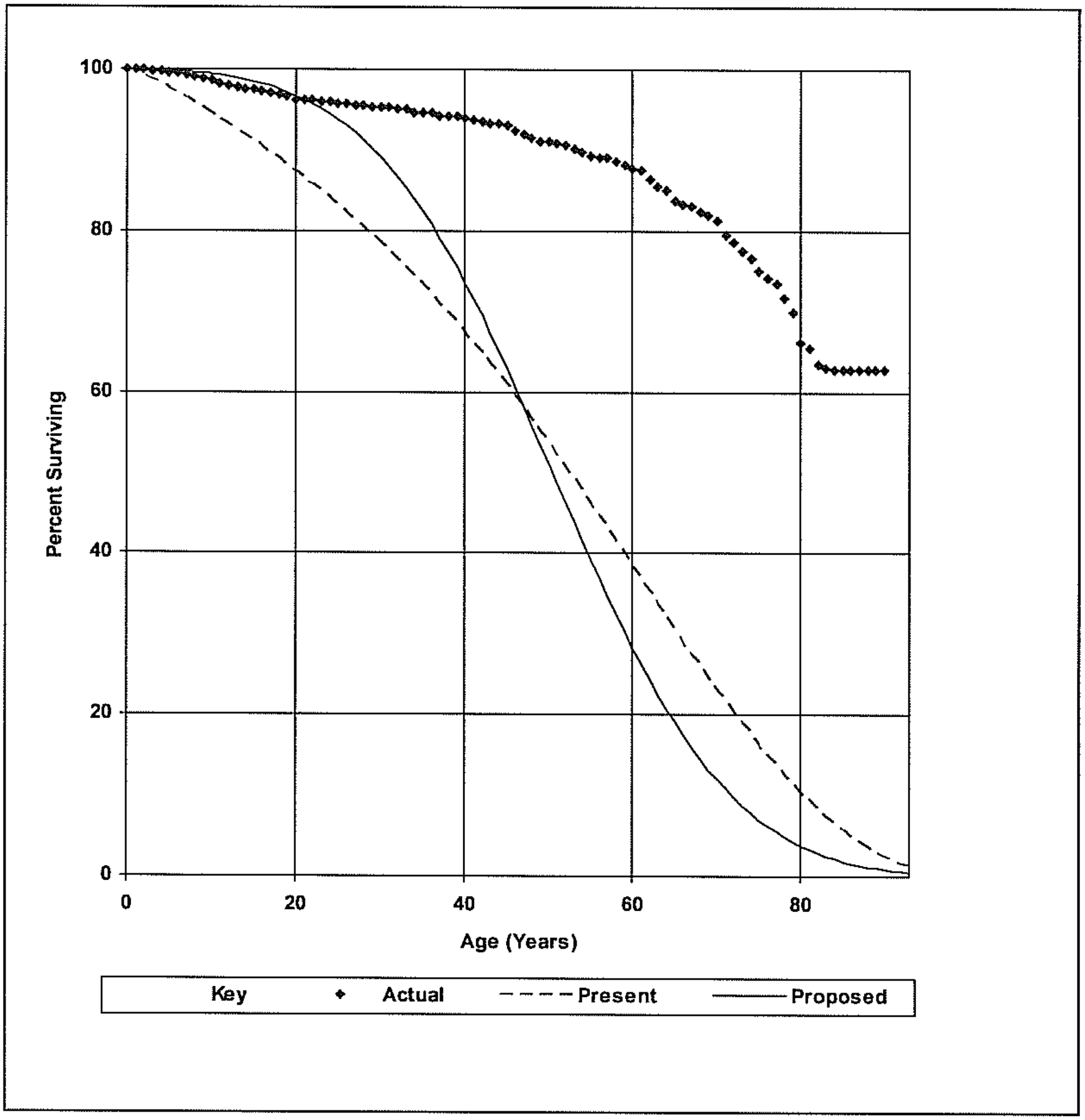
T-Cut: None

Placement Band: 1919-2008

Observation Band: 1996-2008

Present and Proposed Projection Life Curves

Present: 50.0-R1 **Proposed: 50.0-H3**



Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 358.00 Underground Conductors and Devices

Unadjusted Net Salvage History

Year	Retirements	Gross Salvage Amount	Gross Salvage Pct.	Gross Salvage 5-Yr Avg.	Cost of Retiring Amount	Cost of Retiring Pct.	Cost of Retiring 5-Yr Avg.	Net Salvage Amount	Net Salvage Pct.	Net Salvage 5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998	100,054		0.0		25,060	25.0		(25,060)	-25.0	
1999	215,254		0.0		71,275	33.1		(71,275)	-33.1	
2000	360,729	34,412	9.5		239,887	66.5		(205,475)	-57.0	
2001	318,804	34,862	10.9		311,797	97.8		(276,935)	-86.9	
2002	523,049	14,049	2.7	5.5	184,888	35.3	54.9	(170,839)	-32.7	-49.4
2003	118,002	(7,938)	-6.7	4.9	219,831	186.3	66.9	(227,770)	-193.0	-62.0
2004	179,126		0.0	5.0	164,109	91.6	74.7	(164,109)	-91.6	-69.7
2005	218,295		0.0	3.0	131,376	60.2	74.6	(131,376)	-60.2	-71.5
2006	102,736		0.0	0.5	187,417	182.4	77.8	(187,417)	-182.4	-77.2
2007	105,231		0.0	-1.1	175,720	167.0	121.4	(175,720)	-167.0	-122.5
2008	202,808		0.0	0.0	460,260	226.9	138.4	(460,260)	-226.9	-138.4
Total	2,444,089	75,384	3.1		2,171,621	88.9		(2,096,237)	-85.8	

Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 358.00 Underground Conductors and Devices

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998	100,054		0.0		25,060	25.0		(25,060)	-25.0	
1999	215,254		0.0		71,275	33.1		(71,275)	-33.1	
2000	360,729	34,412	9.5		239,887	66.5		(205,475)	-57.0	
2001	318,804	34,862	10.9		311,797	97.8		(276,935)	-86.9	
2002	523,049	14,049	2.7	5.5	184,888	35.3	54.9	(170,839)	-32.7	-49.4
2003	118,002	(7,938)	-6.7	4.9	219,831	186.3	66.9	(227,770)	-193.0	-62.0
2004	179,126		0.0	5.0	164,109	91.6	74.7	(164,109)	-91.6	-69.7
2005	218,295		0.0	3.0	131,376	60.2	74.6	(131,376)	-60.2	-71.5
2006	102,736		0.0	0.5	187,417	182.4	77.8	(187,417)	-182.4	-77.2
2007	105,231		0.0	-1.1	175,720	167.0	121.4	(175,720)	-167.0	-122.5
2008	202,808		0.0	0.0	460,260	226.9	138.4	(460,260)	-226.9	-138.4
Total	2,444,089	75,384	3.1		2,171,621	88.9		(2,096,237)	-85.8	

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant
Account: 359.00 Roads and Trails

Dispersion: 75 - H4
Procedure: Broad Group

Generation Arrangement

Vintage	Age (December 31, 2008)	Surviving Plant (December 31, 2008)	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2006	2.5	9,555	75.00	72.50	0.9667	1.0000	9,237	127
2003	5.5	40,069	75.00	69.51	0.9267	1.0000	37,134	534
2002	6.5	10,030	75.00	68.51	0.9134	1.0000	9,161	134
2001	7.5	2,231,897	75.00	67.51	0.9001	1.0000	2,008,978	29,759
2000	8.5	1,728	75.00	66.51	0.8868	1.0000	1,533	23
1999	9.5	4,642	75.00	65.51	0.8735	1.0000	4,054	62
1997	11.5	944	75.00	63.52	0.8470	1.0000	799	13
1975	33.5	23,422	75.00	42.15	0.5620	1.0000	13,164	312
1964	44.5	26,284	75.00	32.60	0.4347	1.0000	11,425	350
Total	8.1	$2,348,571	75.00	66.92	0.8922	1.0000	$2,095,485	$31,314

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Transmission Plant
Account: 359.00 Roads and Trails

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2006	2.5	9,555		9,555	1.0000	2.5000
2003	5.5	40,069		40,069	1.0000	5.5000
2002	6.5	10,030		10,030	1.0000	6.5000
2001	7.5	2,231,897		2,231,897	1.0000	7.5000
2000	8.5	1,728		1,728	1.0000	8.5000
1999	9.5	4,642		4,642	1.0000	9.5000
1997	11.5	944		944	1.0000	11.5000
1975	33.5		23,422	23,422	1.0000	33.5000
1964	44.5		26,284	26,284	1.0000	44.5000
Total	8.1	$2,298,865	$49,706	$2,348,571	1.0000	

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Transmission Plant
Account: 359.00 Roads and Trails

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996		49,706			49,706
1997	49,706				49,706
1998	49,706				49,706
1999	49,706				49,706
2000	49,706	4,642			54,347
2001	54,347	2,243,943			2,298,291
2002	2,298,291	2,118			2,300,409
2003	2,300,409	(1,326)			2,299,082
2004	2,299,082	21,429			2,320,512
2005	2,320,512	29,380			2,349,892
2006	2,349,892	(50,362)			2,299,530
2007	2,299,530	1,244			2,300,774
2008	2,300,774	47,797			2,348,571

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 359.00 Roads and Trails

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996	49,706				49,706
1997	49,706	944			50,649
1998	50,649				50,649
1999	50,649	4,642			55,291
2000	55,291	1,728			57,019
2001	57,019	2,231,897			2,288,916
2002	2,288,916	10,030			2,298,946
2003	2,298,946	40,069			2,339,016
2004	2,339,016				2,339,016
2005	2,339,016				2,339,016
2006	2,339,016	9,555			2,348,571
2007	2,348,571				2,348,571
2008	2,348,571				2,348,571

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant
Account: 360.01 Land Rights

Dispersion: 75 - H5
Procedure: Broad Group

Generation Arrangement

Vintage	December 31, 2008 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2007	1.5	1,022,492	75.00	73.50	0.9800	1.0000	1,002,042	13,633
2006	2.5	2,996,658	75.00	72.50	0.9667	1.0000	2,896,768	39,955
2005	3.5	5,305,454	75.00	71.50	0.9533	1.0000	5,057,865	70,739
2001	7.5	922	75.00	67.50	0.9000	1.0000	830	12
2000	8.5	1,038	75.00	66.50	0.8867	1.0000	920	14
1999	9.5	6,411	75.00	65.50	0.8733	1.0000	5,599	85
1992	16.5	43,757	75.00	58.50	0.7800	1.0000	34,132	583
1989	19.5	352	75.00	55.51	0.7401	1.0000	261	5
1987	21.5	5,301	75.00	53.51	0.7135	1.0000	3,782	71
1985	23.5	6,854	75.00	51.52	0.6869	1.0000	4,708	91
1984	24.5	4,299	75.00	50.52	0.6736	1.0000	2,896	57
1983	25.5	259	75.00	49.53	0.6603	1.0000	171	3
1982	26.5	1,268	75.00	48.53	0.6471	1.0000	821	17
1981	27.5	812	75.00	47.54	0.6339	1.0000	515	11
1980	28.5	219	75.00	46.55	0.6207	1.0000	136	3
1979	29.5	1,206	75.00	45.56	0.6075	1.0000	733	16
1978	30.5	3,316	75.00	44.57	0.5943	1.0000	1,971	44
1977	31.5	4,365	75.00	43.59	0.5812	1.0000	2,537	58
1976	32.5	7,174	75.00	42.61	0.5681	1.0000	4,076	96
1975	33.5	2,010	75.00	41.63	0.5551	1.0000	1,116	27
1974	34.5	35,041	75.00	40.66	0.5421	1.0000	18,995	467
1973	35.5	1,790	75.00	39.69	0.5292	1.0000	947	24
1972	36.5	2,769	75.00	38.72	0.5163	1.0000	1,430	37
1971	37.5	15,277	75.00	37.76	0.5035	1.0000	7,692	204
1970	38.5	13,323	75.00	36.81	0.4908	1.0000	6,539	178
1969	39.5	5,492	75.00	35.87	0.4782	1.0000	2,626	73
1968	40.5	1,367	75.00	34.93	0.4657	1.0000	636	18
1967	41.5	13,495	75.00	34.00	0.4534	1.0000	6,118	180
1966	42.5	3,705	75.00	33.08	0.4411	1.0000	1,634	49
1965	43.5	5,224	75.00	32.17	0.4290	1.0000	2,241	70
1964	44.5	40,111	75.00	31.27	0.4170	1.0000	16,726	535
1963	45.5	37,431	75.00	30.39	0.4052	1.0000	15,166	499
1962	46.5	21,335	75.00	29.51	0.3935	1.0000	8,396	284
1961	47.5	11,610	75.00	28.65	0.3821	1.0000	4,436	155
1960	48.5	7,864	75.00	27.81	0.3708	1.0000	2,916	105
1959	49.5	58,731	75.00	26.98	0.3597	1.0000	21,125	783

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant
Account: 360.01 Land Rights

Dispersion: 75 - H5
Procedure: Broad Group

Generation Arrangement

Vintage	December 31, 2008 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1958	50.5	43,784	75.00	26.16	0.3488	1.0000	15,274	584
1957	51.5	62,418	75.00	25.36	0.3382	1.0000	21,110	832
1956	52.5	6,994	75.00	24.58	0.3278	1.0000	2,292	93
1955	53.5	29,401	75.00	23.82	0.3176	1.0000	9,338	392
1954	54.5	16,505	75.00	23.07	0.3077	1.0000	5,078	220
1953	55.5	18,448	75.00	22.35	0.2980	1.0000	5,497	246
1952	56.5	12,996	75.00	21.64	0.2885	1.0000	3,750	173
1951	57.5	3,435	75.00	20.95	0.2794	1.0000	960	46
1950	58.5	12,203	75.00	20.28	0.2704	1.0000	3,300	163
1949	59.5	5,740	75.00	19.63	0.2618	1.0000	1,503	77
1948	60.5	3,699	75.00	19.00	0.2534	1.0000	937	49
1947	61.5	3,877	75.00	18.39	0.2452	1.0000	951	52
1946	62.5	11,853	75.00	17.80	0.2374	1.0000	2,814	158
1945	63.5	5,967	75.00	17.23	0.2298	1.0000	1,371	80
1944	64.5	2,372	75.00	16.68	0.2224	1.0000	528	32
1943	65.5	17,288	75.00	16.15	0.2153	1.0000	3,723	231
1942	66.5	3,039	75.00	15.64	0.2085	1.0000	634	41
1941	67.5	5,614	75.00	15.14	0.2019	1.0000	1,133	75
1940	68.5	3,956	75.00	14.66	0.1955	1.0000	774	53
1939	69.5	3,021	75.00	14.21	0.1894	1.0000	572	40
1938	70.5	2,577	75.00	13.76	0.1835	1.0000	473	34
1937	71.5	4,123	75.00	13.34	0.1778	1.0000	733	55
1936	72.5	1,940	75.00	12.93	0.1724	1.0000	334	26
1935	73.5	4,173	75.00	12.53	0.1671	1.0000	697	56
1934	74.5	1,914	75.00	12.16	0.1621	1.0000	310	26
1933	75.5	2,729	75.00	11.79	0.1573	1.0000	429	36
1932	76.5	6,711	75.00	11.45	0.1526	1.0000	1,024	89
1931	77.5	7,995	75.00	11.11	0.1481	1.0000	1,184	107
1930	78.5	8,575	75.00	10.79	0.1438	1.0000	1,233	114
1929	79.5	17,298	75.00	10.48	0.1397	1.0000	2,417	231
1928	80.5	5,799	75.00	10.18	0.1358	1.0000	787	77
1927	81.5	16,776	75.00	9.90	0.1320	1.0000	2,214	224
1926	82.5	2,532	75.00	9.62	0.1283	1.0000	325	34
1925	83.5	3,969	75.00	9.36	0.1248	1.0000	495	53
1924	84.5	14,575	75.00	9.11	0.1214	1.0000	1,770	194
1923	85.5	2,412	75.00	8.87	0.1182	1.0000	285	32

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant
Account: 360.01 Land Rights

Dispersion: 75 - H5
Procedure: Broad Group

Generation Arrangement

Vintage	Age	December 31, 2008 Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1922	86.5	386	75.00	8.63	0.1151	1.0000	44	5
1921	87.5	3,322	75.00	8.41	0.1121	1.0000	372	44
1920	88.5	8,395	75.00	8.20	0.1093	1.0000	917	112
1919	89.5	11,361	75.00	7.99	0.1065	1.0000	1,210	151
1918	90.5	12,861	75.00	7.79	0.1038	1.0000	1,335	171
1917	91.5	667	75.00	7.60	0.1013	1.0000	68	9
1916	92.5	846	75.00	7.41	0.0988	1.0000	84	11
1915	93.5	625	75.00	7.23	0.0965	1.0000	60	8
1914	94.5	101	75.00	7.07	0.0942	1.0000	9	1
1913	95.5	420	75.00	6.90	0.0920	1.0000	39	6
1912	96.5	29	75.00	6.74	0.0899	1.0000	3	
1911	97.5	1,084	75.00	6.60	0.0879	1.0000	95	14
1909	99.5	33	75.00	6.30	0.0840	1.0000	3	
1907	101.5	59	75.00	6.03	0.0805	1.0000	5	1
1906	102.5	3,356	75.00	5.91	0.0788	1.0000	264	45
1899	109.5	4,520	75.00	5.14	0.0686	1.0000	310	60
1898	110.5	244	75.00	5.04	0.0672	1.0000	16	3
Total	6.9	$10,113,745	75.00	68.52	0.9137	1.0000	$9,240,583	$134,850

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 360.01 Land Rights

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2007	1.5	1,022,492		1,022,492	1.0000	1.5000
2006	2.5	2,996,658		2,996,658	1.0000	2.5000
2005	3.5	5,305,454		5,305,454	1.0000	3.5000
2001	7.5	922		922	1.0000	7.5000
2000	8.5	1,038		1,038	1.0000	8.5000
1999	9.5	6,411		6,411	1.0000	9.5000
1992	16.5		43,757	43,757	1.0000	16.5000
1989	19.5		352	352	1.0000	19.5000
1987	21.5		5,301	5,301	1.0000	21.5000
1985	23.5		6,854	6,854	1.0000	23.5000
1984	24.5		4,299	4,299	1.0000	24.5000
1983	25.5		259	259	1.0000	25.5000
1982	26.5		1,268	1,268	1.0000	26.5000
1981	27.5		812	812	1.0000	27.5000
1980	28.5		219	219	1.0000	28.5000
1979	29.5		1,206	1,206	1.0000	29.5000
1978	30.5		3,316	3,316	1.0000	30.5000
1977	31.5		4,365	4,365	1.0000	31.5000
1976	32.5		7,174	7,174	1.0000	32.5000
1975	33.5		2,010	2,010	1.0000	33.5000
1974	34.5		35,041	35,041	1.0000	34.5000
1973	35.5		1,790	1,790	1.0000	35.5000
1972	36.5		2,769	2,769	1.0000	36.5000
1971	37.5		15,277	15,277	1.0000	37.5000
1970	38.5		13,323	13,323	1.0000	38.5000
1969	39.5		5,492	5,492	1.0000	39.5000
1968	40.5		1,367	1,367	1.0000	40.5000
1967	41.5		13,495	13,495	1.0000	41.5000
1966	42.5		3,705	3,705	1.0000	42.5000
1965	43.5		5,224	5,224	1.0000	43.5000
1964	44.5		40,111	40,111	1.0000	44.5000
1963	45.5		37,431	37,431	1.0000	45.5000
1962	46.5		21,335	21,335	1.0000	46.5000
1961	47.5		11,610	11,610	1.0000	47.5000
1960	48.5		7,864	7,864	1.0000	48.5000
1959	49.5		58,731	58,731	1.0000	49.5000
1958	50.5		43,784	43,784	1.0000	50.5000

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 360.01 Land Rights

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1957	51.5		62,418	62,418	1.0000	51.5000
1956	52.5		6,994	6,994	1.0000	52.5000
1955	53.5		29,401	29,401	1.0000	53.5000
1954	54.5		16,505	16,505	1.0000	54.5000
1953	55.5		18,448	18,448	1.0000	55.5000
1952	56.5		12,996	12,996	1.0000	56.5000
1951	57.5		3,435	3,435	1.0000	57.5000
1950	58.5		12,203	12,203	1.0000	58.5000
1949	59.5		5,740	5,740	1.0000	59.5000
1948	60.5		3,699	3,699	1.0000	60.5000
1947	61.5		3,877	3,877	1.0000	61.5000
1946	62.5		11,853	11,853	1.0000	62.5000
1945	63.5		5,967	5,967	1.0000	63.5000
1944	64.5		2,372	2,372	1.0000	64.5000
1943	65.5		17,288	17,288	1.0000	65.5000
1942	66.5		3,039	3,039	1.0000	66.5000
1941	67.5		5,614	5,614	1.0000	67.5000
1940	68.5		3,956	3,956	1.0000	68.5000
1939	69.5		3,021	3,021	1.0000	69.5000
1938	70.5		2,577	2,577	1.0000	70.5000
1937	71.5		4,123	4,123	1.0000	71.5000
1936	72.5		1,940	1,940	1.0000	72.5000
1935	73.5		4,173	4,173	1.0000	73.5000
1934	74.5		1,914	1,914	1.0000	74.5000
1933	75.5		2,729	2,729	1.0000	75.5000
1932	76.5		6,711	6,711	1.0000	76.5000
1931	77.5		7,995	7,995	1.0000	77.5000
1930	78.5		8,575	8,575	1.0000	78.5000
1929	79.5		17,298	17,298	1.0000	79.5000
1928	80.5		5,799	5,799	1.0000	80.5000
1927	81.5		16,776	16,776	1.0000	81.5000
1926	82.5		2,532	2,532	1.0000	82.5000
1925	83.5		3,969	3,969	1.0000	83.5000
1924	84.5		14,575	14,575	1.0000	84.5000
1923	85.5		2,412	2,412	1.0000	85.5000
1922	86.5		386	386	1.0000	86.5000
1921	87.5		3,322	3,322	1.0000	87.5000

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Distribution Plant

Account: 360.01 Land Rights

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1920	88.5		8,395	8,395	1.0000	88.5000
1919	89.5		11,361	11,361	1.0000	89.5000
1918	90.5		12,861	12,861	1.0000	90.5000
1917	91.5		667	667	1.0000	91.5000
1916	92.5		846	846	1.0000	92.5000
1915	93.5		625	625	1.0000	93.5000
1914	94.5		101	101	1.0000	94.5000
1913	95.5		420	420	1.0000	95.5000
1912	96.5		29	29	1.0000	96.5000
1911	97.5		1,084	1,084	1.0000	97.5000
1909	99.5		33	33	1.0000	99.5000
1907	101.5		59	59	1.0000	101.5000
1906	102.5		3,356	3,356	1.0000	102.5000
1899	109.5		4,520	4,520	1.0000	109.5000
1898	110.5		244	244	1.0000	110.5000
Total	6.9	$9,332,973	$780,772	$10,113,745	1.0000	

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Distribution Plant
Account: 360.01 Land Rights

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996		716,204			716,204
1997	716,204	60,009			776,213
1998	776,213				776,213
1999	776,213				776,213
2000	776,213	16,088		(4,080)	788,220
2001	788,220	922			789,142
2002	789,142				789,142
2003	789,142				789,142
2004	789,142				789,142
2005	789,142	5,881,138			6,670,280
2006	6,670,280	2,197,873			8,868,154
2007	8,868,154	1,249,997			10,118,151
2008	10,118,151	(4,405)			10,113,745

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Distribution Plant
Account: 360.01 Land Rights

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996	784,852				784,852
1997	784,852				784,852
1998	784,852				784,852
1999	784,852	6,411			791,263
2000	791,263	1,038		(4,080)	788,220
2001	788,220	922			789,142
2002	789,142				789,142
2003	789,142				789,142
2004	789,142				789,142
2005	789,142	5,305,454			6,094,596
2006	6,094,596	2,996,658			9,091,254
2007	9,091,254	1,022,492			10,113,745
2008	10,113,745				10,113,745

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant
Account: 361.00 Structures and Improvements

Dispersion: 65 - H2.5
Procedure: Broad Group

Generation Arrangement

Vintage	December 31, 2008 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2008	0.5	146,527	65.00	64.52	0.9927	1.0000	145,452	2,254
2007	1.5	190,698	65.00	63.57	0.9780	1.0000	186,507	2,934
2006	2.5	670,692	65.00	62.62	0.9634	1.0000	646,170	10,318
2005	3.5	511,372	65.00	61.68	0.9489	1.0000	485,251	7,867
2004	4.5	174,745	65.00	60.74	0.9345	1.0000	163,295	2,688
2003	5.5	600,894	65.00	59.81	0.9201	1.0000	552,886	9,245
2002	6.5	535,264	65.00	58.88	0.9058	1.0000	484,848	8,235
2001	7.5	360,492	65.00	57.95	0.8916	1.0000	321,417	5,546
2000	8.5	613,844	65.00	57.04	0.8775	1.0000	538,631	9,444
1999	9.5	770,975	65.00	56.12	0.8634	1.0000	665,697	11,861
1998	10.5	497,298	65.00	55.22	0.8495	1.0000	422,457	7,651
1997	11.5	934,131	65.00	54.32	0.8357	1.0000	780,621	14,371
1996	12.5	593,164	65.00	53.43	0.8219	1.0000	487,540	9,126
1995	13.5	890,312	65.00	52.54	0.8083	1.0000	719,645	13,697
1994	14.5	3,294,870	65.00	51.66	0.7948	1.0000	2,618,733	50,690
1993	15.5	4,243,009	65.00	50.79	0.7814	1.0000	3,315,462	65,277
1992	16.5	4,219,652	65.00	49.93	0.7681	1.0000	3,241,185	64,918
1991	17.5	2,680,728	65.00	49.07	0.7550	1.0000	2,023,834	41,242
1990	18.5	1,205,044	65.00	48.23	0.7419	1.0000	894,076	18,539
1989	19.5	594,559	65.00	47.39	0.7290	1.0000	433,461	9,147
1988	20.5	685,693	65.00	46.56	0.7163	1.0000	491,163	10,549
1987	21.5	88,478	65.00	45.74	0.7037	1.0000	62,261	1,361
1986	22.5	345,653	65.00	44.93	0.6912	1.0000	238,924	5,318
1985	23.5	23,287	65.00	44.13	0.6789	1.0000	15,809	358
1984	24.5	163,685	65.00	43.34	0.6667	1.0000	109,135	2,518
1983	25.5	121,430	65.00	42.56	0.6547	1.0000	79,503	1,868
1982	26.5	463,607	65.00	41.79	0.6429	1.0000	298,036	7,132
1981	27.5	281,851	65.00	41.03	0.6312	1.0000	177,897	4,336
1980	28.5	329,255	65.00	40.28	0.6196	1.0000	204,018	5,065
1979	29.5	88,996	65.00	39.54	0.6083	1.0000	54,134	1,369
1978	30.5	584,281	65.00	38.81	0.5971	1.0000	348,852	8,989
1977	31.5	291,633	65.00	38.09	0.5860	1.0000	170,909	4,487
1976	32.5	62,924	65.00	37.39	0.5752	1.0000	36,192	968
1975	33.5	413,339	65.00	36.69	0.5645	1.0000	233,326	6,359
1974	34.5	1,410,229	65.00	36.01	0.5540	1.0000	781,212	21,696
1973	35.5	641,778	65.00	35.34	0.5436	1.0000	348,888	9,874

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant
Account: 361.00 Structures and Improvements

Dispersion: 65 - H2.5
Procedure: Broad Group

Generation Arrangement

Vintage	Age	December 31, 2008 Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1972	36.5	366,875	65.00	34.67	0.5335	1.0000	195,713	5,644
1971	37.5	750,207	65.00	34.03	0.5235	1.0000	392,711	11,542
1970	38.5	267,962	65.00	33.39	0.5137	1.0000	137,639	4,122
1969	39.5	331,550	65.00	32.76	0.5040	1.0000	167,106	5,101
1968	40.5	543,103	65.00	32.15	0.4946	1.0000	268,595	8,355
1967	41.5	134,747	65.00	31.54	0.4853	1.0000	65,388	2,073
1966	42.5	71,425	65.00	30.95	0.4762	1.0000	34,010	1,099
1965	43.5	122,897	65.00	30.37	0.4672	1.0000	57,419	1,891
1964	44.5	65,789	65.00	29.80	0.4585	1.0000	30,162	1,012
1963	45.5	114,033	65.00	29.24	0.4499	1.0000	51,299	1,754
1962	46.5	108,527	65.00	28.69	0.4415	1.0000	47,910	1,670
1961	47.5	83,250	65.00	28.16	0.4332	1.0000	36,064	1,281
1960	48.5	99,728	65.00	27.63	0.4251	1.0000	42,397	1,534
1959	49.5	133,023	65.00	27.12	0.4172	1.0000	55,499	2,047
1958	50.5	160,871	65.00	26.62	0.4095	1.0000	65,872	2,475
1957	51.5	264,285	65.00	26.12	0.4019	1.0000	106,212	4,066
1956	52.5	74,962	65.00	25.64	0.3945	1.0000	29,570	1,153
1955	53.5	126,519	65.00	25.17	0.3872	1.0000	48,990	1,946
1954	54.5	119,002	65.00	24.71	0.3801	1.0000	45,233	1,831
1953	55.5	134,370	65.00	24.26	0.3732	1.0000	50,141	2,067
1952	56.5	129,937	65.00	23.81	0.3664	1.0000	47,603	1,999
1951	57.5	60,641	65.00	23.38	0.3597	1.0000	21,814	933
1950	58.5	53,681	65.00	22.96	0.3532	1.0000	18,961	826
1949	59.5	42,389	65.00	22.55	0.3469	1.0000	14,704	652
1948	60.5	70,817	65.00	22.14	0.3407	1.0000	24,124	1,089
1947	61.5	6,391	65.00	21.75	0.3346	1.0000	2,139	98
1946	62.5	6,526	65.00	21.36	0.3287	1.0000	2,145	100
1945	63.5	3,180	65.00	20.99	0.3229	1.0000	1,027	49
1944	64.5	3,930	65.00	20.62	0.3172	1.0000	1,247	60
1943	65.5	1,885	65.00	20.26	0.3117	1.0000	588	29
1942	66.5	34,273	65.00	19.91	0.3063	1.0000	10,497	527
1941	67.5	31,886	65.00	19.57	0.3010	1.0000	9,598	491
1940	68.5	46,137	65.00	19.23	0.2958	1.0000	13,649	710
1939	69.5	62,017	65.00	18.90	0.2908	1.0000	18,035	954
1938	70.5	38,290	65.00	18.58	0.2859	1.0000	10,947	589
1937	71.5	26,734	65.00	18.27	0.2811	1.0000	7,514	411

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant
Account: 361.00 Structures and Improvements

Dispersion: 65 - H2.5
Procedure: Broad Group

Generation Arrangement

Vintage	Age	December 31, 2008 Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1936	72.5	3,226	65.00	17.97	0.2764	1.0000	892	50
1935	73.5	951	65.00	17.67	0.2718	1.0000	258	15
1934	74.5	7,165	65.00	17.38	0.2673	1.0000	1,915	110
1933	75.5	492	65.00	17.09	0.2630	1.0000	129	8
1932	76.5	48,293	65.00	16.81	0.2587	1.0000	12,492	743
1931	77.5	178,474	65.00	16.54	0.2545	1.0000	45,423	2,746
1930	78.5	178,425	65.00	16.28	0.2504	1.0000	44,683	2,745
1929	79.5	57,832	65.00	16.02	0.2464	1.0000	14,252	890
1928	80.5	81,130	65.00	15.77	0.2426	1.0000	19,679	1,248
1927	81.5	85,726	65.00	15.52	0.2388	1.0000	20,467	1,319
1926	82.5	37,796	65.00	15.28	0.2350	1.0000	8,884	581
1925	83.5	43,186	65.00	15.04	0.2314	1.0000	9,994	664
1924	84.5	104,038	65.00	14.81	0.2279	1.0000	23,709	1,601
1923	85.5	342	65.00	14.59	0.2244	1.0000	77	5
1922	86.5	7,490	65.00	14.37	0.2210	1.0000	1,655	115
1919	89.5	8,353	65.00	13.74	0.2113	1.0000	1,765	129
1918	90.5	153	65.00	13.54	0.2082	1.0000	32	2
1917	91.5	48,225	65.00	13.34	0.2052	1.0000	9,897	742
1916	92.5	252	65.00	13.15	0.2023	1.0000	51	4
1914	94.5	29,315	65.00	12.78	0.1966	1.0000	5,762	451
1912	96.5	4,896	65.00	12.42	0.1911	1.0000	936	75
1911	97.5	2,701	65.00	12.25	0.1885	1.0000	509	42
1910	98.5	974	65.00	12.08	0.1859	1.0000	181	15
1907	101.5	481	65.00	11.60	0.1785	1.0000	86	7
1906	102.5	230	65.00	11.45	0.1761	1.0000	41	4
1905	103.5	113	65.00	11.30	0.1738	1.0000	20	2
1900	108.5	33,171	65.00	10.59	0.1630	1.0000	5,406	510
1898	110.5	7,961	65.00	10.33	0.1590	1.0000	1,266	122
1896	112.5	25,096	65.00	10.08	0.1551	1.0000	3,892	386
Total	22.6	$35,412,715	65.00	46.15	0.7100	1.0000	$25,144,299	$544,811

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Distribution Plant
Account: 361.00 Structures and Improvements

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2008	0.5	146,527		146,527	1.0000	0.5000
2007	1.5	190,698		190,698	1.0000	1.5000
2006	2.5	670,692		670,692	1.0000	2.5000
2005	3.5	511,372		511,372	1.0000	3.5000
2004	4.5	174,745		174,745	1.0000	4.5000
2003	5.5	600,894		600,894	1.0000	5.5000
2002	6.5	535,264		535,264	1.0000	6.5000
2001	7.5	362,327		360,492	0.9949	7.4721
2000	8.5	613,844		613,844	1.0000	8.5000
1999	9.5	790,860		770,975	0.9749	9.3366
1998	10.5	497,298		497,298	1.0000	10.5000
1997	11.5	939,599		934,131	0.9942	11.4938
1996	12.5	593,635		593,164	0.9992	12.4964
1995	13.5		931,736	890,312	0.9555	13.0747
1994	14.5		3,294,870	3,294,870	1.0000	14.5000
1993	15.5		4,296,439	4,243,009	0.9876	15.4723
1992	16.5		4,246,270	4,219,652	0.9937	16.4655
1991	17.5		2,708,675	2,680,728	0.9897	17.4675
1990	18.5		1,205,044	1,205,044	1.0000	18.5000
1989	19.5		700,919	594,559	0.8483	18.3893
1988	20.5		689,883	685,693	0.9939	20.4362
1987	21.5		88,478	88,478	1.0000	21.5000
1986	22.5		345,653	345,653	1.0000	22.5000
1985	23.5		23,287	23,287	1.0000	23.5000
1984	24.5		174,101	163,685	0.9402	24.3721
1983	25.5		140,760	121,430	0.8627	25.3107
1982	26.5		476,624	463,607	0.9727	26.2201
1981	27.5		282,088	281,851	0.9992	27.4937
1980	28.5		353,119	329,255	0.9324	27.7952
1979	29.5		110,381	88,996	0.8063	27.8082
1978	30.5		604,491	584,281	0.9666	30.1261
1977	31.5		314,145	291,633	0.9283	30.8264
1976	32.5		67,229	62,924	0.9360	32.2993
1975	33.5		498,744	413,339	0.8288	32.3578
1974	34.5		1,430,859	1,410,229	0.9856	34.3797
1973	35.5		654,638	641,778	0.9804	35.3320
1972	36.5		386,532	366,875	0.9491	36.1908

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 361.00 Structures and Improvements

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1971	37.5		750,719	750,207	0.9993	37.4956
1970	38.5		271,072	267,962	0.9885	38.4569
1969	39.5		340,790	331,550	0.9729	39.3715
1968	40.5		560,431	543,103	0.9691	40.1902
1967	41.5		141,336	134,747	0.9534	41.3228
1966	42.5		74,364	71,425	0.9605	42.2453
1965	43.5		132,152	122,897	0.9300	42.9294
1964	44.5		80,157	65,789	0.8208	43.3360
1963	45.5		118,411	114,033	0.9630	45.1397
1962	46.5		112,125	108,527	0.9679	46.2500
1961	47.5		84,799	83,250	0.9817	47.3553
1960	48.5		104,328	99,728	0.9559	48.0799
1959	49.5		137,538	133,023	0.9672	49.3889
1958	50.5		186,978	160,871	0.8604	49.5415
1957	51.5		283,937	264,285	0.9308	51.0463
1956	52.5		85,968	74,962	0.8720	52.3138
1955	53.5		168,759	126,519	0.7497	51.7465
1954	54.5		129,406	119,002	0.9196	54.3031
1953	55.5		140,743	134,370	0.9547	55.2557
1952	56.5		140,254	129,937	0.9264	55.9764
1951	57.5		66,501	60,641	0.9119	56.7643
1950	58.5		57,394	53,681	0.9353	57.9270
1949	59.5		45,049	42,389	0.9410	58.8880
1948	60.5		74,909	70,817	0.9454	60.3467
1947	61.5		8,050	6,391	0.7939	59.5422
1946	62.5		9,619	6,526	0.6784	60.5931
1945	63.5		3,180	3,180	1.0000	63.5000
1944	64.5		3,930	3,930	1.0000	64.5000
1943	65.5		5,233	1,885	0.3602	59.7973
1942	66.5		38,624	34,273	0.8873	66.0240
1941	67.5		35,027	31,886	0.9103	67.0655
1940	68.5		50,817	46,137	0.9079	68.0689
1939	69.5		62,930	62,017	0.9855	69.4379
1938	70.5		38,290	38,290	1.0000	70.5000
1937	71.5		33,088	26,734	0.8080	70.4503
1936	72.5		7,319	3,226	0.4408	66.9621
1935	73.5		951	951	1.0000	73.5000

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 361.00 Structures and Improvements

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1934	74.5		7,165	7,165	1.0000	74.5000
1933	75.5		2,040	492	0.2414	70.1395
1932	76.5		53,673	48,293	0.8998	75.9014
1931	77.5		201,710	178,474	0.8848	76.5911
1930	78.5		198,458	178,425	0.8991	77.5649
1929	79.5		59,195	57,832	0.9770	79.2810
1928	80.5		81,788	81,130	0.9920	80.4177
1927	81.5		92,411	85,726	0.9277	80.6684
1926	82.5		40,654	37,796	0.9297	81.8203
1925	83.5		64,282	43,186	0.6718	80.5304
1924	84.5		224,669	104,038	0.4631	79.4183
1923	85.5		1,688	342	0.2029	76.3329
1922	86.5		11,303	7,490	0.6626	84.0815
1919	89.5		8,353	8,353	1.0000	89.5000
1918	90.5		153	153	1.0000	90.5000
1917	91.5		49,289	48,225	0.9784	91.2517
1916	92.5		252	252	1.0000	92.5000
1914	94.5		29,315	29,315	1.0000	94.5000
1912	96.5		4,896	4,896	1.0000	96.5000
1911	97.5		2,701	2,701	1.0000	97.5000
1910	98.5		10,328	974	0.0943	89.8958
1909	99.5		5,927		0.0000	89.0000
1907	101.5		61,193	481	0.0079	90.0904
1906	102.5		230	230	1.0000	102.5000
1905	103.5		113	113	1.0000	103.5000
1900	108.5		33,171	33,171	1.0000	108.5000
1898	110.5		7,961	7,961	1.0000	110.5000
1896	112.5		25,096	25,096	1.0000	112.5000
Total	22.6	$6,627,754	$29,888,159	$35,412,715	0.9698	

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 361.00 Structures and Improvements

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996		26,662,875		(2,005)	26,660,870
1997	26,660,870	2,871,122	148,800	(805,391)	28,577,801
1998	28,577,801	77,961	131,953	(959)	28,522,850
1999	28,522,850	3,987,019	323,148	(368,740)	31,817,982
2000	31,817,982	607,229	31,991		32,393,220
2001	32,393,220	472,931	99,203		32,766,949
2002	32,766,949	715,784	36,746		33,445,986
2003	33,445,986	1,065,433	39,751	(140,458)	34,331,210
2004	34,331,210	546,905	15,126		34,862,989
2005	34,862,989	201,894	56,655	(28,563)	34,979,665
2006	34,979,665	(14,097)	66,621		34,898,947
2007	34,898,947	(52,744)	45,170		34,801,033
2008	34,801,033	719,718	108,036		35,412,715

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Distribution Plant
Account: 361.00 Structures and Improvements

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996	30,414,295	593,635		(2,005)	31,005,924
1997	31,005,924	1,590,557	148,800	(805,391)	31,642,291
1998	31,642,291	497,298	131,953	(959)	32,006,677
1999	32,006,677	790,860	323,148	(368,740)	32,105,651
2000	32,105,651	613,844	31,991		32,687,503
2001	32,687,503	362,327	99,203		32,950,627
2002	32,950,627	541,236	36,746		33,455,117
2003	33,455,117	735,381	39,751	(140,458)	34,010,289
2004	34,010,289	174,745	15,126		34,169,909
2005	34,169,909	539,934	56,655	(28,563)	34,624,625
2006	34,624,625	670,692	66,621		35,228,696
2007	35,228,696	190,698	45,170		35,374,224
2008	35,374,224	146,527	108,036		35,412,715

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 361.00 Structures and Improvements

T-Cut: None

Placement Band: 1940-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2000	71.6	93.8	L1	1.89	92.8	L1	1.90	70.7	R2 *	1.85
1997-2001	66.8	84.0	L1	1.14	126.0	SC *	0.86	84.3	S0 *	0.81
1998-2002	67.7	93.4	L1	1.52	90.9	L1	1.50	137.7	SC *	1.55
1999-2003	66.3	114.3	S-.5	4.44	114.0	S-.5	4.45	154.6	R0.5 *	4.50
2000-2004	81.9	120.7	S0 *	0.85	118.5	S0 *	0.84	172.6	R2 *	0.83
2001-2005	82.0	128.0	S0	1.96	163.6	R1 *	2.05	175.4	R2 *	2.02
2002-2006	79.6	147.3	R1	2.03	104.9	S1.5	1.28	86.2	R3	1.28
2003-2007	81.2	130.7	S0 *	1.12	104.7	S1	0.76	86.2	R3 *	0.54
2004-2008	76.2	114.6	S0 *	1.17	90.5	S1.5	1.30	79.1	R3 *	1.37

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 361.00 Structures and Improvements

T-Cut: None
Placement Band: 1940-2008
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2008	71.6	109.9	L1 *	1.10	96.1	S0.5	0.78	81.8	R2.5 *	0.86
1998-2008	70.8	109.3	L1	1.40	91.2	S1	0.93	82.0	R2.5	1.04
2000-2008	74.3	115.4	S0 *	1.16	97.0	S1	0.76	84.0	R2.5 *	0.84
2002-2008	76.6	123.2	S0 *	1.39	91.1	S1.5	0.82	81.3	R3	0.96
2004-2008	76.2	114.6	S0 *	1.17	90.5	S1.5	1.30	79.1	R3 *	1.37
2006-2008	71.6	104.0	L1.5 *	1.49	82.7	S1.5	1.69	74.4	R3 *	1.76
2008-2008	55.2	89.3	L1.5 *	8.09	73.3	S1.5	7.60	69.0	R3 *	8.63

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 361.00 Structures and Improvements

T-Cut: None

Placement Band: 1940-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

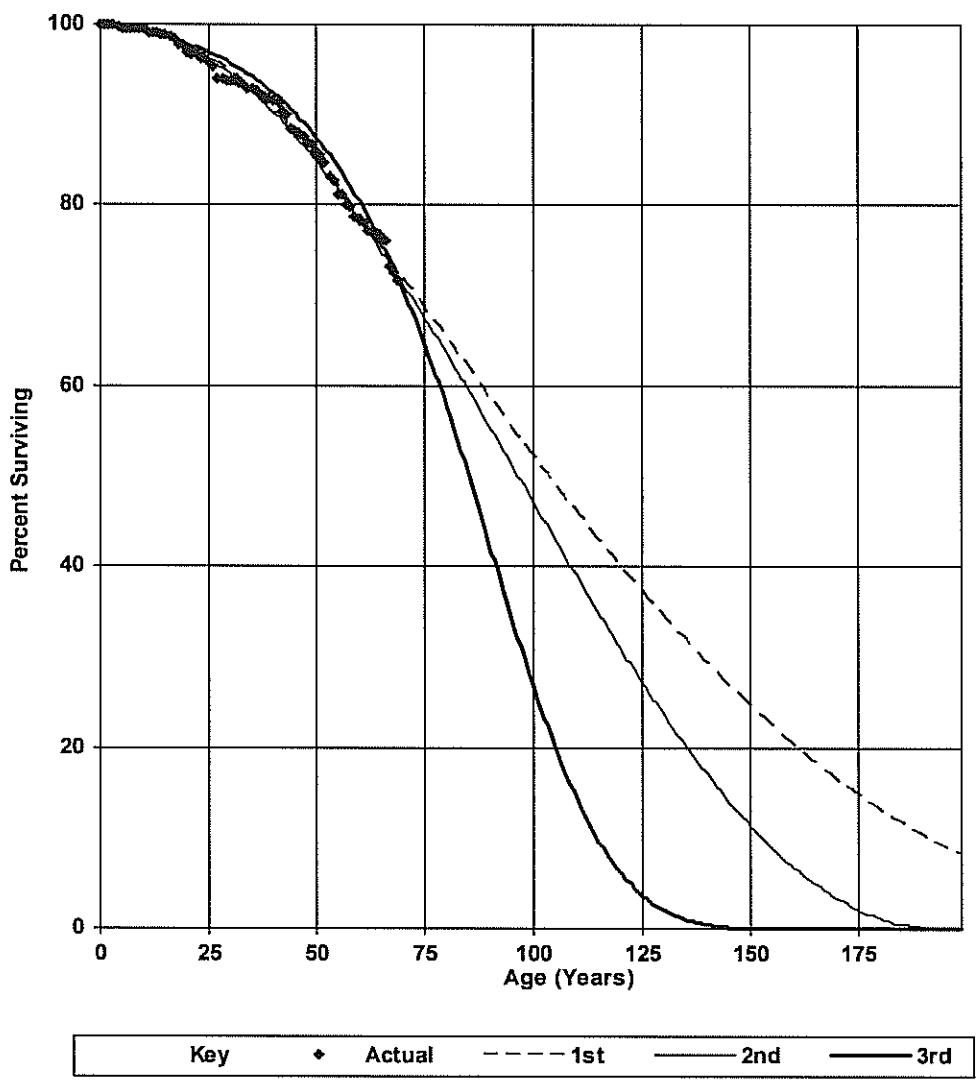
		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-1997	85.6	117.2	S0 *	2.50	178.5	R2.5 *	1.78	178.5	R2.5 *	1.77
1996-1999	64.0	88.7	L1	3.67	109.1	L0 *	3.73	65.0	R2.5 *	3.29
1996-2001	71.6	90.1	L1	1.13	128.6	SC *	0.72	84.1	S0.5 *	0.73
1996-2003	74.6	103.0	L1	0.96	119.8	SC	1.00	98.7	S0.5	0.99
1996-2005	78.2	111.6	L1	0.99	126.4	SC	1.00	153.2	R0.5 *	1.00
1996-2007	75.3	113.3	L1	1.02	108.0	S0	0.97	91.8	R2	0.97
1996-2008	71.6	109.9	L1 *	1.10	96.1	S0.5	0.78	81.8	R2.5 *	0.86

Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Distribution Plant
Account: 361.00 Structures and Improvements

T-Cut: None
Placement Band: 1940-2008 Observation Band: 1996-2008
Hazard Function: Proportion Retired
Weighting: Exposures

Graphics Analysis
1st: 109.9-L1 2nd: 96.1-S0.5 3rd: 81.8-R2.5



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 361.00 Structures and Improvements

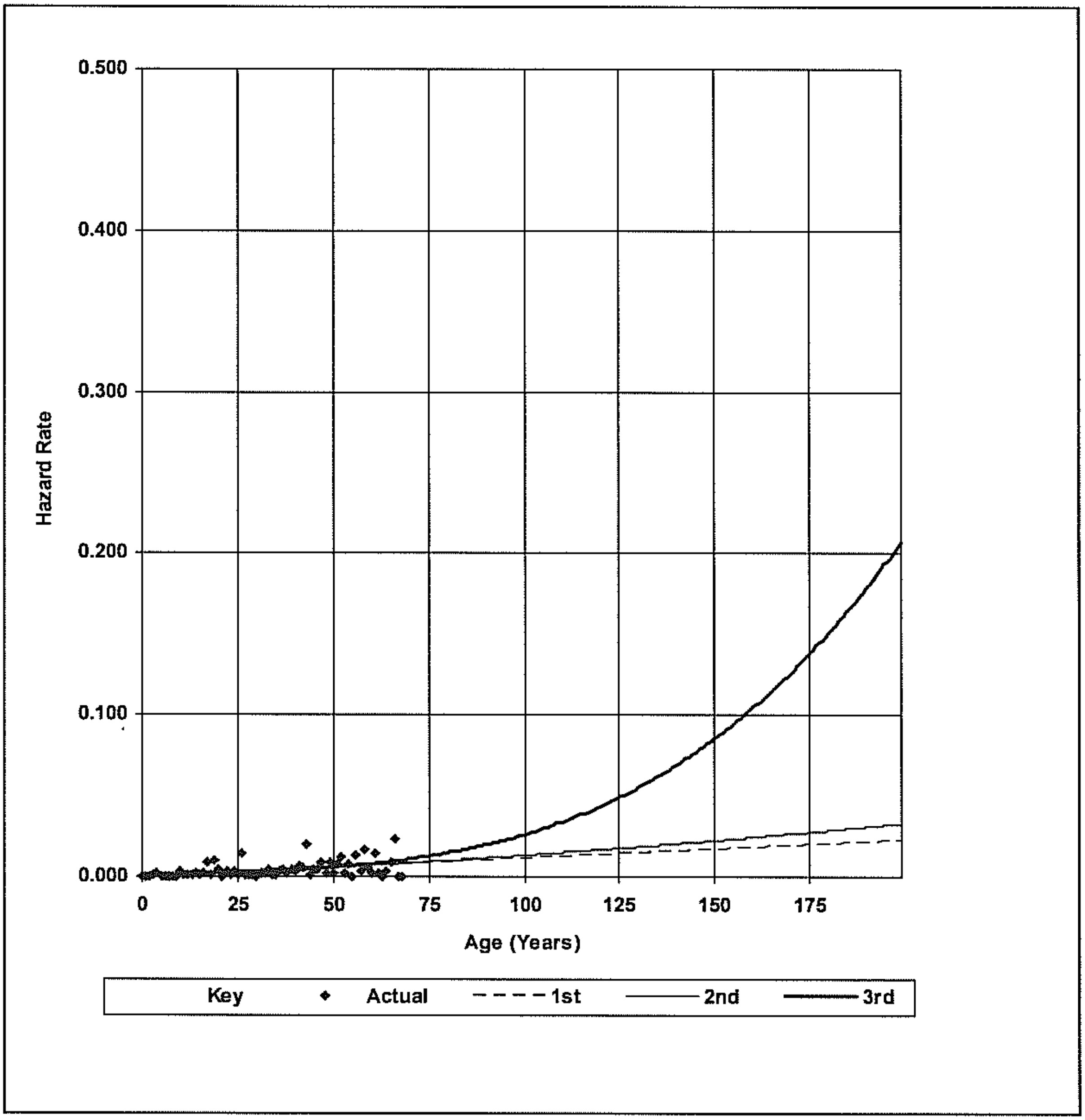
T-Cut: None

Placement Band: 1940-2007 Observation Band: 1996-2007

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function **1st: 113.3-L1 2nd: 108.0-S0 3rd: 91.8-R2**



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

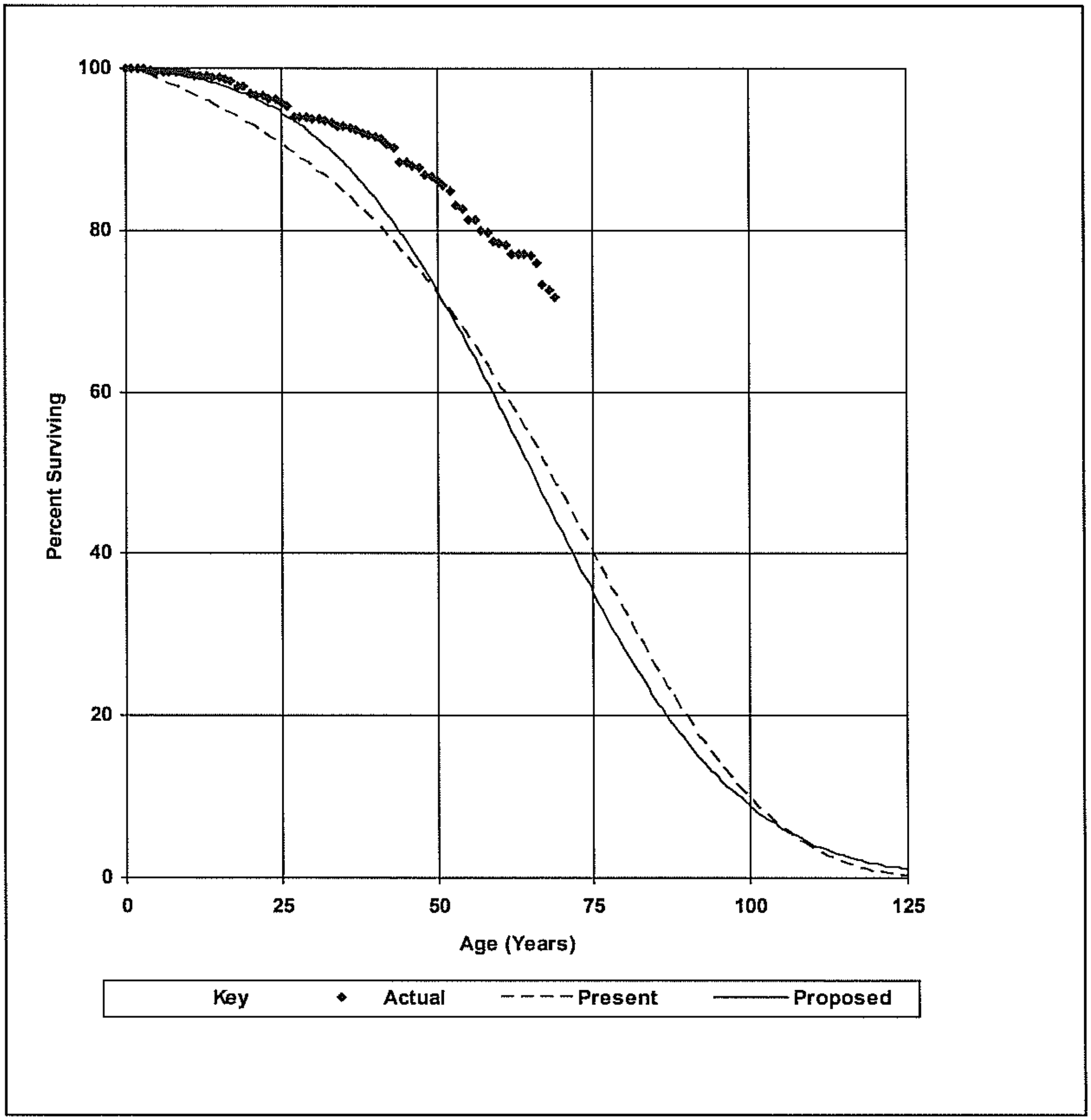
Account: 361.00 Structures and Improvements

T-Cut: None

Placement Band: 1940-2008

Observation Band: 1996-2008

Present and Proposed Projection Life Curves **Present: 65.0-R1.5** **Proposed: 65.0-H2.5**



Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Distribution Plant
Account: 361.00 Structures and Improvements

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998	131,953	(219)	-0.2		88,154	66.8		(88,373)	-67.0	
1999	323,148	14,375	4.4		158,948	49.2		(144,573)	-44.7	
2000	31,991	(3,696)	-11.6		128,150	400.6		(131,846)	-412.1	
2001	99,203	(1,351)	-1.4		104,448	105.3		(105,799)	-106.6	
2002	36,746	40,151	109.3	7.9	24,091	65.6	80.9	16,060	43.7	-73.0
2003	39,751	4,287	10.8	10.1	38,058	95.7	85.5	(33,770)	-85.0	-75.3
2004	15,126		0.0	17.7	213,453	1411.2	228.1	(213,453)	1411.2	-210.4
2005	56,655		0.0	17.4		0.0	153.6		0.0	-136.2
2006	66,621		0.0	20.7	35,495	53.3	144.8	(35,495)	-53.3	-124.1
2007	45,170		0.0	1.9	27,599	61.1	140.9	(27,599)	-61.1	-139.0
2008	108,036		0.0	0.0	177,223	164.0	155.6	(177,223)	-164.0	-155.6
Total	954,400	53,547	5.6		995,618	104.3		(942,071)	-98.7	

Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Distribution Plant
Account: 361.00 Structures and Improvements

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998	131,953	(219)	-0.2		88,154	66.8		(88,373)	-67.0	
1999	323,148	14,375	4.4		158,948	49.2		(144,573)	-44.7	
2000	31,991	(3,696)	-11.6		128,150	400.6		(131,846)	-412.1	
2001	99,203	(1,351)	-1.4		104,448	105.3		(105,799)	-106.6	
2002	36,746	40,151	109.3	7.9	24,091	65.6	80.9	16,060	43.7	-73.0
2003	39,751	4,287	10.8	10.1	38,058	95.7	85.5	(33,770)	-85.0	-75.3
2004	15,126		0.0	17.7	213,453	1411.2	228.1	(213,453)	1411.2	-210.4
2005	56,655		0.0	17.4		0.0	153.6		0.0	-136.2
2006	66,621		0.0	20.7	35,495	53.3	144.8	(35,495)	-53.3	-124.1
2007	45,170		0.0	1.9	27,599	61.1	140.9	(27,599)	-61.1	-139.0
2008	108,036		0.0	0.0	177,223	164.0	155.6	(177,223)	-164.0	-155.6
Total	954,400	53,547	5.6		995,618	104.3		(942,071)	-98.7	

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant
Account: 362.01 Station Equipment

Dispersion: 60 - H2
Procedure: Broad Group

Generation Arrangement

Vintage	Age	December 31, 2008 Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2008	0.5	13,382,012	60.00	59.56	0.9926	1.0000	13,283,425	223,034
2007	1.5	29,218,546	60.00	58.68	0.9780	1.0000	28,574,827	486,976
2006	2.5	14,940,932	60.00	57.80	0.9634	1.0000	14,394,229	249,016
2005	3.5	21,183,409	60.00	56.94	0.9490	1.0000	20,102,453	353,057
2004	4.5	15,973,472	60.00	56.08	0.9346	1.0000	14,929,581	266,225
2003	5.5	11,942,654	60.00	55.23	0.9204	1.0000	10,992,529	199,044
2002	6.5	6,960,748	60.00	54.38	0.9064	1.0000	6,308,958	116,013
2001	7.5	9,701,590	60.00	53.55	0.8924	1.0000	8,657,863	161,693
2000	8.5	7,316,109	60.00	52.72	0.8786	1.0000	6,427,905	121,935
1999	9.5	13,509,071	60.00	51.90	0.8649	1.0000	11,684,256	225,151
1998	10.5	5,102,851	60.00	51.08	0.8514	1.0000	4,344,432	85,048
1997	11.5	7,179,420	60.00	50.28	0.8380	1.0000	6,016,098	119,657
1996	12.5	14,425,446	60.00	49.48	0.8247	1.0000	11,896,730	240,424
1995	13.5	19,282,086	60.00	48.70	0.8116	1.0000	15,649,240	321,368
1994	14.5	21,990,283	60.00	47.92	0.7986	1.0000	17,561,986	366,505
1993	15.5	38,788,040	60.00	47.15	0.7858	1.0000	30,480,015	646,467
1992	16.5	30,393,298	60.00	46.39	0.7732	1.0000	23,498,709	506,555
1991	17.5	18,261,762	60.00	45.64	0.7606	1.0000	13,890,789	304,363
1990	18.5	8,696,158	60.00	44.90	0.7483	1.0000	6,507,324	144,936
1989	19.5	7,454,569	60.00	44.17	0.7361	1.0000	5,487,435	124,243
1988	20.5	7,195,093	60.00	43.45	0.7241	1.0000	5,209,888	119,918
1987	21.5	2,384,419	60.00	42.73	0.7122	1.0000	1,698,245	39,740
1986	22.5	5,254,754	60.00	42.03	0.7005	1.0000	3,681,105	87,579
1985	23.5	2,115,197	60.00	41.34	0.6890	1.0000	1,457,350	35,253
1984	24.5	2,288,091	60.00	40.66	0.6776	1.0000	1,550,470	38,135
1983	25.5	3,244,051	60.00	39.99	0.6664	1.0000	2,161,919	54,068
1982	26.5	4,052,029	60.00	39.32	0.6554	1.0000	2,655,655	67,534
1981	27.5	2,620,830	60.00	38.67	0.6445	1.0000	1,689,199	43,681
1980	28.5	5,829,917	60.00	38.03	0.6338	1.0000	3,695,207	97,165
1979	29.5	1,536,910	60.00	37.40	0.6233	1.0000	957,961	25,615
1978	30.5	4,678,833	60.00	36.78	0.6129	1.0000	2,867,873	77,981
1977	31.5	3,373,117	60.00	36.17	0.6028	1.0000	2,033,193	56,219
1976	32.5	2,732,562	60.00	35.56	0.5927	1.0000	1,619,689	45,543
1975	33.5	3,338,672	60.00	34.97	0.5829	1.0000	1,946,064	55,645
1974	34.5	7,217,721	60.00	34.39	0.5732	1.0000	4,137,208	120,295
1973	35.5	5,471,821	60.00	33.82	0.5637	1.0000	3,084,365	91,197

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant
Account: 362.01 Station Equipment

Dispersion: 60 - H2
Procedure: Broad Group

Generation Arrangement

Vintage	December 31, 2008 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1972	36.5	5,605,030	60.00	33.26	0.5543	1.0000	3,107,013	93,417
1971	37.5	7,000,359	60.00	32.71	0.5451	1.0000	3,816,198	116,673
1970	38.5	2,986,617	60.00	32.17	0.5361	1.0000	1,601,175	49,777
1969	39.5	3,814,436	60.00	31.64	0.5273	1.0000	2,011,182	63,574
1968	40.5	4,155,542	60.00	31.11	0.5186	1.0000	2,154,886	69,259
1967	41.5	1,568,598	60.00	30.60	0.5100	1.0000	800,008	26,143
1966	42.5	1,016,328	60.00	30.10	0.5016	1.0000	509,821	16,939
1965	43.5	1,407,519	60.00	29.60	0.4934	1.0000	694,485	23,459
1964	44.5	1,264,970	60.00	29.12	0.4853	1.0000	613,937	21,083
1963	45.5	1,808,763	60.00	28.65	0.4774	1.0000	863,536	30,146
1962	46.5	1,199,022	60.00	28.18	0.4697	1.0000	563,128	19,984
1961	47.5	1,292,774	60.00	27.72	0.4620	1.0000	597,315	21,546
1960	48.5	1,133,033	60.00	27.27	0.4546	1.0000	515,048	18,884
1959	49.5	1,982,062	60.00	26.84	0.4473	1.0000	886,489	33,034
1958	50.5	2,292,477	60.00	26.40	0.4401	1.0000	1,008,866	38,208
1957	51.5	2,442,356	60.00	25.98	0.4330	1.0000	1,057,641	40,706
1956	52.5	848,105	60.00	25.57	0.4261	1.0000	361,417	14,135
1955	53.5	1,034,255	60.00	25.16	0.4194	1.0000	433,753	17,238
1954	54.5	2,022,701	60.00	24.77	0.4128	1.0000	834,897	33,712
1953	55.5	843,336	60.00	24.38	0.4063	1.0000	342,626	14,056
1952	56.5	849,000	60.00	23.99	0.3999	1.0000	339,526	14,150
1951	57.5	555,357	60.00	23.62	0.3937	1.0000	218,634	9,256
1950	58.5	456,675	60.00	23.25	0.3876	1.0000	176,997	7,611
1949	59.5	625,664	60.00	22.90	0.3816	1.0000	238,753	10,428
1948	60.5	615,589	60.00	22.54	0.3757	1.0000	231,302	10,260
1947	61.5	136,326	60.00	22.20	0.3700	1.0000	50,441	2,272
1946	62.5	23,053	60.00	21.86	0.3644	1.0000	8,400	384
1945	63.5	2,262	60.00	21.53	0.3589	1.0000	812	38
1944	64.5	25,672	60.00	21.21	0.3535	1.0000	9,075	428
1943	65.5	16,914	60.00	20.89	0.3482	1.0000	5,890	282
1942	66.5	151,767	60.00	20.58	0.3430	1.0000	52,061	2,529
1941	67.5	164,810	60.00	20.28	0.3380	1.0000	55,700	2,747
1940	68.5	366,705	60.00	19.98	0.3330	1.0000	122,115	6,112
1939	69.5	273,725	60.00	19.69	0.3281	1.0000	89,823	4,562
1938	70.5	51,449	60.00	19.40	0.3234	1.0000	16,638	857
1937	71.5	13,462	60.00	19.12	0.3187	1.0000	4,291	224

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant
Account: 362.01 Station Equipment

Dispersion: 60 - H2
Procedure: Broad Group

Generation Arrangement

Vintage	Age (December 31, 2008)	Surviving Plant (December 31, 2008)	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1936	72.5	7,018	60.00	18.85	0.3142	1.0000	2,205	117
1935	73.5	9,837	60.00	18.58	0.3097	1.0000	3,046	164
1934	74.5	13,674	60.00	18.32	0.3053	1.0000	4,175	228
1933	75.5	2,141	60.00	18.06	0.3010	1.0000	644	36
1932	76.5	137,949	60.00	17.81	0.2968	1.0000	40,944	2,299
1931	77.5	495,333	60.00	17.56	0.2927	1.0000	144,981	8,256
1930	78.5	557,473	60.00	17.32	0.2887	1.0000	160,922	9,291
1929	79.5	93,538	60.00	17.08	0.2847	1.0000	26,631	1,559
1928	80.5	108,216	60.00	16.85	0.2808	1.0000	30,392	1,804
1927	81.5	96,310	60.00	16.62	0.2771	1.0000	26,683	1,605
1926	82.5	29,702	60.00	16.40	0.2733	1.0000	8,118	495
1925	83.5	51,705	60.00	16.18	0.2697	1.0000	13,945	862
1924	84.5	35,241	60.00	15.97	0.2661	1.0000	9,379	587
1923	85.5	21,590	60.00	15.76	0.2626	1.0000	5,670	360
1922	86.5	481	60.00	15.55	0.2592	1.0000	125	8
1921	87.5	19,174	60.00	15.35	0.2559	1.0000	4,906	320
1920	88.5	3,939	60.00	15.15	0.2526	1.0000	995	66
1919	89.5	10,246	60.00	14.96	0.2494	1.0000	2,555	171
1918	90.5	18,025	60.00	14.77	0.2462	1.0000	4,437	300
1913	95.5	11	60.00	13.88	0.2313	1.0000	3	
1912	96.5	2,372	60.00	13.71	0.2285	1.0000	542	40
1909	99.5	30	60.00	13.22	0.2204	1.0000	7	
1900	108.5	52	60.00	11.92	0.1987	1.0000	10	1
Total	17.2	$430,797,242	60.00	46.80	0.7800	1.0000	$336,019,368	$7,179,954

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 362.01 Station Equipment

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2008	0.5	13,382,012		13,382,012	1.0000	0.5000
2007	1.5	29,222,790		29,218,546	0.9999	1.4999
2006	2.5	14,942,620		14,940,932	0.9999	2.4999
2005	3.5	21,230,212		21,183,409	0.9978	3.4977
2004	4.5	16,152,011		15,973,472	0.9889	4.4883
2003	5.5	12,165,825		11,942,654	0.9817	5.4786
2002	6.5	7,107,344		6,960,748	0.9794	6.4707
2001	7.5	9,925,761		9,701,590	0.9774	7.4763
2000	8.5	7,511,992		7,316,109	0.9739	8.4361
1999	9.5	14,126,271		13,509,071	0.9563	9.3856
1998	10.5	5,146,031		5,102,851	0.9916	10.4745
1997	11.5	7,982,362		7,179,420	0.8994	11.2003
1996	12.5	14,584,480		14,425,446	0.9891	12.4518
1995	13.5		20,137,449	19,282,086	0.9575	13.2134
1994	14.5		22,747,740	21,990,283	0.9667	14.3361
1993	15.5		39,619,345	38,788,040	0.9790	15.4320
1992	16.5		32,523,365	30,393,298	0.9345	16.2880
1991	17.5		20,075,191	18,261,762	0.9097	17.2643
1990	18.5		9,497,095	8,696,158	0.9157	18.1984
1989	19.5		7,831,961	7,454,569	0.9518	19.2605
1988	20.5		8,339,439	7,195,093	0.8628	20.1239
1987	21.5		2,731,406	2,384,419	0.8730	20.9224
1986	22.5		5,906,065	5,254,754	0.8897	21.7857
1985	23.5		2,338,933	2,115,197	0.9043	22.9368
1984	24.5		2,400,657	2,288,091	0.9531	24.1401
1983	25.5		3,480,491	3,244,051	0.9321	24.9933
1982	26.5		4,262,402	4,052,029	0.9506	26.2998
1981	27.5		2,955,467	2,620,830	0.8868	26.8694
1980	28.5		5,976,368	5,829,917	0.9755	28.2887
1979	29.5		1,703,272	1,536,910	0.9023	28.8967
1978	30.5		5,269,518	4,678,833	0.8879	29.9788
1977	31.5		3,465,536	3,373,117	0.9733	31.2847
1976	32.5		2,976,176	2,732,562	0.9181	31.8549
1975	33.5		3,598,875	3,338,672	0.9277	33.1199
1974	34.5		7,577,937	7,217,721	0.9525	34.1945
1973	35.5		5,713,701	5,471,821	0.9577	35.2763
1972	36.5		5,965,889	5,605,030	0.9395	36.2142

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 362.01 Station Equipment

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1971	37.5		7,754,571	7,000,359	0.9027	36.9667
1970	38.5		3,371,679	2,986,617	0.8858	37.6593
1969	39.5		4,047,071	3,814,436	0.9425	39.0667
1968	40.5		4,507,414	4,155,542	0.9219	40.0626
1967	41.5		1,687,946	1,568,598	0.9293	41.2153
1966	42.5		1,148,558	1,016,328	0.8849	41.5771
1965	43.5		1,653,755	1,407,519	0.8511	42.4831
1964	44.5		1,477,533	1,264,970	0.8561	43.7165
1963	45.5		2,163,226	1,808,763	0.8361	44.1450
1962	46.5		1,407,546	1,199,022	0.8519	45.5797
1961	47.5		1,543,727	1,292,774	0.8374	46.8094
1960	48.5		1,414,422	1,133,033	0.8011	47.1209
1959	49.5		2,373,594	1,982,062	0.8350	48.5852
1958	50.5		2,777,019	2,292,477	0.8255	49.4545
1957	51.5		3,018,171	2,442,356	0.8092	50.4797
1956	52.5		1,275,622	848,105	0.6649	50.6590
1955	53.5		1,500,031	1,034,255	0.6895	51.5471
1954	54.5		2,450,525	2,022,701	0.8254	53.5515
1953	55.5		1,113,702	843,336	0.7572	54.5664
1952	56.5		1,074,968	849,000	0.7898	54.7335
1951	57.5		910,503	555,357	0.6099	55.4401
1950	58.5		623,768	456,675	0.7321	56.5568
1949	59.5		707,934	625,664	0.8838	58.7559
1948	60.5		823,357	615,589	0.7477	58.9047
1947	61.5		200,285	136,326	0.6807	59.5809
1946	62.5		41,076	23,053	0.5612	59.4485
1945	63.5		13,432	2,262	0.1684	55.7819
1944	64.5		27,359	25,672	0.9383	63.9918
1943	65.5		42,734	16,914	0.3958	63.6857
1942	66.5		298,776	151,767	0.5080	63.4471
1941	67.5		242,051	164,810	0.6809	66.1069
1940	68.5		493,299	366,705	0.7434	66.8792
1939	69.5		372,189	273,725	0.7354	68.4229
1938	70.5		193,324	51,449	0.2661	64.8563
1937	71.5		42,227	13,462	0.3188	66.6817
1936	72.5		15,345	7,018	0.4574	66.8057
1935	73.5		10,448	9,837	0.9415	73.1623

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 362.01 Station Equipment

Age Distribution

				Experience to 12/31/2008		
Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1934	74.5		17,225	13,674	0.7939	72.9827
1933	75.5		18,781	2,141	0.1140	69.2991
1932	76.5		195,996	137,949	0.7038	75.2638
1931	77.5		662,753	495,333	0.7474	75.8851
1930	78.5		709,474	557,473	0.7858	77.2113
1929	79.5		153,411	93,538	0.6097	75.6557
1928	80.5		155,003	108,216	0.6982	78.0055
1927	81.5		124,742	96,310	0.7721	79.5868
1926	82.5		75,688	29,702	0.3924	75.8299
1925	83.5		128,135	51,705	0.4035	82.3272
1924	84.5		61,311	35,241	0.5748	80.4015
1923	85.5		59,087	21,590	0.3654	79.5655
1922	86.5		3,234	481	0.1488	79.2330
1921	87.5		38,173	19,174	0.5023	83.3308
1920	88.5		15,398	3,939	0.2558	80.4498
1919	89.5		15,846	10,246	0.6466	85.4359
1918	90.5		36,056	18,025	0.4999	84.7490
1917	91.5		9,760		0.0000	81.9945
1916	92.5		456		0.0000	85.7705
1915	93.5		7		0.0000	82.0000
1913	95.5		11	11	1.0000	95.5000
1912	96.5		2,372	2,372	1.0000	96.5000
1910	98.5		15		0.0000	87.0000
1909	99.5		30	30	1.0000	99.5000
1900	108.5		297	52	0.1753	99.0161
Total	17.2	$173,479,711	$282,396,722	$430,797,242	0.9450	

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 362.01 Station Equipment

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996		262,551,081		(773,824)	261,777,258
1997	261,777,258	23,300,138	1,786,760	(6,683,438)	276,607,198
1998	276,607,198	1,268,037	1,234,952	(1,054,385)	275,585,898
1999	275,585,898	37,461,447	2,622,021	(2,156,395)	308,268,930
2000	308,268,930	15,847,629	1,089,082	(18,496)	323,008,980
2001	323,008,980	5,426,504	1,328,168		327,107,317
2002	327,107,317	13,725,605	1,430,799	(1,676,865)	337,725,258
2003	337,725,258	10,713,913	1,784,119	(2,298,679)	344,356,373
2004	344,356,373	8,997,147	537,900		352,815,619
2005	352,815,619	20,937,627	2,358,728	(764,916)	370,629,602
2006	370,629,602	24,794,522	2,765,344	707,686	393,366,465
2007	393,366,465	24,432,277	2,373,535	345,963	415,771,171
2008	415,771,171	20,538,625	5,767,783	255,229	430,797,242

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Distribution Plant
Account: 362.01 Station Equipment

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996	290,109,054	15,015,811		(773,824)	304,351,042
1997	304,351,042	11,250,668	1,786,760	(6,683,438)	307,131,512
1998	307,131,512	5,284,353	1,234,952	(1,054,385)	310,126,528
1999	310,126,528	14,136,918	2,622,021	(2,156,395)	319,485,030
2000	319,485,030	7,547,566	1,089,082	(18,496)	325,925,018
2001	325,925,018	9,999,309	1,328,168		334,596,159
2002	334,596,159	9,910,103	1,430,799	(1,676,865)	341,398,598
2003	341,398,598	12,158,850	1,784,119	(2,298,679)	349,474,650
2004	349,474,650	16,137,672	537,900		365,074,422
2005	365,074,422	20,904,612	2,358,728	(764,916)	382,855,390
2006	382,855,390	14,962,584	2,765,344	707,686	395,760,315
2007	395,760,315	29,194,949	2,373,535	345,963	422,927,693
2008	422,927,693	13,382,103	5,767,783	255,229	430,797,242

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 362.01 Station Equipment

T-Cut: None

Placement Band: 1900-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper- sion	Conf. Index	Average Life	Disper- sion	Conf. Index	Average Life	Disper- sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2000	6.9	66.0	L1.5 *	7.33	60.1	S1	2.20	59.7	R2	2.14
1997-2001	6.0	62.7	L1.5 *	6.17	58.2	S1	2.47	57.8	S1	2.42
1998-2002	14.5	65.7	L1.5 *	5.33	61.6	S0.5	3.56	61.5	S0.5	3.59
1999-2003	15.8	67.4	L1 *	4.99	64.3	S0.5	3.61	64.0	S0.5	3.62
2000-2004	1.1	81.5	L1 *	13.95	81.4	L1	13.90	100.2	O3 *	15.30
2001-2005	34.5	80.3	L1	4.20	77.6	L1	4.16	81.3	L1	3.95
2002-2006	37.0	79.6	L0.5	4.56	77.1	L1	4.84	84.1	L0 *	4.34
2003-2007	19.3	77.1	L0.5	10.36	68.9	S0.5	7.31	67.8	S0.5	7.33
2004-2008	15.9	66.0	L0.5	5.65	61.5	S0	4.26	59.8	R1	5.49

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 362.01 Station Equipment

T-Cut: None
Placement Band: 1900-2008
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2008	13.7	67.5	L1	4.45	63.0	S0.5	2.75	61.4	R1.5	4.03
1998-2008	18.2	66.7	L1	4.06	62.8	S0	3.67	61.2	S0.5	5.15
2000-2008	21.6	69.3	L1	3.93	65.5	S0	3.75	63.1	R1	5.61
2002-2008	16.9	67.7	L1	5.73	63.7	S0	4.40	61.6	R1	5.36
2004-2008	15.9	66.0	L0.5	5.65	61.5	S0	4.26	59.8	R1	5.49
2006-2008	11.7	58.1	L0.5	4.28	55.3	S0	3.54	54.4	R1	4.70
2008-2008	2.5	46.6	L0.5	5.83	46.6	L0.5	5.73	46.1	S-.5 *	5.08

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 362.01 Station Equipment

T-Cut: None

Placement Band: 1900-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-1997	0.0	76.0	L1.5 *	20.27	64.6	S2	11.42	63.8	R2.5	11.02
1996-1999	0.2	63.1	L1.5 *	10.98	57.9	S1.5	4.83	57.4	R2	4.40
1996-2001	9.0	67.5	L1.5 *	6.55	61.5	S1	2.58	61.0	S1	2.60
1996-2003	11.7	69.1	L1 *	5.34	63.7	S1	1.91	63.1	S1	2.04
1996-2005	18.7	72.9	L1 *	4.16	66.7	S0.5	2.97	66.5	S0.5	3.10
1996-2007	17.8	71.7	L1	4.50	65.5	S0.5	3.37	64.8	S0.5	3.96
1996-2008	13.7	67.5	L1	4.45	63.0	S0.5	2.75	61.4	R1.5	4.03

Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 362.01 Station Equipment

T-Cut: None

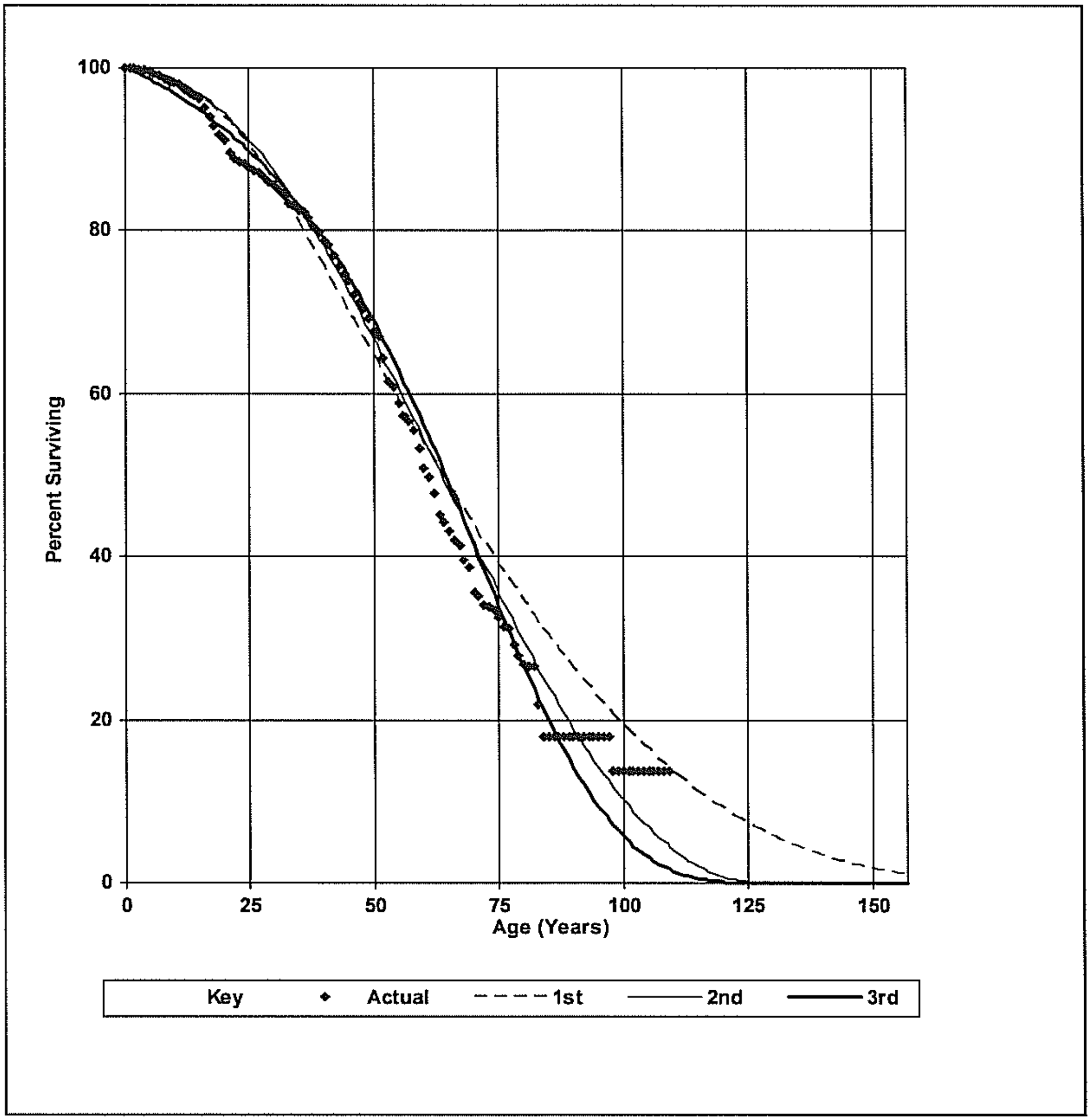
Placement Band: 1900-2008 Observation Band: 1996-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 67.5-L1 2nd: 63.0-S0.5 3rd: 61.4-R1.5



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 362.01 Station Equipment

T-Cut: None

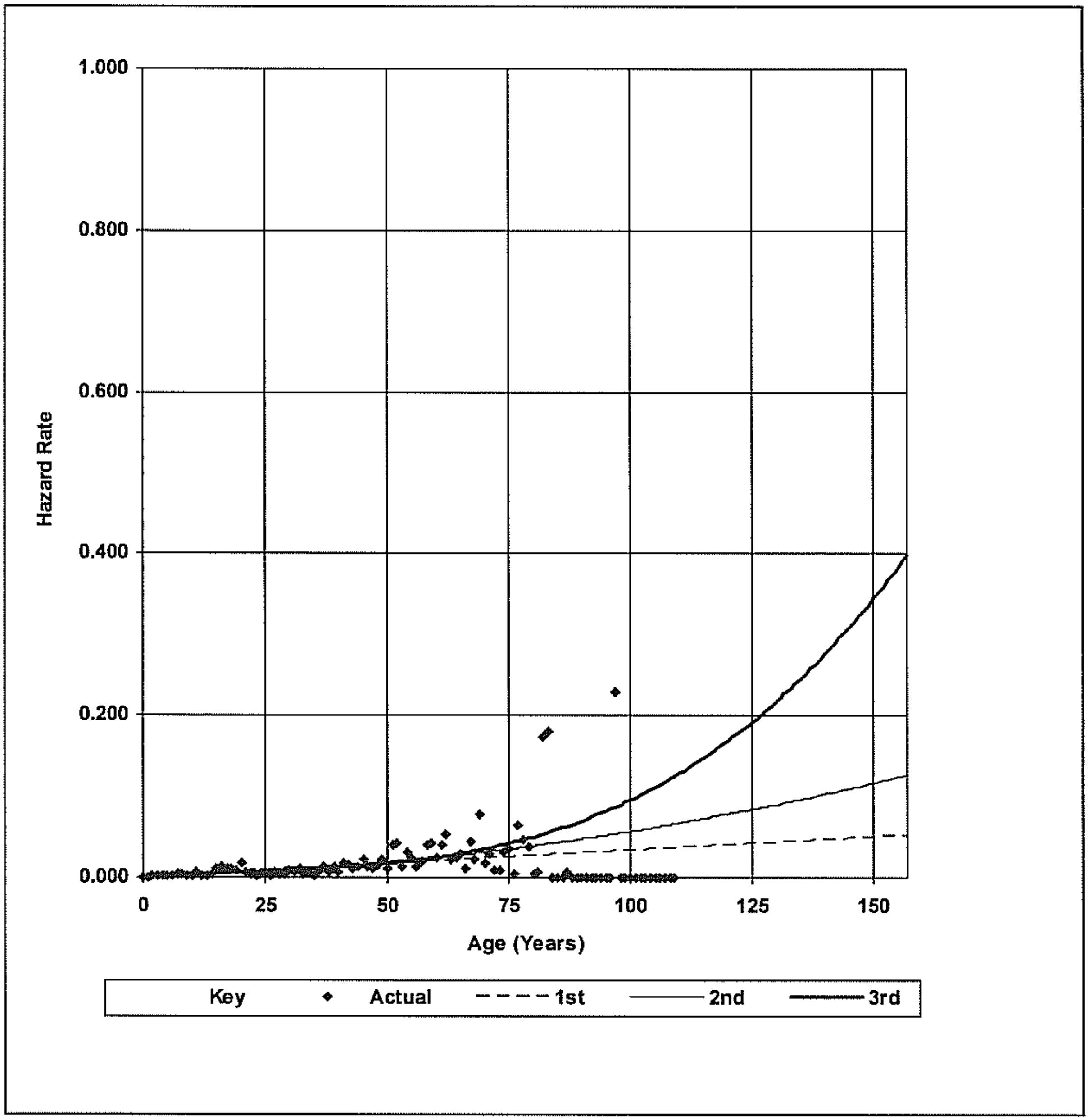
Placement Band: 1900-2008 Observation Band: 1996-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 67.5-L1 2nd: 63.0-S0.5 3rd: 61.4-R1.5



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

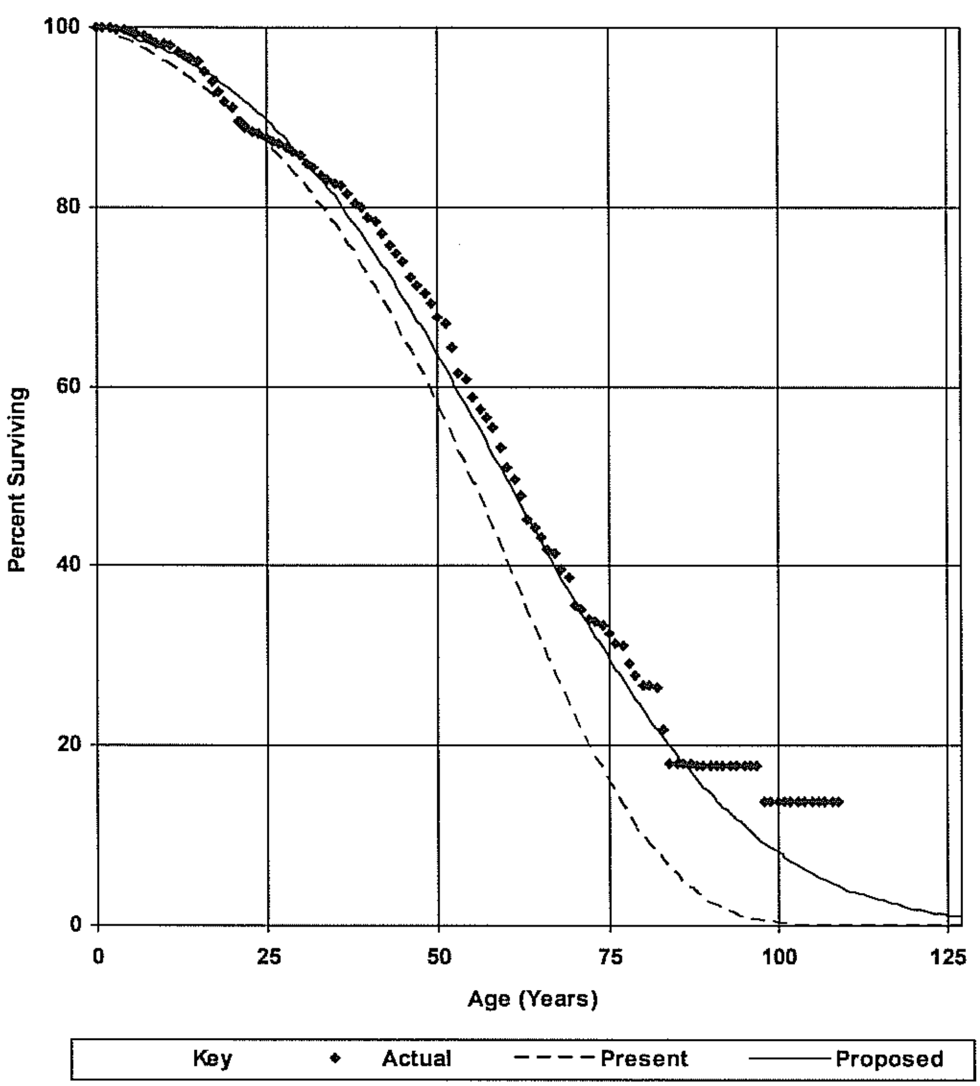
Account: 362.01 Station Equipment

T-Cut: None

Placement Band: 1900-2008

Observation Band: 1996-2008

Present and Proposed Projection Life Curves **Present: 52.0-R1.5** **Proposed: 60.0-H2**



Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 362.01 Station Equipment

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998	1,234,952	6,881	0.6		557,054	45.1		(550,173)	-44.6	
1999	2,622,021	140,900	5.4		1,030,941	39.3		(890,042)	-33.9	
2000	1,089,082	121,313	11.1		426,773	39.2		(305,460)	-28.0	
2001	1,328,168	(16,833)	-1.3		920,541	69.3		(937,374)	-70.6	
2002	1,430,799	439,065	30.7	9.0	439,168	30.7	43.8	(104)	0.0	-34.8
2003	1,784,119	30,776	1.7	8.7	698,186	39.1	42.6	(667,410)	-37.4	-33.9
2004	537,900	(109)	0.0	9.3	579,814	107.8	49.7	(579,923)	-107.8	-40.4
2005	2,358,728		0.0	6.1	499,076	21.2	42.2	(499,076)	-21.2	-36.1
2006	2,765,344		0.0	5.3	(18,075)	-0.7	24.8	18,075	0.7	-19.5
2007	2,373,535		0.0	0.3	1,081,088	45.5	28.9	(1,081,088)	-45.5	-28.6
2008	5,767,783		0.0	0.0		0.0	15.5		0.0	-15.5
Total	23,292,432	721,992	3.1		6,214,566	26.7		(5,492,574)	-23.6	

Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 362.01 Station Equipment

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998	1,234,952	6,881	0.6		557,054	45.1		(550,173)	-44.6	
1999	2,622,021	140,900	5.4		1,030,941	39.3		(890,042)	-33.9	
2000	1,089,082	121,313	11.1		426,773	39.2		(305,460)	-28.0	
2001	1,328,168	(16,833)	-1.3		920,541	69.3		(937,374)	-70.6	
2002	1,430,799	439,065	30.7	9.0	439,168	30.7	43.8	(104)	0.0	-34.8
2003	1,784,119	30,776	1.7	8.7	698,186	39.1	42.6	(667,410)	-37.4	-33.9
2004	537,900	(109)	0.0	9.3	579,814	107.8	49.7	(579,923)	-107.8	-40.4
2005	2,358,728		0.0	6.1	499,076	21.2	42.2	(499,076)	-21.2	-36.1
2006	2,765,344		0.0	5.3	(18,075)	-0.7	24.8	18,075	0.7	-19.5
2007	2,373,535		0.0	0.3	1,081,088	45.5	28.9	(1,081,088)	-45.5	-28.6
2008	5,767,783		0.0	0.0		0.0	15.5		0.0	-15.5
Total	23,292,432	721,992	3.1		6,214,566	26.7		(5,492,574)	-23.6	

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant
Account: 362.55 Station Equipnent - EMS RTU

Dispersion: 20 - H2
Procedure: Broad Group

Generation Arrangement

Vintage	December 31, 2008 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2007	1.5	67,969	20.00	18.69	0.9347	1.0000	63,529	3,398
2006	2.5	62,631	20.00	17.85	0.8925	1.0000	55,895	3,132
2005	3.5	61,273	20.00	17.03	0.8514	1.0000	52,169	3,064
2004	4.5	290,650	20.00	16.23	0.8116	1.0000	235,905	14,533
2003	5.5	71,871	20.00	15.46	0.7732	1.0000	55,572	3,594
2002	6.5	2,544	20.00	14.72	0.7362	1.0000	1,873	127
2001	7.5	165,649	20.00	14.01	0.7006	1.0000	116,055	8,282
2000	8.5	1,293,334	20.00	13.33	0.6665	1.0000	862,034	64,667
1999	9.5	1,867,860	20.00	12.68	0.6339	1.0000	1,184,118	93,393
1998	10.5	342,361	20.00	12.06	0.6029	1.0000	206,405	17,118
1997	11.5	2,567,610	20.00	11.47	0.5733	1.0000	1,472,118	128,381
1996	12.5	1,957,195	20.00	10.91	0.5453	1.0000	1,067,260	97,860
1995	13.5	3,134,065	20.00	10.37	0.5187	1.0000	1,625,745	156,703
1994	14.5	3,485,441	20.00	9.87	0.4936	1.0000	1,720,437	174,272
1993	15.5	4,358,460	20.00	9.40	0.4699	1.0000	2,047,925	217,923
1992	16.5	3,750,919	20.00	8.95	0.4475	1.0000	1,678,518	187,546
1991	17.5	3,021,714	20.00	8.53	0.4264	1.0000	1,288,485	151,086
1990	18.5	2,778,122	20.00	8.13	0.4066	1.0000	1,129,476	138,906
1989	19.5	213,126	20.00	7.76	0.3879	1.0000	82,670	10,656
Total	14.3	$29,492,793	20.00	10.14	0.5068	1.0000	$14,946,189	$1,474,640

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 362.55 Station Equipnent - EMS RTU

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2007	1.5	67,969		67,969	1.0000	1.5000
2006	2.5	62,631		62,631	1.0000	2.5000
2005	3.5	61,273		61,273	1.0000	3.5000
2004	4.5	290,650		290,650	1.0000	4.5000
2003	5.5	71,871		71,871	1.0000	5.5000
2002	6.5	2,544		2,544	1.0000	6.5000
2001	7.5	165,649		165,649	1.0000	7.5000
2000	8.5	1,293,334		1,293,334	1.0000	8.5000
1999	9.5	1,867,860		1,867,860	1.0000	9.5000
1998	10.5	342,361		342,361	1.0000	10.5000
1997	11.5	2,591,610		2,567,610	0.9907	11.4676
1996	12.5	1,957,195		1,957,195	1.0000	12.5000
1995	13.5		3,134,065	3,134,065	1.0000	13.5000
1994	14.5		3,485,441	3,485,441	1.0000	14.5000
1993	15.5		4,358,460	4,358,460	1.0000	15.5000
1992	16.5		3,750,919	3,750,919	1.0000	16.5000
1991	17.5		3,021,714	3,021,714	1.0000	17.5000
1990	18.5		2,778,122	2,778,122	1.0000	18.5000
1989	19.5		213,126	213,126	1.0000	19.5000
Total	14.3	$8,774,945	$20,741,848	$29,492,793	0.9992	

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 362.55 Station Equipnent - EMS RTU

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996		21,546,881		(96,162)	21,450,719
1997	21,450,719	4,573,836		(822,326)	25,202,229
1998	25,202,229				25,202,229
1999	25,202,229	2,770,038		(1,229,996)	26,742,271
2000	26,742,271	2,118,988		(298,182)	28,563,077
2001	28,563,077	271,901			28,834,978
2002	28,834,978	95,504			28,930,482
2003	28,930,482	291,213		(2,544)	29,219,152
2004	29,219,152	170,942			29,390,093
2005	29,390,093	89,361	24,000		29,455,454
2006	29,455,454	(144,573)			29,310,881
2007	29,310,881	68,958		31,379	29,411,218
2008	29,411,218	81,575			29,492,793

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Distribution Plant
Account: 362.55 Station Equipnent - EMS RTU

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996	20,924,211	2,463,635		(96,162)	23,291,684
1997	23,291,684	4,349,471		(822,326)	26,818,830
1998	26,818,830	342,361			27,161,191
1999	27,161,191	1,867,860		(1,229,996)	27,799,055
2000	27,799,055	1,293,334		(298,182)	28,794,206
2001	28,794,206	165,649			28,959,855
2002	28,959,855	5,088			28,964,943
2003	28,964,943	71,871		(2,544)	29,034,270
2004	29,034,270	290,650			29,324,920
2005	29,324,920	45,089	24,000		29,346,009
2006	29,346,009	47,436			29,393,445
2007	29,393,445	67,969		31,379	29,492,793
2008	29,492,793				29,492,793

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 362.55 Station Equipnent - EMS RTU

T-Cut: None

Placement Band: 1989-2007

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2000	100.0				No Retirements					
1997-2001	100.0				No Retirements					
1998-2002	100.0				No Retirements					
1999-2003	100.0				No Retirements					
2000-2004	100.0				No Retirements					
2001-2005	99.8	198.4	SQ *	0.12	198.6	SQ *	0.04	52.7	R4 *	0.05
2002-2006	99.8	198.3	SQ *	0.17	198.5	SQ *	0.04	43.9	R4 *	0.05
2003-2007	99.8	198.0	SQ *	0.24	198.3	SQ *	0.10	42.4	R4 *	0.07
2004-2008	99.7	197.7	SQ *	0.33	198.0	SQ *	0.22	43.0	R4 *	0.10

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 362.55 Station Equipnent - EMS RTU

T-Cut: None

Placement Band: 1989-2007

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2008	99.9	198.6	SQ *	0.03	198.8	SQ *	0.02	68.5	S3 *	0.02
1998-2008	99.9	198.7	SQ *	0.05	198.8	SQ *	0.02	61.9	S3 *	0.03
2000-2008	99.9	198.6	SQ *	0.08	198.7	SQ *	0.03	54.5	R4 *	0.04
2002-2008	99.8	198.4	SQ *	0.16	198.5	SQ *	0.07	47.4	R4 *	0.05
2004-2008	99.7	197.7	SQ *	0.33	198.0	SQ *	0.22	43.0	R4 *	0.10
2006-2008	100.0				No Retirements					
2008-2008	100.0				No Retirements					

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 362.55 Station Equipnent - EMS RTU

T-Cut: None
Placement Band: 1989-2007
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-1997	100.0				No Retirements					
1996-1999	100.0				No Retirements					
1996-2001	100.0				No Retirements					
1996-2003	100.0				No Retirements					
1996-2005	99.9	189.7	R5	0.03	198.8	SQ *	0.02	198.8	SQ *	0.02
1996-2007	99.9	197.6	S6	0.03	198.8	SQ *	0.02	79.0	R4 *	0.02
1996-2008	99.9	198.6	SQ *	0.03	198.8	SQ *	0.02	68.5	S3 *	0.02

Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 362.55 Station Equipnent - EMS RTU

T-Cut: None

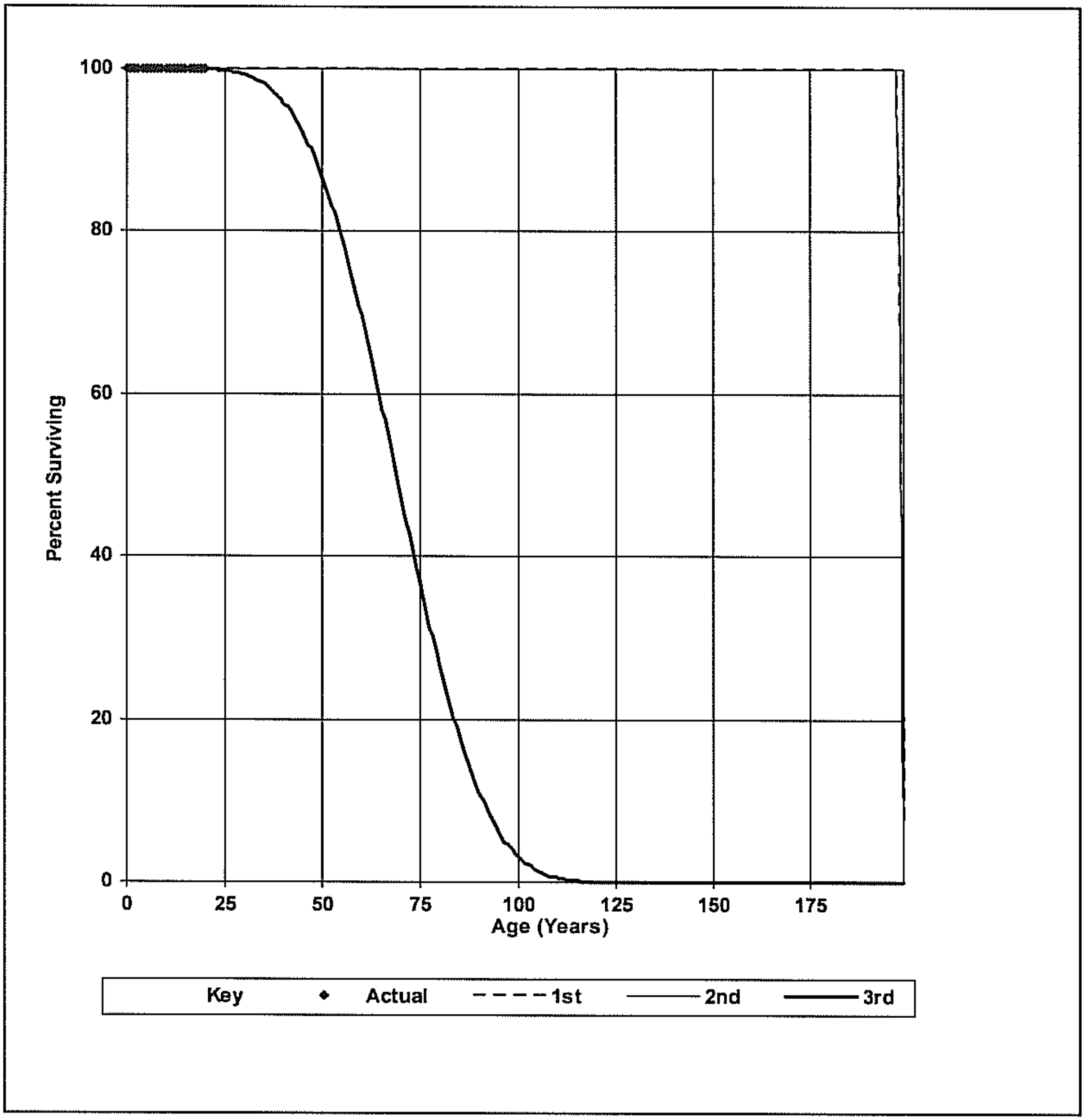
Placement Band: 1989-2007 Observation Band: 1996-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 198.6-SQ 2nd: 198.8-SQ 3rd: 68.5-S3



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 362.55 Station Equipnent - EMS RTU

T-Cut: None

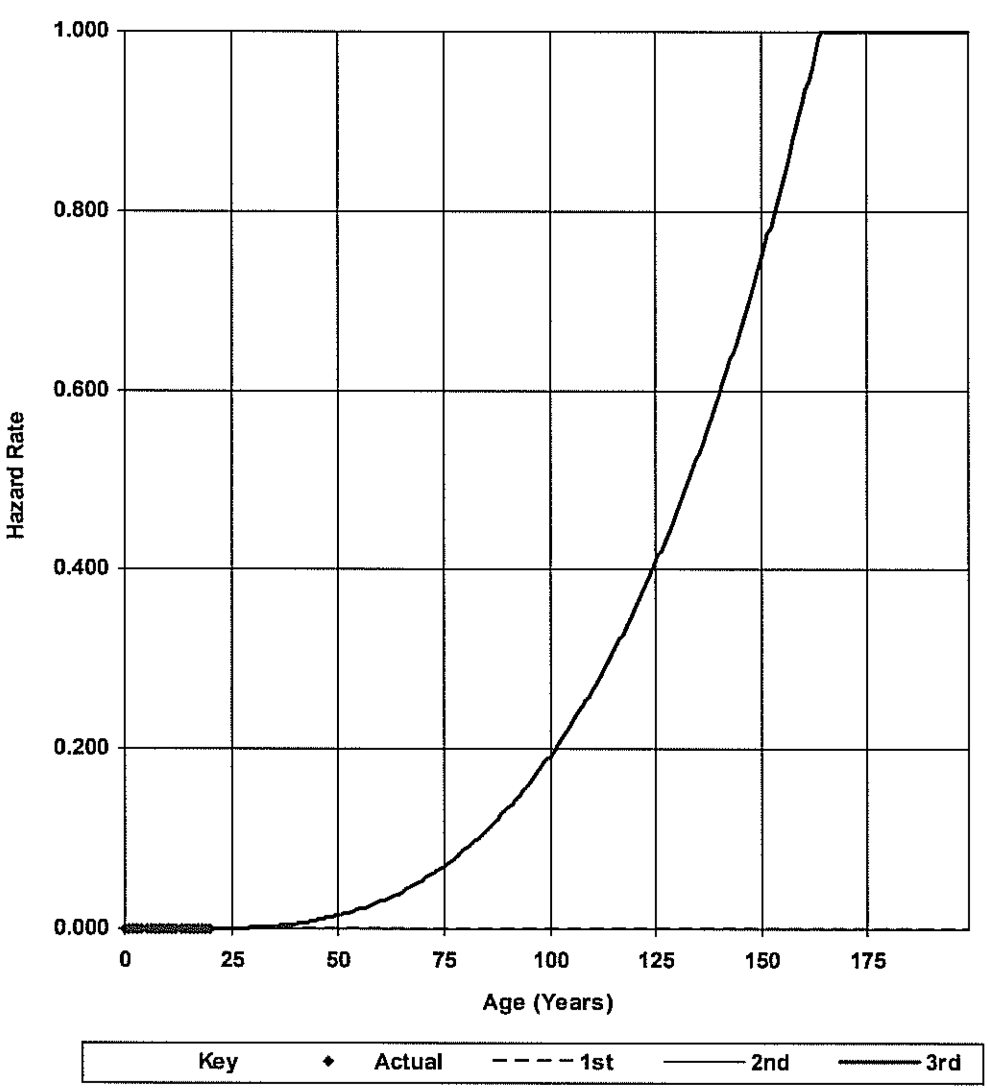
Placement Band: 1989-2007 Observation Band: 1996-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 198.6-SQ 2nd: 198.8-SQ 3rd: 68.5-S3



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

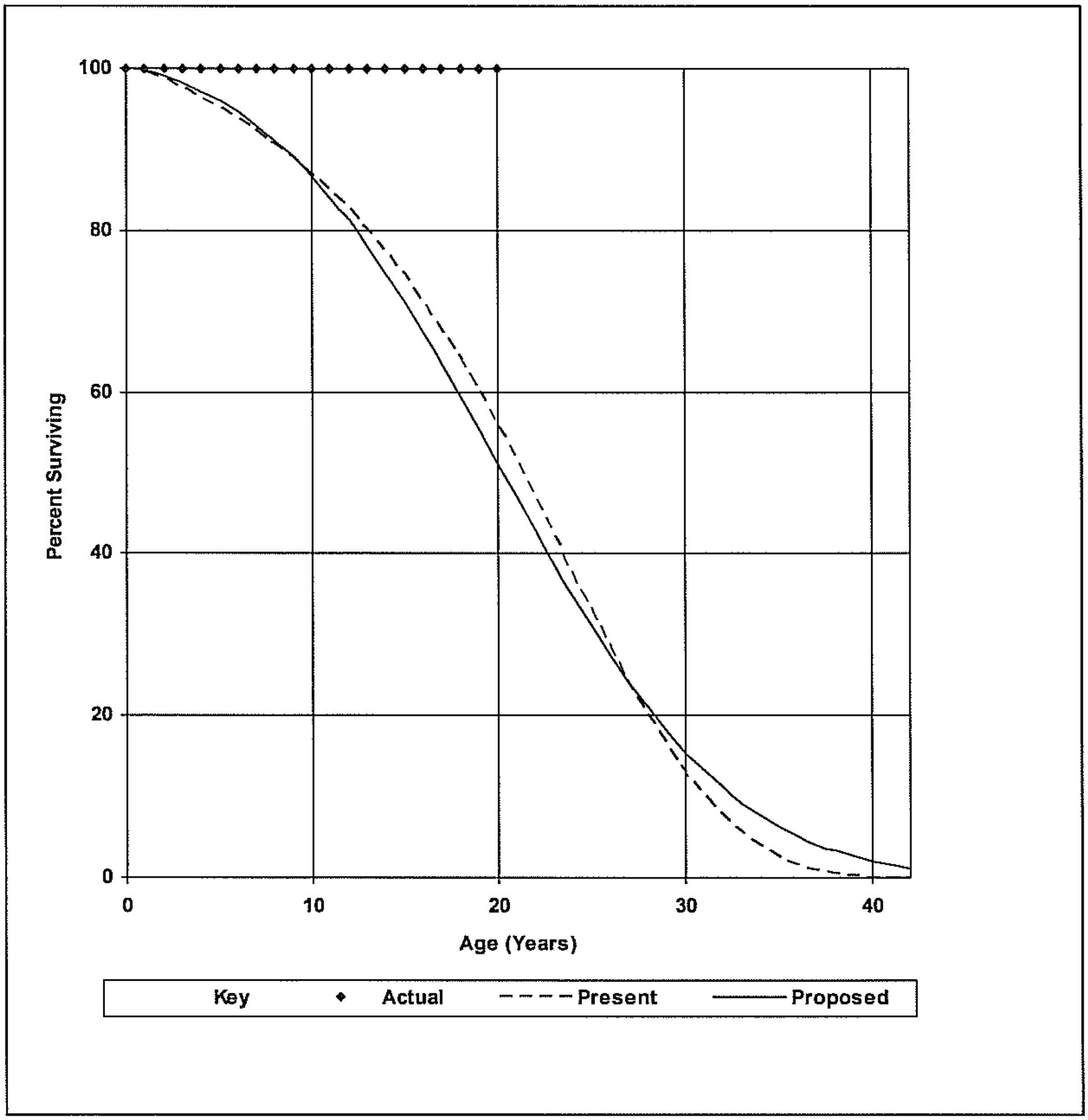
Account: 362.55 Station Equipnent - EMS RTU

T-Cut: None

Placement Band: 1989-2007

Observation Band: 1996-2008

Present and Proposed Projection Life Curves **Present: 20.0-R1.5** **Proposed: 20.0-H2**



Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 362.55 Station Equipnent - EMS RTU

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998			0.0			0.0			0.0	
1999			0.0			0.0			0.0	
2000			0.0		4,843	0.0		(4,843)	0.0	
2001			0.0			0.0			0.0	
2002			0.0	0.0		0.0	0.0		0.0	0.0
2003			0.0	0.0		0.0	0.0		0.0	0.0
2004			0.0	0.0		0.0	0.0		0.0	0.0
2005	24,000		0.0	0.0		0.0	0.0		0.0	0.0
2006			0.0	0.0	(29,913)	0.0	-124.6	29,913	0.0	124.6
2007			0.0	0.0		0.0	-124.6		0.0	124.6
2008			0.0	0.0		0.0	-124.6		0.0	124.6
Total	24,000		0.0		(25,070)	-104.5		25,070	104.5	

Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 362.55 Station Equipnent - EMS RTU

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998			0.0			0.0			0.0	
1999			0.0			0.0			0.0	
2000			0.0		4,843	0.0		(4,843)	0.0	
2001			0.0			0.0			0.0	
2002			0.0	0.0		0.0	0.0		0.0	0.0
2003			0.0	0.0		0.0	0.0		0.0	0.0
2004			0.0	0.0		0.0	0.0		0.0	0.0
2005	24,000		0.0	0.0		0.0	0.0		0.0	0.0
2006			0.0	0.0	(29,913)	0.0	-124.6	29,913	0.0	124.6
2007			0.0	0.0		0.0	-124.6		0.0	124.6
2008			0.0	0.0		0.0	-124.6		0.0	124.6
Total	24,000		0.0		(25,070)	-104.5		25,070	104.5	

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

Dispersion: 65 - H2
Procedure: Broad Group

Generation Arrangement

Vintage	December 31, 2008 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2008	0.5	34,171,395	65.00	64.56	0.9932	1.0000	33,939,017	525,714
2007	1.5	25,670,144	65.00	63.68	0.9797	1.0000	25,147,893	394,925
2006	2.5	24,204,440	65.00	62.80	0.9662	1.0000	23,386,290	372,376
2005	3.5	23,277,341	65.00	61.94	0.9528	1.0000	22,179,765	358,113
2004	4.5	28,354,201	65.00	61.07	0.9396	1.0000	26,641,353	436,219
2003	5.5	38,500,369	65.00	60.22	0.9264	1.0000	35,668,190	592,313
2002	6.5	33,884,646	65.00	59.37	0.9134	1.0000	30,949,517	521,302
2001	7.5	37,774,064	65.00	58.53	0.9004	1.0000	34,013,532	581,139
2000	8.5	20,637,072	65.00	57.69	0.8876	1.0000	18,317,756	317,493
1999	9.5	33,547,866	65.00	56.87	0.8749	1.0000	29,351,185	516,121
1998	10.5	6,867,037	65.00	56.05	0.8623	1.0000	5,921,460	105,647
1997	11.5	1,217,955	65.00	55.24	0.8498	1.0000	1,035,039	18,738
1996	12.5	18,665,924	65.00	54.43	0.8375	1.0000	15,631,818	287,168
1995	13.5	29,716,092	65.00	53.64	0.8252	1.0000	24,522,087	457,171
1994	14.5	31,494,274	65.00	52.85	0.8131	1.0000	25,607,900	484,527
1993	15.5	24,320,695	65.00	52.07	0.8011	1.0000	19,483,441	374,165
1992	16.5	22,202,385	65.00	51.30	0.7892	1.0000	17,523,189	341,575
1991	17.5	23,210,369	65.00	50.54	0.7775	1.0000	18,046,304	357,083
1990	18.5	21,746,304	65.00	49.78	0.7659	1.0000	16,655,977	334,559
1989	19.5	21,978,356	65.00	49.04	0.7544	1.0000	16,581,453	338,129
1988	20.5	19,644,052	65.00	48.30	0.7431	1.0000	14,597,992	302,216
1987	21.5	18,761,741	65.00	47.58	0.7319	1.0000	13,732,269	288,642
1986	22.5	19,797,272	65.00	46.86	0.7209	1.0000	14,271,502	304,573
1985	23.5	20,126,996	65.00	46.15	0.7100	1.0000	14,289,369	309,646
1984	24.5	17,326,224	65.00	45.45	0.6992	1.0000	12,114,252	266,557
1983	25.5	18,912,762	65.00	44.76	0.6886	1.0000	13,022,384	290,966
1982	26.5	17,166,761	65.00	44.07	0.6781	1.0000	11,640,087	264,104
1981	27.5	15,686,929	65.00	43.40	0.6677	1.0000	10,474,256	241,337
1980	28.5	11,986,681	65.00	42.74	0.6575	1.0000	7,881,180	184,411
1979	29.5	9,518,993	65.00	42.08	0.6474	1.0000	6,162,958	146,446
1978	30.5	8,222,785	65.00	41.44	0.6375	1.0000	5,242,098	126,504
1977	31.5	7,619,622	65.00	40.80	0.6277	1.0000	4,783,133	117,225
1976	32.5	7,731,966	65.00	40.18	0.6181	1.0000	4,779,108	118,953
1975	33.5	8,104,817	65.00	39.56	0.6086	1.0000	4,932,735	124,690
1974	34.5	9,184,720	65.00	38.95	0.5993	1.0000	5,504,095	141,303
1973	35.5	7,897,528	65.00	38.35	0.5901	1.0000	4,660,087	121,500

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

Dispersion: 65 - H2
Procedure: Broad Group

Generation Arrangement

	December 31, 2008				Net			
Vintage	Age	Surviving Plant	Avg. Life	Rem. Life	Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1972	36.5	6,856,110	65.00	37.77	0.5810	1.0000	3,983,445	105,479
1971	37.5	6,159,192	65.00	37.19	0.5721	1.0000	3,523,612	94,757
1970	38.5	4,731,064	65.00	36.62	0.5633	1.0000	2,665,089	72,786
1969	39.5	4,464,899	65.00	36.05	0.5547	1.0000	2,476,593	68,691
1968	40.5	3,917,638	65.00	35.50	0.5462	1.0000	2,139,775	60,271
1967	41.5	3,372,430	65.00	34.96	0.5378	1.0000	1,813,814	51,884
1966	42.5	3,017,350	65.00	34.43	0.5296	1.0000	1,598,059	46,421
1965	43.5	2,793,631	65.00	33.90	0.5215	1.0000	1,456,990	42,979
1964	44.5	2,471,587	65.00	33.38	0.5136	1.0000	1,269,428	38,024
1963	45.5	2,187,332	65.00	32.88	0.5058	1.0000	1,106,336	33,651
1962	46.5	2,224,069	65.00	32.38	0.4981	1.0000	1,107,878	34,216
1961	47.5	2,119,097	65.00	31.89	0.4906	1.0000	1,039,611	32,601
1960	48.5	2,193,169	65.00	31.41	0.4832	1.0000	1,059,717	33,741
1959	49.5	2,271,243	65.00	30.93	0.4759	1.0000	1,080,902	34,942
1958	50.5	2,150,387	65.00	30.47	0.4688	1.0000	1,008,024	33,083
1957	51.5	2,128,612	65.00	30.01	0.4617	1.0000	982,882	32,748
1956	52.5	2,015,597	65.00	29.57	0.4549	1.0000	916,804	31,009
1955	53.5	1,543,143	65.00	29.13	0.4481	1.0000	691,463	23,741
1954	54.5	1,553,978	65.00	28.69	0.4414	1.0000	685,990	23,907
1953	55.5	1,510,593	65.00	28.27	0.4349	1.0000	656,982	23,240
1952	56.5	1,217,049	65.00	27.85	0.4285	1.0000	521,514	18,724
1951	57.5	911,014	65.00	27.44	0.4222	1.0000	384,654	14,016
1950	58.5	894,252	65.00	27.04	0.4161	1.0000	372,054	13,758
1949	59.5	767,290	65.00	26.65	0.4100	1.0000	314,586	11,804
1948	60.5	751,410	65.00	26.26	0.4041	1.0000	303,609	11,560
1947	61.5	576,836	65.00	25.88	0.3982	1.0000	229,707	8,874
1946	62.5	437,110	65.00	25.51	0.3925	1.0000	171,562	6,725
1945	63.5	324,678	65.00	25.15	0.3869	1.0000	125,610	4,995
1944	64.5	294,496	65.00	24.79	0.3814	1.0000	112,311	4,531
1943	65.5	203,821	65.00	24.44	0.3760	1.0000	76,628	3,136
1942	66.5	268,396	65.00	24.09	0.3707	1.0000	99,482	4,129
1941	67.5	311,043	65.00	23.75	0.3655	1.0000	113,671	4,785
1940	68.5	267,975	65.00	23.42	0.3603	1.0000	96,563	4,123
1939	69.5	272,504	65.00	23.10	0.3553	1.0000	96,830	4,192
1938	70.5	298,713	65.00	22.78	0.3504	1.0000	104,675	4,596
1937	71.5	226,037	65.00	22.46	0.3456	1.0000	78,119	3,477

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

Dispersion: 65 - H2
Procedure: Broad Group

Generation Arrangement

Vintage	December 31, 2008 Age	December 31, 2008 Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1936	72.5	332,913	65.00	22.16	0.3409	1.0000	113,479	5,122
1935	73.5	354,305	65.00	21.86	0.3362	1.0000	119,128	5,451
1934	74.5	138,390	65.00	21.56	0.3317	1.0000	45,901	2,129
1933	75.5	103,861	65.00	21.27	0.3272	1.0000	33,985	1,598
1932	76.5	143,171	65.00	20.98	0.3228	1.0000	46,221	2,203
1931	77.5	208,043	65.00	20.71	0.3185	1.0000	66,270	3,201
1930	78.5	195,672	65.00	20.43	0.3143	1.0000	61,504	3,010
1929	79.5	129,717	65.00	20.16	0.3102	1.0000	40,236	1,996
1928	80.5	85,680	65.00	19.90	0.3061	1.0000	26,230	1,318
1927	81.5	72,367	65.00	19.64	0.3021	1.0000	21,866	1,113
1926	82.5	53,147	65.00	19.39	0.2983	1.0000	15,851	818
1925	83.5	40,652	65.00	19.14	0.2944	1.0000	11,968	625
1924	84.5	8,998	65.00	18.89	0.2907	1.0000	2,615	138
1923	85.5	8,669	65.00	18.65	0.2870	1.0000	2,488	133
1922	86.5	6,668	65.00	18.42	0.2834	1.0000	1,889	103
1921	87.5	21,398	65.00	18.19	0.2798	1.0000	5,987	329
1920	88.5	1,124	65.00	17.96	0.2763	1.0000	311	17
1919	89.5	186	65.00	17.74	0.2729	1.0000	51	3
1918	90.5	393	65.00	17.52	0.2695	1.0000	106	6
1917	91.5	385	65.00	17.31	0.2663	1.0000	103	6
1916	92.5	88	65.00	17.10	0.2630	1.0000	23	1
1915	93.5	171	65.00	16.89	0.2599	1.0000	45	3
1914	94.5	51,247	65.00	16.69	0.2567	1.0000	13,157	788
1913	95.5	2,597	65.00	16.49	0.2537	1.0000	659	40
1912	96.5	2,929	65.00	16.29	0.2507	1.0000	734	45
1910	98.5	70	65.00	15.91	0.2448	1.0000	17	1
1906	102.5	770	65.00	15.20	0.2338	1.0000	180	12
1904	104.5	14	65.00	14.86	0.2286	1.0000	3	
1900	108.5	2,882	65.00	14.21	0.2187	1.0000	630	44
Total	17.3	$788,801,034	65.00	51.40	0.7908	1.0000	$623,787,279	$12,135,400

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

Age Distribution

			1996	Experience to 12/31/2008		
Vintage	Age as of 12/31/2008	Derived Additions	Opening Balance	Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2008	0.5	34,196,259		34,171,395	0.9993	0.4996
2007	1.5	25,779,941		25,670,144	0.9957	1.4971
2006	2.5	24,434,238		24,204,440	0.9906	2.4869
2005	3.5	23,488,145		23,277,341	0.9910	3.4849
2004	4.5	28,545,158		28,354,201	0.9933	4.4864
2003	5.5	39,105,122		38,500,369	0.9845	5.4571
2002	6.5	34,806,170		33,884,646	0.9735	6.4115
2001	7.5	39,183,607		37,774,064	0.9640	7.3517
2000	8.5	21,359,444		20,637,072	0.9662	8.3448
1999	9.5	35,067,860		33,547,866	0.9567	9.2766
1998	10.5	7,298,157		6,867,037	0.9409	10.2715
1997	11.5	1,259,751		1,217,955	0.9668	11.2921
1996	12.5	20,050,991		18,665,924	0.9309	12.1216
1995	13.5		31,807,194	29,716,092	0.9343	13.1888
1994	14.5		34,175,521	31,494,274	0.9215	14.1117
1993	15.5		26,717,367	24,320,695	0.9103	15.0576
1992	16.5		23,625,044	22,202,385	0.9398	16.1959
1991	17.5		24,441,280	23,210,369	0.9496	17.2079
1990	18.5		23,055,798	21,746,304	0.9432	18.1790
1989	19.5		23,183,655	21,978,356	0.9480	19.1990
1988	20.5		20,738,369	19,644,052	0.9472	20.1862
1987	21.5		19,821,330	18,761,741	0.9465	21.1916
1986	22.5		21,079,083	19,797,272	0.9392	22.1516
1985	23.5		21,448,733	20,126,996	0.9384	23.1528
1984	24.5		18,398,725	17,326,224	0.9417	24.1522
1983	25.5		20,231,653	18,912,762	0.9348	25.1111
1982	26.5		18,426,314	17,166,761	0.9316	26.0971
1981	27.5		16,884,590	15,686,929	0.9291	27.0930
1980	28.5		12,808,489	11,986,681	0.9358	28.1254
1979	29.5		10,247,719	9,518,993	0.9289	29.0985
1978	30.5		8,797,190	8,222,785	0.9347	30.1378
1977	31.5		8,230,719	7,619,622	0.9258	31.0688
1976	32.5		8,403,353	7,731,966	0.9201	32.0324
1975	33.5		8,762,977	8,104,817	0.9249	33.0672
1974	34.5		9,928,076	9,184,720	0.9251	34.0641
1973	35.5		8,526,737	7,897,528	0.9262	35.0678
1972	36.5		7,394,563	6,856,110	0.9272	36.0809

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1971	37.5		6,641,697	6,159,192	0.9274	37.0807
1970	38.5		5,144,451	4,731,064	0.9196	38.0757
1969	39.5		4,847,739	4,464,899	0.9210	39.0197
1968	40.5		4,230,740	3,917,638	0.9260	40.0684
1967	41.5		3,665,276	3,372,430	0.9201	41.0439
1966	42.5		3,313,238	3,017,350	0.9107	41.9739
1965	43.5		3,081,488	2,793,631	0.9066	42.9712
1964	44.5		2,721,577	2,471,587	0.9081	43.9894
1963	45.5		2,413,973	2,187,332	0.9061	44.9527
1962	46.5		2,508,799	2,224,069	0.8865	45.8496
1961	47.5		2,360,106	2,119,097	0.8979	46.9150
1960	48.5		2,461,525	2,193,169	0.8910	47.8936
1959	49.5		2,551,014	2,271,243	0.8903	48.8814
1958	50.5		2,417,570	2,150,387	0.8895	49.8836
1957	51.5		2,410,459	2,128,612	0.8831	50.8576
1956	52.5		2,264,808	2,015,597	0.8900	51.8765
1955	53.5		1,750,164	1,543,143	0.8817	52.8497
1954	54.5		1,781,248	1,553,978	0.8724	53.7908
1953	55.5		1,753,621	1,510,593	0.8614	54.7423
1952	56.5		1,433,189	1,217,049	0.8492	55.6283
1951	57.5		1,092,772	911,014	0.8337	56.5573
1950	58.5		1,059,808	894,252	0.8438	57.6338
1949	59.5		935,727	767,290	0.8200	58.4797
1948	60.5		938,108	751,410	0.8010	59.3612
1947	61.5		716,558	576,836	0.8050	60.2946
1946	62.5		552,516	437,110	0.7911	61.2116
1945	63.5		422,410	324,678	0.7686	62.0837
1944	64.5		381,812	294,496	0.7713	63.1334
1943	65.5		265,922	203,821	0.7665	64.1621
1942	66.5		354,071	268,396	0.7580	65.1958
1941	67.5		392,012	311,043	0.7935	66.3666
1940	68.5		339,027	267,975	0.7904	67.3926
1939	69.5		343,770	272,504	0.7927	68.3871
1938	70.5		383,492	298,713	0.7789	69.3048
1937	71.5		282,761	226,037	0.7994	70.3489
1936	72.5		425,876	332,913	0.7817	71.3510
1935	73.5		460,458	354,305	0.7695	72.2501

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

Age Distribution

			1996	Experience to 12/31/2008		
Vintage	Age as of 12/31/2008	Derived Additions	Opening Balance	Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1934	74.5		175,495	138,390	0.7886	73.4747
1933	75.5		135,231	103,861	0.7680	74.2789
1932	76.5		186,685	143,171	0.7669	75.4235
1931	77.5		270,996	208,043	0.7677	76.3783
1930	78.5		264,208	195,672	0.7406	77.1869
1929	79.5		186,381	129,717	0.6960	77.9594
1928	80.5		124,834	85,680	0.6864	79.0844
1927	81.5		105,072	72,367	0.6887	80.0697
1926	82.5		83,469	53,147	0.6367	80.8283
1925	83.5		59,754	40,652	0.6803	82.1452
1924	84.5		18,303	8,998	0.4916	82.6094
1923	85.5		12,169	8,669	0.7124	84.2481
1922	86.5		7,632	6,668	0.8736	86.0134
1921	87.5		22,303	21,398	0.9594	87.3554
1920	88.5		2,754	1,124	0.4083	85.9001
1919	89.5		359	186	0.5172	87.4124
1918	90.5		732	393	0.5371	89.5627
1917	91.5		544	385	0.7077	90.7445
1916	92.5		150	88	0.5860	92.0199
1915	93.5		465	171	0.3684	91.1340
1914	94.5		51,429	51,247	0.9965	94.4816
1913	95.5		2,824	2,597	0.9196	95.2721
1912	96.5		3,026	2,929	0.9677	96.3546
1911	97.5		10		0.0000	97.0000
1910	98.5		97	70	0.7248	96.7114
1909	99.5		221		0.0000	93.0000
1907	101.5		66		0.0000	100.6749
1906	102.5		770	770	1.0000	102.5000
1905	103.5		23		0.0000	100.6694
1904	104.5		22	14	0.6415	101.8109
1903	105.5		100		0.0000	103.0000
1902	106.5		35		0.0000	103.0000
1900	108.5		3,870	2,882	0.7448	107.6039
Total	17.3	$334,574,842	$497,954,289	$788,801,034	0.9475	

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996	497,809,337	19,982,652			517,791,988
1997	517,791,988	553,444	1,381,718		516,963,715
1998	516,963,715	82,541	657,425	(2,309)	516,386,521
1999	516,386,521	8,309,517	3,524,184		521,171,854
2000	521,171,854	42,758,942	3,761,988	(39,801)	560,129,008
2001	560,129,008	34,133,168	4,023,483	(18,397)	590,220,295
2002	590,220,295	38,584,354	5,022,242	(35,296)	623,747,111
2003	623,747,111	36,411,726	4,718,086	(849)	655,439,902
2004	655,439,902	40,010,186	3,750,408		691,699,680
2005	691,699,680	31,881,827	5,291,008	18,145	718,308,643
2006	718,308,643	26,044,096	4,668,438	12,491	739,696,792
2007	739,696,792	26,683,682	4,015,116	36,905	762,402,264
2008	762,402,264	29,309,692	2,914,001	3,080	788,801,034

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996	498,001,792	20,053,410			518,055,202
1997	518,055,202	1,260,621	1,381,718		517,934,105
1998	517,934,105	7,298,157	657,425	(2,309)	524,572,528
1999	524,572,528	35,067,860	3,524,184		556,116,205
2000	556,116,205	21,351,604	3,761,988	(39,801)	573,666,020
2001	573,666,020	39,184,064	4,023,483	(18,397)	608,808,203
2002	608,808,203	34,806,016	5,022,242	(35,296)	638,556,681
2003	638,556,681	39,095,936	4,718,086	(849)	672,933,682
2004	672,933,682	28,536,205	3,750,408		697,719,478
2005	697,719,478	23,489,060	5,291,008	18,145	715,935,675
2006	715,935,675	24,434,238	4,668,438	12,491	735,713,966
2007	735,713,966	25,779,941	4,015,116	36,905	757,515,696
2008	757,515,696	34,196,259	2,914,001	3,080	788,801,034

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

T-Cut: None
Placement Band: 1926-2008
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2000	58.8	98.1	L0.5	1.24	90.8	L1	0.86	78.5	R1.5	0.85
1997-2001	48.7	86.2	L0.5	1.94	75.6	S0	0.82	70.6	R1	0.80
1998-2002	40.3	79.0	L0	2.55	68.0	S0	0.81	66.0	R1	0.79
1999-2003	33.0	72.2	L0	3.08	62.3	R0.5	0.84	61.5	S0	0.85
2000-2004	32.9	74.8	L0	3.53	63.4	S0	0.87	62.0	R1	0.88
2001-2005	29.4	74.3	L0	3.76	63.1	S0	0.91	61.0	R1	0.78
2002-2006	26.3	74.1	L0	3.82	63.5	S0	1.09	60.8	R1	0.74
2003-2007	29.1	78.5	L0	3.91	66.7	S0	1.27	62.8	R1	0.72
2004-2008	31.8	84.7	L0	4.28	70.8	S0	1.66	65.5	R1.5	0.67

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

T-Cut: None

Placement Band: 1926-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2008	32.3	84.0	L0.5	3.94	71.1	S0	1.37	66.4	R1.5	0.53
1998-2008	30.5	81.2	L0	3.97	68.6	S0	1.24	64.7	R1	0.56
2000-2008	28.9	79.2	L0	4.21	66.8	S0	1.23	63.4	R1	0.62
2002-2008	29.4	80.4	L0	4.30	67.4	S0	1.27	63.7	R1	0.61
2004-2008	31.8	84.7	L0	4.28	70.8	S0	1.66	65.5	R1.5	0.67
2006-2008	33.8	88.4	L0	4.44	73.0	R1	1.76	67.2	R1.5	0.62
2008-2008	42.1	102.8	L0.5	4.71	80.3	R1.5	1.73	73.1	R2	0.46

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

T-Cut: None

Placement Band: 1926-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-1997	79.4	138.4	R1	0.92	113.1	S1	0.28	103.4	R2	0.29
1996-1999	68.6	112.6	S-.5	0.93	107.7	S-.5	0.79	89.8	R1.5	0.81
1996-2001	53.1	92.5	L0.5	1.74	81.4	S0	0.79	73.9	R1.5	0.73
1996-2003	41.6	83.4	L0.5	2.66	71.2	S0	0.73	68.5	R1	0.67
1996-2005	35.8	82.0	L0.5	3.08	70.2	S0	0.92	66.4	R1	0.63
1996-2007	31.8	82.0	L0.5	3.66	70.0	S0	1.29	65.7	R1.5	0.62
1996-2008	32.3	84.0	L0.5	3.94	71.1	S0	1.37	66.4	R1.5	0.53

Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

T-Cut: None

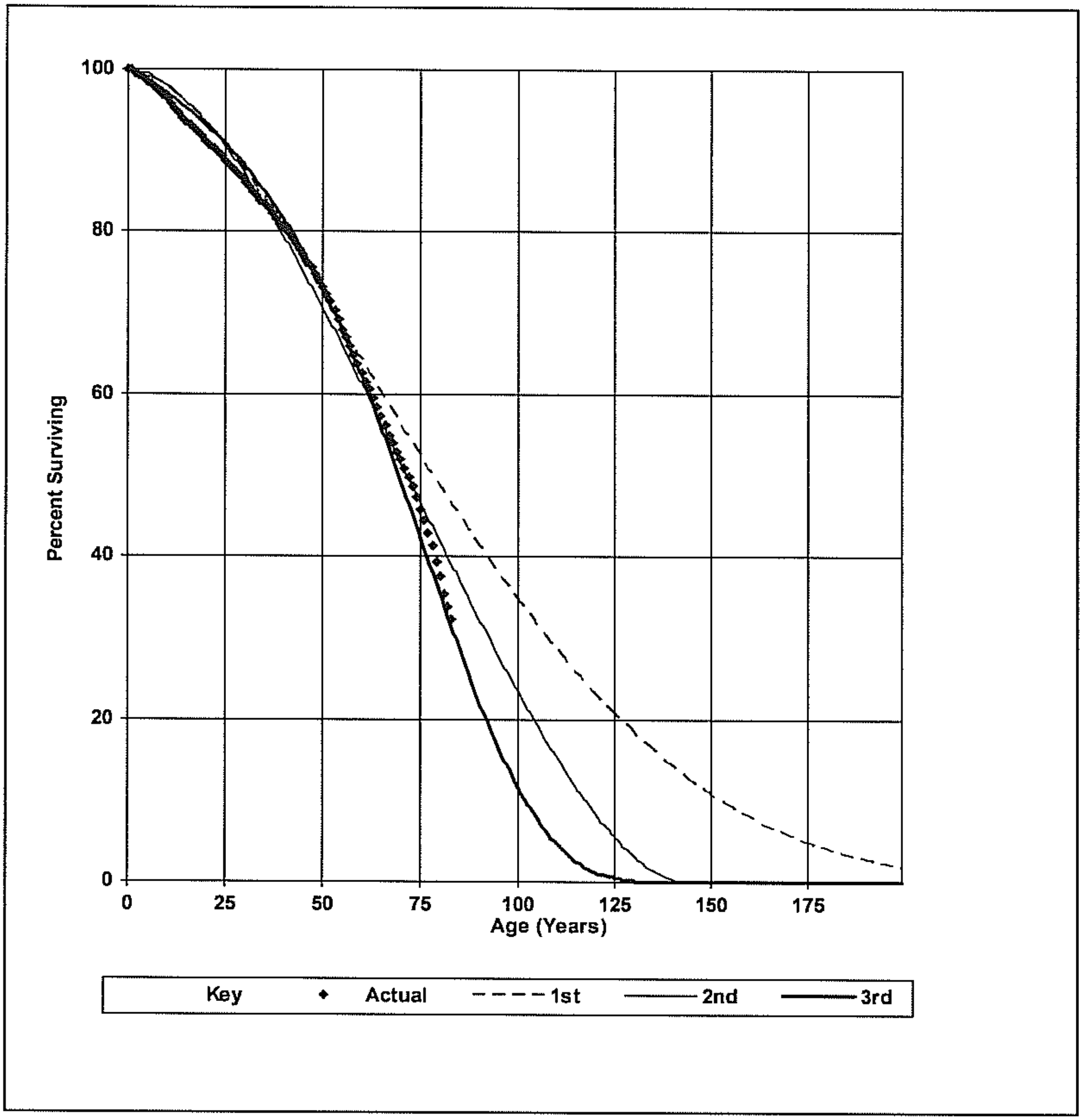
Placement Band: 1926-2008 Observation Band: 1996-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 84.0-L0.5 2nd: 71.1-S0 3rd: 66.4-R1.5



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

T-Cut: None

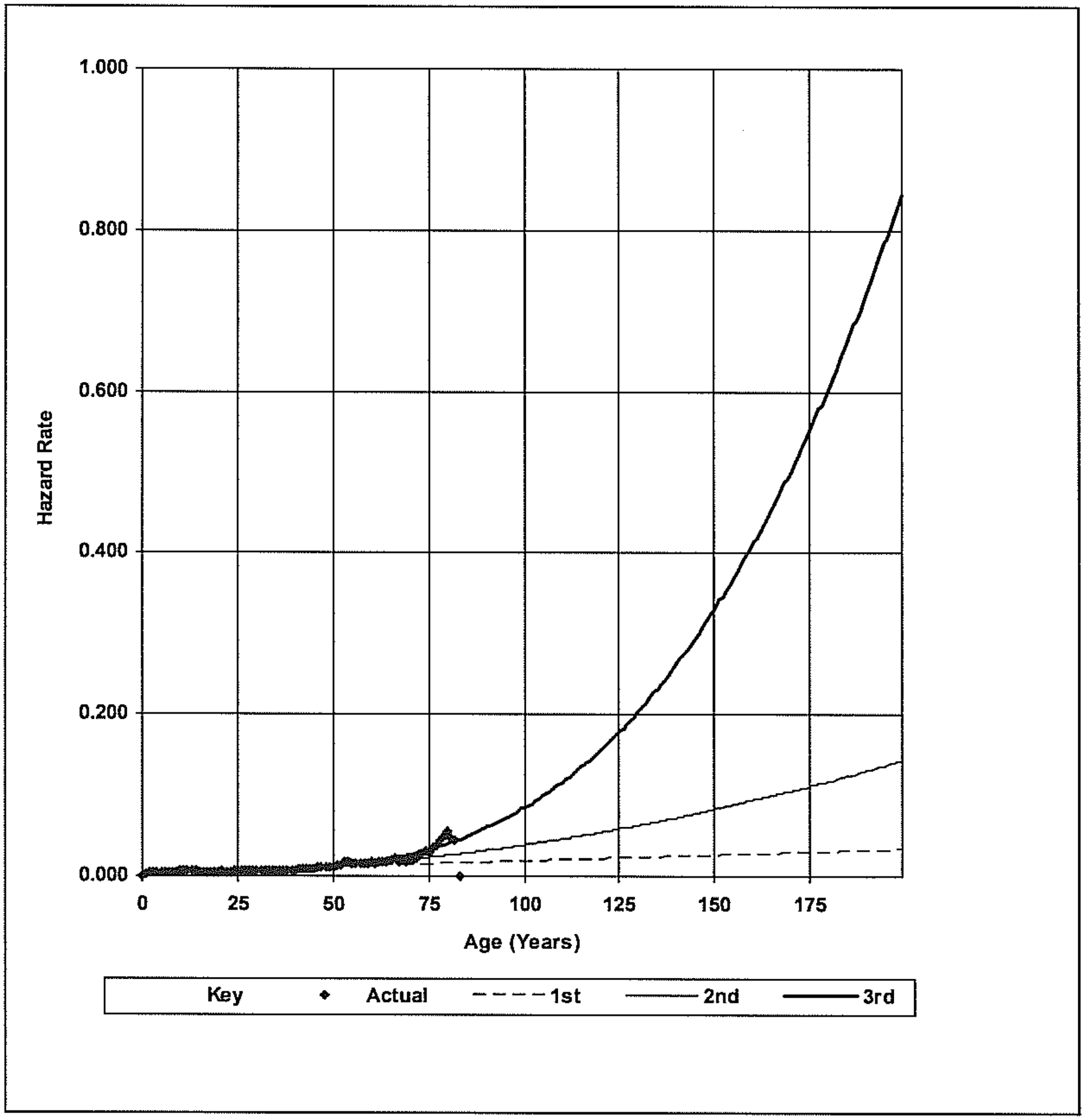
Placement Band: 1926-2008 Observation Band: 1996-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 84.0-L0.5 2nd: 71.1-S0 3rd: 66.4-R1.5



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

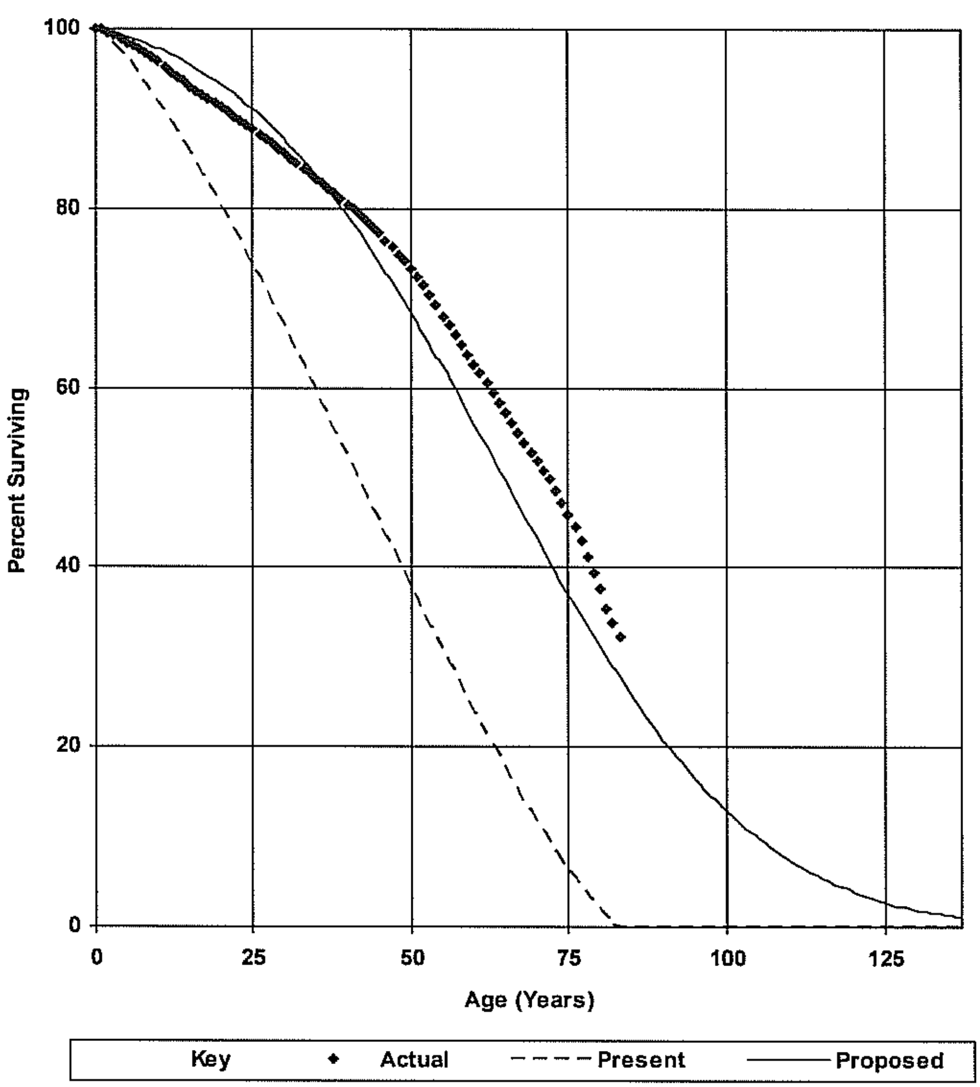
Account: 364.00 Poles, Towers and Fixtures

T-Cut: None

Placement Band: 1926-2008

Observation Band: 1996-2008

Present and Proposed Projection Life Curves **Present: 41.0-S-.5** **Proposed: 65.0-H2**



Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998	657,425	48,020	7.3		107,933	16.4		(59,913)	-9.1	
1999	3,524,184	587,550	16.7		1,135,244	32.2		(547,694)	-15.5	
2000	3,761,988	2,369,421	63.0		4,695,098	124.8		(2,325,677)	-61.8	
2001	4,023,483	1,810,675	45.0		5,378,340	133.7		(3,567,665)	-88.7	
2002	5,022,242	1,470,457	29.3	37.0	7,744,889	154.2	112.2	(6,274,433)	-124.9	-75.2
2003	4,718,086	417,353	8.8	31.6	9,320,364	197.5	134.3	(8,903,011)	-188.7	-102.7
2004	3,750,408	49,755	1.3	28.8	4,182,934	111.5	147.2	(4,133,179)	-110.2	-118.5
2005	5,291,008		0.0	16.4	2,137,519	40.4	126.1	(2,137,519)	-40.4	-109.7
2006	4,668,438		0.0	8.3	(11,619,732)	-248.9	50.2	11,619,732	248.9	-41.9
2007	4,015,116		0.0	2.1	5,284,061	131.6	41.5	(5,284,061)	-131.6	-39.4
2008	2,914,001		0.0	0.2	2,824,522	96.9	13.6	(2,824,522)	-96.9	-13.4
Total	42,346,379	6,753,231	15.9		31,191,172	73.7		(24,437,941)	-57.7	

Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998	657,425	48,020	7.3		107,933	16.4		(59,913)	-9.1	
1999	3,524,184	587,550	16.7		1,135,244	32.2		(547,694)	-15.5	
2000	3,761,988	2,369,421	63.0		4,695,098	124.8		(2,325,677)	-61.8	
2001	4,023,483	1,810,675	45.0		5,378,340	133.7		(3,567,665)	-88.7	
2002	5,022,242	1,470,457	29.3	37.0	7,744,889	154.2	112.2	(6,274,433)	-124.9	-75.2
2003	4,718,086	417,353	8.8	31.6	9,320,364	197.5	134.3	(8,903,011)	-188.7	-102.7
2004	3,750,408	49,755	1.3	28.8	4,182,934	111.5	147.2	(4,133,179)	-110.2	-118.5
2005	5,291,008		0.0	16.4	2,137,519	40.4	126.1	(2,137,519)	-40.4	-109.7
2006	4,668,438		0.0	8.3	(11,619,732)	-248.9	50.2	11,619,732	248.9	-41.9
2007	4,015,116		0.0	2.1	5,284,061	131.6	41.5	(5,284,061)	-131.6	-39.4
2008	2,914,001		0.0	0.2	2,824,522	96.9	13.6	(2,824,522)	-96.9	-13.4
Total	42,346,379	6,753,231	15.9		31,191,172	73.7		(24,437,941)	-57.7	

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant
Account: 365.00 Overhead Conductors and Devices

Dispersion: 50 - H4
Procedure: Broad Group

Generation Arrangement

Vintage	Age	December 31, 2008 Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2008	0.5	44,365,917	50.00	49.50	0.9900	1.0000	43,922,660	887,318
2007	1.5	46,407,827	50.00	48.50	0.9700	1.0000	45,016,470	928,157
2006	2.5	49,781,866	50.00	47.50	0.9500	1.0000	47,294,668	995,637
2005	3.5	43,674,431	50.00	46.50	0.9301	1.0000	40,620,116	873,489
2004	4.5	26,819,827	50.00	45.50	0.9101	1.0000	24,408,561	536,397
2003	5.5	27,814,838	50.00	44.51	0.8901	1.0000	24,759,070	556,297
2002	6.5	28,730,802	50.00	43.51	0.8702	1.0000	25,001,560	574,616
2001	7.5	26,397,039	50.00	42.51	0.8503	1.0000	22,444,822	527,941
2000	8.5	24,909,867	50.00	41.52	0.8304	1.0000	20,684,418	498,197
1999	9.5	32,491,543	50.00	40.52	0.8105	1.0000	26,334,186	649,831
1998	10.5	8,223,489	50.00	39.53	0.7906	1.0000	6,501,867	164,470
1997	11.5	1,073,576	50.00	38.54	0.7708	1.0000	827,548	21,472
1996	12.5	26,518,200	50.00	37.55	0.7511	1.0000	19,917,213	530,364
1995	13.5	30,422,375	50.00	36.57	0.7314	1.0000	22,250,135	608,447
1994	14.5	35,854,804	50.00	35.59	0.7117	1.0000	25,519,138	717,096
1993	15.5	29,137,792	50.00	34.61	0.6922	1.0000	20,168,772	582,756
1992	16.5	26,152,262	50.00	33.64	0.6727	1.0000	17,593,328	523,045
1991	17.5	23,907,616	50.00	32.67	0.6534	1.0000	15,620,743	478,152
1990	18.5	25,002,706	50.00	31.71	0.6342	1.0000	15,855,616	500,054
1989	19.5	23,411,659	50.00	30.75	0.6151	1.0000	14,400,194	468,233
1988	20.5	21,664,285	50.00	29.81	0.5962	1.0000	12,915,802	433,286
1987	21.5	18,883,081	50.00	28.87	0.5775	1.0000	10,904,339	377,662
1986	22.5	19,338,322	50.00	27.95	0.5590	1.0000	10,809,391	386,766
1985	23.5	19,770,356	50.00	27.03	0.5407	1.0000	10,689,700	395,407
1984	24.5	16,967,573	50.00	26.13	0.5227	1.0000	8,868,645	339,351
1983	25.5	18,928,637	50.00	25.25	0.5050	1.0000	9,558,082	378,573
1982	26.5	17,573,848	50.00	24.38	0.4875	1.0000	8,567,874	351,477
1981	27.5	17,671,137	50.00	23.52	0.4704	1.0000	8,313,351	353,423
1980	28.5	13,965,851	50.00	22.69	0.4537	1.0000	6,336,433	279,317
1979	29.5	9,984,801	50.00	21.87	0.4373	1.0000	4,366,845	199,696
1978	30.5	8,486,970	50.00	21.07	0.4214	1.0000	3,576,269	169,739
1977	31.5	7,520,991	50.00	20.29	0.4058	1.0000	3,052,249	150,420
1976	32.5	8,538,055	50.00	19.54	0.3907	1.0000	3,335,861	170,761
1975	33.5	9,407,686	50.00	18.80	0.3760	1.0000	3,537,490	188,154
1974	34.5	11,458,498	50.00	18.09	0.3618	1.0000	4,145,583	229,170
1973	35.5	9,358,489	50.00	17.40	0.3480	1.0000	3,256,986	187,170

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant
Account: 365.00 Overhead Conductors and Devices

Dispersion: 50 - H4
Procedure: Broad Group

Generation Arrangement

	December 31, 2008				Net			
Vintage	Age	Surviving Plant	Avg. Life	Rem. Life	Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1972	36.5	7,866,726	50.00	16.74	0.3347	1.0000	2,633,203	157,335
1971	37.5	6,871,091	50.00	16.10	0.3219	1.0000	2,211,815	137,422
1970	38.5	5,336,744	50.00	15.48	0.3095	1.0000	1,651,973	106,735
1969	39.5	5,367,850	50.00	14.88	0.2977	1.0000	1,597,823	107,357
1968	40.5	4,630,159	50.00	14.31	0.2863	1.0000	1,325,402	92,603
1967	41.5	4,058,037	50.00	13.77	0.2753	1.0000	1,117,198	81,161
1966	42.5	3,911,409	50.00	13.24	0.2648	1.0000	1,035,794	78,228
1965	43.5	3,539,412	50.00	12.74	0.2548	1.0000	901,721	70,788
1964	44.5	2,731,171	50.00	12.26	0.2452	1.0000	669,561	54,623
1963	45.5	2,231,413	50.00	11.80	0.2360	1.0000	526,547	44,628
1962	46.5	2,502,906	50.00	11.36	0.2272	1.0000	568,654	50,058
1961	47.5	2,001,960	50.00	10.94	0.2188	1.0000	438,080	40,039
1960	48.5	2,243,286	50.00	10.54	0.2108	1.0000	472,964	44,866
1959	49.5	2,256,464	50.00	10.16	0.2032	1.0000	458,554	45,129
1958	50.5	2,151,760	50.00	9.80	0.1960	1.0000	421,652	43,035
1957	51.5	2,200,676	50.00	9.45	0.1890	1.0000	416,011	44,014
1956	52.5	1,979,295	50.00	9.12	0.1824	1.0000	361,118	39,586
1955	53.5	1,374,555	50.00	8.81	0.1762	1.0000	242,150	27,491
1954	54.5	1,233,986	50.00	8.51	0.1702	1.0000	210,007	24,680
1953	55.5	860,800	50.00	8.22	0.1645	1.0000	141,593	17,216
1951	57.5	575	50.00	7.69	0.1539	1.0000	88	12
1950	58.5	6,068	50.00	7.45	0.1490	1.0000	904	121
1948	60.5	435	50.00	6.99	0.1398	1.0000	61	9
1947	61.5	53	50.00	6.78	0.1355	1.0000	7	1
1944	64.5	922	50.00	6.19	0.1239	1.0000	114	18
1940	68.5	225	50.00	5.53	0.1107	1.0000	25	4
1939	69.5	246	50.00	5.39	0.1077	1.0000	27	5
1938	70.5	15	50.00	5.24	0.1049	1.0000	2	
1937	71.5	1,203	50.00	5.11	0.1022	1.0000	123	24
1936	72.5	29	50.00	4.98	0.0996	1.0000	3	1
1935	73.5	1,594	50.00	4.86	0.0971	1.0000	155	32
1932	76.5	160	50.00	4.51	0.0903	1.0000	14	3
1930	78.5	1,963	50.00	4.31	0.0862	1.0000	169	39
1929	79.5	763	50.00	4.21	0.0842	1.0000	64	15
1928	80.5	938	50.00	4.12	0.0824	1.0000	77	19
1927	81.5	9	50.00	4.03	0.0806	1.0000	1	

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant
Account: 365.00 Overhead Conductors and Devices

Dispersion: 50 - H4
Procedure: Broad Group

Generation Arrangement

Vintage	December 31, 2008 Age	December 31, 2008 Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1925	83.5	2,839	50.00	3.86	0.0772	1.0000	219	57
1922	86.5	243	50.00	3.62	0.0725	1.0000	18	5
Total	16.0	$875,984,992	50.00	34.75	0.6950	1.0000	$608,779,872	$17,519,700

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 365.00 Overhead Conductors and Devices

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2008	0.5	44,365,917		44,365,917	1.0000	0.5000
2007	1.5	46,407,827		46,407,827	1.0000	1.5000
2006	2.5	49,781,866		49,781,866	1.0000	2.5000
2005	3.5	43,674,431		43,674,431	1.0000	3.5000
2004	4.5	27,380,002		26,819,827	0.9795	4.4343
2003	5.5	28,054,968		27,814,838	0.9914	5.4765
2002	6.5	29,006,175		28,730,802	0.9905	6.4662
2001	7.5	26,693,574		26,397,039	0.9889	7.4546
2000	8.5	25,295,934		24,909,867	0.9847	8.4311
1999	9.5	32,940,155		32,491,543	0.9864	9.4373
1998	10.5	8,340,079		8,223,489	0.9860	10.4363
1997	11.5	1,075,636		1,073,576	0.9981	11.4891
1996	12.5	27,065,782		26,518,200	0.9798	12.3720
1995	13.5		31,055,697	30,422,375	0.9796	13.3770
1994	14.5		36,541,706	35,854,804	0.9812	14.3945
1993	15.5		29,697,581	29,137,792	0.9812	15.3685
1992	16.5		26,595,309	26,152,262	0.9833	16.4013
1991	17.5		24,422,854	23,907,616	0.9789	17.3592
1990	18.5		25,583,629	25,002,706	0.9773	18.3752
1989	19.5		24,043,442	23,411,659	0.9737	19.3223
1988	20.5		22,170,471	21,664,285	0.9772	20.3461
1987	21.5		19,301,376	18,883,081	0.9783	21.3659
1986	22.5		19,940,314	19,338,322	0.9698	22.3394
1985	23.5		20,310,505	19,770,356	0.9734	23.3363
1984	24.5		17,464,230	16,967,573	0.9716	24.2921
1983	25.5		19,801,640	18,928,637	0.9559	25.1744
1982	26.5		18,186,081	17,573,848	0.9663	26.2829
1981	27.5		18,141,301	17,671,137	0.9741	27.3564
1980	28.5		14,360,807	13,965,851	0.9725	28.3166
1979	29.5		10,235,403	9,984,801	0.9755	29.3485
1978	30.5		8,715,851	8,486,970	0.9737	30.3392
1977	31.5		7,871,560	7,520,991	0.9555	31.1994
1976	32.5		8,820,009	8,538,055	0.9680	32.2943
1975	33.5		9,631,071	9,407,686	0.9768	33.3439
1974	34.5		11,915,155	11,458,498	0.9617	34.2484
1973	35.5		9,663,990	9,358,489	0.9684	35.2904
1972	36.5		8,238,515	7,866,726	0.9549	36.1966

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 365.00 Overhead Conductors and Devices

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1971	37.5		7,111,009	6,871,091	0.9663	37.2869
1970	38.5		5,500,897	5,336,744	0.9702	38.3095
1969	39.5		5,553,211	5,367,850	0.9666	39.2743
1968	40.5		4,804,929	4,630,159	0.9636	40.2715
1967	41.5		4,223,719	4,058,037	0.9608	41.2489
1966	42.5		4,106,274	3,911,409	0.9525	42.2089
1965	43.5		3,725,003	3,539,412	0.9502	43.1817
1964	44.5		2,911,658	2,731,171	0.9380	44.1475
1963	45.5		2,327,567	2,231,413	0.9587	45.2557
1962	46.5		2,704,659	2,502,906	0.9254	46.0768
1961	47.5		2,142,878	2,001,960	0.9342	47.1467
1960	48.5		2,414,463	2,243,286	0.9291	48.1387
1959	49.5		2,482,632	2,256,464	0.9089	49.0349
1958	50.5		2,345,175	2,151,760	0.9175	50.0294
1957	51.5		2,418,623	2,200,676	0.9099	51.1172
1956	52.5		2,272,782	1,979,295	0.8709	51.9827
1955	53.5		1,636,016	1,374,555	0.8402	52.8676
1954	54.5		1,639,633	1,233,986	0.7526	53.6227
1953	55.5		1,641,793	860,800	0.5243	54.0244
1952	56.5		1,258,041		0.0000	45.0000
1951	57.5		1,206,404	575	0.0005	46.0055
1950	58.5		1,153,422	6,068	0.0053	47.0605
1949	59.5		1,089,538		0.0000	48.0000
1948	60.5		1,027,498	435	0.0004	49.0049
1947	61.5		951,455	53	0.0001	50.0006
1946	62.5		870,074		0.0000	51.0000
1945	63.5		787,142		0.0000	52.0000
1944	64.5		702,506	922	0.0013	53.0151
1943	65.5		591,889		0.0000	54.0000
1942	66.5		503,690		0.0000	55.0000
1941	67.5		409,150		0.0000	56.0000
1940	68.5		304,380	225	0.0007	57.0085
1939	69.5		224,847	246	0.0011	58.0126
1938	70.5		162,162	15	0.0001	59.0010
1937	71.5		1,203	1,203	1.0000	71.5000
1936	72.5		69	29	0.4259	70.4907
1935	73.5		1,729	1,594	0.9216	73.2254

Schedule B

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 365.00 Overhead Conductors and Devices

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1996 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1934	74.5		664		0.0000	71.0000
1933	75.5		120		0.0000	72.0000
1932	76.5		340	160	0.4707	75.4732
1930	78.5		2,086	1,963	0.9411	78.3528
1929	79.5		3,853	763	0.1981	74.5967
1928	80.5		293,359	938	0.0032	69.0376
1927	81.5		9	9	1.0000	81.5000
1925	83.5		3,342	2,839	0.8495	83.0023
1924	84.5		964		0.0000	77.0000
1922	86.5		5,389	243	0.0451	83.4910
1921	87.5		86		0.0000	84.0000
1919	89.5		6,734		0.0000	82.4190
Total	16.0	$390,082,345	$516,233,562	$875,984,992	0.9665	

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 365.00 Overhead Conductors and Devices

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996	504,502,369	38,490,753			542,993,122
1997	542,993,122	152,268	12,479,026		530,666,365
1998	530,666,365	242,074	529,454	(269)	530,378,716
1999	530,378,716	10,862,669	2,366,062	(51)	538,875,272
2000	538,875,272	42,527,331	1,751,331	(27,786)	579,623,486
2001	579,623,486	24,766,997	1,240,759	(39,169)	603,110,555
2002	603,110,555	33,725,712	2,035,560	(52,930)	634,747,777
2003	634,747,777	26,763,328	1,369,940		660,141,165
2004	660,141,165	28,551,536	1,350,695		687,342,006
2005	687,342,006	34,652,261	2,611,067	4,304	719,387,504
2006	719,387,504	57,535,593	2,410,193	2,499	774,515,403
2007	774,515,403	49,016,710	1,309,036	(342)	822,222,735
2008	822,222,735	54,640,049	877,792		875,984,992

Schedule C

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 365.00 Overhead Conductors and Devices

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1996	516,348,990	27,066,501			543,415,491
1997	543,415,491	1,075,636	12,479,026		532,012,101
1998	532,012,101	8,340,079	529,454	(269)	539,822,457
1999	539,822,457	32,940,156	2,366,062	(51)	570,396,500
2000	570,396,500	25,295,934	1,751,331	(27,786)	593,913,316
2001	593,913,316	26,695,048	1,240,759	(39,169)	619,328,437
2002	619,328,437	29,008,758	2,035,560	(52,930)	646,248,704
2003	646,248,704	28,054,968	1,369,940		672,933,732
2004	672,933,732	27,375,038	1,350,695		698,958,075
2005	698,958,075	43,672,934	2,611,067	4,304	740,024,245
2006	740,024,245	49,781,866	2,410,193	2,499	787,398,418
2007	787,398,418	46,407,827	1,309,036	(342)	832,496,867
2008	832,496,867	44,365,917	877,792		875,984,992

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 365.00 Overhead Conductors and Devices

T-Cut: None
Placement Band: 1925-2008
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2000	0.0	41.7	L2 *	19.56	38.1	R3 *	17.67	42.1	R4 *	10.19
1997-2001	0.0	41.9	L2 *	19.06	37.0	R3 *	18.60	40.4	R4 *	12.01
1998-2002	60.9	108.8	S-.5	3.51	95.0	S0	4.02	70.4	R2.5	8.67
1999-2003	60.8	107.6	L0.5	3.82	85.8	S0.5	5.36	72.6	R2	8.09
2000-2004	53.3	114.6	S-.5	5.05	82.4	S1	5.40	73.2	R2.5	7.49
2001-2005	26.4	104.2	L1	12.24	71.9	S1.5	5.12	61.4	R3	10.06
2002-2006	18.1	96.3	L1	15.77	65.0	R2.5	5.25	57.6	R4	11.42
2003-2007	24.9	97.9	L1 *	13.58	66.0	S2	4.46	58.3	R4 *	13.93
2004-2008	26.9	100.2	L1 *	13.30	67.2	S2	4.42	59.1	R4 *	14.78

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 365.00 Overhead Conductors and Devices

T-Cut: None

Placement Band: 1925-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-2008	0.0	63.0	L1.5 *	23.38	49.3	R3 *	9.71	48.5	R4 *	4.85
1998-2008	33.1	104.3	L1	12.43	71.0	S1.5	3.76	60.3	R3	13.51
2000-2008	31.6	103.0	L1	12.59	69.5	S2	3.84	60.1	R4	13.59
2002-2008	24.5	102.5	L1	14.91	68.6	S2	4.31	59.8	R4	12.30
2004-2008	26.9	100.2	L1 *	13.30	67.2	S2	4.42	59.1	R4 *	14.78
2006-2008	28.5	102.6	L1.5 *	12.44	67.6	S2	7.37	59.8	R4 *	17.69
2008-2008	76.1	124.9	S0 *	3.25	79.2	S2 *	10.87	65.8	R4 *	24.76

Schedule D

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 365.00 Overhead Conductors and Devices

T-Cut: None

Placement Band: 1925-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1996-1997	0.0	31.3	L3 *	33.16	34.4	R3 *	25.84	40.0	R5 *	16.85
1996-1999	0.0	38.6	L2 *	22.28	36.8	R3 *	20.19	41.6	R5 *	11.71
1996-2001	0.0	44.8	L2 *	18.53	39.6	R3 *	15.82	42.8	R4 *	9.25
1996-2003	0.0	50.6	L2 *	18.73	42.5	R3 *	12.55	44.3	R4 *	7.46
1996-2005	0.0	55.6	L2 *	20.31	45.3	R3 *	10.66	45.8	R4 *	6.18
1996-2007	0.0	60.1	L2 *	22.14	47.8	R3 *	9.82	47.5	R4 *	5.25
1996-2008	0.0	63.0	L1.5 *	23.38	49.3	R3 *	9.71	48.5	R4 *	4.85

Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 365.00 Overhead Conductors and Devices

T-Cut: None

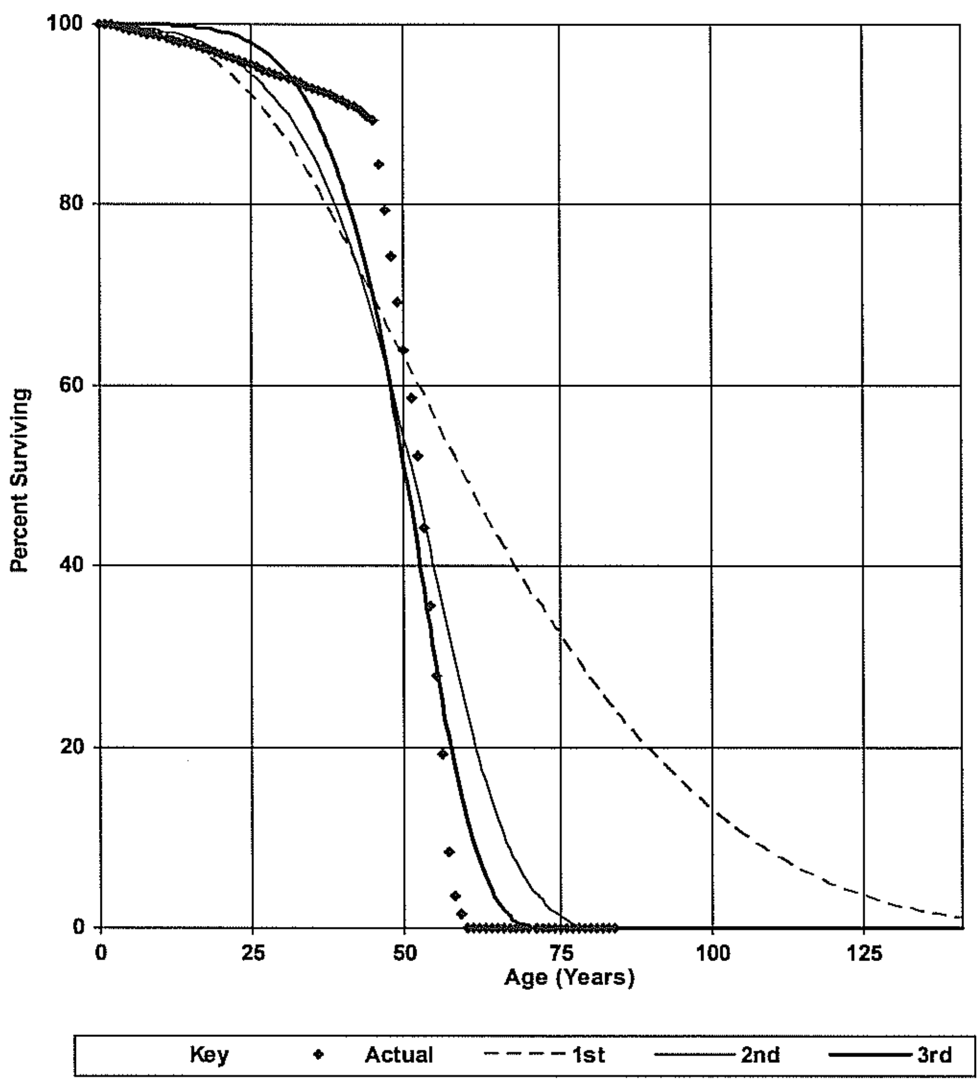
Placement Band: 1925-2008 Observation Band: 1996-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 63.0-L1.5 2nd: 49.3-R3 3rd: 48.5-R4



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 365.00 Overhead Conductors and Devices

T-Cut: None

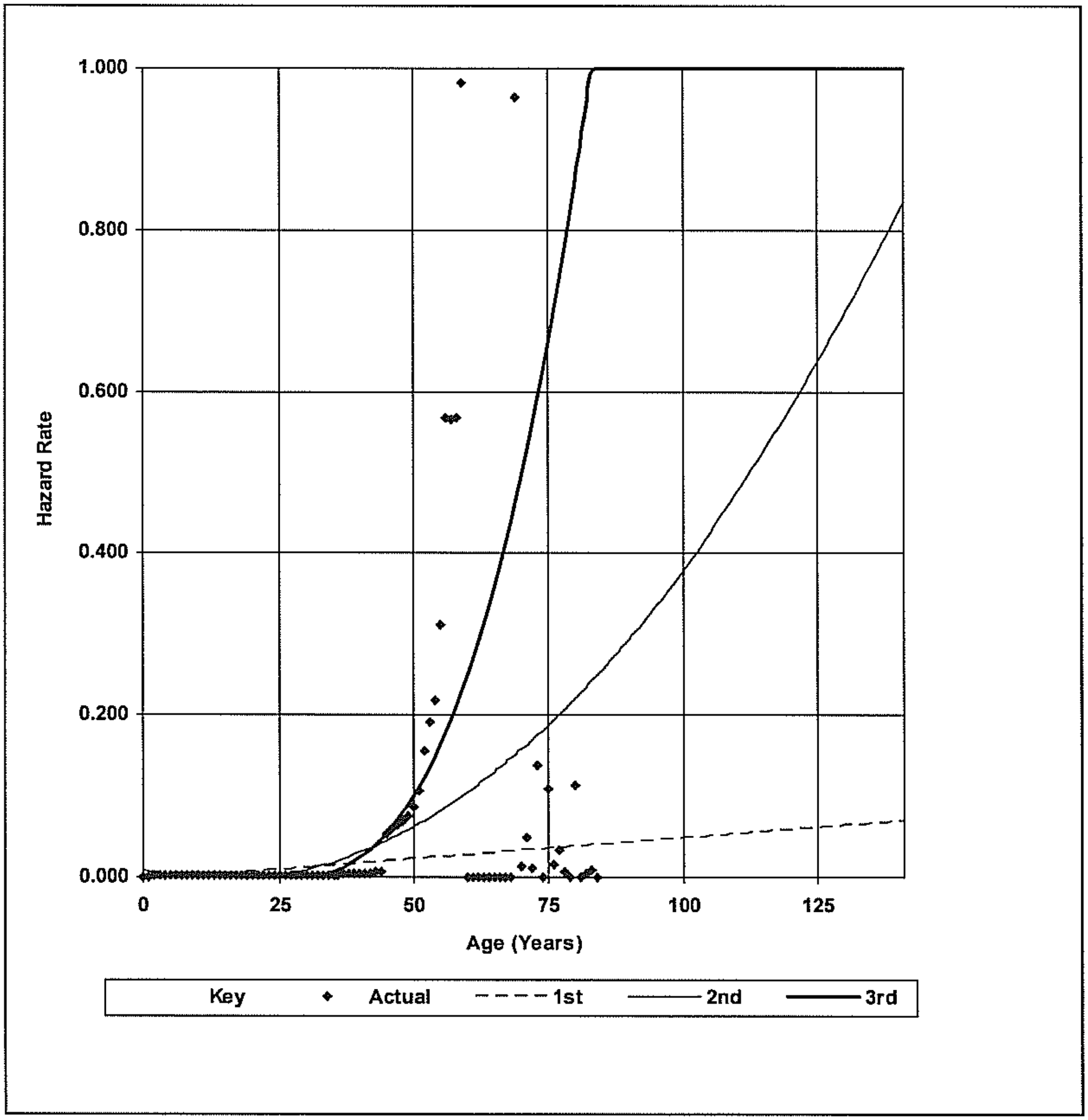
Placement Band: 1925-2008 Observation Band: 1996-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 63.0-L1.5 2nd: 49.3-R3 3rd: 48.5-R4



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

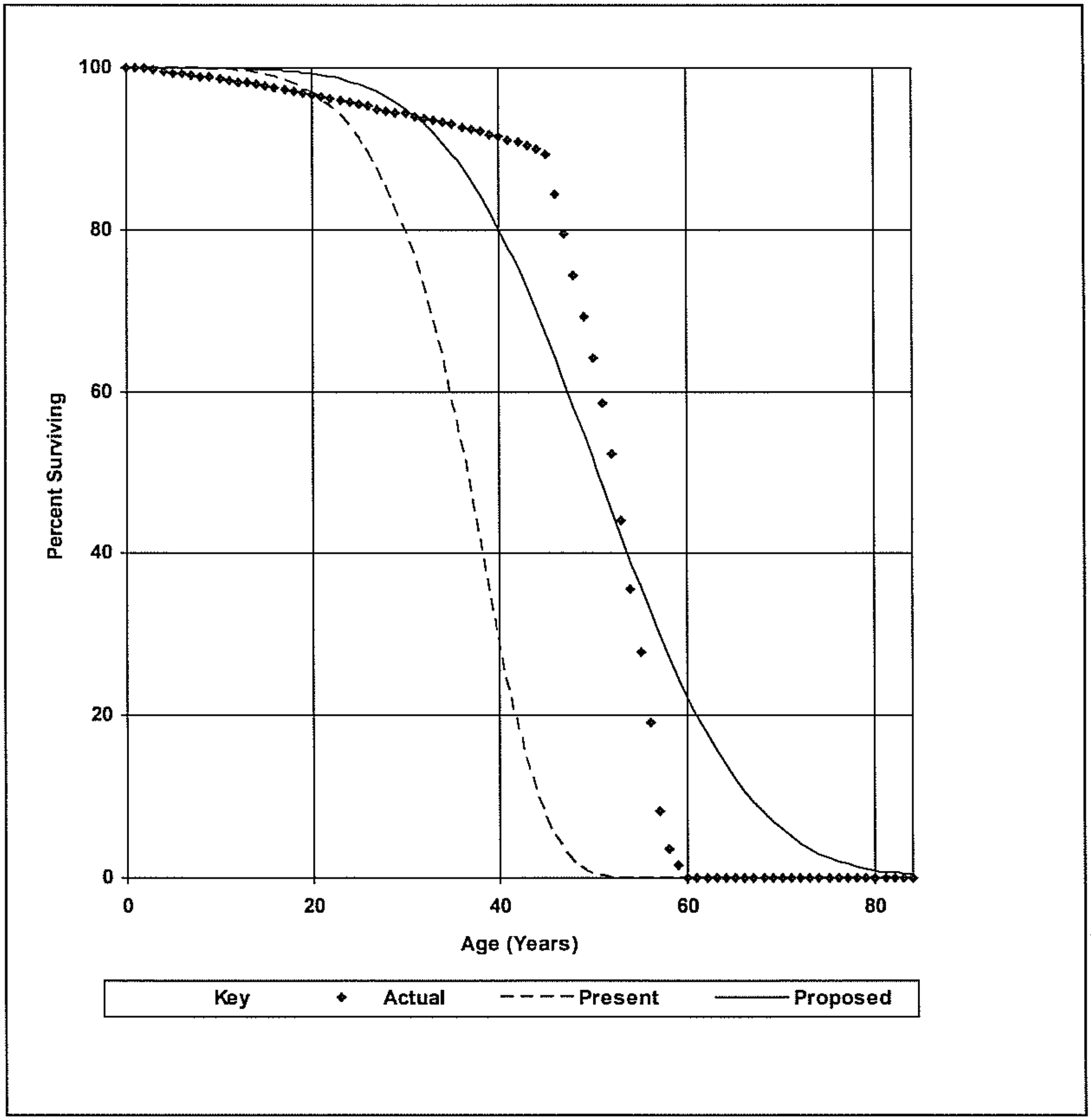
Account: 365.00 Overhead Conductors and Devices

T-Cut: None

Placement Band: 1925-2008

Observation Band: 1996-2008

Present and Proposed Projection Life Curves **Present: 35.0-R4** **Proposed: 50.0-H4**



Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 365.00 Overhead Conductors and Devices

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998	529,454	(526)	-0.1		97,361	18.4		(97,887)	-18.5	
1999	2,366,062	43,199	1.8		550,590	23.3		(507,391)	-21.4	
2000	1,751,331	(45,934)	-2.6		2,393,638	136.7		(2,439,572)	-139.3	
2001	1,240,759	131,211	10.6		1,964,670	158.3		(1,833,459)	-147.8	
2002	2,035,560	142,918	7.0	3.4	2,855,542	140.3	99.2	(2,712,625)	-133.3	-95.8
2003	1,369,940	126,769	9.3	4.5	2,924,254	213.5	122.0	(2,797,485)	-204.2	-117.4
2004	1,350,695	6,656	0.5	4.7	1,347,765	99.8	148.2	(1,341,109)	-99.3	-143.6
2005	2,611,067		0.0	4.7	2,931,384	112.3	139.7	(2,931,384)	-112.3	-134.9
2006	2,410,193		0.0	2.8	7,724,694	320.5	181.9	(7,724,694)	-320.5	-179.1
2007	1,309,036		0.0	1.5	4,298,422	328.4	212.4	(4,298,422)	-328.4	-211.0
2008	877,792		0.0	0.1	3,610,964	411.4	232.7	(3,610,964)	-411.4	-232.6
Total	17,851,889	404,293	2.3		30,699,283	172.0		(30,294,991)	-169.7	

Schedule F

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 365.00 Overhead Conductors and Devices

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1998	529,454	(526)	-0.1		97,361	18.4		(97,887)	-18.5	
1999	2,366,062	43,199	1.8		550,590	23.3		(507,391)	-21.4	
2000	1,751,331	(45,934)	-2.6		2,393,638	136.7		(2,439,572)	-139.3	
2001	1,240,759	131,211	10.6		1,964,670	158.3		(1,833,459)	-147.8	
2002	2,035,560	142,918	7.0	3.4	2,855,542	140.3	99.2	(2,712,625)	-133.3	-95.8
2003	1,369,940	126,769	9.3	4.5	2,924,254	213.5	122.0	(2,797,485)	-204.2	-117.4
2004	1,350,695	6,656	0.5	4.7	1,347,765	99.8	148.2	(1,341,109)	-99.3	-143.6
2005	2,611,067		0.0	4.7	2,931,384	112.3	139.7	(2,931,384)	-112.3	-134.9
2006	2,410,193		0.0	2.8	7,724,694	320.5	181.9	(7,724,694)	-320.5	-179.1
2007	1,309,036		0.0	1.5	4,298,422	328.4	212.4	(4,298,422)	-328.4	-211.0
2008	877,792		0.0	0.1	3,610,964	411.4	232.7	(3,610,964)	-411.4	-232.6
Total	17,851,889	404,293	2.3		30,699,283	172.0		(30,294,991)	-169.7	

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant
Account: 366.01 Underground conduit

Dispersion: 75 - H4
Procedure: Broad Group

Generation Arrangement

Vintage	December 31, 2008 Age	December 31, 2008 Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2008	0.5	4,602,138	75.00	74.50	0.9933	1.0000	4,571,486	61,362
2007	1.5	4,672,023	75.00	73.50	0.9800	1.0000	4,578,627	62,294
2006	2.5	3,446,122	75.00	72.50	0.9667	1.0000	3,331,329	45,948
2005	3.5	3,495,779	75.00	71.50	0.9534	1.0000	3,332,766	46,610
2004	4.5	3,252,169	75.00	70.50	0.9400	1.0000	3,057,195	43,362
2003	5.5	4,664,960	75.00	69.51	0.9267	1.0000	4,323,188	62,199
2002	6.5	5,507,399	75.00	68.51	0.9134	1.0000	5,030,577	73,432
2001	7.5	4,293,776	75.00	67.51	0.9001	1.0000	3,864,920	57,250
2000	8.5	4,549,032	75.00	66.51	0.8868	1.0000	4,034,149	60,654
1999	9.5	4,273,438	75.00	65.51	0.8735	1.0000	3,732,945	56,979
1998	10.5	501,147	75.00	64.52	0.8602	1.0000	431,105	6,682
1997	11.5	29,277	75.00	63.52	0.8470	1.0000	24,797	390
1996	12.5	6,999,179	75.00	62.53	0.8337	1.0000	5,835,127	93,322
1995	13.5	3,535,286	75.00	61.53	0.8204	1.0000	2,900,450	47,137
1994	14.5	2,987,175	75.00	60.54	0.8072	1.0000	2,411,202	39,829
1993	15.5	2,351,356	75.00	59.55	0.7940	1.0000	1,866,866	31,351
1992	16.5	2,997,341	75.00	58.55	0.7807	1.0000	2,340,122	39,965
1991	17.5	3,314,153	75.00	57.57	0.7675	1.0000	2,543,741	44,189
1990	18.5	2,584,010	75.00	56.58	0.7544	1.0000	1,949,294	34,453
1989	19.5	1,123,735	75.00	55.59	0.7412	1.0000	832,934	14,983
1988	20.5	1,886,082	75.00	54.61	0.7281	1.0000	1,373,255	25,148
1987	21.5	1,250,563	75.00	53.63	0.7150	1.0000	894,161	16,674
1986	22.5	3,272,315	75.00	52.65	0.7019	1.0000	2,296,995	43,631
1985	23.5	2,447,839	75.00	51.67	0.6889	1.0000	1,686,409	32,638
1984	24.5	1,323,830	75.00	50.70	0.6760	1.0000	894,863	17,651
1983	25.5	1,341,015	75.00	49.73	0.6630	1.0000	889,140	17,880
1982	26.5	2,203,576	75.00	48.76	0.6502	1.0000	1,432,699	29,381
1981	27.5	2,601,770	75.00	47.80	0.6374	1.0000	1,658,250	34,690
1980	28.5	2,767,987	75.00	46.85	0.6246	1.0000	1,728,899	36,907
1979	29.5	1,078,806	75.00	45.89	0.6119	1.0000	660,152	14,384
1978	30.5	651,663	75.00	44.95	0.5993	1.0000	390,557	8,689
1977	31.5	1,345,244	75.00	44.01	0.5868	1.0000	789,389	17,937
1976	32.5	1,047,623	75.00	43.08	0.5744	1.0000	601,726	13,968
1975	33.5	2,334,422	75.00	42.15	0.5620	1.0000	1,312,031	31,126
1974	34.5	2,876,205	75.00	41.23	0.5498	1.0000	1,581,320	38,349
1973	35.5	945,974	75.00	40.33	0.5377	1.0000	508,632	12,613

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant
Account: 366.01 Underground conduit

Dispersion: 75 - H4
Procedure: Broad Group

Generation Arrangement

Vintage	December 31, 2008 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1972	36.5	2,116,178	75.00	39.43	0.5257	1.0000	1,112,417	28,216
1971	37.5	1,846,329	75.00	38.53	0.5138	1.0000	948,611	24,618
1970	38.5	803,602	75.00	37.65	0.5020	1.0000	403,437	10,715
1969	39.5	2,137,819	75.00	36.78	0.4904	1.0000	1,048,439	28,504
1968	40.5	1,145,345	75.00	35.92	0.4789	1.0000	548,558	15,271
1967	41.5	909,874	75.00	35.07	0.4676	1.0000	425,496	12,132
1966	42.5	1,115,780	75.00	34.24	0.4565	1.0000	509,334	14,877
1965	43.5	1,282,775	75.00	33.41	0.4455	1.0000	571,450	17,104
1964	44.5	798,635	75.00	32.60	0.4347	1.0000	347,143	10,648
1963	45.5	744,515	75.00	31.80	0.4240	1.0000	315,694	9,927
1962	46.5	1,358,812	75.00	31.02	0.4135	1.0000	561,931	18,117
1961	47.5	503,864	75.00	30.25	0.4033	1.0000	203,202	6,718
1960	48.5	722,897	75.00	29.49	0.3932	1.0000	284,246	9,639
1959	49.5	1,237,848	75.00	28.75	0.3833	1.0000	474,468	16,505
1958	50.5	1,399,471	75.00	28.02	0.3736	1.0000	522,880	18,660
1957	51.5	881,819	75.00	27.31	0.3641	1.0000	321,105	11,758
1956	52.5	746,686	75.00	26.61	0.3548	1.0000	264,953	9,956
1955	53.5	854,872	75.00	25.93	0.3458	1.0000	295,599	11,398
1954	54.5	858,625	75.00	25.27	0.3369	1.0000	289,284	11,448
1953	55.5	286,557	75.00	24.62	0.3282	1.0000	94,060	3,821
1952	56.5	313,341	75.00	23.99	0.3198	1.0000	100,210	4,178
1951	57.5	430,439	75.00	23.37	0.3116	1.0000	134,114	5,739
1950	58.5	395,413	75.00	22.77	0.3035	1.0000	120,022	5,272
1949	59.5	166,729	75.00	22.18	0.2957	1.0000	49,307	2,223
1948	60.5	250,346	75.00	21.61	0.2881	1.0000	72,130	3,338
1947	61.5	139,640	75.00	21.05	0.2807	1.0000	39,198	1,862
1946	62.5	19,737	75.00	20.51	0.2735	1.0000	5,399	263
1945	63.5	103,101	75.00	19.99	0.2665	1.0000	27,479	1,375
1944	64.5	58,291	75.00	19.48	0.2597	1.0000	15,139	777
1943	65.5	146,353	75.00	18.98	0.2531	1.0000	37,045	1,951
1942	66.5	191,994	75.00	18.50	0.2467	1.0000	47,368	2,560
1941	67.5	249,800	75.00	18.04	0.2405	1.0000	60,073	3,331
1940	68.5	567,532	75.00	17.58	0.2345	1.0000	133,065	7,567
1939	69.5	606,330	75.00	17.15	0.2286	1.0000	138,614	8,084
1938	70.5	704,848	75.00	16.72	0.2229	1.0000	157,135	9,398
1937	71.5	391,396	75.00	16.31	0.2174	1.0000	85,106	5,219

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant
Account: 366.01 Underground conduit

Dispersion: 75 - H4
Procedure: Broad Group

Generation Arrangement

Vintage	December 31, 2008 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1936	72.5	408,557	75.00	15.91	0.2121	1.0000	86,660	5,447
1935	73.5	210,255	75.00	15.52	0.2069	1.0000	43,512	2,803
1934	74.5	244,583	75.00	15.15	0.2020	1.0000	49,394	3,261
1933	75.5	164,252	75.00	14.78	0.1971	1.0000	32,375	2,190
1932	76.5	579,187	75.00	14.43	0.1924	1.0000	111,446	7,722
1931	77.5	2,647,651	75.00	14.09	0.1879	1.0000	497,424	35,302
1930	78.5	1,083,746	75.00	13.76	0.1835	1.0000	198,843	14,450
1929	79.5	90,671	75.00	13.44	0.1792	1.0000	16,251	1,209
1928	80.5	338,821	75.00	13.13	0.1751	1.0000	59,327	4,518
1927	81.5	333,999	75.00	12.83	0.1711	1.0000	57,149	4,453
1926	82.5	571,743	75.00	12.54	0.1673	1.0000	95,625	7,623
1925	83.5	276,861	75.00	12.26	0.1635	1.0000	45,267	3,691
1924	84.5	496,450	75.00	11.99	0.1599	1.0000	79,371	6,619
1923	85.5	215,020	75.00	11.73	0.1564	1.0000	33,628	2,867
1922	86.5	139,800	75.00	11.47	0.1530	1.0000	21,386	1,864
1921	87.5	64,657	75.00	11.23	0.1497	1.0000	9,678	862
1920	88.5	112,303	75.00	10.99	0.1465	1.0000	16,456	1,497
1919	89.5	61,696	75.00	10.76	0.1434	1.0000	8,849	823
1918	90.5	260,537	75.00	10.53	0.1404	1.0000	36,589	3,474
1917	91.5	340,295	75.00	10.32	0.1376	1.0000	46,814	4,537
1916	92.5	69,874	75.00	10.11	0.1347	1.0000	9,415	932
1915	93.5	26,044	75.00	9.90	0.1320	1.0000	3,438	347
1914	94.5	101,109	75.00	9.71	0.1294	1.0000	13,086	1,348
1913	95.5	228,774	75.00	9.51	0.1268	1.0000	29,018	3,050
1912	96.5	177,982	75.00	9.33	0.1244	1.0000	22,134	2,373
1911	97.5	11,157	75.00	9.15	0.1220	1.0000	1,361	149
1910	98.5	59,172	75.00	8.97	0.1196	1.0000	7,080	789
1909	99.5	2,470	75.00	8.80	0.1174	1.0000	290	33
1908	100.5	51,327	75.00	8.64	0.1153	1.0000	5,915	684
1907	101.5	1,847	75.00	8.48	0.1131	1.0000	209	25
1906	102.5	6,016	75.00	8.33	0.1110	1.0000	668	80
1905	103.5	23,084	75.00	8.18	0.1091	1.0000	2,518	308
1904	104.5	26,771	75.00	8.03	0.1071	1.0000	2,867	357
1903	105.5	25,380	75.00	7.89	0.1052	1.0000	2,670	338
1902	106.5	3,849	75.00	7.76	0.1034	1.0000	398	51
1901	107.5	2,245	75.00	7.62	0.1016	1.0000	228	30

Schedule A

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant
Account: 366.01 Underground conduit

Dispersion: 75 - H4
Procedure: Broad Group

Generation Arrangement

Vintage	Age (December 31, 2008)	Surviving Plant (December 31, 2008)	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1900	108.5	17,069	75.00	7.49	0.0998	1.0000	1,704	228
Total	25.8	$134,517,260	75.00	51.35	0.6847	1.0000	$92,104,050	$1,793,563

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

Niagara Mohawk Power Corporation

Case 10-E-0050

July 2010

Prepared Testimony of:

Depreciation Panel

Paul J. Darmetko, Jr.
Utility Engineer 2

Colonel Dickens
Utility Engineer 3

Office of Electric, Gas, & Water
State of New York
Department of Public Service
Three Empire State Plaza
Albany, New York 12223-1350

Q. Please state your names, employer, and business address.

A. Our names are Paul J. Darmetko, Jr., and Colonel Dickens. We are employed by the New York State Department of Public Service (Department) and are located at Three Empire State Plaza, Albany, New York 12223.

Q. Mr. Darmetko, what is your position at the Department?

A. I am employed as a Utility Engineer 2 in the Electric Rates Section of the Office of Electric, Gas, and Water.

Q. Please provide a summary of your educational and professional experience.

A. I graduated from the State University of New York Institute of Technology at Utica/Rome with a Bachelor of Science Degree in Civil Engineering Technology in 2003. I have been employed by the Department since October 2005 in the Office of Electric, Gas, and Water, in the Electric Rates Section. While with the Department I have analyzed, reviewed, and prepared reports and studies involving operating revenues, operation and maintenance expense, capital budgets, depreciation, cost of service, revenue allocation, rate design, and sales forecasts.

Q. Have you previously testified in proceedings before the New York State Public Service Commission (Commission)?

A. Yes. I have testified in numerous proceedings before the Commission regarding cost of service, capital budgets, rate base, depreciation, rate design, and other revenue requirement issues.

Q. Mr. Dickens, what is your position at the Department?

A. I am a Utility Engineer 3 in the Office of Electric, Gas and Water in the Electric Rates and Tariff Section.

Q. Mr. Dickens, please summarize your educational background and professional experience.

A. I graduated from Alfred University with a Bachelors of Science degree in Ceramic Engineering in 1972. I also received a Masters in Business Administration from Sage College in 1999. I have been employed by the Department since 1978. During that time I have worked as an engineer in the Electric Rates Section. My responsibilities at the Department include analysis of electric utility applications for rate increases, analysis of rate design and revenue allocation proposals, as well as analysis of various utility petitions and tariff filings.

Q. Mr. Dickens, have you previously testified before the Commission?

A. Yes. I have testified in numerous proceedings regarding revenue allocation, rate design, depreciation and other revenue requirement issues. More recently, I have testified with regard to depreciation in the New York State Electric and Gas Corporation rate case (Case 05-E-1222) and Central Hudson rate cases (Case 08-E-0887 and Case 05-E-0934).

Q. What is the purpose of the Panel's testimony?

A. We have reviewed projections of Niagara Mohawk Power Corporation (Niagara Mohawk or the Company) Depreciation Expense, based upon the Company's Depreciation Study (Study) results and the specific recommendations made by the Company's depreciation consultant, witness Ronald E. White, of Foster Associates, Inc. (FAI). Based upon the results of the Study provided, which includes an analysis of average service life, net salvage factors, and retirement dispersion patterns using historical data through December 31, 2008, we will present our recommendations for average service lives, survivor curves, and net salvage for various plant accounts.

Q. Please explain what "depreciation" is, as it is used in ratemaking?

A. Depreciation is a method of recovering capital cost (less net salvage) related to plant in service over the plants' expected life.

Q. What is a depreciation rate and expense?

A. A depreciation rate is a percentage rate applied to the gross plant in service, by account, to determine the annual depreciation expense.

Q. What are the book and theoretical reserves?

A. The book reserve is the accumulation of the annual depreciation expense accruals, by account, less any retirements and cost of removal, plus any salvage received. The book reserve is subtracted from the original, or gross, plant to derive the net plant. The theoretical reserve is the amount that should have been collected given the survivor curve and net salvage selected when determining the depreciation rates.

Q. What is a survivor curve?

A. A survivor curve indicates the percentage of original plant, by age, which is still in service. Known curves, such as Iowa or h-curves, are fit to the observed curve. The area under the survivor curve is the average service life or whole life. The observed curves are generated in a mortality study that examines the actual retirement patterns over several years.

Q. How are the depreciation rates calculated?

A. The rates are calculated differently depending on the depreciation system used. Each system is composed of a method, a procedure, and a technique.

Q. What depreciation system do Niagara Mohawk and other New York State utilities currently use for most, if not all, of their plant accounts?

A. Niagara Mohawk and other utilities currently use the straight line method, broad group procedure, and whole life technique.

Q. Please explain how the depreciation rates are calculated for each account.

A. The depreciation system, as previously described, uses the following formula.

Rate = (1-net salvage) / average service life

Net salvage is the sum of the cost to remove the plant and any revenue received for the retired plant. The net salvage is usually expressed as a percentage. The percentage commonly is some historic actual net salvage amount, divided by the original cost of the plant that was retired. For example, if the average service life for a plant account was 50 years and the net salvage was negative 50%, then the rate would be

$$R = (1-(-.5)) / 50$$

$$R = 0.03 \text{ or } 3.0\%$$

Again, the rate is multiplied by the gross plant to obtain the depreciation expense for ratemaking purposes.

Q. Please explain the process of comparing the book reserve to the theoretical reserve.

A. Under the whole life technique, when a depreciation study is performed, the current book reserve is compared to the proposed theoretical reserve. The proposed theoretical reserve incorporates any changes to the survivor curve and net salvage. Traditionally, if the book to theoretical reserve difference is within plus or minus 10 percent, no adjustment is usually made to the over or under accruals.

However, if the difference is above or below 10 percent, an amortization of the difference could be made. If it is an excess, the funds could be used for other rate making treatments. The use of a 10 percent margin and the treatment are discretionary. An adjustment is usually made because the difference is too large to be corrected, going forward, with appropriate life or salvage changes.

Q. Has the Panel reviewed the results of the Company's Depreciation Study performed by FAI, as presented in Niagara Mohawk's filing?

A. Yes. The Company provided a summary of the results of the Study and its recommendations in pre-filed testimony. FAI reviewed both the average service lives of most of the Company's electric plant accounts and also provided a net salvage study summary. The study also included a rolling and shrinking band analysis.

Q. What information does the rolling and shrinking band analysis provide?

A. A retirement band is a period of years over which actual retirements are examined. Rolling bands are retirement bands of constant width (constant # of years in each band). Shrinking bands aggregate all retirements initially and then subtract one year at a time. The analysis provides average service lives by bands and is an indication of how well a known survivor curve may fit the actual curve.

Q. What did the rolling and shrinking band analysis results provided in the study show?

A. The results include set groupings or bands of vintages for most of the Company's electric plant accounts. This formed the basis for the various Iowa curves and fit indices provided. However, FAI selected only h-curves in its curve selection process. Mr. White explains in footnote 2, on page 11 of his direct testimony, that FAI selected the family of h-curves because of a Commission directive that came out of the last Niagara Mohawk gas rate case in which the parties agreed in settlement that "when the Company next files for new gas rates, its filing will include . . . the observed curve and selected h-curve."

Q. Does the Panel know of any reason not to also look at Iowa curves when selecting known curves to fit to the observed data?

A. No. In fact, we believe that omitting one set of curves actually reduces the quality of the analysis because an analyst should look for a known curve that best fits the observed curve. We also don't believe a Commission directive referring to a future, gas case meant to exclude the use of Iowa curves from all future analysis, nor did it intend to show a preference for the type of curve used in a Joint Proposal. In fact, the Commission has just recently, in Case 08-E-0887, accepted the use of Iowa curves.

Q. Can the Panel determine what depreciation rates should be employed from the information provided in the Company's Study?

A. Yes. We have examined the Study results using the data supplied in the rolling and shrinking band analysis, in addition to the graphical curve fittings included in the Study, and were able to agree with some of the recommendations contained in the Company's filing.

Q. Please quantify your adjustments to depreciation expense and the theoretical reserve.

A. Our adjustments to depreciation rates will decrease electric depreciation expense by approximately $36.2 million in the rate year. Our adjustments will decrease the Company's proposed theoretical reserve for electric plant by approximately $67.1 million. This will change the resulting book-to-theoretical reserve surplus, or over-accrual, of approximately $61.1 million as calculated by the Company, to a reserve surplus of approximately $128.5 million as calculated by our Panel.

Q. Are you sponsoring any Exhibits in this testimony?

A. Yes. Exhibit___(DP-1) shows Staff's forecast versus actual electric depreciation expense as applied to depreciable plant in service for calendar year 2008. Exhibit___(DP-2) shows Staff's selected curves and the curves selected by the Company, compared to the observed curves for 8 specific accounts. Exhibit___(DP-3) is a compilation of our work papers we relied upon to develop our testimony.

Average Service Lives and Survivor Curves

Q. Do you have any adjustments to the average service lives, survivor curves, and net salvage rates proposed by Niagara Mohawk?

A. Yes. We recommend changes to average service lives, survivor curves, and net salvage rates for certain Company accounts.

Q. What are the Panel's recommended changes to the average service lives and survivor curves proposed by FAI for Niagara Mohawk?

A. Exhibit___(DP-1), compares the Company's recommendations with our Panel's recommendations. It shows that Staff is proposing different service lives, and/or survivor curves, for 9 electric accounts. These accounts are: Account 353.55, 358.00, 361.00, 362.55, 364.00, 365.00, 367.10, 368.01, and 368.30.

Q. Please explain why the Panel is recommending adjustments to the average service lives and or survivor curves proposed by FAI?

A. The Panel reviewed the rolling and shrinking retirement bands provided in the Study. We requested, through Staff Interrogatory DPS-309 (PJD-2) and (PJD-2 SUPP) that the Company provide different survivor curves for several accounts. Based on that response, and our review of the company's Study, the Panel is proposing different survivor curves and/or average service lives than those proposed by the Company for 9 accounts.

Q. Why is the Panel proposing different survivor curves than those proposed by the Company?

A. As shown on Exhibit___ (DP-2), the survivor curves for the 8 accounts we selected (titled Staff Curve) fit or track actual retirement history more accurately than the curves selected by the Company (titled Company Curve). As such, we recommend that our survivor curves be used for the 8 accounts. For the remaining account, Account 368.01 Line Transformers – Bare Cost, we accept the curve shape selected by the Company, but changed the average service life to be consistent with Account 368.30 Line Transformers – Install Cost.

Q. What are the effects of the proposed changes?

A. The survivor curves we selected produce longer service lives, which reduce the depreciation accrual for those accounts, as shown on Exhibit___(DP-1).

Salvage

Q. Generally, what is the recommendation of FAI with regard to salvage rates?

A. FAI proposes to maintain the current salvage rates for 3 accounts, increase the salvage rates for 23 accounts, and reduce salvage rates for 5 accounts, as shown on Exhibit___ (DP-1).

Q. Does the Panel agree with all of FAI's proposed changes?

A. No. Staff recommends maintaining the current salvage rates for 3 accounts, increasing the salvage rates for 21 accounts, and reducing the salvage rates for 7 accounts, as shown on Exhibit___ (DP-1).

Q. Please explain why the Panel disagrees with the Company's proposed changes to certain net salvage rates for electric plant.

A. We compared the trend of actual, historical, net salvage dollars incurred by the Company to the dollars accrued by the current and Company-proposed net salvage rates for all electric accounts. We found significant differences between the Company's proposed salvage rate accruals and the current actual salvage expenses, as shown in Exhibit____ (DP-1). Based on these findings, we recommend that the rates be adjusted to more closely reflect the recent, five year average of actual dollars of net salvage incurred.

Q. Please provide an example of such a situation.

A. As an example, Account 364.00 (Distribution Poles), currently has a net salvage expense of about $552,000 per year, based on the most recent five years of experience. The current negative net salvage rate of -25% produces an annual accrual of about $4,809,762. The Company's proposed -40.9% negative net salvage rate produces an annual accrual of about $4,963,379 million.

Q. What does the Panel recommend for this account?

A. Based on the comparison discussed above, we recommend changing the current accrual rate of negative -25% to negative -5%. Staff's rate would produce an annual accrual of about $607,000.

Q. What is the basis for the Niagara Mohawk's proposal?

A. The Company's proposed rate was developed based the relationship between net salvage costs to plant dollars retired.

Q. Why does the Panel disagree with the Company's approach?

A. The Company's concept implies a direct relationship between the net salvage and the original cost of the plant. However, salvage, unlike depreciation expense, is a true expense or revenue for which the Company receives either a bill or payment, depending on the outcome. A negative net salvage, which means that the cost of removal exceeds the salvage costs, has a closer relationship to the current labor costs of plant removal than to the original cost of the plant retired. Generally, using the relationship of plant removal costs to original costs accrues more than current actual costs. The accrual of additional costs is often said to be required for future retirements. It is not reasonable to assume that a utility would dismantle all or a large portion of its mass property accounts, such as poles, at one time, as it might with a production plant. Therefore, there is little need to accrue salvage costs above current costs for future retirements.

Q. Does the Panel's proposal always maintain or reduce the net salvage rates recommended by Niagara Mohawk?

A. No. For 13 accounts we are recommending a negative net salvage rate that is higher than the rate recommended by the Company.

Q. Has the Panel's salvage proposal been accepted in other rate cases?

A. Yes. The Commission adopted this methodology in the Central Hudson rate case, Case 08-E-0887, and the New York State Electric and Gas Corporation proceeding, Case 05-E-1222.

Q. What is the overall effect of the Panel's recommended electric salvage adjustments?

A. Overall, the adjustments reduce depreciation expense and the theoretical reserve, as shown on Exhibit___(DP-1).

<u>Book Reserve</u>

Q. Is the Company recommending a rebalancing of depreciation reserves?

A. Yes. The Company is proposing to rebalance the current book reserves of the individual accounts with no change to the current total book reserve.

Q. Does the Panel agree with the rebalancing of the individual account book reserves?

A. No. We do not believe it is necessary to rebalance the accounts unless an adjustment to the total book reserve is made.

<u>General Plant</u>

Q. Is the Company proposing changes to the amortization periods for all the General Accounts.

A. Yes. The Company has changed the amortization periods for all the common accounts to be consistent with the periods supported by Staff in the recent Niagara Mohawk gas case, 08-G-0609.

Q. Does the Panel agree with the Company’s recommendations regarding common plant amortization periods?

A. Yes.

Q. Does this conclude the Panel’s testimony at this time?

A. Yes.

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

Niagara Mohawk Power Corporation

Case 10-E-0050

July 2010

Prepared Exhibits of:

Depreciation Panel

Paul J. Darmetko, Jr.
Utility Engineer 2

Colonel Dickens
Utility Engineer 3

Office of Electric, Gas, & Water
State of New York
Department of Public Service
Three Empire State Plaza
Albany, New York 12223-1350

National Grid
Niagara Mohawk Power Corporation
Case 10-E-0050
Staff Depreciation Summary

		Current							Company Proposed							Staff Recommendations						
Acct. #	Acct Name	12/31/2008 Plant Investment	ASL	Curve	Dep. Rate	Net Salvage	Accrual	Book Res	ASL	Curve	Dep. Rate	Net Salvage	Accrual	Computed Theo Reserve	Diff of Book to Theo Res	ASL	Curve	Dep. Rate	Net Salvage	Accrual	Computed Theo Reserve	Diff of Book to Theo Res
	Transmission Plant																					
350.40	Land Rights - Transmission Lines	$27,123,696	75.00	R3	1.33%	0.00%	$360,745	$13,069,807	75.00	H5	1.33%	0.50%	$360,745	$12,539,339	$530,468	75.00	H5	1.32%	1.00%	$358,033	$12,601,724	$468,083
352.00	Structures and Improvements	$31,004,576	65.00	R1.5	1.92%	-25.00%	$595,288	$11,287,636	65.00	H3	2.05%	-33.10%	$635,594	$12,993,484	($1,705,848)	65.00	H3	2.08%	-35.00%	$644,895	$13,178,966	($1,891,330)
353.01	Substation Equipment	$623,806,673	58.00	R2	1.90%	-10.00%	$11,852,327	$181,239,442	45.00	H0.5	2.52%	-13.60%	$15,719,928	$131,092,556	$50,146,886	45.00	H0.5	2.44%	-10.00%	$15,220,883	$126,938,214	$54,301,228
353.55	Substation Equipment - EMS RTU	$42,485,893	20.00	R2	5.00%	0.00%	$2,124,295	$30,807,700	20.00	H2	5.01%	-0.10%	$2,128,543	$21,115,383	$9,692,317	30.00	S3	3.40%	-2.00%	$1,444,520	$20,656,684	$10,151,016
354.00	Towers and Fixtures	$133,237,659	68.00	R3	1.47%	0.00%	$1,958,594	$68,330,989	70.00	H4	1.87%	-31.20%	$2,491,544	$82,184,034	($13,853,045)	70.00	H4	1.71%	-20.00%	$2,278,364	$75,168,324	($6,837,335)
355.00	Poles and Fixtures	$365,859,185	55.00	S2	1.91%	-5.00%	$6,987,910	$111,143,069	65.00	H4	2.10%	-36.60%	$7,683,043	$131,773,473	($20,630,404)	65.00	H4	2.00%	-30.00%	$7,317,184	$125,406,673	($14,263,604)
356.01	Overhead Conductors and Device	$236,780,774	60.00	R2.5	1.51%	5.00%	$3,575,390	$77,469,018	75.00	H2	2.01%	-50.80%	$4,759,294	$91,799,717	($14,330,699)	75.00	H2	1.60%	-20.00%	$3,788,492	$73,050,173	$4,418,845
357.01	Underground Conduit	$29,049,970	62.00	R4	2.02%	-25.00%	$586,809	$14,222,294	75.00	H4	1.33%	0.00%	$386,365	$10,093,896	$4,128,398	75.00	H4	1.33%	0.00%	$386,365	$10,093,896	$4,128,398
358.00	Underground Conductors and Devices	$102,159,262	50.00	R1	1.40%	30.00%	$1,430,230	$24,750,616	50.00	H3	2.24%	-11.80%	$2,288,367	$40,146,220	($15,395,604)	75.00	R3	1.49%	-12.00%	$1,522,173	$29,249,130	($4,498,514)
359.00	Roads and Trails	$2,348,571	75.00	R3	1.33%	0.00%	$31,236	$231,855	75.00	H4	1.33%	0.00%	$31,236	$253,019	($21,164)	75.00	H4	1.33%	0.00%	$31,236	$253,019	($21,164)
	Total Transmission Plant	$1,593,856,259					$29,502,823	$532,552,426					$36,484,659	$533,991,121	($1,438,695)					$32,992,145	$486,596,802	$45,955,624
	Distribution Plant						1.85%															
360.01	Land Rights	$10,113,745	55.00	R2	1.82%	0.00%	$184,070	$1,323,743	75.00	H5	1.33%	0.00%	$134,513	$873,828	$449,915	75.00	H5	1.33%	0.00%	$134,513	$873,828	$449,915
361.00	Structures and Improvements	$35,412,715	65.00	R1.5	2.31%	-50.00%	$818,034	$12,178,825	65.00	H2.5	2.03%	-32.10%	$718,878	$12,822,590	($643,765)	75.00	R1.5	1.67%	-25.00%	$591,392	$9,518,774	$2,660,051
362.01	Station Equipment	$430,797,242	52.00	R1.5	2.12%	-10.00%	$9,132,902	$115,803,129	60.00	H2	1.93%	-15.50%	$8,314,387	$107,311,593	$8,491,536	60.00	H2	1.83%	-10.00%	$7,883,590	$102,201,517	$13,601,612
362.55	Station Equipment - EMS RTU	$29,492,793	20.00	R1.5	5.00%	0.00%	$1,474,640	$20,774,597	20.00	H2	5.00%	-0.10%	$1,474,640	$14,554,900	$6,219,697	30.00	S3	3.30%	1.00%	$973,262	-$13,813,736	$34,588,333
364.00	Poles, Towers and Fixtures	$788,801,034	41.00	S-0.5	2.97%	-25.00%	$23,427,391	$286,517,204	65.00	H2	2.17%	-40.90%	$17,116,982	$225,444,190	$61,073,014	65.00	R1.5	1.62%	-5.00%	$12,778,577	$165,582,110	$120,935,094
365.00	Overhead Conductors and Devices	$875,984,992	35.00	R4	3.71%	-30.00%	$32,499,043	$460,447,571	50.00	H4	4.05%	-102.30%	$35,477,392	$520,348,225	($59,900,654)	50.00	R4	2.50%	-25.00%	$21,899,625	$643,173,784	($182,726,213)
366.01	Underground Conduit	$134,517,260	70.00	R1.5	1.71%	-20.00%	$2,300,245	$49,140,823	75.00	H4	1.35%	-1.50%	$1,815,983	$41,036,284	$8,104,539	75.00	H4	1.47%	-10.00%	$1,977,404	$44,472,820	$4,668,003
367.10	Underground Conductors and Devices	$415,936,368	50.00	R1.5	1.80%	10.00%	$7,486,855	$98,539,455	50.00	H3	2.22%	-10.90%	$9,233,787	$119,601,088	($21,061,633)	75.00	R3	1.53%	-15.00%	$6,363,826	$86,171,174	$12,368,281
368.01	Line Transformers - Bare Cost	$451,751,287	36.00	L1.5	3.19%	-15.00%	$14,410,866	$169,144,375	35.00	H0.5	2.93%	-2.60%	$13,236,313	$76,186,435	$92,957,940	45.00	H0.5	2.67%	-20.00%	$12,061,759	$137,569,098	$31,575,277
368.30	Line Transformers - Install Cost	$239,904,970	36.00	L1.5	3.19%	-15.00%	$7,652,969	$15,544,011	35.00	H2.5	3.56%	-24.50%	$8,540,617	$84,014,378	($68,470,367)	45.00	R1.5	2.67%	-20.00%	$6,405,463	$57,151,722	($41,607,711)
369.10	Overhead Services	$284,680,583	40.00	R2	4.00%	-60.00%	$11,387,223	$181,592,696	50.00	H4	3.54%	-77.20%	$10,077,693	$170,800,379	$10,792,317	50.00	H4	2.60%	-30.00%	$7,401,695	$125,305,018	$56,287,678
369.20	Underground Services - Conduit	$8,035,024	50.00	R1	2.20%	-10.00%	$176,771	$3,669,572	75.00	H4	1.40%	-5.00%	$112,490	$2,726,766	$942,806	75.00	H4	1.35%	-1.00%	$108,473	$2,622,889	$1,046,683
369.21	Underground Services - Cable	$102,850,405	42.00	R1.5	1.90%	20.00%	$1,954,158	$24,530,820	75.00	H2.5	1.66%	-24.30%	$1,707,317	$22,708,958	$1,821,862	75.00	H2.5	1.40%	-5.00%	$1,439,906	$19,182,949	$5,347,871
370.10	Small Meters - Bare Cost	$49,724,890	32.00	S1.5	3.13%	0.00%	$1,556,389	($41,088,459)	20.00	H0.5	4.98%	0.50%	$2,476,300	$5,740,490	($46,828,949)	20.00	H0.5	6.25%	-25.00%	$3,107,806	$7,139,913	($48,228,372)
370.20	Small Meters - Install Cost	$26,080,597	36.00	S1.5	2.78%	0.00%	$725,041	($29,670,856)	20.00	H0.5	5.89%	-17.80%	$1,536,147	$4,014,743	($33,685,599)	20.00	H0.5	6.25%	-25.00%	$1,630,037	$4,260,126	($33,930,982)
370.30	Large Meters - Bare Cost	$6,871,977	36.00	R3	2.78%	0.00%	$191,041	$3,696,845	20.00	H3	5.00%	0.00%	$343,599	$1,810,766	$1,886,079	20.00	H3	5.05%	-1.00%	$347,035	$1,828,874	$1,867,971
370.35	Large Meters - Install Cost	$28,016,510	36.00	S1.5	2.78%	0.00%	$778,859	$2,438,144	20.00	H3	6.00%	-19.90%	$1,680,991	$10,441,473	($8,003,329)	20.00	H3	5.05%	-1.00%	$1,414,834	$8,795,569	($6,357,425)
371.00	Installations on Customers' Premises	$8,074,220	15.00	SC	7.33%	-10.00%	$591,840	$6,216,948	40.00	H1.5	3.34%	-33.40%	$269,679	$2,792,521	$3,424,427	40.00	H1.5	3.50%	-40.00%	$282,598	$2,930,682	$3,286,266
373.10	Overhead Street Lighting	$68,539,314	30.00	L0.5	3.80%	-10.00%	$2,604,494	$37,286,469	50.00	H1.5	3.07%	-53.60%	$2,104,157	$23,767,460	$13,519,009	50.00	H1.5	2.60%	-30.00%	$1,782,022	$20,115,689	$17,170,780
373.20	Underground Street Lighting	$121,233,487	30.00	L0.5	3.80%	-10.00%	$4,606,873	$54,217,646	70.00	H1	1.78%	-24.80%	$2,157,956	$20,516,585	$33,701,061	70.00	H1	1.86%	-30.00%	$2,254,943	$21,371,443	$32,846,203
	Total Distribution Plant	$4,116,819,413					$123,959,701	$1,472,303,558					$118,529,820	$1,467,513,652	$4,789,906					$90,838,759	$1,446,454,244	$25,849,314
	General Plant						3.01%															
390.00	Structures and Improvements	$89,809,731	55.00	R3	1.91%	-5.00%	$1,715,366	$12,912,812	55.00	H0.5	1.88%	-3.20%	$1,688,423	$15,755,044	($2,842,232)	55.00	H0.5	2.00%	-10.00%	$1,796,195	$16,793,167	($3,880,355)
	Total General Plant	$89,809,731					$1,715,366	$12,912,812					$1,688,423	$15,755,044	($2,842,232)					$1,796,195	$16,793,167	($3,880,355)
	Amortizable						1.91%															
391.01	Office Furniture and Equipment	$7,409,461	42.00	R2.5	2.74%	0.00%	$203,019	$2,623,489	22.00	SQ	4.55%	0.00%	$336,790	$4,422,845	($1,799,356)	22.00	SQ	4.55%	0.00%	$336,790	$4,422,845	($1,799,356)
391.20	Office Data Processing Equipment	$2,392,757	5.00	R3	20.00%	0.00%	$478,551	$1,317,454	5.00	SQ	17.74%	0.00%	$424,451	$1,300,386	$17,068	5.00	SQ	17.74%	0.00%	$424,451	$1,300,386	$17,068
393.00	Stores Equipment	$2,143,249	40.00	L1.5	2.50%	0.00%	$53,581	$806,037	22.00	SQ	4.55%	0.00%	$97,419	$1,397,328	($591,291)	22.00	SQ	4.55%	0.00%	$97,419	$1,397,328	($591,291)
394.01	Tools, Shop and Garage Equipment	$41,504,502	34.00	L0	2.96%	0.00%	$1,228,533	$12,515,135	22.00	SQ	4.54%	0.00%	$1,884,844	$19,426,223	($6,911,088)	22.00	SQ	4.54%	0.00%	$1,884,844	$19,426,223	($6,911,088)
395.01	Laboratory Equipment	$20,437,793	40.00	L1.5	2.50%	0.00%	$510,945	$5,972,720	22.00	SQ	4.55%	0.00%	$928,979	$11,315,257	($5,342,537)	22.00	SQ	4.55%	0.00%	$928,979	$11,315,257	($5,342,537)
397.01	Communication Equip. - Radio	$54,408,239	20.00	L1	5.00%	0.00%	$2,720,412	$18,508,540	22.00	SQ	4.52%	0.00%	$2,460,993	$18,048,404	$460,136	22.00	SQ	4.52%	0.00%	$2,460,993	$18,048,404	$460,136
397.02	Communication Equip. - Telephone	$3,443,130	8.00	S2	12.50%	0.00%	$430,391	$6,719,466	8.00	SQ	0.21%	0.00%	$7,100	$3,415,145	$3,304,321	8.00	SQ	0.21%	0.00%	$7,100	$3,415,145	$3,304,321
397.50	Communication Equip. - Network NY	$6,824,926	15.00	L1	6.67%	0.00%	$455,223	$1,565,296	22.00	SQ	4.55%	0.00%	$310,220	$1,461,989	$103,307	22.00	SQ	4.55%	0.00%	$310,220	$1,461,989	$103,307
397.60	Communication Equip. - Network Site NY	$11,247,365	15.00	L1	6.67%	0.00%	$750,199	$19,536,824	22.00	SQ	4.55%	0.00%	$511,238	$6,471,582	$13,065,242	22.00	SQ	4.55%	0.00%	$511,238	$6,471,582	$13,065,242
398.01	Miscellaneous Equipment	$51,182,084	10.00	L0	8.81%	0.00%	$4,509,142	$95,650,952	22.00	SQ	4.54%	0.00%	$2,325,919	$37,389,877	$58,261,075	22.00	SQ	4.54%	0.00%	$2,325,919	$37,389,877	$58,261,075
	Total Amortizable Plant	$200,993,506					$11,339,997	$165,215,913					$9,287,953	$104,649,036	$60,566,877					$9,287,953	$104,649,036	$60,566,877
							5.64%															
	Total Electric Plant	$6,001,478,909					$166,517,887	$2,182,984,709					$165,990,855	$2,121,908,853	$61,075,856					$134,915,051	$2,054,493,249	$128,491,460

Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

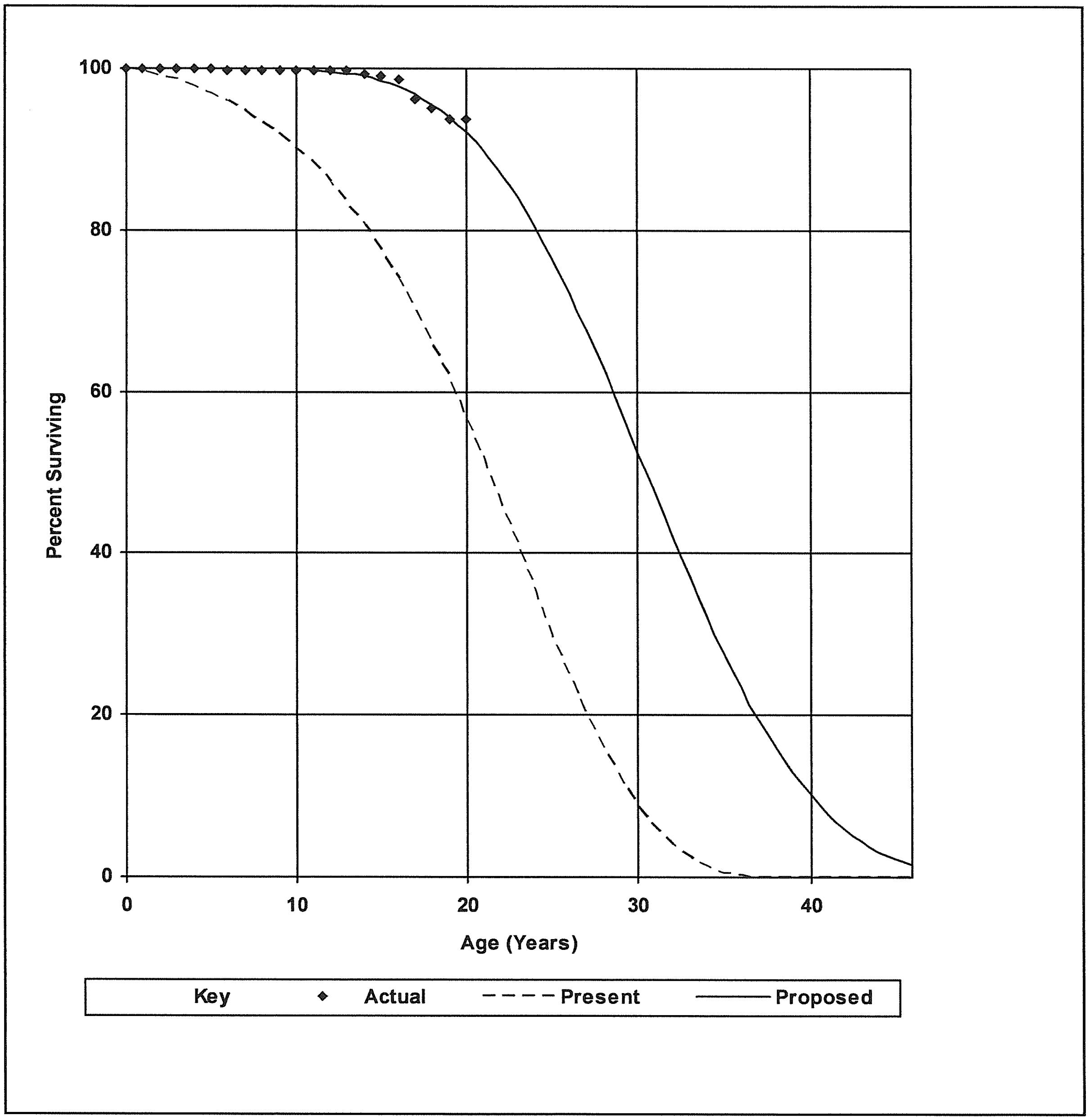
Account: 353.55 Station Equipment - EMS RTU

T-Cut: None

Placement Band: 1989-2008

Observation Band: 1996-2008

Present and Proposed Projection Life Curves **Present: 20.0-R2** **Proposed: 30.0-S3**



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

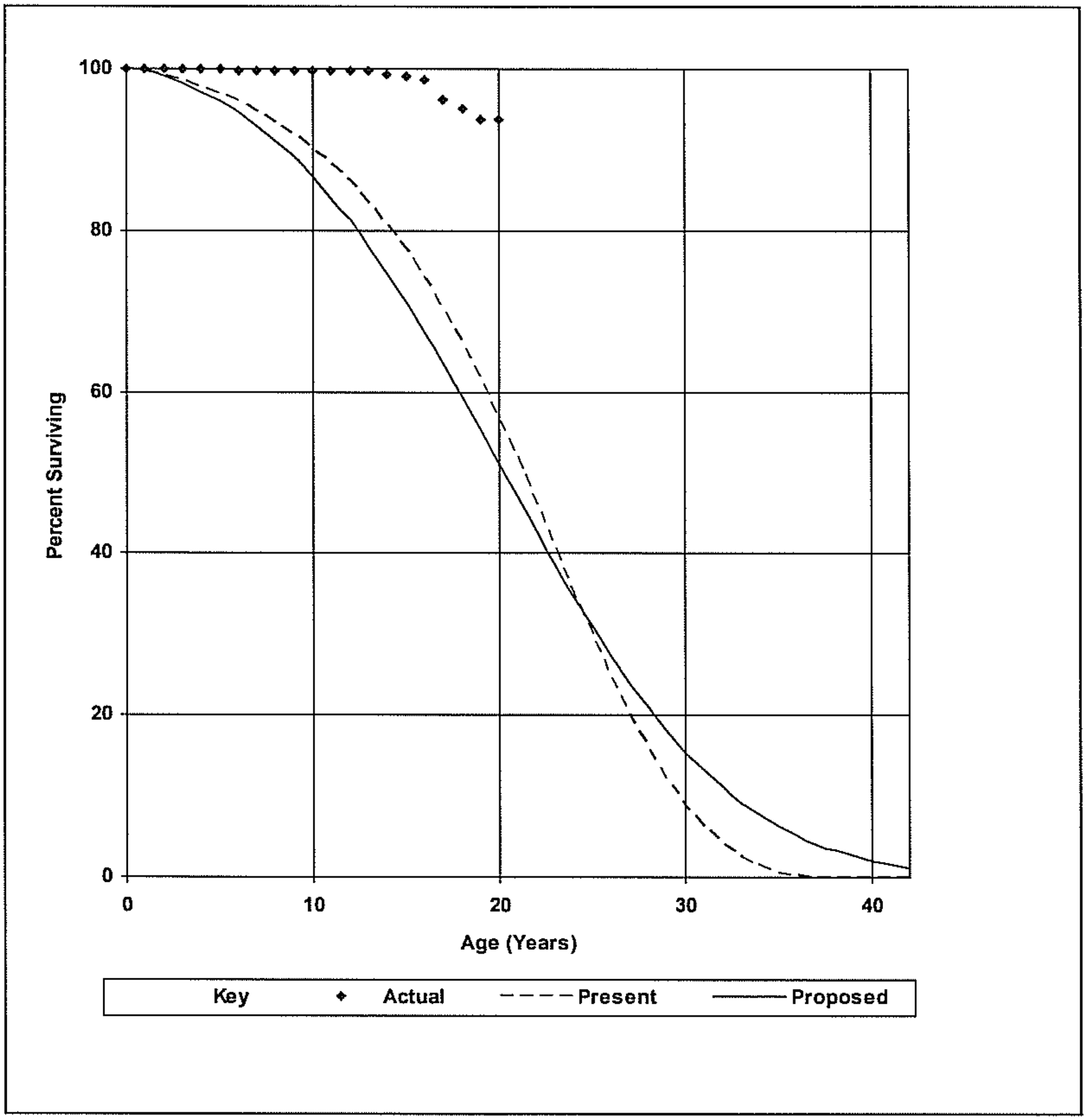
Account: 353.55 Station Equipment - EMS RTU

T-Cut: None

Placement Band: 1989-2008

Observation Band: 1996-2008

Present and Proposed Projection Life Curves **Present: 20.0-R2** **Proposed: 20.0-H2**



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

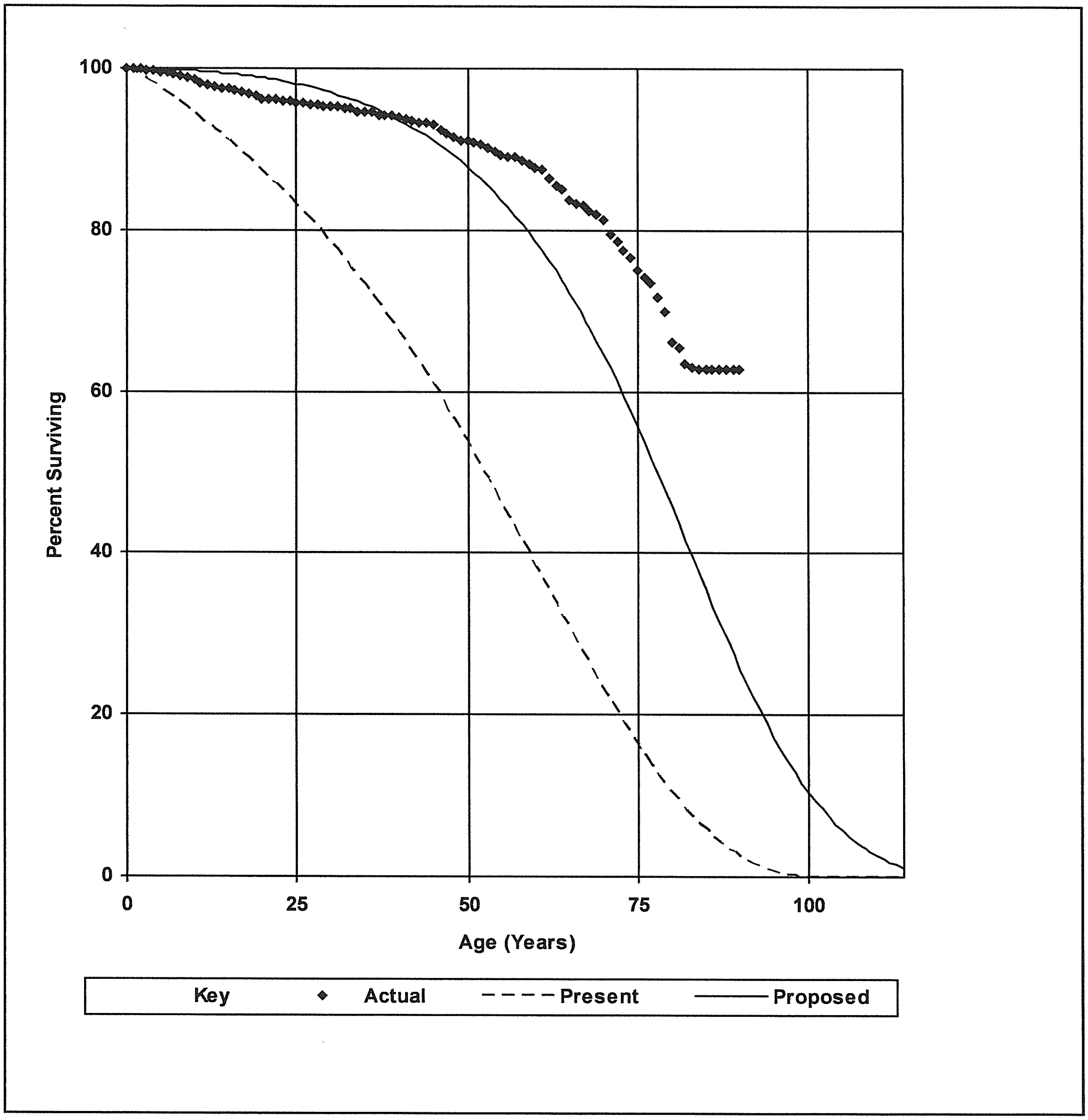
Account: 358.00 Underground Conductors and Devices

T-Cut: None

Placement Band: 1919-2008

Observation Band: 1996-2008

Present and Proposed Projection Life Curves **Present: 50.0-R1** **Proposed: 75.0-R3**



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

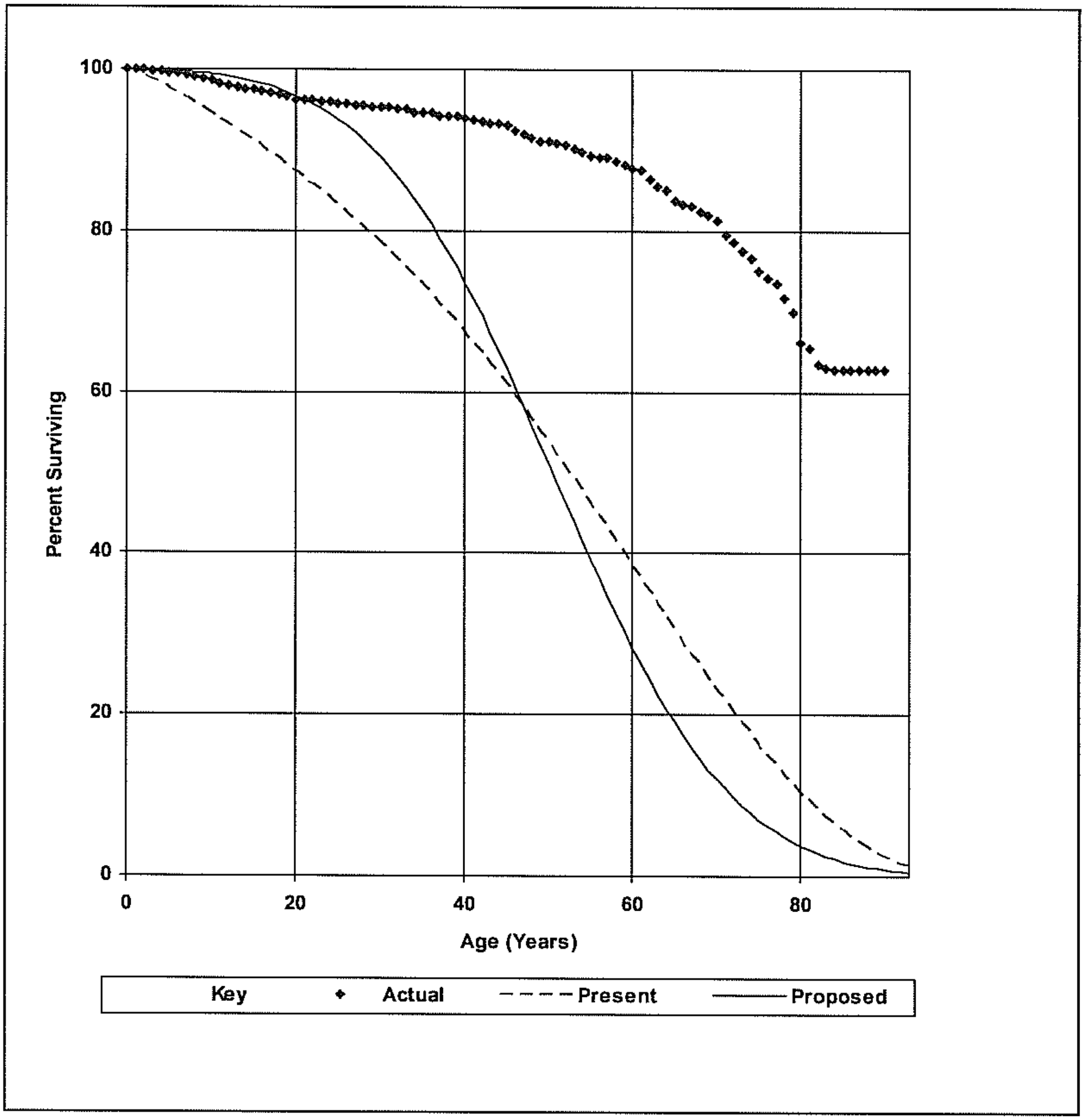
Account: 358.00 Underground Conductors and Devices

T-Cut: None

Placement Band: 1919-2008

Observation Band: 1996-2008

Present and Proposed Projection Life Curves Present: 50.0-R1 Proposed: 50.0-H3



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

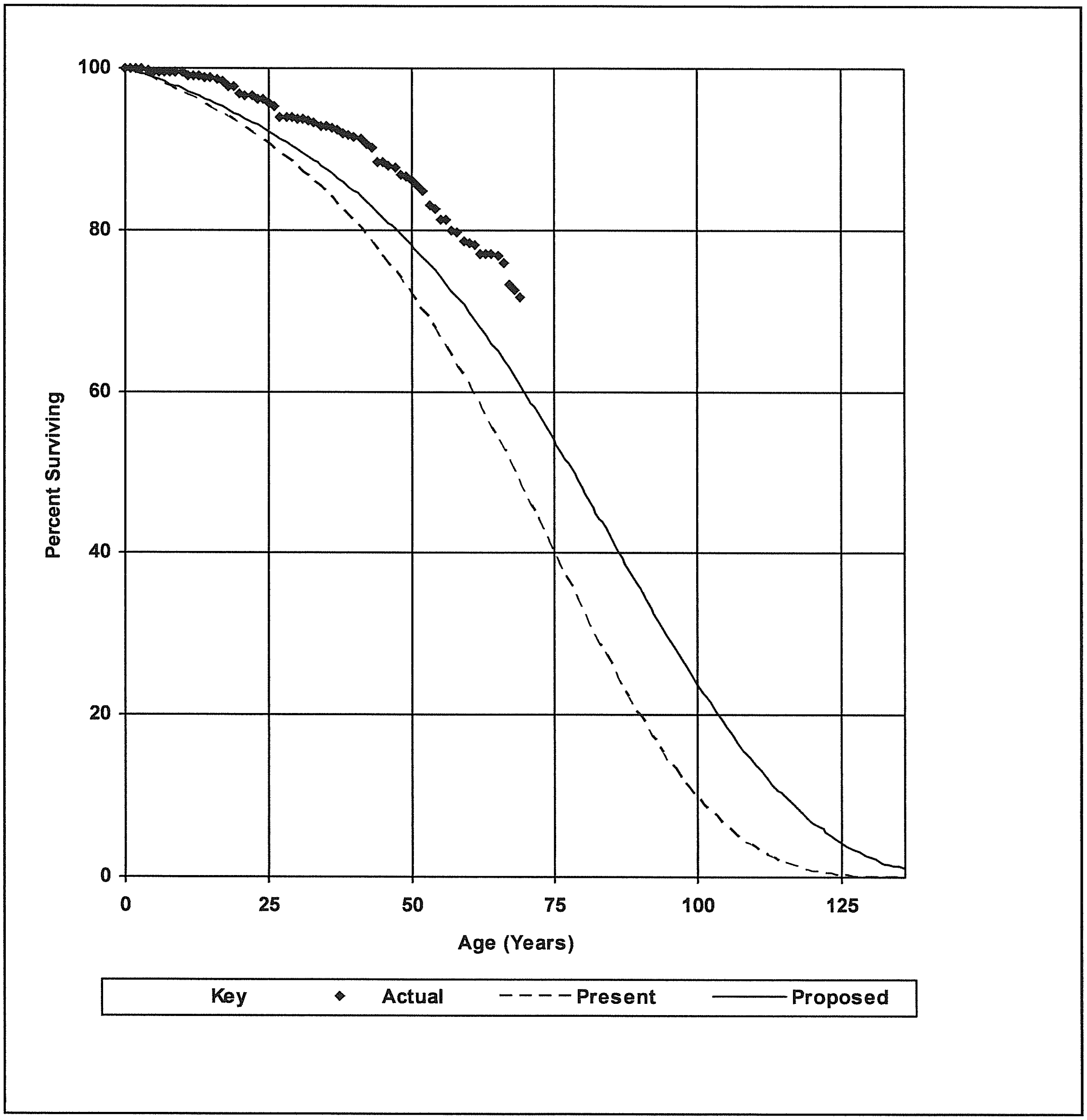
Account: 361.00 Structures and Improvements

T-Cut: None

Placement Band: 1940-2008

Observation Band: 1996-2008

Present and Proposed Projection Life Curves **Present: 65.0-R1.5** **Proposed: 75.0-R1.5**



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

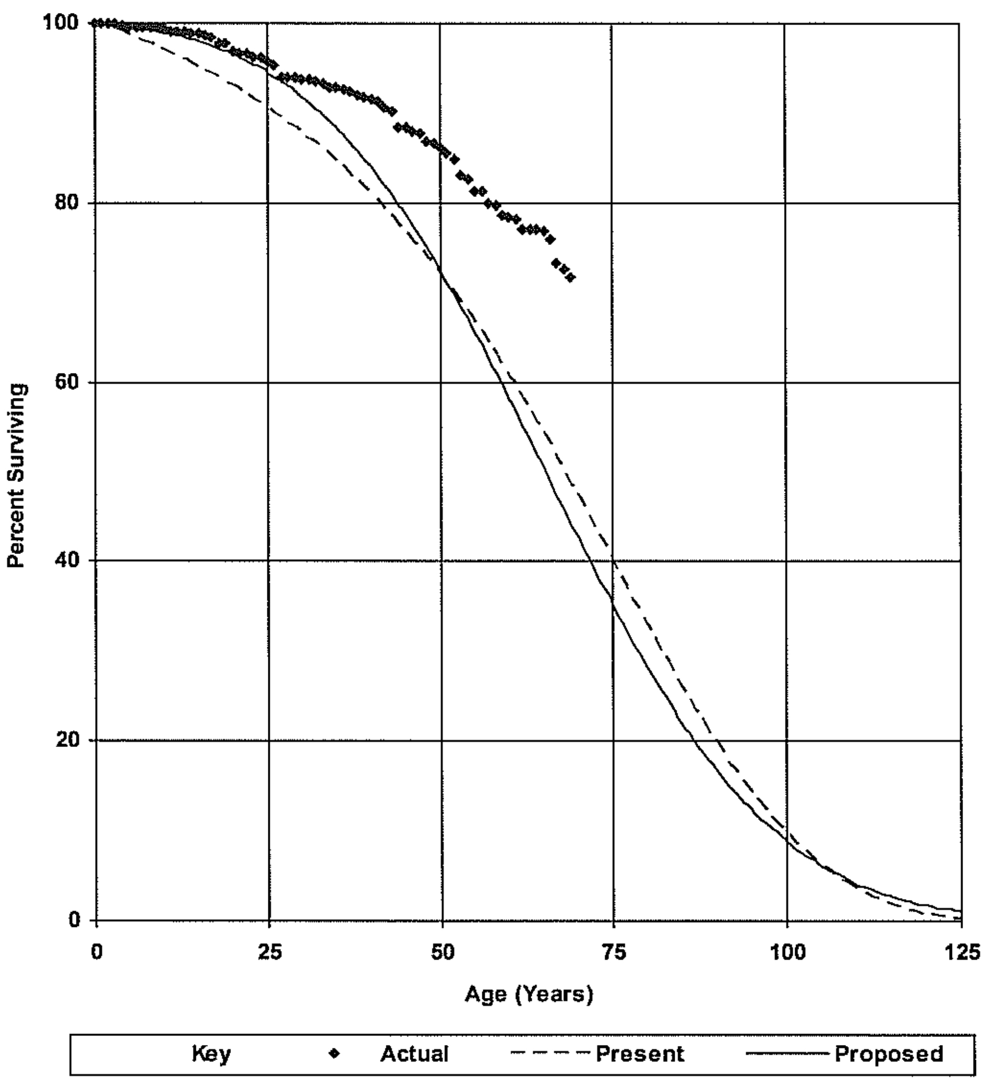
Account: 361.00 Structures and Improvements

T-Cut: None

Placement Band: 1940-2008

Observation Band: 1996-2008

Present and Proposed Projection Life Curves Present: 65.0-R1.5 Proposed: 65.0-H2.5



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

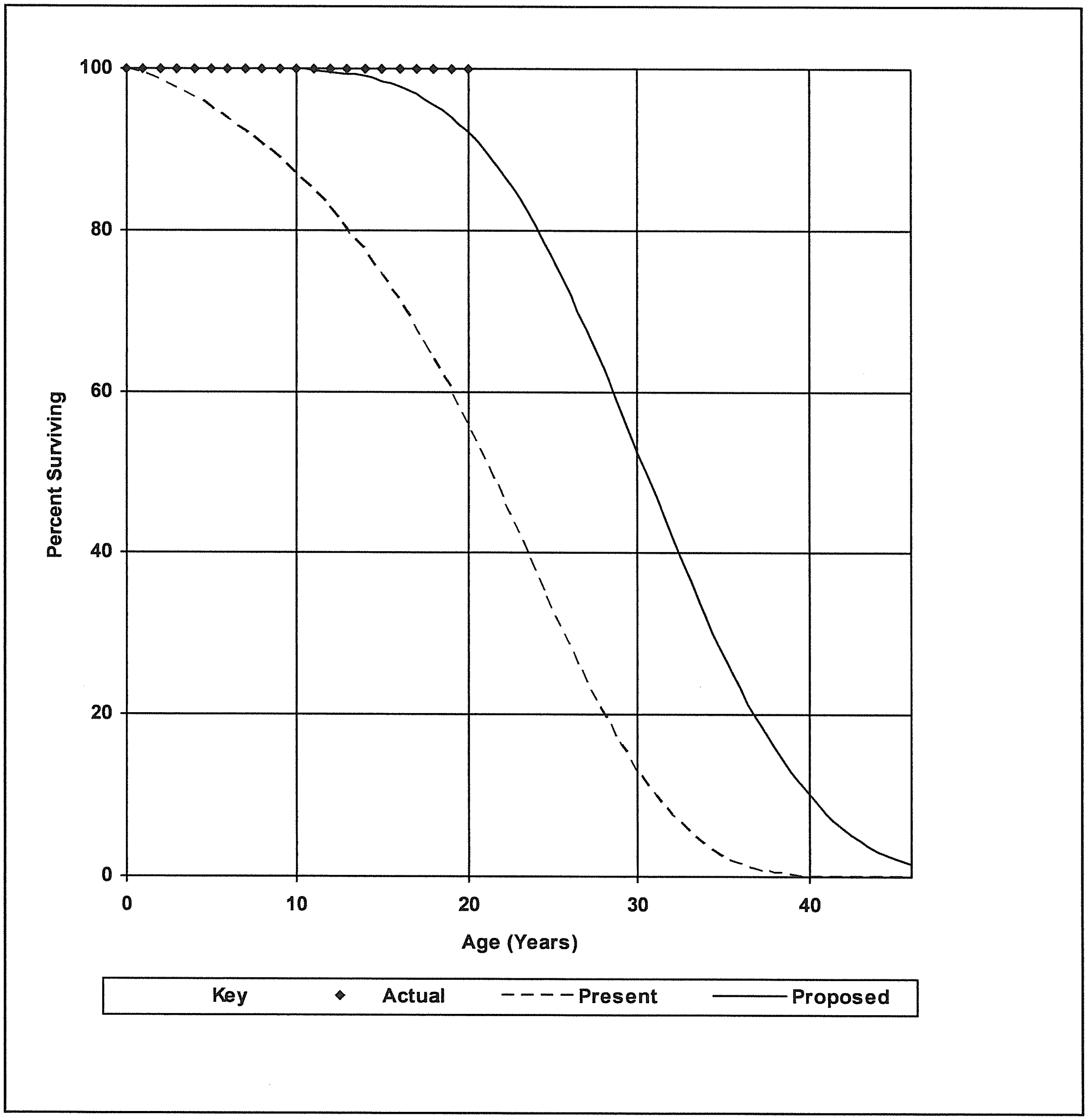
Account: 362.55 Station Equipnent - EMS RTU

T-Cut: None

Placement Band: 1989-2007

Observation Band: 1996-2008

Present and Proposed Projection Life Curves **Present: 20.0-R1.5** **Proposed: 30.0-S3**



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

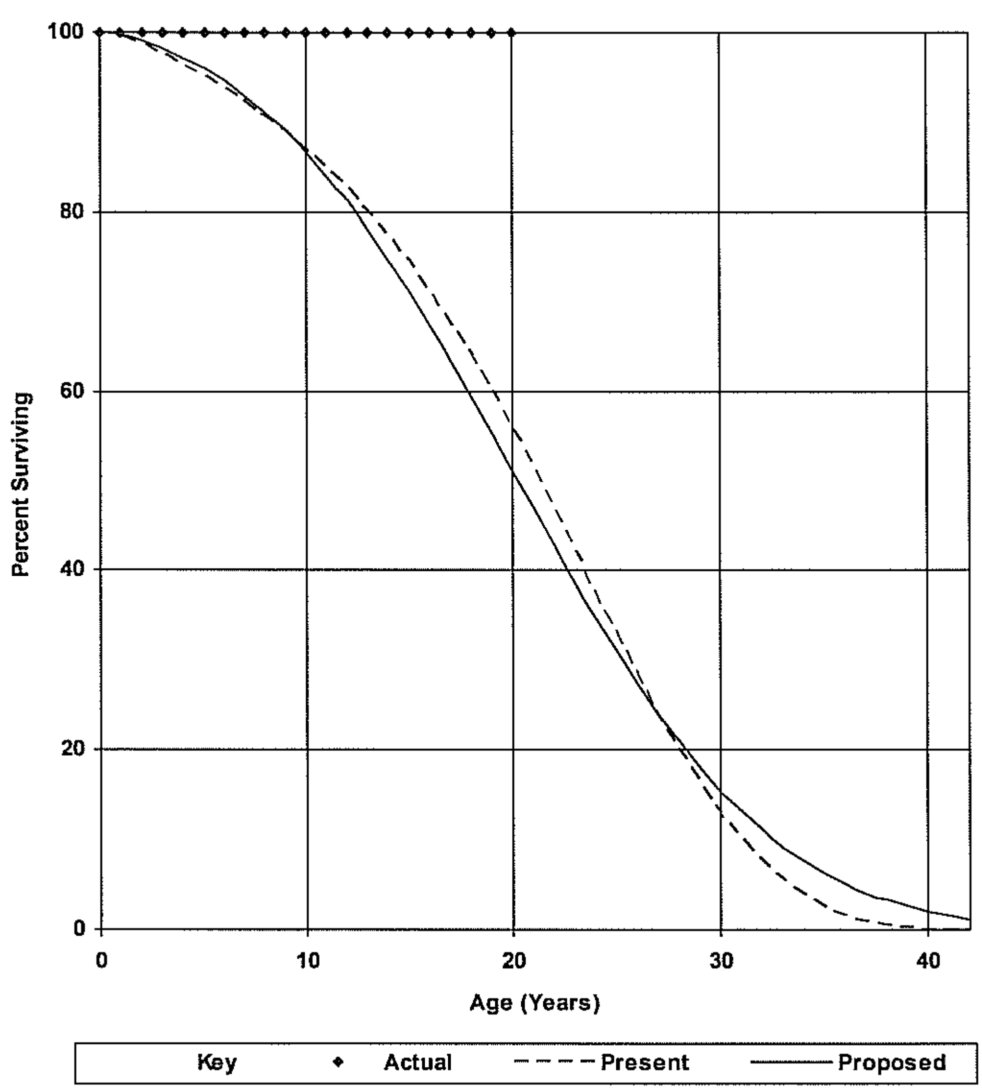
Account: 362.55 Station Equipnent - EMS RTU

T-Cut: None

Placement Band: 1989-2007

Observation Band: 1996-2008

Present and Proposed Projection Life Curves **Present: 20.0-R1.5** **Proposed: 20.0-H2**



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

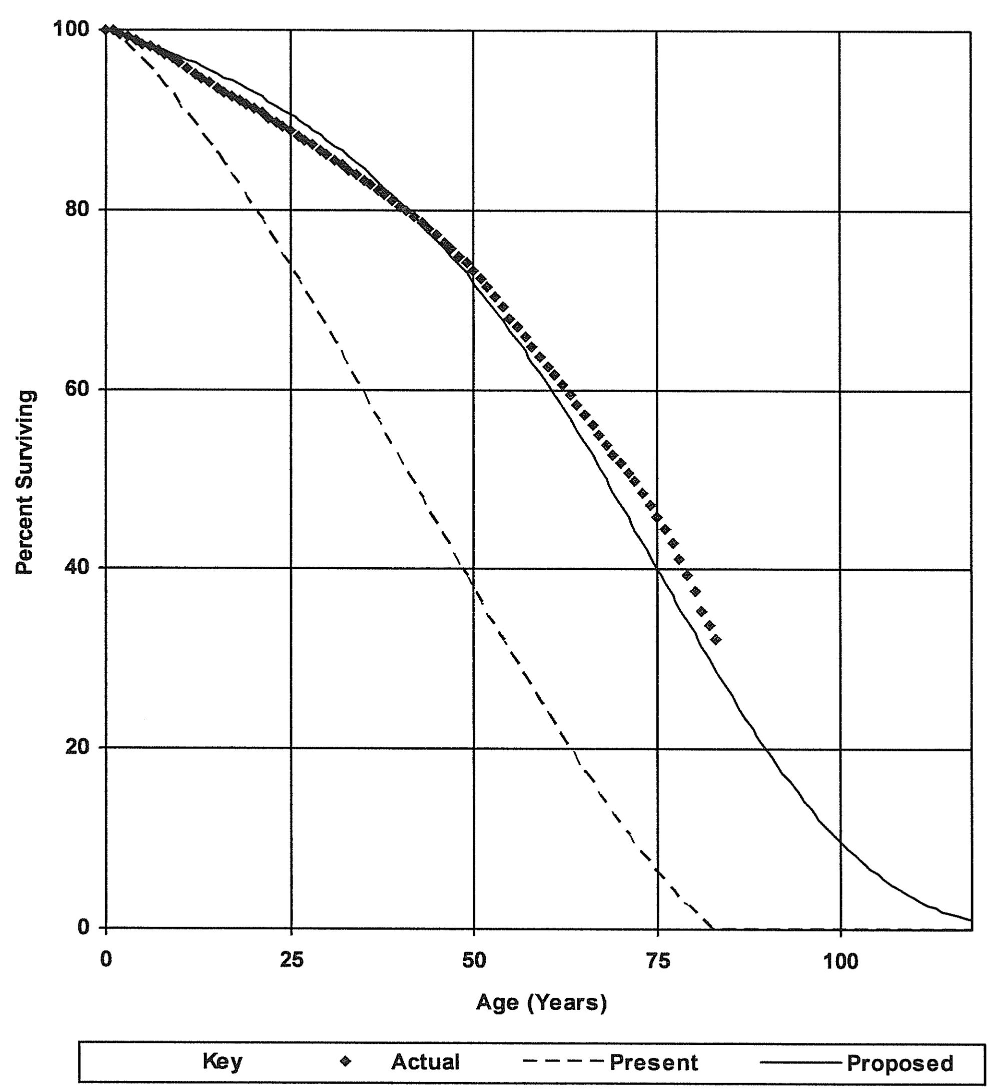
Account: 364.00 Poles, Towers and Fixtures

T-Cut: None

Placement Band: 1926-2008

Observation Band: 1996-2008

Present and Proposed Projection Life Curves **Present: 41.0-S-.5** **Proposed: 65.0-R1.5**

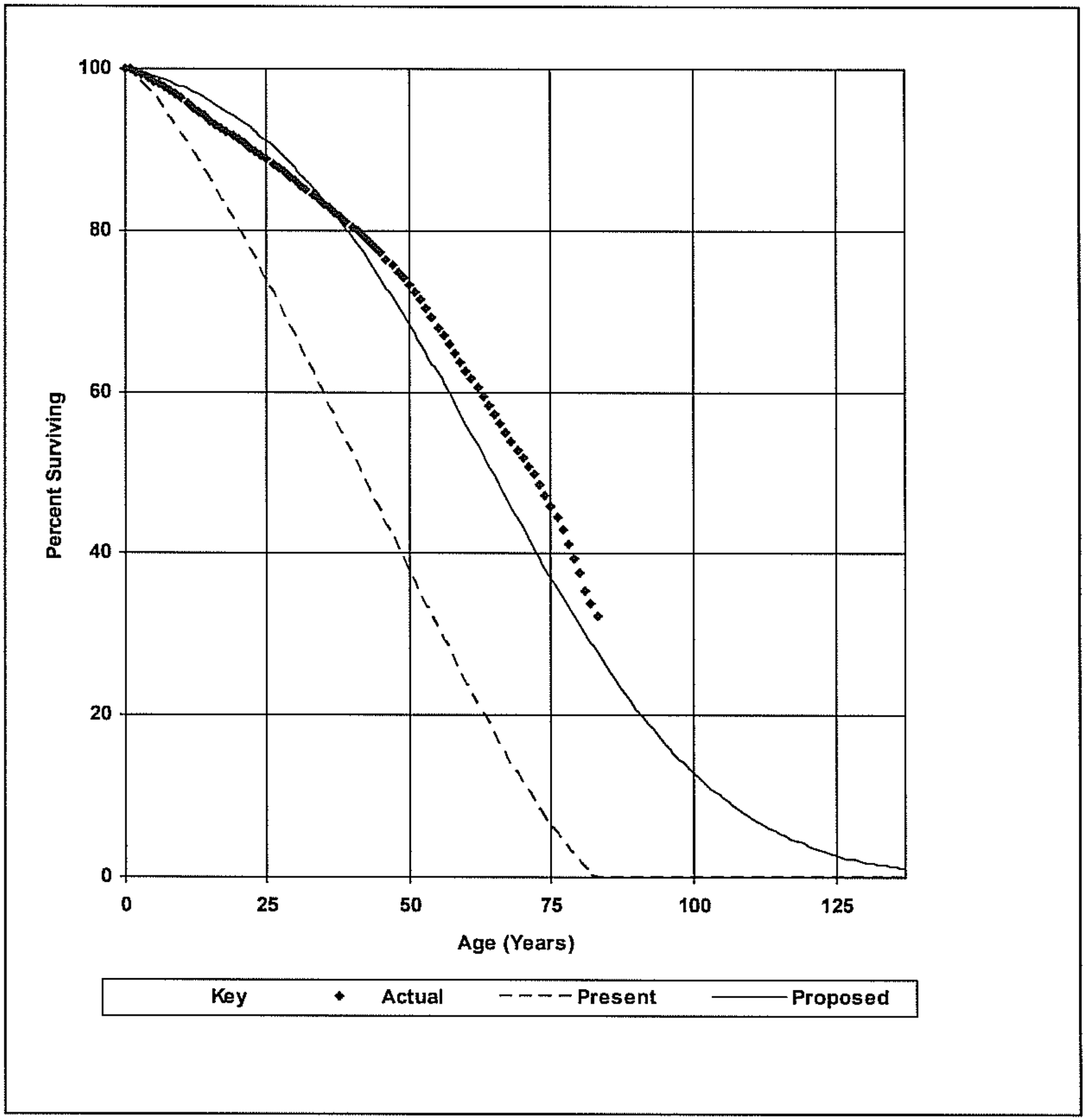


Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC
Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

T-Cut: None
Placement Band: 1926-2008
Observation Band: 1996-2008

Present and Proposed Projection Life Curves **Present: 41.0-S-.5** **Proposed: 65.0-H2**



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

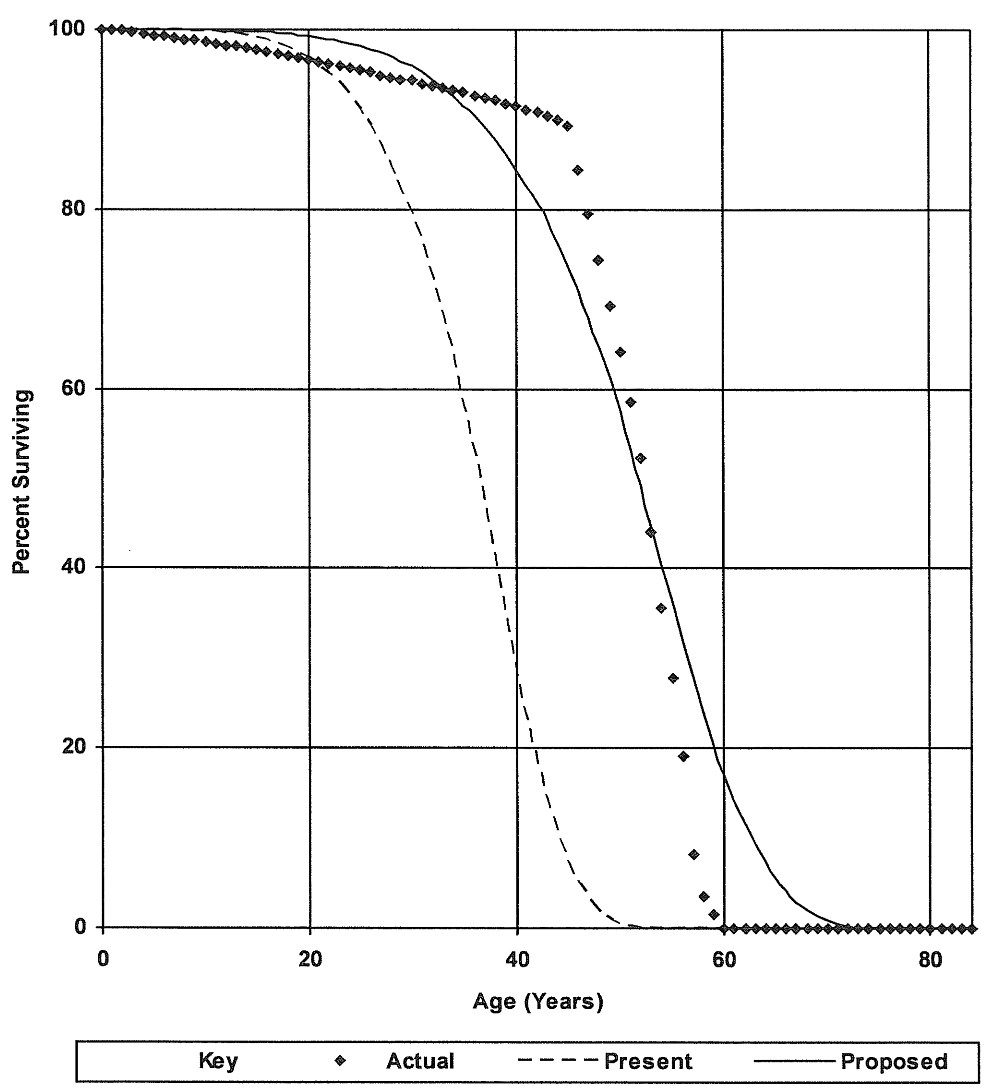
Account: 365.00 Overhead Conductors and Devices

T-Cut: None

Placement Band: 1925-2008

Observation Band: 1996-2008

Present and Proposed Projection Life Curves **Present: 35.0-R4** **Proposed: 50.0-R4**



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

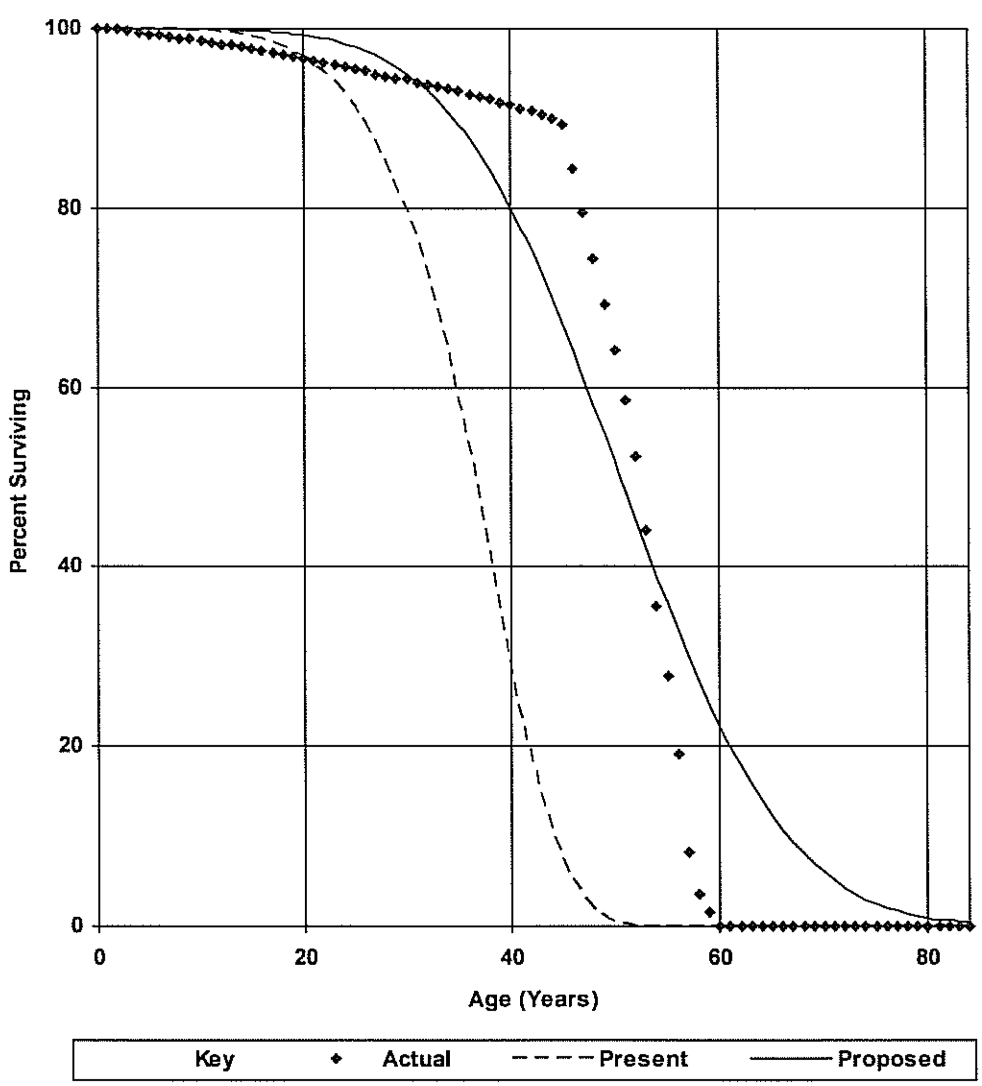
Account: 365.00 Overhead Conductors and Devices

T-Cut: None

Placement Band: 1925-2008

Observation Band: 1996-2008

Present and Proposed Projection Life Curves **Present: 35.0-R4** **Proposed: 50.0-H4**



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

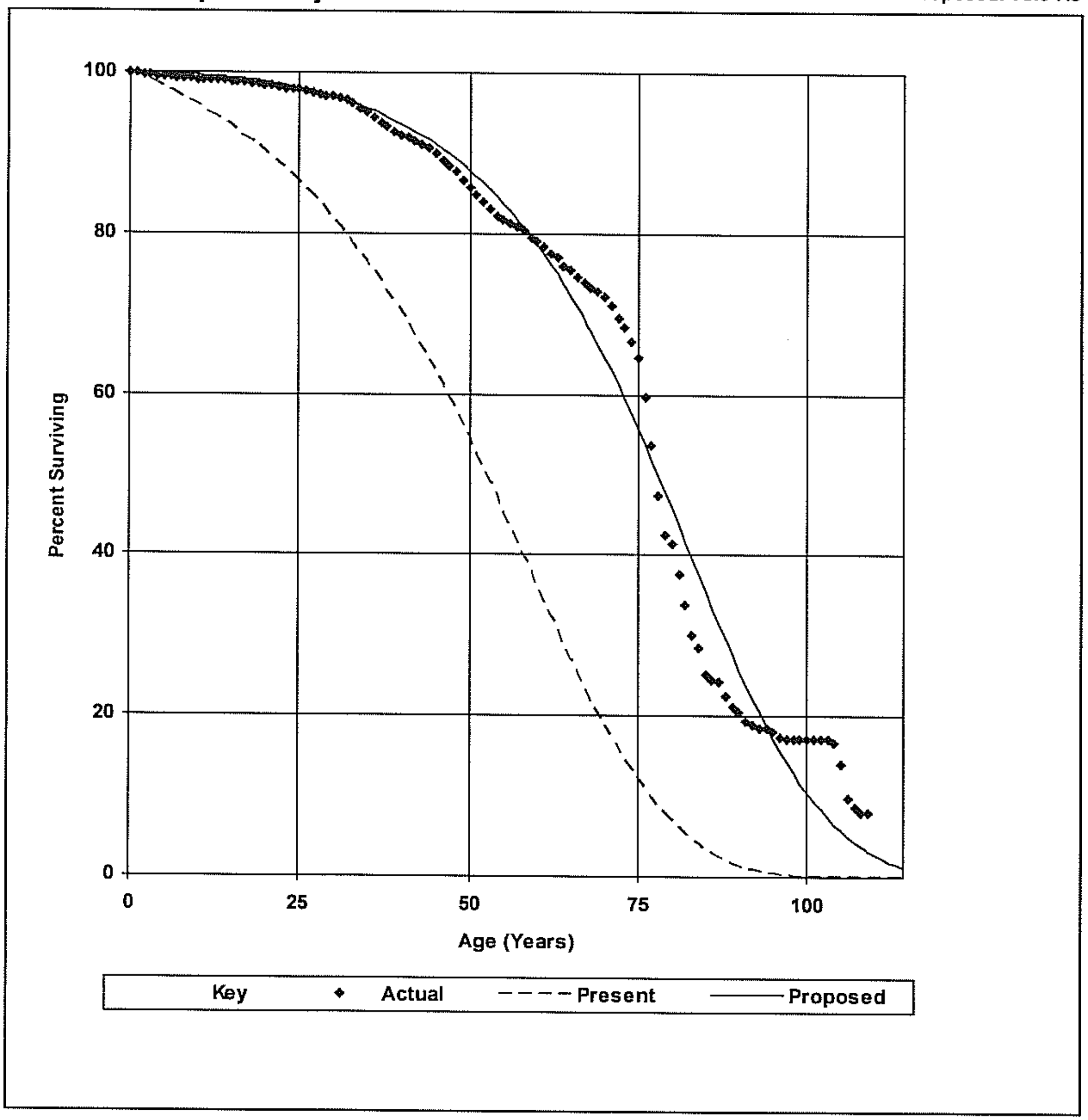
Account: 367.10 Underground Conductors and Devices

T-Cut: None

Placement Band: 1900-2008

Observation Band: 1996-2008

Present and Proposed Projection Life Curves **Present: 50.0-R1.5** **Proposed: 75.0-R3**



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

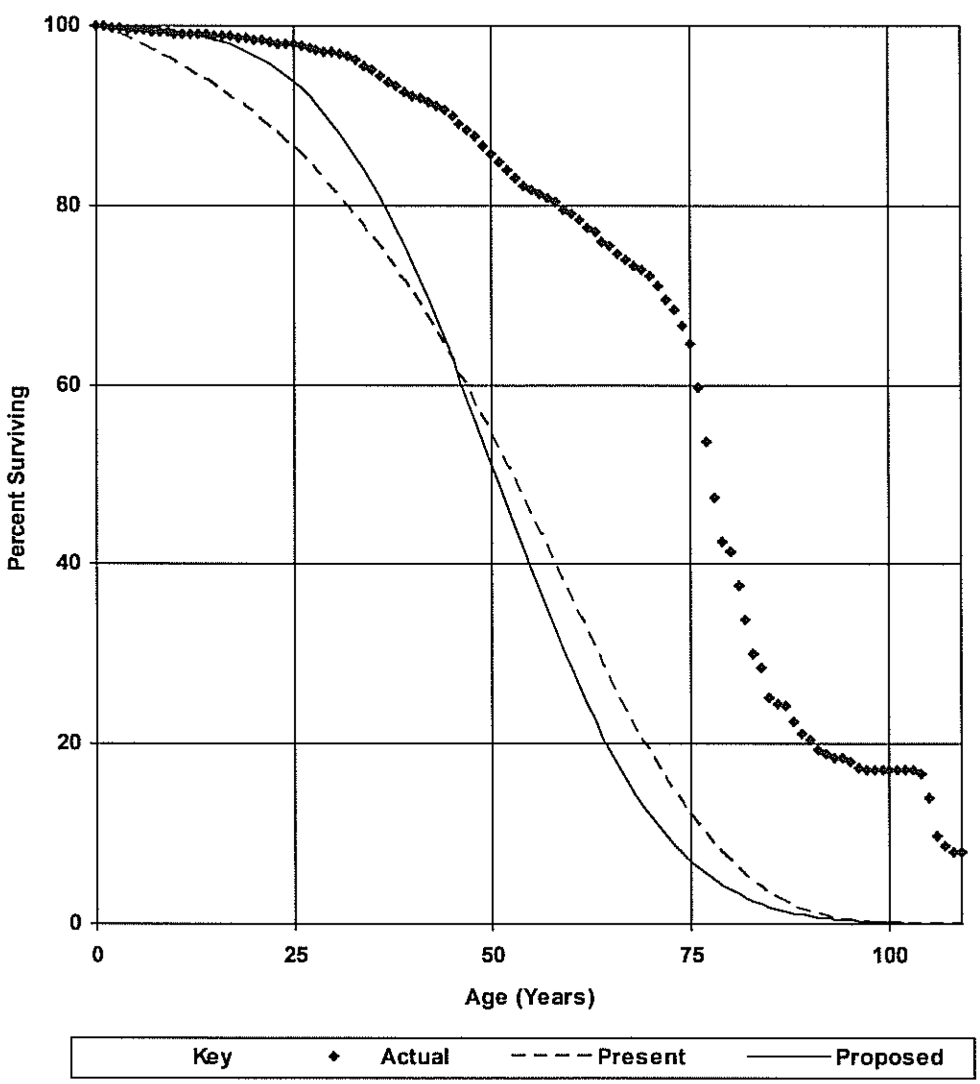
Account: 367.10 Underground Conductors and Devices

T-Cut: None

Placement Band: 1900-2008

Observation Band: 1996-2008

Present and Proposed Projection Life Curves **Present: 50.0-R1.5** **Proposed: 50.0-H3**



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

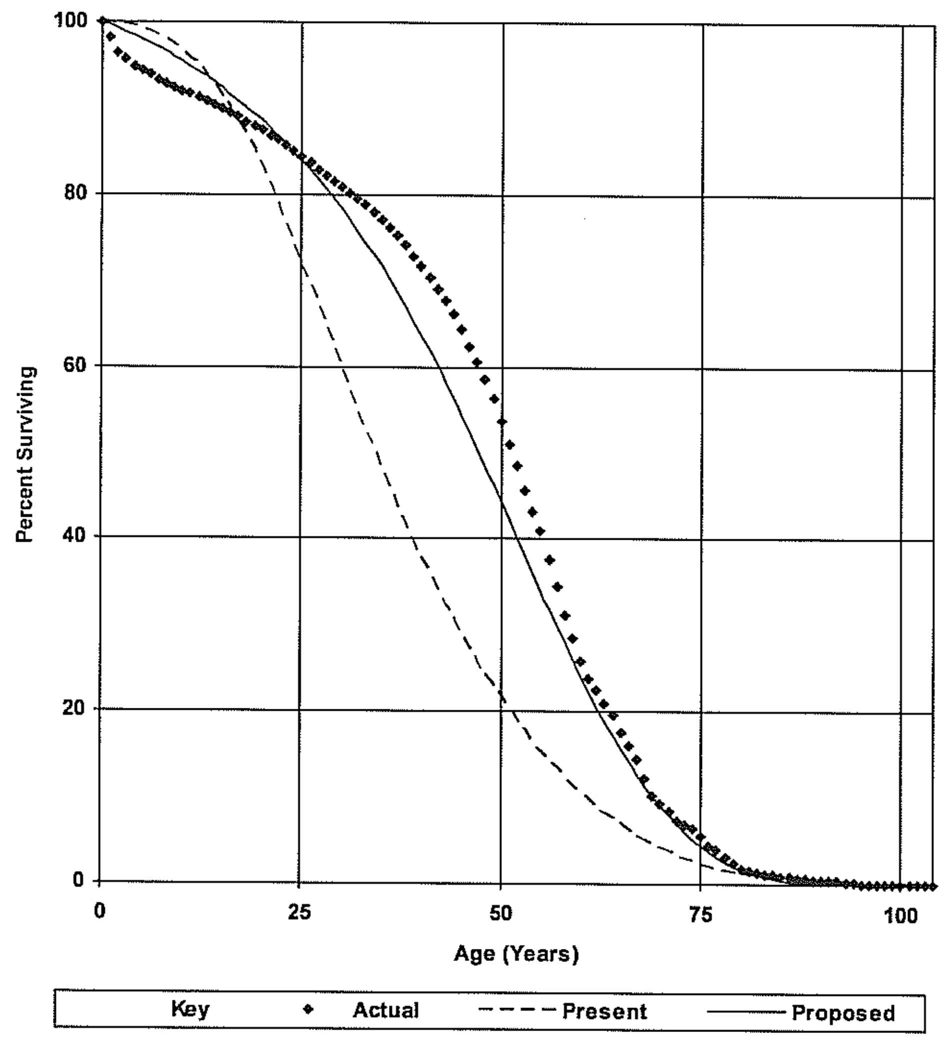
Account: 368.30 Line Transformers - Install Cost

T-Cut: None

Placement Band: 1901-2008

Observation Band: 1996-2008

Present and Proposed Projection Life Curves **Present: 36.0-L1.5** **Proposed: 45.0-R1.5**



Schedule E

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

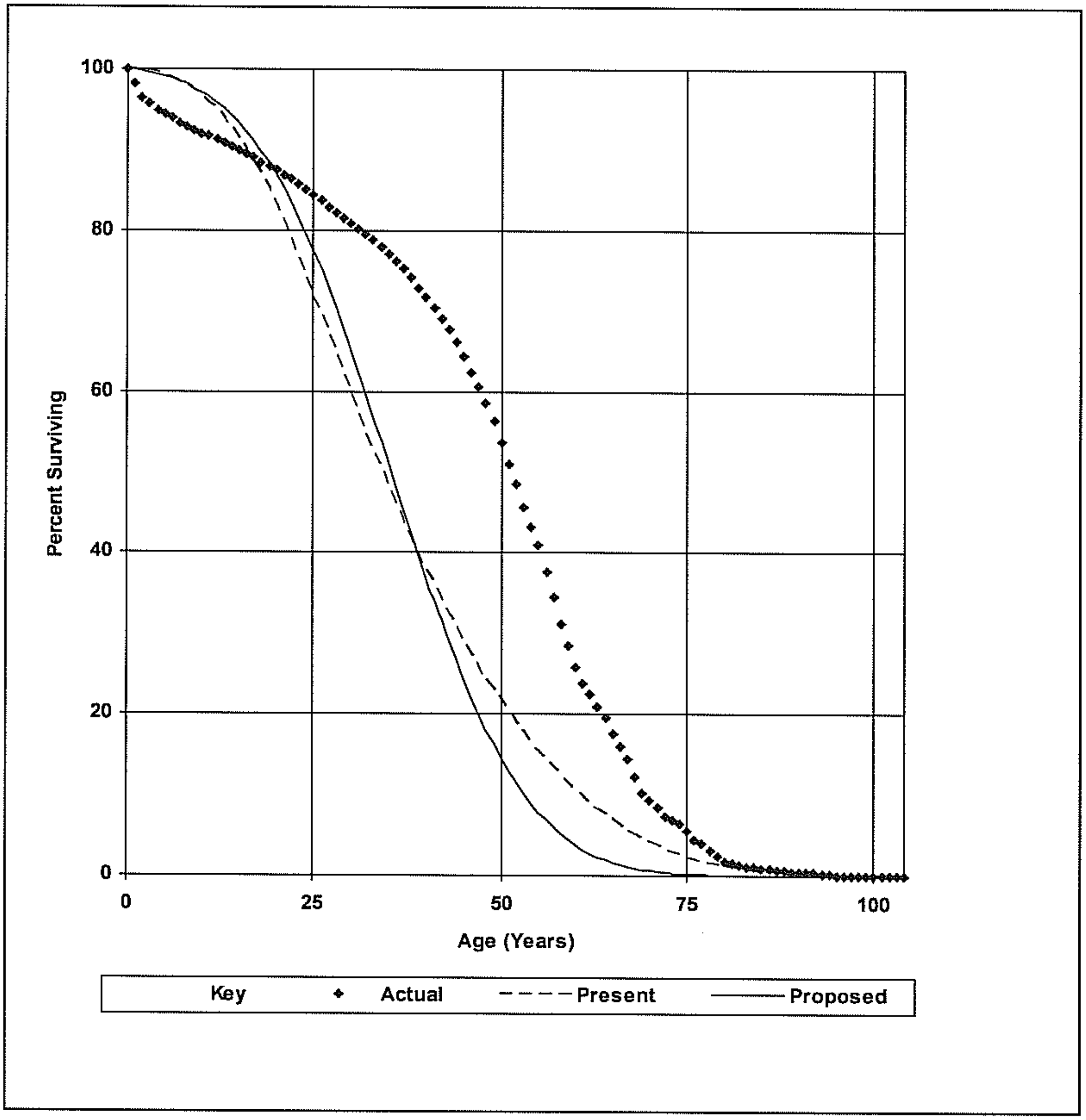
Account: 368.30 Line Transformers - Install Cost

T-Cut: None

Placement Band: 1901-2008

Observation Band: 1996-2008

Present and Proposed Projection Life Curves **Present: 36.0-L1.5** **Proposed: 35.0-H2.5**



National Grid
Niagara Mohawk Power Corporation
Case 10-E-0050

Key:
Same as company
Different than Company

Staff - Average Life and Curve Comparison

		Current		Company Proposed		Staff Proposed	
Acct. #	Acct Name	Average Life	Curve	Average Life	Curve	Average Life	Curve
	Transmission Plant						
350.40	Land Rights - Transmission Lines	75.00	R3	75.00	H5	75.00	H5
352.00	Structures and Improvements	65.00	R1.5	65.00	H3	65.00	H3
353.01	Substation Equipment	58.00	R2	45.00	H0.5	45.00	H0.5
353.55	Substation Equipment - EMS RTU	20.00	R2	20.00	H2	30.00	S3
354.00	Towers and Fixtures	68.00	R3	70.00	H4	70.00	H4
355.00	Poles and Fixtures	55.00	S2	65.00	H4	65.00	H4
356.01	Overhead Conductors and Device	60.00	R2.5	75.00	H2	75.00	H2
357.01	Underground Conduit	62.00	R4	75.00	H4	75.00	H4
358.00	Underground Conductors and Devices	50.00	R1	50.00	H3	75.00	R3
359.00	Roads and Trails	75.00	R3	75.00	H4	75.00	H4
	Distribution Plant						
360.01	Land Rights	55.00	R2	75.00	H5	75.00	H5
361.00	Structures and Improvements	65.00	R1.5	65.00	H2.5	75.00	R1.5
362.01	Station Equipment	52.00	R1.5	60.00	H2	60.00	H2
362.55	Station Equipment - EMS RTU	20.00	R1.5	20.00	H2	30.00	S3
364.00	Poles, Towers and Fixtures	41.00	S-0.5	65.00	H2	65.00	R1.5
365.00	Overhead Conductors and Devices	35.00	R4	50.00	H4	50.00	R4
366.01	Underground Conduit	70.00	R1.5	75.00	H4	75.00	H4
367.10	Underground Conductors and Devices	50.00	R1.5	50.00	H3	75.00	R3
368.01	Line Transformers - Bare Cost	36.00	L1.5	35.00	H0.5	45.00	H0.5
368.30	Line Transformers - Install Cost	36.00	L1.5	35.00	H2.5	45.00	R1.5
369.10	Overhead Services	40.00	R2	50.00	H4	50.00	H4
369.20	Underground Services - Conduit	50.00	R1	75.00	H4	75.00	H4
369.21	Underground Services - Cable	42.00	R1.5	75.00	H2.5	75.00	H2.5
370.10	Small Meters - Bare Cost	32.00	S1.5	20.00	H0.5	20.00	H0.5
370.20	Small Meters - Install Cost	36.00	S1.5	20.00	H0.5	20.00	H0.5
370.30	Large Meters - Bare Cost	36.00	R3	20.00	H3	20.00	H3
370.35	Large Meters - Install Cost	36.00	S1.5	20.00	H3	20.00	H3
371.00	Installations on Customers' Premises	15.00	SC	40.00	H1.5	40.00	H1.5
373.10	Overhead Street Lighting	30.00	L0.5	50.00	H1.5	50.00	H1.5
373.20	Underground Street Lighting	30.00	L0.5	70.00	H1	70.00	H1
	General Plant						
390.00	Structures and Improvements	55.00	R3	55.00	H0.5	55.00	H0.5
	Amortizable						
391.01	Office Furniture and Equipment	42.00	R2.5	22.00	SQ	22.00	SQ
391.20	Office Data Processing Equipment	5.00	R3	5.00	SQ	5.00	SQ
393.00	Stores Equipment	40.00	L1.5	22.00	SQ	22.00	SQ
394.01	Tools, Shop and Garage Equipment	34.00	L0	22.00	SQ	22.00	SQ
395.01	Laboratory Equipment	40.00	L1.5	22.00	SQ	22.00	SQ
397.01	Communication Equip. - Radio	20.00	L1	22.00	SQ	22.00	SQ
397.02	Communication Equip. - Telephone	8.00	S2	8.00	SQ	8.00	SQ
397.50	Communication Equip. - Network NY	15.00	L1	22.00	SQ	22.00	SQ
397.60	Communication Equip. - Network Site NY	15.00	L1	22.00	SQ	22.00	SQ
398.01	Miscellaneous Equipment	10.00	L0	22.00	SQ	22.00	SQ

National Grid
Niagara Mohawk Power Corporation
Case 10-E-0050

Staff - Salvage Rate Comparison

Acct. #	**Electric** Acct Name	Current Salvage Rate	Company Proposed Salvage Rate	Staff Proposed Salvage Rate
	Transmission Plant			
350.40	Land Rights - Transmission Lines	0.0%	0.5%	1.0%
352.00	Structures and Improvements	-25.0%	-33.1%	-35.0%
353.01	Substation Equipment	-10.0%	-13.6%	-10.0%
353.55	Substation Equipment - EMS RTU	0.0%	-0.1%	-2.0%
354.00	Towers and Fixtures	0.0%	-31.2%	-20.0%
355.00	Poles and Fixtures	-5.0%	-36.6%	-30.0%
356.01	Overhead Conductors and Device	5.0%	-50.8%	-20.0%
357.01	Underground Conduit	-25.0%	0.0%	0.0%
358.00	Underground Conductors and Devices	30.0%	-11.8%	-12.0%
359.00	Roads and Trails	0.0%	0.0%	0.0%
	Distribution Plant			
360.01	Land Rights	0.0%	0.0%	0.0%
361.00	Structures and Improvements	-50.0%	-32.1%	-25.0%
362.01	Station Equipment	-10.0%	-15.5%	-10.0%
362.55	Station Equipment - EMS RTU	0.0%	-0.1%	1.0%
364.00	Poles, Towers and Fixtures	-25.0%	-40.9%	-5.0%
365.00	Overhead Conductors and Devices	-30.0%	-102.3%	-25.0%
366.01	Underground Conduit	-20.0%	-1.5%	-10.0%
367.10	Underground Conductors and Devices	10.0%	-10.9%	-15.0%
368.01	Line Transformers - Bare Cost	-15.0%	-2.6%	-20.0%
368.30	Line Transformers - Install Cost	-15.0%	-24.5%	-20.0%
369.10	Overhead Services	-60.0%	-77.2%	-30.0%
369.20	Underground Services - Conduit	-10.0%	-5.0%	-1.0%
369.21	Underground Services - Cable	20.0%	-24.3%	-5.0%
370.10	Small Meters - Bare Cost	0.0%	0.5%	-25.0%
370.20	Small Meters - Install Cost	0.0%	-17.8%	-25.0%
370.30	Large Meters - Bare Cost	0.0%	0.0%	-1.0%
370.35	Large Meters - Install Cost	0.0%	-19.9%	-1.0%
371.00	Installations on Customers' Premises	-10.0%	-33.4%	-40.0%
373.10	Overhead Street Lighting	-10.0%	-53.6%	-30.0%
373.20	Underground Street Lighting	-10.0%	-24.8%	-30.0%
	General Plant			
390.00	Structures and Improvements	-5.0%	-3.2%	-10.0%
	Amortizable			
391.01	Office Furniture and Equipment	0.0%	0.0%	0.0%
391.20	Office Data Processing Equipment	0.0%	0.0%	0.0%
393.00	Stores Equipment	0.0%	0.0%	0.0%
394.01	Tools, Shop and Garage Equipment	0.0%	0.0%	0.0%
395.01	Laboratory Equipment	0.0%	0.0%	0.0%
397.01	Communication Equip. - Radio	0.0%	0.0%	0.0%
397.02	Communication Equip. - Telephone	0.0%	0.0%	0.0%
397.50	Communication Equip. - Network NY	0.0%	0.0%	0.0%
397.60	Communication Equip. - Network Site NY	0.0%	0.0%	0.0%
398.01	Miscellaneous Equipment	0.0%	0.0%	0.0%

National Grid
Niagara Mohawk Power Corporation
Case 10-E-0050

Staff - Depreciation Rate Comparison

Acct. #	Acct Name	Current Rate	Company Proposed Rate	Staff Proposed Rate
	Electric Plant			
	Transmission			
350.40	Land Rights - Transmission Lines	1.33%	1.33%	1.32%
352.00	Structures and Improvements	1.92%	2.05%	2.08%
353.01	Substation Equipment	1.90%	2.52%	2.44%
353.55	Substation Equipment - EMS RTU	5.00%	5.01%	3.40%
354.00	Towers and Fixtures	1.47%	1.87%	1.71%
355.00	Poles and Fixtures	1.91%	2.10%	2.00%
356.01	Overhead Conductors and Device	1.51%	2.01%	1.60%
357.01	Underground Conduit	2.02%	1.33%	1.33%
358.00	Underground Conductors and Devices	1.40%	2.24%	1.49%
359.00	Roads and Trails	1.33%	1.33%	1.33%
	Distribution			
360.01	Land Rights	1.82%	1.33%	1.33%
361.00	Structures and Improvements	2.31%	2.03%	1.67%
362.01	Station Equipment	2.12%	1.93%	1.83%
362.55	Station Equipment - EMS RTU	5.00%	5.00%	3.30%
364.00	Poles, Towers and Fixtures	2.97%	2.17%	1.62%
365.00	Overhead Conductors and Devices	3.71%	4.05%	2.50%
366.01	Underground Conduit	1.71%	1.35%	1.47%
367.10	Underground Conductors and Devices	1.80%	2.22%	1.53%
368.01	Line Transformers - Bare Cost	3.19%	2.93%	2.67%
368.30	Line Transformers - Install Cost	3.19%	3.56%	2.67%
369.10	Overhead Services	4.00%	3.54%	2.60%
369.20	Underground Services - Conduit	2.20%	1.40%	1.35%
369.21	Underground Services - Cable	1.90%	1.66%	1.40%
370.10	Small Meters - Bare Cost	3.13%	4.98%	6.25%
370.20	Small Meters - Install Cost	2.78%	5.89%	6.25%
370.30	Large Meters - Bare Cost	2.78%	5.00%	5.05%
370.35	Large Meters - Install Cost	2.78%	6.00%	5.05%
371.00	Installations on Customers' Premises	7.33%	3.34%	3.50%
373.10	Overhead Street Lighting	3.80%	3.07%	2.60%
373.20	Underground Street Lighting	3.80%	1.78%	1.86%
	General			
390.00	Structures and Improvements	1.91%	1.88%	2.00%
	Amortizable*			
391.01	Office Furniture and Equipment	2.74%	4.55%	4.55%
391.20	Office Data Processing Equipment	20.00%	17.74%	17.74%
393.00	Stores Equipment	2.50%	4.55%	4.55%
394.01	Tools, Shop and Garage Equipment	2.96%	4.54%	4.54%
395.01	Laboratory Equipment	2.50%	4.55%	4.55%
397.01	Communication Equip. - Radio	5.00%	4.52%	4.52%
397.02	Communication Equip. - Telephone	12.50%	0.21%	0.21%
397.50	Communication Equip. - Network NY	6.67%	4.55%	4.55%
397.60	Communication Equip. - Network Site NY	6.67%	4.55%	4.55%
398.01	Miscellaneous Equipment	8.81%	4.54%	4.54%

National Grid
Niagara Mohawk Power Corporation
Case 10-E-0050

Staff - Annual Expense Accrual Comparison

Acct. #	Acct Name	12/31/2008 Plant Investment	Current	Company Proposed	Staff Proposed	12/31/2008 Book Reserve	Company Theoretical Reserve	Staff Theoretical Reserve
	Transmission Plant							
350.40	Land Rights - Transmission Lines	$27,123,696	$360,745	$360,745	$358,033	$13,069,807	$12,539,339	$12,601,724
352.00	Structures and Improvements	$31,004,576	$595,288	$635,594	$644,895	$11,287,636	$12,993,484	$13,178,966
353.01	Substation Equipment	$623,806,673	$11,852,327	$15,719,928	$15,220,883	$181,239,442	$131,092,556	$126,938,214
353.55	Substation Equipment - EMS RTU	$42,485,893	$2,124,295	$2,128,543	$1,444,520	$30,807,700	$21,115,383	$20,656,684
354.00	Towers and Fixtures	$133,237,659	$1,958,594	$2,491,544	$2,278,364	$68,330,989	$82,184,034	$75,168,324
355.00	Poles and Fixtures	$365,859,185	$6,987,910	$7,683,043	$7,317,184	$111,143,069	$131,773,473	$125,406,673
356.01	Overhead Conductors and Device	$236,780,774	$3,575,390	$4,759,294	$3,788,492	$77,469,018	$91,799,717	$73,050,173
357.01	Underground Conduit	$29,049,970	$586,809	$386,365	$386,365	$14,222,294	$10,093,896	$10,093,896
358.00	Underground Conductors and Devices	$102,159,262	$1,430,230	$2,288,367	$1,522,173	$24,750,616	$40,146,220	$29,249,130
359.00	Roads and Trails	$2,348,571	$31,236	$31,236	$31,236	$231,855	$253,019	$253,019
	Total Transmission Plant	$1,593,856,259	$29,502,823	$36,484,659	$32,992,145	$532,552,426	$533,991,121	$486,596,802
	Distribution Plant							
360.01	Land Rights	$10,113,745	$184,070	$134,513	$134,513	$1,323,743	$873,828	$873,828
361.00	Structures and Improvements	$35,412,715	$818,034	$718,878	$591,392	$12,178,825	$12,822,590	$9,518,774
362.01	Station Equipment	$430,797,242	$9,132,902	$8,314,387	$7,883,590	$115,803,129	$107,311,593	$102,201,517
362.55	Station Equipment - EMS RTU	$29,492,793	$1,474,640	$1,474,640	$973,262	$20,774,597	$14,554,900	-$13,813,736
364.00	Poles, Towers and Fixtures	$788,801,034	$23,427,391	$17,116,982	$12,778,577	$286,517,204	$225,444,190	$165,582,110
365.00	Overhead Conductors and Devices	$875,984,992	$32,499,043	$35,477,392	$21,899,625	$460,447,571	$520,348,225	$643,173,784
366.01	Underground Conduit	$134,517,260	$2,300,245	$1,815,983	$1,977,404	$49,140,823	$41,036,284	$44,472,820
367.10	Underground Conductors and Devices	$415,936,368	$7,486,855	$9,233,787	$6,363,826	$98,539,455	$119,601,088	$86,171,174
368.01	Line Transformers - Bare Cost	$451,751,287	$14,410,866	$13,236,313	$12,061,759	$169,144,375	$76,186,435	$137,569,098
368.30	Line Transformers - Install Cost	$239,904,970	$7,652,969	$8,540,617	$6,405,463	$15,544,011	$84,014,378	$57,151,722
369.10	Overhead Services	$284,680,583	$11,387,223	$10,077,693	$7,401,695	$181,592,696	$170,800,379	$125,305,018
369.20	Underground Services - Conduit	$8,035,024	$176,771	$112,490	$108,473	$3,669,572	$2,726,766	$2,622,889
369.21	Underground Services - Cable	$102,850,405	$1,954,158	$1,707,317	$1,439,906	$24,530,820	$22,708,958	$19,182,949
370.10	Small Meters - Bare Cost	$49,724,890	$1,556,389	$2,476,300	$3,107,806	-$41,088,459	$5,740,490	$7,139,913
370.20	Small Meters - Install Cost	$26,080,597	$725,041	$1,536,147	$1,630,037	-$29,670,856	$4,014,743	$4,260,126
370.30	Large Meters - Bare Cost	$6,871,977	$191,041	$343,599	$347,035	$3,696,845	$1,810,766	$1,828,874
370.35	Large Meters - Install Cost	$28,016,510	$778,859	$1,680,991	$1,414,834	$2,438,144	$10,441,473	$8,795,569
371.00	Installations on Customers' Premises	$8,074,220	$591,840	$269,679	$282,598	$6,216,948	$2,792,521	$2,930,682
373.10	Overhead Street Lighting	$68,539,314	$2,604,494	$2,104,157	$1,782,022	$37,286,469	$23,767,460	$20,115,689
373.20	Underground Street Lighting	$121,233,487	$4,606,873	$2,157,956	$2,254,943	$54,217,646	$20,516,585	$21,371,443
	Total Distribution Plant	$4,116,819,413	$123,959,701	$118,529,820	$90,838,759	$1,472,303,558	$1,467,513,652	$1,446,454,244
	General Plant							
390.00	Structures and Improvements	$89,809,731	$1,715,366	$1,688,423	$1,796,195	$12,912,812	$15,755,044	$16,793,167
	Total General Plant	$89,809,731	$1,715,366	$1,688,423	$1,796,195	$12,912,812	$15,755,044	$16,793,167
	Amortizable							
391.01	Office Furniture and Equipment	$7,409,461	$203,019	$336,790	$336,790	$2,623,489	$4,422,845	$4,422,845
391.20	Office Data Processing Equipment	$2,392,757	$478,551	$424,451	$424,451	$1,317,454	$1,300,386	$1,300,386
393.00	Stores Equipment	$2,143,249	$53,581	$97,419	$97,419	$806,037	$1,397,328	$1,397,328
394.01	Tools, Shop and Garage Equipment	$41,504,502	$1,228,533	$1,884,844	$1,884,844	$12,515,135	$19,426,223	$19,426,223
395.01	Laboratory Equipment	$20,437,793	$510,945	$928,979	$928,979	$5,972,720	$11,315,257	$11,315,257
397.01	Communication Equip. - Radio	$54,408,239	$2,720,412	$2,460,993	$2,460,993	$18,508,540	$18,048,404	$18,048,404
397.02	Communication Equip. - Telephone	$3,443,130	$430,391	$7,100	$7,100	$6,719,466	$3,415,145	$3,415,145
397.50	Communication Equip. - Network NY	$6,824,926	$455,223	$310,220	$310,220	$1,565,296	$1,461,989	$1,461,989
397.60	Communication Equip. - Network Site NY	$11,247,365	$750,199	$511,238	$511,238	$19,536,824	$6,471,582	$6,471,582
398.01	Miscellaneous Equipment	$51,182,084	$4,509,142	$2,325,919	$2,325,919	$95,650,952	$37,389,877	$37,389,877
	Total Amortizable Plant	$200,993,506	$11,339,997	$9,287,953	$9,287,953	$165,215,913	$104,649,036	$104,649,036
	Total General Plant	$290,803,237	$13,055,362	$10,976,376	$11,084,148	$178,128,725	$120,404,080	$121,442,203
	Total Electric Operations	$6,001,478,909	$166,517,887	$165,990,855	$134,915,051	$2,182,984,709	$2,121,908,853	$2,054,493,249

National Grid
Niagara Mohawk Power Corporation
Case 10-E-0050

Staff - Theoretical Reserve Correction

Acct. #	Acct Name	Company computed staff Theoretical reserve	Salvage % Company used		Removal of company salvage	Staff proposed Salvage		Staff Corrected Theoretical Reserve	
	Transmission Plant								
350.40	Land Rights - Transmission Lines	$12,539,339	0.50%	1.01	12,476,954	1.00%	1.01	$12,601,724	-$62,385
352.00	Structures and Improvements	$12,993,484	-33.10%	-1.33	(9,762,197)	-35.00%	-1.35	$13,178,966	-$185,482
353.01	Substation Equipment	$131,092,556	-13.60%	-1.14	(115,398,377)	-10.00%	-1.10	$126,938,214	$4,154,342
353.55	Substation Equipment - EMS RTU	$20,271,903	-0.10%	-1.00	(20,251,651)	-2.00%	-1.02	$20,656,684	-$384,781
354.00	Towers and Fixtures	$82,184,034	-31.20%	-1.31	(62,640,270)	-20.00%	-1.20	$75,168,324	$7,015,710
355.00	Poles and Fixtures	$131,773,473	-36.60%	-1.37	(96,466,671)	-30.00%	-1.30	$125,406,673	$6,366,800
356.01	Overhead Conductors and Device	$91,799,717	-50.80%	-1.51	(60,875,144)	-20.00%	-1.20	$73,050,173	$18,749,544
357.01	Underground Conduit	$10,093,896	0.00%	0.00		0.00%	0.00	$10,093,896	$0
358.00	Underground Conductors and Devices	$29,196,899	-11.80%	-1.12	(26,115,294)	-12.00%	-1.12	$29,249,130	-$52,231
359.00	Roads and Trails	$253,019	0.00%	0.00		0.00%	0.00	$253,019	$0
	Total Transmission Plant	$522,198,320						$486,596,802	$35,601,518
	Distribution Plant								
360.01	Land Rights	$873,828	0.00%	0.00		0.00%	0.00	$873,828	$0
361.00	Structures and Improvements	$10,059,440	-32.10%	-1.32	(7,615,019)	-25.00%	-1.25	$9,518,774	$540,666
362.01	Station Equipment	$107,311,593	-15.50%	-1.16	(92,910,470)	-10.00%	-1.10	$102,201,517	$5,110,076
362.55	Station Equipment - EMS RTU	$13,690,643	-0.10%	-1.00	(13,676,966)	1.00%	1.01	-$13,813,736	$27,504,379
364.00	Poles, Towers and Fixtures	$222,195,422	-40.90%	-1.41	(157,697,248)	-5.00%	-1.05	$165,582,110	$56,613,312
365.00	Overhead Conductors and Devices	$526,373,425	-102.30%	-1.02	(514,539,027)	-25.00%	-1.25	$643,173,784	-$116,800,359
366.01	Underground Conduit	$41,036,284	-1.50%	-1.02	(40,429,836)	-10.00%	-1.10	$44,472,820	-$3,436,536
367.10	Underground Conductors and Devices	$83,098,984	-10.90%	-1.11	(74,931,455)	-15.00%	-1.15	$86,171,174	-$3,072,190
368.01	Line Transformers - Bare Cost	$117,621,579	-2.60%	-1.03	(114,640,915)	-20.00%	-1.20	$137,569,098	-$19,947,519
368.30	Line Transformers - Install Cost	$59,294,912	-24.50%	-1.25	(47,626,435)	-20.00%	-1.20	$57,151,722	$2,143,190
369.10	Overhead Services	$170,800,379	-77.20%	-1.77	(96,388,476)	-30.00%	-1.30	$125,305,018	$45,495,361
369.20	Underground Services - Conduit	$2,726,766	-5.00%	-1.05	(2,596,920)	-1.00%	-1.01	$2,622,889	$103,877
369.21	Underground Services - Cable	$22,708,958	-24.30%	-1.24	(18,269,475)	-5.00%	-1.05	$19,182,949	$3,526,009
370.10	Small Meters - Bare Cost	$5,740,490	0.50%	-1.01	(5,711,930)	-25.00%	-1.25	$7,139,913	-$1,399,423
370.20	Small Meters - Install Cost	$4,014,743	-17.80%	-1.18	(3,408,101)	-25.00%	-1.25	$4,260,126	-$245,383
370.30	Large Meters - Bare Cost	$1,810,766	0.00%	0.00		-1.00%	-0.01	$1,828,874	-$18,108
370.35	Large Meters - Install Cost	$10,441,473	-19.90%	-1.20	(8,708,485)	-1.00%	-1.01	$8,795,569	$1,645,904
371.00	Installations on Customers' Premises	$2,792,521	-33.40%	-1.33	(2,093,344)	-40.00%	-1.40	$2,930,682	-$138,161
373.10	Overhead Street Lighting	$23,767,460	-53.60%	-1.54	(15,473,607)	-30.00%	-1.30	$20,115,689	$3,651,771
373.20	Underground Street Lighting	$20,516,585	-24.80%	-1.25	(16,439,571)	-30.00%	-1.30	$21,371,443	-$854,858
	Total Distribution Plant	$1,446,876,251						$1,446,454,244	$422,007
	General Plant								
390.00	Structures and Improvements	$15,755,044	-3.20%	-1.03	(15,266,516)	-10.00%	-1.10	$16,793,167	-$1,038,123
	Total General Plant	$15,755,044						$16,793,167	-$1,038,123

NATIONAL GRID ELECTRIC DEPRECIATION
SALVAGE ANALYSIS

	CURRENT					COMPANY PROPOSED			STAFF PROPOSED		
		Salvage			net salvage		Salvage			Salvage	
	% rate	accrual rate	book cost	accrual	5yr avg	% rate	accrual rate	accrual	% rate	accrual rate	accrual
TRANSMISSION											
350	0	0.000	27,123,696	0	-3,743	0.50%	0.000	-1,808	1	0.000	-3,616
352	-25	0.004	31,004,576	119,248	171,125	-33	0.005	157,408	-30	0.005	155,023
353.01	-10	0.002	623,806,673	1,075,529	1,247,741	-13.6	0.003	1,885,282	-10	0.002	1,386,237
353.55	0	0.000	42,485,893	0	14,476	-0.1	0.000	2,124	-2	0.000	18,883
354	0	0.000	133,237,659	0	350,331	-31.2	0.004	593,859	-20	0.003	380,679
355	-5	0.001	365,859,185	332,599	1,436,362	-36.6	0.006	2,060,069	-30	0.005	1,688,581
356.01	5	-0.001	236,780,774	(197,317)	575,399	-50.8	0.007	1,603,795	-20	0.003	631,415
357.01	-25	0.004	29,049,970	117,137	0	0	0.000	0	0	0.000	0
358	30	-0.006	102,159,262	(612,956)	223,776	-11.8	0.002	241,096	-12	0.002	245,182
359	0	0.000	2,348,571	0		0	0.000	0			
DISTRIBUTION											
360	0	0.000	10,113,745	0	0	0	0.000	0	0	0.000	0
361	-50%	0.008	35,412,715	272,406	90,754	-32.1	0.005	174,884	-25	0.003	118,042
362.01	-10%	0.002	430,797,242	828,456	568,018	-15.5	0.003	1,112,893	-10	0.002	717,995
362.55	0%	0.000	29,492,793	0	-5,000	0.1	0.000	-1,475	1	0.000	-6,554
364	-25	0.006	788,801,034	4,809,762	551,910	-40.9	0.006	4,963,379	-5	0.001	606,770
365	-30	0.009	875,984,992	7,508,443	3,981,315	-102.3	0.020	17,922,653	-25	0.005	4,379,925
366.01	-20	0.003	134,517,260	384,335	126,261	-1.5	0.000	26,903	-10	0.001	168,147
367.1	10	-0.002	415,936,368	(831,873)	751,450	-10.9	0.002	906,741	-15	0.002	831,873
368.01	-15	0.004	451,751,287	1,882,297	152,272	-2.8	0.001	335,587	-2	0.001	258,144
368.3	-15	0.004	239,904,970	999,604	2,703,607	-24.5	0.007	1,679,335	-55	0.012	2,932,172
369.1	-60	0.015	284,680,583	4,270,209	1,446,756	-77.2	0.015	4,395,468	-30	0.006	1,581,559
369.2	-10	0.002	8,035,024	16,070	342	-5	0.001	5,357	-1	0.000	1,004
369.21	20	-0.005	102,850,405	(489,764)	28,971	-24.3	-0.003	-333,235	-5	0.001	68,567
370.1	0	0.000	49,724,890	0	-67,000	0.5	0.000	-12,431	2	-0.001	-49,725
370.2	0	0.000	26,080,597	0	889,127	-17.8	0.009	232,117	-50	0.025	652,015
370.3	0	0.000	6,871,977	0	0	0	0.000	0	0	0.000	0
370.35	0	0.000	28,016,510	0	7,247	-19.9	0.010	278,764	-1	0.001	14,008
371	-10	0.007	8,074,220	53,828	87,306	-33.4	0.008	67,420	-40	0.010	80,742
373.1	-10	0.003	68,539,314	228,464	407,791	-53.6	0.011	734,741	-30	0.006	411,236
373.2	-10	0.003	121,233,487	404,112	465,959	-24.8	0.004	429,513	-30	0.004	519,572
390	-5	0.001	89,809,731	81,645	78,734	-3.2	0.001	52,253	-10	0.001	128,300