ORIGINAL

NIAGARA MOHAWK POWER CORPORATION
FERC Docket No. ER08-552-000

Niagara Mohawk Power Corporation

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

Volume I

nationalgrid

25 Research Drive
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February 11, 2008

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Niagara Mohawk Power Corporation

Amendments to the
New York Independent System Operator, Inc.
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Original Volume I
Attachment H - Annual Transmission Revenue Requirement for Point-to-Point Transmission Service and Network Integration Transmission Service

Volume I

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February 11, 2008

VIA MESSENGER

Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Niagara Mohawk Power Corporation d/b/a National Grid
Docket No. ER08-_____

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and Part 35 of the Commission's Regulations, 18 C.F.R. Part 35, Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid" or "Company") submits for filing six copies of revised tariff sheets to the FERC Open Access Transmission Tariff ("OATT") administered by the New York Independent System Operator, Inc. ("NYISO"). These tariff sheets, which are included as Attachments A and B hereto, update certain National Grid-specific components of the wholesale Transmission Service Charge ("Wholesale TSC") formula under NYISO's OATT, to become effective May 1, 2008. National Grid is updating its Wholesale TSC to change its Revenue Requirement, Control Center Costs and Billing Unit component values. National Grid respectfully submits that its proposal is just and reasonable and should be accepted without suspension or hearing.

I. STATEMENT OF NATURE, REASONS AND BASIS FOR FILING

The objective of this filing is to establish a just and reasonable methodology for determining the transmission revenue requirements that will be recovered in the rates of National Grid. The Wholesale TSC is a formula rate. Attachment H to the NYISO OATT specifically provides for the Revenue Requirement ("RR") component, Scheduling, System Control and Dispatch 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."[1] Each Transmission Owner is entitled to amend these three components of Attachment H to the NYISO Tariff on its own initiative.

National Grid is seeking to revise the Wholesale TSC in order to ensure that wholesale transmission customers are paying for transmission service at a level that reflects as closely as possible actual costs incurred to provide service. Specifically, National Grid proposes to replace fixed (or "stated") values for RR, CCC, and BU with formulas that annualize recent actual monthly costs and usage data. For RR and CCC, that monthly data will be data for the month ended one month prior to the month in which the Wholesale TSC rate is posted. For the BU component, National Grid will initially estimate billing units by annualizing its projected monthly load, as adjusted. The estimated BU component will be trued up when the actual load data becomes available from the NYISO, which, under current NYISO practice, normally occurs within five months.

Since it is the NYISO that administers the Wholesale TSC, National Grid has consulted with the NYISO to determine a mutually acceptable means for National Grid to exercise its FPA Section 205 rights with respect to its RR, CCC, and BU components of the Wholesale TSC. National Grid requests that the Commission include in any order it makes accepting the proposed amendment an order directing the NYISO to make a compliance filing implementing the exact tariff changes proposed by National Grid, subject, of course, to any revisions that might be ordered by the Commission. National Grid requests waiver of the filing requirements prescribed in Sections 35.9 and 35.10 of the Commission's Rules and Regulations, 18 C.F.R. §§ 35.9 and 35.10, to give effect to the protocol National Grid has agreed upon with the NYISO to facilitate National Grid's exercise of its FPA Section 205 rights with respect to portions of the NYISO OATT.

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1 NYISO FERC Electric Tariff, Original Volume No. 1, Attachment H ("Attachment H"), Substitute First Revised Sheet No. 397 & First Revised Sheet No. 400.

II. BACKGROUND

A. *National Grid*

National Grid, a New York corporation, is a combination gas and electric utility. National Grid is primarily engaged in the business of transmission and distribution of electricity, and the distribution and transportation of natural gas in New York State. National Grid serves over 1.6 million retail electric and 568,000 retail gas customers in Buffalo, Syracuse, Albany, and other portions of upstate New York. National Grid owns approximately 6,000 miles of electric transmission lines and 8,500 miles of main and distribution gas pipelines. All of National Grid's bulk transmission facilities are subject to the operational control of the NYISO. Transmission service and generator interconnections associated with National Grid's facilities are provided to customers on a non-discriminatory basis pursuant to the NYISO OATT. Niagara Mohawk Holdings, Inc., the direct parent of National Grid, is owned by National Grid USA, which in turn is owned by National Grid plc.

B. *The Wholesale TSC*

On January 27, 1999, the Commission conditionally accepted the proposal made by National Grid and the other New York Transmission Owners ("NYTOs") to establish the NYISO in Docket ER97-1523-000. In conjunction with that filing, on November 17, 1999, the NYTOs filed a joint settlement agreement among all parties except Sithe/Independence Power Partners, L.P. ("Sithe") resolving all issues set for hearing in Docket No. ER97-1523-000 ("the NYISO Settlement"). The NYISO Settlement established as part of Attachment H to the NYISO OATT a "settlement" Revenue Requirement and Transmission Service Charge for wholesale transmission services provided using National Grid's facilities that was made applicable to parties except those who were excepted.[2]

Approximately 30 municipal electric utilities in upstate New York currently take service under National Grid's Wholesale TSC. In addition, approximately 80 customers external to the NYISO take service under the Company's Wholesale TSC. It should be noted that under National Grid's current retail rate plan, which

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2 Non-settling parties were made subject to a separate "filed" Revenue Requirement and Transmission Service Charge ("Filed TSC"). The NYISO Settlement also required National Grid to make a compliance filing revising its Filed TSC under the NYISO OATT based on the outcome of the hearing in Docket No. OA96-194-000. The NYISO Settlement was approved by the Commission by letter order dated July 31, 2000. National Grid subsequently filed to revised its Filed TSC rate based on the final outcome of Docket No OA96-194-000.

remains effective through December 31, 2011, any increase in wholesale transmission revenues as a result of implementing this filing will be credited to retail customers for at least as long as the current retail rate plan remains effective.

III. DESCRIPTION OF FILING

This filing proposes to update the National Grid-specific components of the Wholesale TSC. The formula will appear in the tariff as new Section 9.0 of Attachment H, Section I. The proposed rate formula is described in detail in the attached testimony of Pamela A. Viapiano. As described further below, the proposed filing also is supported by the attached testimony of Dr. William E. Avera, which addresses National Grid's return on equity, and by the attached testimony of Thomas F. Killeen, which addresses National Grid's cost of capital.

National Grid's formula is fundamentally similar to cost-of-service formulas recently approved by the Commission.[3] National Grid has followed this approach in order to facilitate the Commission's review of its filing and to enable the Commission to accept the filing without further investigation. Specifically, National Grid's monthly update is similar to Schedule 21 to ISO New England's OATT, New England Power Company's ("NEP") Local Service Schedule ("Schedule 21-NEP"). NEP is an affiliate of National Grid. ISO New England's OATT provides for a two-tier transmission arrangement integrating regional transmission service over PTF and Local Service over Non-PTF. The rates, terms and conditions of Schedule 21-NEP supplement and, where applicable, replace the rates, terms and conditions of the ISO-New England OATT with respect to Local Service. Under Attachment RR to Schedule 21-NEP, the Transmission Revenue Requirement is calculated based on a formula and determined on a monthly basis.[4] This approach was approved by the Commission.[5]

A. Proposed Rate Formulas

The testimony of Pamela A. Viapiano, which is attached hereto as Exhibit NMP-1, describes and explains National Grid's filing to update certain utility-specific components of the Wholesale TSC formula under the NYISO OATT.

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3 *See, e.g., Duquesne Light Co.*, 118 FERC ¶ 61,087 (2007); *Baltimore Gas & Elec. Co., et al.*, 115 FERC ¶ 61,066 (2006).

4 ISO New England, FERC Electric Tariff No. 3, Section II, Schedule 21 – NEP, Original Sheet No. 3117 ("In determining the rate for Local Network Service, the Revenue Requirement calculation as set forth below will be determined on a monthly basis ").

5 *ISO New England Inc.*,106 FERC ¶ 61,280 (2004); *order on reh'g*, 109 FERC ¶ 61,147 (2004); *aff'd sub nom. Maine Public Utilities Commission v. FERC*, 454 F.3d 278 (D.C. Cir 2006)

Currently, each of components RR, CCC, and BU is defined as an annual amount as stated in Table 1 of Attachment H to the NYISO OATT.

First, National Grid proposes to calculate and update the RR component monthly based on a formula rate methodology. Second, National Grid proposes to set the CCC component to actual monthly costs recorded in regulatory account 561 for the Transmission function. Finally, National Grid proposes to calculate the BU component by annualizing National Grid's estimated monthly Corporate Load and then truing up that estimated value once historical data become available. As required by Commission policy, Return on Equity and PBOP (Post-Retirement Benefits Other than Pensions) expense will be set at stated levels and will be subject to change only upon a further rate filing with the Commission.[6] Consistent with Commission precedent, National Grid expects to update PBOP expense annually by means of a Section 205 rate filing limited to that issue.[7]

Formula rates present a reasonable and appropriate basis for establishing National Grid's components of the Wholesale TSC. They will ensure that rates track National Grid's costs accurately and on a reasonably current basis, and will avoid the necessity of frequent rate adjustment filings. Moreover, the implementation of a formula rate for National Grid's TSC components RR, CCC, and BU is consistent with the Commission's policy of encouraging investment in transmission facilities to meet customer needs. National Grid has made significant investments in its transmission system since its Wholesale TSC rate was set using 1995 financial information. Last year, National Grid committed publicly to invest at least $1.47 billion in its transmission and distribution system over the five-year period 2007-2011. Of that amount, approximately $572 million is targeted for transmission investment. This represents an increase of approximately 36 percent over the gross transmission plant investment as of the end of 2007. National Grid also has filed with the New York Public Service Commission ("NYPSC") a capital investment plan under which the Company, with regulatory support from the NYPSC, could invest as much as $2.4 billion in transmission and distribution over the same five-year period. Of this higher amount, approximately $1.082 billion would be targeted for transmission investment. National Grid's proposed formula rates are consistent with Commission precedent and policy.

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6 *See e.g., Maine Yankee Atomic Power Co.*, 66 FERC ¶ 61,375 at 62,252-53 & n.10 (1994), *clarified*, 68 FERC ¶ 61,190 (1994).

7 *See Maine Yankee Atomic Power Co.*, 68 FERC ¶ 61,190 at 61,958-59 (1994).

B. Base Return on Equity

The testimony of Dr. William E. Avera, which is attached hereto as Exhibit NMP-2, supports proposed return on equity ("ROE") based on a Discounted Cash Flow ("DCF") analysis. Dr. Avera then confirmed these findings through an analysis of alternative ROE benchmarks developed using the Capital Asset Pricing Model ("CAPM") and comparable earned rates of return expected for utilities and industrial firms. Dr. Avera concludes that an ROE range of reasonableness for National Grid of 7.9 percent to 15.9 percent, with a midpoint of 11.9 percent. This ROE range corresponds to the adjusted zone of reasonableness produced by applying the Commission's DCF approach to a proxy group of electric utilities. The Commission has approved ROE's at or above this level in other cases.[8] Dr. Avera then reviews the standards governing eligibility for a 50-basis point ROE adder for a public utility's membership in an ISO or RTO, and concludes that National Grid meets those standards as a voluntary participant in the NYISO. Finally, he recommends that National Grid's ROE be set at 12.4 percent, or 50 basis points above the midpoint of his estimated range based on market benchmarks.

Dr. Avera has undertaken a comprehensive evaluation of the capital markets in general and as they relate to National Grid in particular, with special emphasis on risks inherent in the transmission business. His analysis is grounded upon accepted Commission practice in applying the DCF model. Dr. Avera also presents National Grid's recommended capital structure. He concludes that the proposed formula which relies on National Grid's actual capitalization, as reflected in the Company's Form 1 filing, achieves a reasonable equity ratio for National Grid in the range of 56 percent to 60 percent.

C. Cost of Capital

The testimony of Thomas M. Killeen, which is attached hereto as Exhibit NMP-8, addresses National Grid's cost of capital. Mr. Killeen, based on his own testimony regarding National Grid's cost of debt and preferred stock costs as well as the ROE testimony of Dr. Avera, determines that National Grid's overall cost of capital. This cost of capital formula rate is applied in the testimony of National Grid witness Viapiano.

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8 *See e.g., Midwest Independent System* Operator Corp., 100 FERC ¶ 61,292 at P 1 (2002)(approving an ROE of 12.88%), *aff'd in relevant part sub nom. Public Service Commission of Kentucky v. FERC*, 397 F.3d 1004 (D.C. Cir. 2005).

IV. CONTENTS OF FILING

- Attachment A: Revised sheets to the tariff (Clean version;
- Attachment B: Revised sheets to the tariff (Black-lined version);
- Attachment C: Service list;
- Exhibits NMP-1 through NMP-48, which include:
  - Direct Testimony of Pamela A. Viapiano (Exhibit NMP-1);
  - Direct Testimony of Dr. William E. Avera (Exhibit NMP-2) and supporting exhibits (Exhibits NMP-3 through NMP-7);
  - Direct Testimony of Thomas F. Killeen (Exhibit NMP-8); and
  - Statements required by Section 35.13 of the Commission's Rules and Regulations (Exhibits NMP-9 through NMP-46) and supporting workpapers (Exhibit NMP-47).
  - Actuarial study supporting the PBOP expense component of National Grid's cost of service (Exhibit NMP-48).

National Grid notes that all components of this filing except for Exhibits NMP-9 through NMP-48 are bound in Volume I of this filing. Exhibits NMP-9 through NMP-48 are bound in Volume II.

V. PROPOSED EFFECTIVE DATE

National Grid respectfully requests the formula rate and associated tariff revisions be accepted for filing effective as of May 1, 2008. As noted above, the Commission has actively encouraged transmission owners to adopt the type of formula rate that National Grid has proposed herein. Consistent with this Commission policy, its practice has been to permit such formula rate filings to become effective after a suspension period of no more than one day.[9]

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9 *Allegheny Power System Operating Companies*, 111 FERC ¶ 61,308 at P 51 (2005) (accepting a formula rate proposal for filing and suspending it to become effective one day after the FERC order "where the Commission has, in fact, urged transmission owners to move from stated rates to formula rates"), *order on reh'g*, 115 FERC ¶ 61,156 (2006).

VI. COMMUNICATIONS

National Grid requests that all correspondence, pleadings and other communications concerning this filing be served upon the following, and further requests waiver of the Commission's regulations to allow three persons to be designated for service:

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VII. SERVICE

Pursuant to Section 32.5(d) of the Commission's Regulations, a copy of this filing is being served on National Grid's customers under the rate affected by this filing, on the New York State Public Service Commission, and on the NYISO. The service list for this filing may be found in Attachment C.

VIII. REQUEST FOR WAIVER

National Grid respectfully requests waiver by the Commission of Sections 35.9 and 35.10 as described in Section I of the letter; requests waiver of any requirements of the Commission's rules and regulations, as well as any authorization as may be necessary or required, to permit the revised rates to be accepted by the Commission and made effective in the manner proposed herein; and further requests waiver to allow three persons to be designated for service.

IX. MISCELLANEOUS

No agreement is required by contract for the filing of this rate filing. There are no costs included in this filing that have been alleged or adjudged in an administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs, nor has any expense or cost been demonstrated to be the product of discriminatory or employment practices, within the meaning of Section 35.13(d)(3).

X. CONCLUSION

For the foregoing reasons, National Grid respectfully requests that the Commission accept these proposed tariff changes without suspension, condition or modification.

Respectfully submitted,

William Glew
Alston & Bird, LLP
The Atlantic Building
950 F Street, NW
Washington, DC 20004

Attorneys for
Niagara Mohawk Power Corporation
d/b/a National Grid

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Attachment A

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 9	See Attachment H, Section 9	See Attachment H, Section 9	See Attachment H, Section 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 I.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.

9.0 Niagara Mohawk Power Corporation Wholesale TSC Formula Components RR, CCC and BU

Niagara Mohawk Power Corporation's ("NMPC") will calculate and update each of its RR, CCC, and BU components monthly using the formulas described below for each component. In each case, the cost data used in the formula will be cost data from NMPC's official books and records for the month that ended one month prior to the month in which the TSC rate will be posted. Components RR, CCC and BU will be posted by the 14th of each month.

Definitions

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

Allocation Factors

1. Electric Wages and Salaries Allocation Factor shall equal the ratio of NMPC electric direct wages and salaries (including any direct wages or salaries charged to NMPC by a National Grid Affiliate) to NMPC's total gas and electric direct wages and salaries (including any wages charged to NMPC by a National Grid Affiliate) excluding any administrative and general wages and salaries.

2. Transmission Plant Allocation Factor shall equal the total investment in Transmission Plant divided by the sum of the total Transmission Plant plus the total Distribution Plant, excluding Intangible Plant, Electric General Plant and Common General Plant.

3. Transmission Wages and Salaries Allocation Factor shall equal the ratio of NMPC Transmission-related direct electric wages and salaries (including any direct wages or salaries charged to NMPC by a National Grid Affiliate) to NMPC's total electric direct wagesand salaries (including any wages charged to NMPC by a National Grid Affiliate) excluding any administrative and general wages and salaries.

Ratebase and Expense items

4. 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. Administrative and General Expenses shall exclude the actual Post-Employment Benefits Other than Pensions expenses ("PBOP") included in FERC Account 926, and add back the FERC accepted Post Employment Benefit Other than Pensions of $88,464,000 annually or $7,372,000 per month or any other amount subsequently approved by FERC under Section 205 of the Federal Power Act.

5. Amortization of Investment Tax Credits shall equal credits as recorded in FERC Account No. 411.4.

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

7. Common General Plant shall equal the balance of plant recorded in FERC Account Nos. 389-399. Common General Plant shall be defined as the general plant common to NMPC's gas and electric functions.

8. Common General Plant Depreciation Expense shall equal the common plant depreciation expenses as recorded in FERC Account No. 403 associated with Common General Plant.

9. Common General Plant Depreciation Reserve shall equal the common plant depreciation reserve balance as recorded in FERC Account No. 108 associated with Common General Plant.

10. 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	Annual Rate
350. Land -Rights of Way and Easements	1.33
352 Structures and Improvements	1. 92
353 Station Equipment	1.90
353.55 Station Equipment -_EMS	5.00
354 Towers and Fixtures	1.47
355 Poles and Fixtures	1.91

356	Overhead Conductors and Devices	
	Steel Tower Lines	1.40
	Wood Pole Lines	1.58
357	Underground Conduit	2.02
358	Underground Conductors and Devices	1.40
359	Road and Trails	1.33
370	Meters	
	Meters	3.13
	Installation	2.78

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

12. Equity AFUDC shall equal the activity recorded in FERC Account No. 419.1.

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

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

15. 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.

16. Loss on Reacquired Debt shall equal the loss on reacquired debt as recorded in FERC Account 189.

17. Materials and Supplies shall equal materials and supplies balance as recorded in FERC Account No. 154.

18. Payroll Taxes shall equal the electric payroll tax expenses as recorded in FERC Account Nos. 408.100, 408.110 and 408.130.

19. Plant Held for Future Use shall equal the balance as recorded in FERC Account No. 105.

20. Prepayments shall equal prepayment balance as recorded in FERC Account No. 165.

21. Real Estate Tax Expenses shall equal electric real estate tax expense as recorded in FERC Account No. 408.140 and 408.180.

22. 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.

23. 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.

24. Transmission Depreciation Reserve shall equal electric transmission plant related depreciation reserve balance as recorded in FERC Account 108 associated with Transmission Plant.

25. Transmission Operation and Maintenance Expense shall equal the sum of electric expenses as recorded in FERC Account Nos. 560, 562-573.

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

27. Transmission Related Taxes and Fees Charge shall include any transmission-related fee or assessment imposed by any governmental authority on transmission service provided which is not specifically identified under any other section contained herein.

28. Transmission Related Bad Debt Expense shall equal Bad Debt Expense as reported in Account 904 related to wholesale transmission billing.

29. Wholesale Metering Investment shall equal the net 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 23V. The net plant investment shall be determined monthly by multiplying the number of such existing wholesale meters recorded in FERC Account No. 370.3 and in blanket metering accounts by the monthly average net cost of the meters plus the monthly average net costs of installation. To the extent future gross plant investment for Wholesale Metering can be specifically identified, actual net meter costs will be used.

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.

Calculation of RR

The RR component, determined monthly, shall equal the annualized sum of NMPC's monthly (A) Return and Associated Income Taxes, (B) Transmission Related Depreciation Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Real Estate Tax Expense, (E) Transmission Related Amortization of Investment Tax Credits, (F) Transmission Operation and Maintenance Expense, (G) Transmission Related Administrative and General Expenses, (H) Transmission Related Payroll Tax Expense, less (I) Revenue Credits, plus (J) Billing Adjustments, and plus (K) Bad Debt Expense. "Annualized" as used in this Section 9.0 shall mean multiplied by twelve.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. Transmission Investment Base shall be defined as

(a) Transmission Plant in Service, plus (b) Transmission Related Electric General Plant, plus (c) Transmission Related Common General Plant, plus (d) Plant Held for Future Use, less (e) Transmission Related Depreciation Reserve, less (f) Transmission Related Accumulated

Deferred Taxes, plus (g) Transmission Related Loss on Reacquired Debt, plus (h) Transmission Related Regulatory Assets net of Regulatory Liabilities, plus (i) Transmission Related Prepayments, plus (j) Transmission Related Materials and Supplies, plus (k) Transmission Related Cash Working Capital.

(a) Transmission Plant in Service shall equal the balance of total investment in Transmission Plant plus Wholesale Metering Investment.

(b) Transmission Related Electric General Plant shall equal the balance of investment in Electric General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

(c) Transmission Related Common General Plant shall equal Common General Plant multiplied by the Electric Wages and Salaries Allocation Factor and further multiplied by the Transmission Wages and Salaries Allocation Factor.

(d) Transmission Related Plant Held for Future Use shall equal Plant Held for Future multiplied by the Electric Wages and Salaries Allocation Factor and further multiplied by the Transmission Wages and Salaries Allocation Factor.

(e) Transmission Related Depreciation Reserve shall equal the balance of: (i) Transmission Depreciation Reserve, plus (ii) the product of Electric General Plant Depreciation Reserve multiplied by the Transmission Wages and Salaries Allocation Factor, plus (iii) the product of Common General Plant Depreciation Reserve multiplied by the Electric Wages and Salaries Allocation Factor and further multiplied by the Transmission Wages and Salaries Allocation Factor.

(f) Transmission Related Accumulated Deferred Income Taxes shall equal the electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Transmission Plant Allocation Factor.

(g) Transmission Related Loss on Reacquired Debt shall equal the product of Loss on Reacquired Debt multiplied by the Electric Wages and Salaries Allocation Factor and further multiplied by the Transmission Plant Allocation Factor.

(h) Transmission Related Regulatory Assets shall be Regulatory Assets net of Regulatory Liabilities multiplied by the Transmission Plant Allocation Factor.

(i) Transmission Related Prepayments shall be the product of Prepayments multiplied by the Electric Wages and Salaries Allocation Factor and further multiplied by the Transmission Plant Allocation Factor.

(j) Transmission Related Materials and Supplies shall equal: (i) the balance of Materials and Supplies assigned to Transmission plus (ii) the product of Material and Supplies assigned to Construction multiplied by the Electric Wages and Salaries Allocation Factor and further multiplied by Transmission Plant Allocation Factor.

(k) Transmission Related Cash Working Capital shall be an allowance equal to the product of: (i) 1.5 (45 days = 1.5 months) multiplied by (ii) Transmission Operation and Maintenance Expense plus Transmission-Related Administrative and General Expense.

2. Cost of Capital Rate

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

(a) 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:

(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 then outstanding and the ratio of actual long-term debt to total capital.

(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;

(iii) the return on equity component, shall be the product of the allowed ROE of 11.9% plus a 50 basis point adder (per FERC Order 697 and 697A) and the ratio of NMPC's actual common equity to total capital.

(b) Federal Income Tax shall equal

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

where A is the sum of the preferred stock component and the return on equity component, each as determined in

Sections 2.(a)(ii) and for the ROE set forth in 2.(a)(iii) above, B is the Equity AFUDC component of Transmission Depreciation Expense as defined at 10. above, and C is the Transmission Investment Base as defined in A.1.a above.

(c) State Income Tax shall equal

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

Where A is the sum of the preferred stock component and the return on equity component as determined in A.2.(a)(ii) and A.2.(a)(iii) above , B is the Equity AFUDC component of Transmission Depreciation Expense as defined at 10. above, and C is the Transmission Investment Base as defined in A.1.a above.

B. Transmission Depreciation Expense shall equal the sum of: (i) Depreciation Expense for Transmission Plant in Service, plus (ii) the product of Electric General Plant Depreciation Expense multiplied by the Transmission Wages and Salaries Allocation Factor plus (iii) Common General Plant Depreciation Expense multiplied by the Electric Wages and Salaries Allocation Factor, further multiplied by the Transmission Wages and Salaries Allocation Factor.

C. Transmission Related Amortization of Loss on Reacquired Debt shall equal the Amortization of Loss on Reacquired Debt multiplied by the Electric Wages and Salaries Allocation Factor and further multiplied by the Transmission Plant Allocation Factor.

D. Transmission Related Real Estate Tax Expense shall equal the electric Real Estate Tax Expenses multiplied by the Transmission Plant Allocation Factor.

E. Transmission Related Amortization of Investment Tax Credits shall equal the product of Amortization of Investment Tax Credits multiplied by the Transmission Plant Allocation Factor.

F. Transmission Operation and Maintenance Expense shall equal the Transmission Operation and Maintenance Expense.

G. Transmission Related Administrative and General Expenses shall equal the product of electric Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor.

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

I. Billing Adjustments shall be plus or minus any billing adjustments from the prior transmission billing periods. Billing adjustments shall include, but not be limited to, corrections to any value included in the TSC rate, including adjustments to the BU components due to metering errors or true-ups. Such adjustments may be corrected prospectively. However, if the error is substantial, or affects an individual Customer, NMPC reserves the right to credit and rebill customers for each affected billing month in which the error occurred.

J. Transmission Related Bad Debt Expense shall equal Transmission Related Bad Debt Expense as defined at 28 above.

K. Revenue Credits shall equal all Transmission revenue recorded in FERC account 456 excluding any NMPC revenues already reflected in the WR, CRR, SR, ECR and Reserved components in Attachment H of the NYISO TSC rate and excluding any revenues associated with expenses that have been excluded from NMPC's revenue requirement.

The Annual Transmission Carrying Charge shall be the Annual Transmission Revenue Requirement as determined per this Section 9, the sum of Component RR Sections (A) through (J) above, divided by the year-end balance of the total transmission plant investment in service determined in accordance (A).1.(a) above. The Annual Revenue Requirement for specific charges related to transmission service under the NYISO tariff, not already provided under this Transmission Service Charge (TSC), shall be determined by multiplying the year-end Gross Plant Investment associated with the specific transmission investment for that transmission service and the average Annual Transmission Carrying Charge.

Formula rate inputs for rate of return on common equity, depreciation rates, and Post Employment Benefits Other than Pensions (PBOP) shall be stated values until changed pursuant to an FPA Section 205 or 206 filing made effective by the Commission. An application under Section 205 or 206 to modify stated values for depreciation rates or PBOP expenses under the formula rate shall not open review of other components of the formula rate.

Calculation of CCC

CCC shall equal the annualized sum of NMPC's monthly Scheduling, System Control and Dispatch Costs (i.e., the transmission component of control center costs) charges from the New York Independent System Operator as recorded in FERC sub-accounts 561 and 561.2.

Calculation of BU

BU shall initially equal the annualized sum of NMPC's estimated Corporate Load. NMPC's Corporate Load is defined as the sum of all NYISO defined NMPC subzones plus (i) historically based estimates for NMPC's load modifiers, less (ii) estimated NYPA Municipal Loads, and less (iii) estimated NYMPA Loads. The Corporate Load will be further reduced by the mostly currently available NYISO monthly data for station power loads and station service loads.

Once the NYISO load data is available for a month, that month's TSC calculation will be recalculated with BU defined as the annualized sum of the total load for NMPC and ESCO's plus loads for the Power for Jobs, Replacement, Expansion and Economic Development NYPA programs. The resulting true-up adjustment will be treated as a Billing Adjustment per J above.

Attachment B

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 (Settlement OA96-194-000) 3~~	~~$153,619,348~~	~~$4,539,625~~	~~34,448,060~~	~~$4.59~~
Niagara Mohawk Power Corporation	See Attachment H, Section 9	See Attachment H, Section 9	See Attachment H, Section 9	See Attachment H, Section 9
~~Niagara Mohawk Power Corporation (Filed OA96-194-000) 4~~	~~$145,294,074~~	~~$4,539,625~~	~~34,448,060~~	~~$4.22~~
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.F 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.
~~3 In Niagara Mohawk Power Corp., 91 FERC ¶ 61,274 (2000), the Commission approved the revenue requirement that forms the basis of these "settlement" rates. Niagara Mohawk's "settlement" TSC applies to wholesale transmission service to all customers except Sithe/Independence Power Partners, L. P.~~
~~4 Niagara Mohawk's "filed" TSC applies only to wholesale transmission service provided to Sithe/Independence Power Partners, L.P.~~

9.0 Niagara Mohawk Power Corporation Wholesale TSC Formula Components RR, CCC and BU

Niagara Mohawk Power Corporation's ("NMPC") will calculate and update each of its RR, CCC, and BU components monthly using the formulas described below for each component. In each case, the cost data used in the formula will be cost data from NMPC's official books and records for the month that ended one month prior to the month in which the TSC rate will be posted. Components RR, CCC and BU will be posted by the 14th of each month.

Definitions

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

Allocation Factors

1. Electric Wages and Salaries Allocation Factor shall equal the ratio of NMPC electric direct wages and salaries (including any direct wages or salaries charged to NMPC by a National Grid Affiliate) to NMPC's total gas and electric direct wages and salaries (including any wages charged to NMPC by a National Grid Affiliate) excluding any administrative and general wages and salaries.

2. Transmission Plant Allocation Factor shall equal the total investment in Transmission Plant divided by the sum of the total Transmission Plant plus the total Distribution Plant, excluding Intangible Plant, Electric General Plant and Common General Plant.

3. Transmission Wages and Salaries Allocation Factor shall equal the ratio of NMPC Transmission-related direct electric wages and salaries (including any direct wages or salaries charged to NMPC by a National Grid Affiliate) to NMPC's total electric direct wagesand salaries (including any wages charged to NMPC by a National Grid Affiliate) excluding any administrative and general wages and salaries.

Ratebase and Expense items

4. 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. Administrative and General Expenses shall exclude the actual Post-Employment Benefits Other than Pensions expenses ("PBOP") included in FERC Account 926, and add back the FERC accepted Post Employment Benefit Other than Pensions of $88,464,000 annually or $7,372,000 per month or any other amount subsequently approved by FERC under Section 205 of the Federal Power Act.

5. Amortization of Investment Tax Credits shall equal credits as recorded in FERC Account No. 411.4.

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

7. Common General Plant shall equal the balance of plant recorded in FERC Account Nos. 389-399. Common General Plant shall be defined as the general plant common to NMPC's gas and electric functions.

8. Common General Plant Depreciation Expense shall equal the common plant depreciation expenses as recorded in FERC Account No. 403 associated with Common General Plant.

9. Common General Plant Depreciation Reserve shall equal the common plant depreciation reserve balance as recorded in FERC Account No. 108 associated with Common General Plant.

10. 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	Annual Rate
350. Land –Rights of Way and Easements	1.33
352 Structures and Improvements	1. 92
353 Station Equipment	1.90
353.55 Station Equipment - EMS	5.00
354 Towers and Fixtures	1.47
355 Poles and Fixtures	1.91

356 Overhead Conductors and Devices	
Steel Tower Lines	1.40
Wood Pole Lines	1.58
357 Underground Conduit	2.02
358 Underground Conductors and Devices	1.40
359 Road and Trails	1.33
370 Meters	
Meters	3.13
Installation	2.78

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

12. Equity AFUDC shall equal the activity recorded in FERC Account No. 419.1.

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

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

15. 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.

16. Loss on Reacquired Debt shall equal the loss on reacquired debt as recorded in FERC Account 189.

17. Materials and Supplies shall equal materials and supplies balance as recorded in FERC Account No. 154.

18. Payroll Taxes shall equal the electric payroll tax expenses as recorded in FERC Account Nos. 408.100, 408.110 and 408.130.

19. Plant Held for Future Use shall equal the balance as recorded in FERC Account No. 105.

20. Prepayments shall equal prepayment balance as recorded in FERC Account No. 165.

21. Real Estate Tax Expenses shall equal electric real estate tax expense as recorded in FERC Account No. 408.140 and 408.180.

22. 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.

23. 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.

24. Transmission Depreciation Reserve shall equal electric transmission plant related depreciation reserve balance as recorded in FERC Account 108 associated with Transmission Plant.

25. Transmission Operation and Maintenance Expense shall equal the sum of electric expenses as recorded in FERC Account Nos. 560, 562-573.

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

27. Transmission Related Taxes and Fees Charge shall include any transmission-related fee or assessment imposed by any governmental authority on transmission service provided which is not specifically identified under any other section contained herein.

28. Transmission Related Bad Debt Expense shall equal Bad Debt Expense as reported in Account 904 related to wholesale transmission billing.

29. Wholesale Metering Investment shall equal the net 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 23V. The net plant investment shall be determined monthly by multiplying the number of such existing wholesale meters recorded in FERC Account No. 370.3 and in blanket metering accounts by the monthly average net cost of the meters plus the monthly average net costs of installation. To the extent future gross plant investment for Wholesale Metering can be specifically identified, actual net meter costs will be used.

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.

Calculation of RR

The RR component, determined monthly, shall equal the annualized sum of NMPC's monthly (A) Return and Associated Income Taxes, (B) Transmission Related Depreciation Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Real Estate Tax Expense, (E) Transmission Related Amortization of Investment Tax Credits, (F) Transmission Operation and Maintenance Expense, (G) Transmission Related Administrative and General Expenses, (H) Transmission Related Payroll Tax Expense, less (I) Revenue Credits, plus (J) Billing Adjustments, and plus (K) Bad Debt Expense. "Annualized" as used in this Section 9.0 shall mean multiplied by twelve.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. Transmission Investment Base shall be defined as

(a) Transmission Plant in Service, plus (b) Transmission Related Electric General Plant, plus (c) Transmission Related Common General Plant, plus (d) Plant Held for Future Use, less (e) Transmission Related Depreciation Reserve, less (f) Transmission Related Accumulated

Deferred Taxes, plus (g) Transmission Related Loss on Reacquired Debt, plus (h) Transmission Related Regulatory Assets net of Regulatory Liabilities, plus (i) Transmission Related Prepayments, plus (j) Transmission Related Materials and Supplies, plus (k) Transmission Related Cash Working Capital.

(a) Transmission Plant in Service shall equal the balance of total investment in Transmission Plant plus Wholesale Metering Investment.

(b) Transmission Related Electric General Plant shall equal the balance of investment in Electric General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

(c) Transmission Related Common General Plant shall equal Common General Plant multiplied by the Electric Wages and Salaries Allocation Factor and further multiplied by the Transmission Wages and Salaries Allocation Factor.

(d) Transmission Related Plant Held for Future Use shall equal Plant Held for Future multiplied by the Electric Wages and Salaries Allocation Factor and further multiplied by the Transmission Wages and Salaries Allocation Factor.

(e) Transmission Related Depreciation Reserve shall equal the balance of: (i) Transmission Depreciation Reserve, plus (ii) the product of Electric General Plant Depreciation Reserve multiplied by the Transmission Wages and Salaries Allocation Factor, plus (iii) the product of Common General Plant Depreciation Reserve multiplied by the Electric Wages and Salaries Allocation Factor and further multiplied by the Transmission Wages and Salaries Allocation Factor.

(f) Transmission Related Accumulated Deferred Income Taxes shall equal the electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Transmission Plant Allocation Factor.

(g) Transmission Related Loss on Reacquired Debt shall equal the product of Loss on Reacquired Debt multiplied by the Electric Wages and Salaries Allocation Factor and further multiplied by the Transmission Plant Allocation Factor.

(h) Transmission Related Regulatory Assets shall be Regulatory Assets net of Regulatory Liabilities multiplied by the Transmission Plant Allocation Factor.

(i) Transmission Related Prepayments shall be the product of Prepayments multiplied by the Electric Wages and Salaries Allocation Factor and further multiplied by the Transmission Plant Allocation Factor.

(j) Transmission Related Materials and Supplies shall equal: (i) the balance of Materials and Supplies assigned to Transmission plus (ii) the product of Material and Supplies assigned to Construction multiplied by the Electric Wages and Salaries Allocation Factor and further multiplied by Transmission Plant Allocation Factor.

(k) Transmission Related Cash Working Capital shall be an allowance equal to the product of: (i) 1.5 (45 days = 1.5 months) multiplied by (ii) Transmission Operation and Maintenance Expense plus Transmission-Related Administrative and General Expense.

2. Cost of Capital Rate

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

(a) 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:

(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 then outstanding and the ratio of actual long-term debt to total capital.

(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;

(iii) the return on equity component, shall be the product of the allowed ROE of 11.9% plus a 50 basis point adder (per FERC Order 697 and 697A) and the ratio of NMPC's actual common equity to total capital.

(b) Federal Income Tax shall equal

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

where A is the sum of the preferred stock component and the return on equity component, each as determined in

Sections 2.(a)(ii) and for the ROE set forth in 2.(a)(iii) above, B is the Equity AFUDC component of Transmission Depreciation Expense as defined at 10. above, and C is the Transmission Investment Base as defined in A.1.a above.

(c) State Income Tax shall equal

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

Where A is the sum of the preferred stock component and the return on equity component as determined in A.2.(a)(ii) and A.2.(a)(iii) above , B is the Equity AFUDC component of Transmission Depreciation Expense as defined at 10. above, and C is the Transmission Investment Base as defined in A.1.a above.

B. Transmission Depreciation Expense shall equal the sum of: (i) Depreciation Expense for Transmission Plant in Service, plus (ii) the product of Electric General Plant Depreciation Expense multiplied by the Transmission Wages and Salaries Allocation Factor plus (iii) Common General Plant Depreciation Expense multiplied by the Electric Wages and Salaries Allocation Factor, further multiplied by the Transmission Wages and Salaries Allocation Factor.

C. Transmission Related Amortization of Loss on Reacquired Debt shall equal the Amortization of Loss on Reacquired Debt multiplied by the Electric Wages and Salaries Allocation Factor and further multiplied by the Transmission Plant Allocation Factor.

D. Transmission Related Real Estate Tax Expense shall equal the electric Real Estate Tax Expenses multiplied by the Transmission Plant Allocation Factor.

E. Transmission Related Amortization of Investment Tax Credits shall equal the product of Amortization of Investment Tax Credits multiplied by the Transmission Plant Allocation Factor.

F. Transmission Operation and Maintenance Expense shall equal the Transmission Operation and Maintenance Expense.

G. Transmission Related Administrative and General Expenses shall equal the product of electric Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor.

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

I. Billing Adjustments shall be plus or minus any billing adjustments from the prior transmission billing periods. Billing adjustments shall include, but not be limited to, corrections to any value included in the TSC rate, including adjustments to the BU components due to metering errors or true-ups. Such adjustments may be corrected prospectively. However, if the error is substantial, or affects an individual Customer, NMPC reserves the right to credit and rebill customers for each affected billing month in which the error occurred.

J. Transmission Related Bad Debt Expense shall equal Transmission Related Bad Debt Expense as defined at 28 above.

K. Revenue Credits shall equal all Transmission revenue recorded in FERC account 456 excluding any NMPC revenues already reflected in the WR, CRR, SR, ECR and Reserved components in Attachment H of the NYISO TSC rate and excluding any revenues associated with expenses that have been excluded from NMPC's revenue requirement.

The Annual Transmission Carrying Charge shall be the Annual Transmission Revenue Requirement as determined per this Section 9, the sum of Component RR Sections (A) through (J) above, divided by the year-end balance of the total transmission plant investment in service determined in accordance (A).1.(a) above. The Annual Revenue Requirement for specific charges related to transmission service under the NYISO tariff, not already provided under this Transmission Service Charge (TSC), shall be determined by multiplying the year-end Gross Plant Investment associated with the specific transmission investment for that transmission service and the average Annual Transmission Carrying Charge.

Formula rate inputs for rate of return on common equity, depreciation rates, and Post Employment Benefits Other than Pensions (PBOP) shall be stated values until changed pursuant to an FPA Section 205 or 206 filing made effective by the Commission. An application under Section 205 or 206 to modify stated values for depreciation rates or PBOP expenses under the formula rate shall not open review of other components of the formula rate.

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UNITED STATES OF AMERICA

BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Niagara Mohawk Power Corporation
d/b/a National Grid

Docket No. ER08- ________

Direct Testimony
of
Pamela A. Viapiano

I. Introduction and Qualifications:

Q. Please state your name and business address.

A. My name is Pamela A. Viapiano. My business address is 25 Research Drive, Westborough, Massachusetts 01582.

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

A. Effective October 1, 2007, I was named Vice President of Transmission Finance for National Grid USA Service Company, Inc. ("Service Co"). Service Co is a subsidiary of National Grid USA, which in turn is a subsidiary of National Grid plc, a London-based international energy company. In my current position I have overall responsibility for financial reporting and wholesale billing, and administration and development of transmission tariffs and rates for, National Grid plc's transmission business in the United States, which includes Niagara Mohawk Power Corporation d/b/a National Grid in New York ("National Grid" or "Company") and New England Power ("NEP") in New England. The U.S. Transmission Finance team provides support for National Grid's and NEP's transmission rate filings at the Federal Energy Regulatory Commission ("FERC" or "Commission"), monitors ISO New England ("ISO-NE") and New York ISO ("NYISO") Transmission Tariffs, and is involved in most transmission-related pricing policy and regulatory matters impacting National Grid and NEP.

Q. Please describe your educational background and training.

A. I graduated from Clark University in Worcester, Massachusetts in 1987 with a Bachelors of Arts in Computer Science. Over my twenty-year career with National Grid USA, I have held a number of positions in the rates and regulatory area, including Manager of Transmission Rates and Manager of Regulatory Policy. I have submitted testimony and testified before FERC in Docket No. EL00-73 and have testified in a number of retail rate filings before the Rhode Island Public Utilities Commission, the New Hampshire Public Utilities Commission, and the Massachusetts Department of Public Utilities.

II. Purpose of Testimony:

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support National Grid's filing under Section 205 of the Federal Power Act to update certain National Grid-specific components of the Wholesale TSC formula under the New York Independent System Operator's Open Access Transmission Tariff, FERC Electric Tariff in Original Volume No. 1 (NYISO OATT). National Grid is invoking its right under Part I, Section 3.0 of Attachment H to update its Wholesale TSC calculation to change its Revenue Requirement (RR), Scheduling, System Control and Dispatch Costs (CCC) and Billing Unit (BU) component values. National Grid proposes to replace the current fixed values for each of those components with values that are updated monthly based on recent actual data. The formulas by which each of RR, CCC, and BU will be updated are included in a new Section I.9 of Attachment H. Those formulas will replace the values for National Grid as currently stated in Table 1 of Attachment H. National Grid is not proposing any modifications to other components of the TSC. Section 9 will apply exclusively to National Grid's RR, CCC, and BU components.

Q. Are you sponsoring any statements included with this filing?

A. Yes. I am sponsoring the following statements: AA, AB, AC, AD, AE, AF, AG, AH, AI, AJ, AK, AL, AM, AN, AO, AP, AQ, AR, AS, AT, AU, AW, AX , AY, BA, BB, BC, BD, BE, BF, BG/BH, BI, BJ, BK, BL, and BM. These statements and the supporting workpapers, which are set forth in Exhibits NMP-9 through NMP-46, explain the derivation and/or calculation of various proposed National Grid-specific components of the Wholesale TSC formula , and provide National Grid's 2006 period 1 actual plant and cost information consistent with the Commission's filing requirements. Additionally, statement BK summarizes the cost information and illustrates using 2006 actual data how the proposed formula Revenue Requirement (RR) and (CCC) component will be determined. Statement BG/BH provides a comparison of charges to customers in 2006 under the current TSC rate to the proposed TSC rate with the formula rate adjustment being proposed in this filing.

Q. Are you sponsoring any other exhibits?

A. Yes. I am sponsoring Exhibit NMP-47, which consists of workpapers supporting certain of the statements I just described, and Exhibit NMP-48, which addresses Post-Retirement Benefits Other than Pensions (PBOP) expense and which I will describe later in my testimony.

Q. Are there other witnesses providing testimony in support of this filing?

A. Yes. National Grid Witness William E. Avera is providing testimony in support of the rate of return on common equity and National Grid Witness Thomas F. Killeen is providing support of the Company's capital structure. National Grid's rate of return on common equity and capital structure are shown in Statement AV, which is sponsored by National Grid Witness Killeen.

III. Background:

Q. Please provide the history of the 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 New York Independent System Operator, Inc. ("NYISO"). On November 17, 1999, the NYTOs filed a joint settlement agreement among all parties except Sithe resolving all issues set for hearing in the same docket ("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 except Sithe and the Original MI Group, and a separate "filed" Revenue Requirement and Transmission Service Charge ("Filed TSC") governing service to Sithe and the Original MI Group. The NYISO Settlement also required the Company to make a compliance filing revising its Filed TSC under the NYISO OATT based on the final outcome of the hearing in Docket No. OA96-194-000. The NYISO Settlement was approved by the Commission by letter order dated July 31, 2000. National Grid subsequently filed to revise its Filed TSC rate on May 23, 2005 based on the final outcome of Docket No. OA96-194-000.

Q. What is the purpose of this filing?

A. In this filing, National Grid proposes to replace certain fixed components of the Wholesale TSC (for both the Filed TSC and the Settled TSC) with formula mechanisms to determine RR, CCC, and BU on a monthly annualized basis.

IV. Description of the Proposed Amendment

Q. How will Attachment H be affected by this filing?

A. Currently each of components RR, CCC, and BU is defined as a stated amount, as set forth in the rows of Table 1 of Attachment H that are identified under "Transmission Owner" as "Niagara Mohawk Power Corporation (Settlement OA96-194-000)" and "Niagara Mohawk Power Corporation (Filed OA96-000-194)." The proposed modification to Table 1 would delete those rows and replace them with a single row identified as "Niagara Mohawk Power Corporation." Each of the remaining cells in that row would refer to the new proposed Section 9.0 of Attachment H, which will be titled "Niagara Mohawk Power Corporation d/b/a National Grid Wholesale TSC Formula Components RR, CC, and BU." Both blacklined and clean versions of proposed Attachment H are provided as part of this filing.

Q. What rate methodology is National Grid proposing?

A. National Grid is proposing to introduce a formula rate methodology to determine the RR, CCC, and BU components of its Wholesale TSC in lieu of the stated values currently used for those components. The Wholesale TSC itself is a formula rate, as shown on Sheet 390 of Attachment H. The RR, CCC, and BU components will be derived by annualizing monthly amounts for such figures.

Q. Please explain the reasons behind this proposed rate methodology.

A. Allowing for monthly updates in a formula rate will ensure that the rates reflect National Grid's costs, including costs associated with new investments in transmission facilities. This will become increasingly important as National Grid upgrades its system and builds new transmission in New York to meet customer needs. National Grid has made significant investments in its transmission system since its Wholesale TSC rate was set using 1995 financial information. National Grid has committed publicly to invest at least $1.47 billion in its transmission and distribution system over 2007-2011. Of that amount, approximately $572 million is targeted for transmission investment. This represents an increase of approximately 36 percent over the gross transmission plant investment as of the end of 2007. National Grid also has filed with the New York Public Service Commission ("NYPSC") a capital investment plan under which the Company, with regulatory support from the NYPSC, could invest as much as $2.4 billion in transmission and distribution over the same five-year period. Of this higher amount, approximately $1,082 million would be targeted for transmission investment. National Grid's proposed approach to establishing formula rates based on monthly costs and rate base adjustments also is consistent with the formula rates in place in New England and is in accord with Commission precedent in other regions.

Q. What data is National Grid proposing to use for its calculation of RR?

A. National Grid proposes to calculate RR by annualizing its transmission revenue requirement for the month ended one month prior to the month in which the TSC rate is posted, minus any revenues received from providing wholesale transmission service not already reflected in the WR, CRR, or ECR components of the TSC.

Q. What data is National Grid proposing to use for its calculation of CCC?

A. National Grid proposes to calculate CCC by annualizing its monthly costs recorded in FERC accounts 561 and 561.2 for the transmission segment for the month ended one month prior to the month in which the TSC rate is posted.

Q. What data is National Grid proposing to use for its calculation of BU?

A. The BU component of the formula will initially be set as the annualized sum of National Grid estimated company total load adjusted for small generators (load modifiers), less estimated wholesale municipal loads, and estimated station power and station service loads. The estimate will be trued-up to the total load for National Grid as reported by the NYISO, including National Grid's NYPA program load, as soon as the NYISO data is made available. Any difference in the actual revenue received under the TSC using the estimated BU and TSC revenues as calculated using the BU reported by the NYISO will be included in the following months item J (Billing Adjustments) of National Grid's Revenue Requirement (RR). National Grid is proposing to forecast the load initially due to the several months delay (approximately five months) in receiving the NYISO load.

Q. Please explain how National Grid proposes to calculate its transmission revenue requirement.

A. As discussed above and illustrated in Statement BK, the transmission revenue requirement will be determined monthly based on the annualized sum of National Grid's (A) Return and Associated Income Taxes, (B) Transmission Related Depreciation Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Real Estate Tax Expense, (E) Transmission Related Amortization of Investment Tax Credits, (F) Transmission Operation and Maintenance Expense, (G) Transmission Related Administrative and General Expenses, (H) Transmission Related Payroll Tax Expense, less (I) Revenue Credits, plus (J) Billing Adjustments, and plus (K) Bad Debt Expense

Q. How is each of the transmission revenue requirement components derived?

A. As reflected in the proposed tariff sheets setting out the formula rate, items (B)-(H) are generally derived based on the monthly balances of FERC accounts tied to those items. Where transmission-specific cost information is not reported in a particular FERC account, account balances are apportioned to transmission using the appropriate allocation factors described in more detail later in my testimony.

Q. You use the qualifier "generally." Does your proposed formula reflect any adjustments to the data reported in the FERC accounts used in the derivation of items (B) – (H)?

A. Yes, National Grid proposes to adjust item (G) Administrative and General Expenses and item (B) Depreciation Expense of the formula. Consistent with FERC policy, Administrative and General expense is adjusted by excluding actual expenses incurred and recorded in account 926 for Post-Employment Benefits Other than the Pensions ("PBOP"), and then adding back the stated value for PBOP expense as determined by National Grid's actuary. The actuarial study supporting National Grid's stated PBOP expense is set forth in Exhibit NMP-47. PBOP expense as reflected in National Grid's TSC formula will remain at this stated value until PBOP expense is amended pursuant to Section 205 or 206 of the Federal Power Act. Depreciation Expense has been adjusted to include the depreciation associated with the Company's investment in Wholesale metering discussed earlier in my testimony.

Q. Please define item (A) Return and Associated Income Taxes.

A. Return and Associated Income Taxes will equal the product of the Transmission Investment Base and the Cost of Capital Rate.

Q. What are the components of the Transmission Investment Base?

A. The Transmission Investment Base is the sum of (a) Transmission Plant, plus (b) Transmission Related Electric General Plant, plus (c) Transmission related Common General Plant, plus (d) Plant Held for Future Use, less (e) Transmission Related Depreciation Reserve, less (f) Transmission Related Accumulated Deferred Taxes, plus (g) Transmission Related Loss on Reacquired Debt, plus (h) Transmission Related Regulatory Assets net of Regulatory Liabilities, plus, (i) Transmission Related Prepayments, plus (j) Transmission Related Materials and Supplies, plus (k) Transmission Related Cash Working Capital.

Q. How are the components of the Transmission Investment Base derived?

A. For the components (a) – (j), if transmission-specific data cannot be taken directly from National Grid monthly financial statements, National Grid total costs are apportioned to transmission using the appropriate allocation factors described in more detail later in my testimony. Transmission-related cash working capital (k) is derived by the product of 45 day (1.5 months) of the transmission-related operations and maintenance expense and the transmission-related administrative and general expense.

Q. Are there any adjustments made to the reported National Grid total Company data used in determining National Grid Transmission Investment Base?

A Yes, National Grid has adjusted three components of total Company data used to determine Transmission Investment Base: Regulatory Assets and Liabilities,Total Accumulated Deferred Taxes and Transmission Plant. First, because the only regulatory assets carried on National Grid's books of account applicable to wholesale transmission service are those related to FAS 109 and excess AFUDC, all other regulatory assets and liabilities have been excluded from the calculation of National Grid's Transmission Investment Base. Second, for the same reason, total electric Accumulated Deferred Taxes as reported in the accounts and records for National Grid have been adjusted to exclude the deferred taxes associated with the generation-related stranded cost regulatory asset. Finally, an adjustment has been made to Transmission Plant to include the Company's investment in any wholesale revenue or remote terminal Unit (RTU) meters and associated equipment found in account 370.3 as shown in Statement BK, page 3 and the associated workpapers.

Q. What is the capital structure that will be used for calculating National Grid's overall rate of return?

A. National Grid is proposing to use the Company's actual capital structure, as discussed in the testimony of Witness Avera.

Q. How is the Cost of Capital Rate determined?

A. The Cost of Capital Rate is equal to the Weighted Cost of Capital plus the federal and state income tax rates. The Weighted Cost of Capital is determined by multiplying the relative percentages of National Grid's actual capital structure for long term debt, preferred stock and common equity times the corresponding cost rate (that is, the actual cost rates for the long term debt and preferred stock components and the proposed return on equity for the common equity component.),

Q. How are the state and federal income tax rates determined?

A. The state and federal income tax rate components of the Cost of Capital Rate are derived from the currently effective statutory federal and state income tax rates.

Q. Are there any further adjustments made to the Cost of Capital Rate?

A. Yes. The formula makes an adjustment for future recovery of FAS 109 expense. This is done by applying the state and federal income tax rates to the ratio of the depreciation component of equity AFUDC over the investment base in addition to the preferred stock and common equity. An example of the calculation is provided on Page 5, of Statement BK. However, as shown in statement BK, page 5 National Grid does not record any equity AFUDC at this time. Therefore, no actual adjustment is currently being made.

Q. What rate return on common equity is used to calculate the Cost of Capital Rate?

A. As determined by and explained in the testimony of Witness Avera, I have used a rate of return on common equity of 12.4%.

Q. What is the derivation of formula rate item (I) Revenue Credits?

A. As defined in Statement AU, we are crediting any wholesale transmission revenues reported in FERC account 456 that are not otherwise already captured in the Wheels Through and Export Transactions (WR), Congestion Payments (CRR), and Net Congestion Rents (ECR) components of the Wholesale TSC formula.

Q. Please explain formula rate item (K) Bad Debt expense

A. Bad Debt expense is defined as any expense reported in FERC Account 904 that can be directly attributable to National Grid wholesale transmission billing.

Q. Please describe the allocation factors used to determine transmission related components of the formula.

A. There are three allocation factors used: the Electric Wages and Salaries Allocation Factor, the Transmission Plant Allocation Factor and the Wages and Salaries Allocation Factor. The derivation of each is shown on page 2 of statement BK.

Q Please explain the derivation of each of the three allocation factors.

A. The Transmission Plant Allocation Factor is equal to Total Transmission Plant in Service divided by the sum of Total Transmission Plant in Service plus Total Distribution Plant in Service. Plant balances used for determining the allocation factors are defined by reference to the FERC accounts. The specific FERC accounts are directly referenced in our proposed formula rate. Electric Wages and

Salaries Factor is the ratio of National Grid total electric direct wages and salaries (including any related wages and salaries charged to National Grid by a National Grid Affiliate) to National Grid's total gas and electric wages and salaries (including any wages and salaries charged to National Grid by a National Grid Affiliate), but excluding all administrative and general salaries). The Transmission Wages and Salaries Allocation Factor is the ratio of National Grid's total direct transmission wages and salaries (including any transmission related wages and salaries charged to National Grid by a National Grid affiliate) to National Grid's total direct electric wages and salaries (including any wages and salaries charged to National Grid by a National Grid Affiliate, but excluding all administrative and general salaries). An illustration of how the wages and salaries allocator is determined is provided on page 2 of Statement BK, and the associated workpapers provided in Exhibit NMP-47..

Q. Please identify the components of the formula to which the Electric Wages and Salaries Allocation Factor will be applied.

A. The Electric Wages and Salaries Allocation Factor is applied to determine the electric portion of the electric and gas ratebase and expense items. The Electric Wages and Salaries Allocation Factor is applied to National Grid electric and gas Common General Plant, Common General Plant Depreciation Reserve, Common General Plant Depreciation Expense, Prepayments, Total Loss on Reacquired Debt, Amortization of Loss on Reacquired Debt, Construction Materials and Supplies and Plant Held for Future Use.

Q. Please identify the formula components to which the Transmission Plant Allocation Factor will be applied.

A. The Transmission Plant Allocation Factor is applied to determine the transmission portion of the electric rate base and expense items. The Transmission Plant Allocation Factor is applied to National Grid's electric Accumulated Deferred Income Taxes, Other Regulatory Assets and Liabilities, Amortization of Investment Tax Credits and Real Estate Tax Expense. Additionally the Transmission Plant Allocation Factor is applied to National Grid's electric Prepayments, Total Loss on Reacquired Debt. Amortization of Loss on Reacquired Debt, and Construction Materials and Supplies, which were previously allocated using the Electric Wages and Salaries Allocation Factor.

Q. Please identify the formula components to which the Transmission Wages and Salaries Allocation Factor will be applied.

A. The Transmission Wages and Salaries Allocation Factor is applied to determine the transmission portion of electric ratebase and expense items. The Transmission Wages and Salaries Allocation Factor is applied to National Grid's Electric General Plant, Electric General Plant Depreciation Reserve, Electric General Plant Depreciation Expense, Electric Payroll Taxes and Electric Administrative and General Expense. Additionally, the Transmission Wages and Salaries Allocation Factor is applied to Common General Plant, Common General Plant Depreciation Reserve, Common General Plant Depreciation Expense, and Plant Held for Future Use, which were previously allocated using the Electric Wages and Salaries Allocation Factor.

Q. Are the monthly values proposed in the formula rate taken directly from the FERC Form 1?

A. No. In order to match revenues and expenses as closely as possible, National Grid proposing to annualize monthly cost and usage data based on the Company's monthly financial statements. National Grid's monthly financial statements are the basis for the data reported in National Grid's FERC Form 1. This means that gross investment for each identified transmission asset, among other items, will be updated monthly, and that over the course of a year that item will be consistent with the information provided in the FERC Form 1. The monthly updates will utilize National Grid's plant accounting records, in which each National Grid transmission asset is assigned a unique designator that enables the Company to maintain an accurate record of all plant additions and retirements related to a specified asset.

Q. Will National Grid continue to post rates by the 14th of each month?

A. Yes, we will adhere to that requirement under the OATT. However, as is currently the practice with the Wheels Through and Export Transactions Revenue (WR) component, we will use data from the month ended one month prior to the month in which the TSC rate is posted for our calculations.

Q. Why is National Grid proposing to amend the RR, CCC, and BU components of the TSC rate at this time?

A. We have determined that the current National Grid fixed components of the Wholesale TSC rates do not reasonably reflect National Grid's costs of providing transmission service.

Q. Please explain the impact of the proposed formula on National Grid's wholesale customers.

A. Statement BH shows the overall rate increase relative to the current RR component. Based on the historical calendar year 2006 information, on average Wholesale TSC customers of National Grid will see a 71% increase from their current Wholesale TSC rate. Our estimates show that this equates to an overall bill impact to the average residential customer of the municipal utilities taking the TSC rate of five to fifteen percent, depending on the rate structure of that utility.

Q. What are the key drivers behind the increase in rates?

A. As stated earlier in my testimony, National Grid has been making significant investments in its transmission system since the Wholesale TSC rate was set using 1995 financial information. National Grid is committed to continuing to replace assets and to invest in technology to improve reliability, accommodate changes brought on by growth, and facilitate energy efficiency and implement state environmental policies.

Q. Have you provided an example of how the Wholesale TSC formula operates before and after the proposed changes to the RR, CCC and BU components?

A. Yes. Schedule BL shows the monthly Wholesale TSC calculation for National Grid for 2006 using both actual data and using the proposed formula.

Q. Thank you I have no further questions at this time

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Niagara Mohawk Power Corporation   Docket No. ER08-___________

DECLARATION OF PAMELA A. VIAPIANO

I, Pamela A. Viapiano, do hereby declare under penalty of perjury under the laws of the United States of America that I am the Pamela A. Viapiano referred to in the document entitled "Direct Testimony of Pamela A. Viapiano;" that I have read such testimony and am familiar with the contents thereof; and that the facts set forth therein are true and correct to the best of my knowledge, information, and belief.

Pamela A. Viapiano

Pamela A. Viapiano

ATTESTATION
(18 C.F.R. § 35.13 (d)(6))

I, Pamela A. Viapiano, Vice President of Transmission Finance of National Grid USA Service Company, Inc., hereby attest that, to the best of my knowledge, information, and belief, the cost of service statements and supporting data submitted in this filing are true, accurate and current representations of the books, budgets and other corporate documents of Niagara Mohawk Power Corporation d/b/a National Grid.

Pamela A Viapiano

Pamela A. Viapiano

FERC Docket No. ER08-_____
Witness: William E. Avera
Exhibit No. NMP-2

UNITED STATES OF AMERICA
BEFORE
THE FEDERAL ENERGY REGULATORY COMMISSION

	)	
Niagara Mohawk Power Corporation	)	Docket No. ER08-___-000
d/b/a National Grid	)	

DIRECT TESTIMONY OF WILLIAM E. AVERA

FINCAP, Inc.
3907 Red River
Austin, Texas 78751
(512) 458-4644

FERC Docket No. ER08-_____
Witness: William E. Avera
Exhibit No. NMP-2

DIRECT TESTIMONY OF WILLIAM E. AVERA

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DIRECT TESTIMONY OF WILLIAM E. AVERA

I. INTRODUCTION AND EXPERIENCE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. William E. Avera, 3907 Red River, Austin, Texas, 78751.

Q. IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am the President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

A. Qualifications

Q. WHAT ARE YOUR QUALIFICATIONS?

A. I received a B.A. degree with a major in economics from Emory University. After serving in the U.S. Navy, I entered the doctoral program in economics at the University of North Carolina at Chapel Hill. Upon receiving my Ph.D., I joined the faculty at the University of North Carolina and taught finance in the Graduate School of Business. I subsequently accepted a position at the University of Texas at Austin where I taught courses in financial management and investment analysis. I then went to work for International Paper Company in New York City as Manager of Financial Education, a position in which I had responsibility for all corporate education programs in finance, accounting, and economics.

In 1977, I joined the staff of the Public Utility Commission of Texas ("PUCT") as Director of the Economic Research Division. During my tenure at the PUCT, I managed a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems, and I testified in cases on a variety of financial and economic issues. Since leaving the PUCT in 1979, I have been engaged as a consultant. I have participated in a wide range of assignments involving utility-related matters on behalf of utilities, industrial customers, municipalities, and regulatory commissions. I have previously testified before the Federal Energy Regulatory Commission ("FERC" or the "Commission"), as well as the Federal Communications Commission ("FCC"), the Surface Transportation Board (and its predecessor, the Interstate Commerce Commission), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies, courts, and legislative committees in over 30 states.

In 1995, I was appointed by the PUCT, with the approval of the Governor, to the Synchronous Interconnection Committee to advise the Texas legislature on the costs and benefits of connecting Texas to the national electric transmission grid. In addition, I served as an outside director of Georgia System Operations Corporation, the system operator for electric cooperatives in Georgia.

I have served as Lecturer in the Finance Department at the University of Texas at Austin and taught in the evening graduate program at St. Edward's University for twenty years. In addition, I have lectured on economic and regulatory topics in programs sponsored by universities and industry groups. I have taught in hundreds of educational programs for financial analysts in programs sponsored by the Association for Investment Management and Research, the Financial Analysts Review, and local financial analysts societies. These programs have been presented in Asia, Europe, and North America, including the Financial Analysts Seminar at Northwestern University. I hold the Chartered Financial Analyst (CFA®) designation and have served as Vice President for Membership of the Financial Management Association. I have also served on the Board of Directors of the North Carolina Society of Financial Analysts. I was elected Vice Chairman of the National Association of Regulatory Commissioners ("NARUC") Subcommittee on Economics and appointed to NARUC's Technical Subcommittee on the National Energy Act. I have also served as an officer of various other professional organizations and societies. A resume containing the details of my experience and qualifications is attached as Exhibit No. NMP-3.

B. <u>Overview</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present to the Commission my independent analysis of a fair rate of return on equity ("ROE") range of reasonableness for the jurisdictional transmission operations of Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid" or "the Company"), as well as a specific ROE from within my range of reasonable returns. My evaluation considered FERC's established precedent and policy objectives, Commission rulemaking,[1] industry

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[1] Promoting Transmission Investment through Pricing Reform, Order No. 679, 116 FERC ¶ 61,057 (July 20, 2006) ("*Order No. 679*"); Order No. 679-A, 117 FERC ¶ 61,327 (Dec. 22, 2006) ("*Order No. 679A*").

fundamentals, and independent estimates of the ROE for a benchmark group of electric utilities.

Q. PLEASE SUMMARIZE THE BASIS OF YOUR KNOWLEDGE AND CONCLUSIONS CONCERNING THE ISSUES TO WHICH YOU ARE TESTIFYING IN THIS CASE.

A. To prepare my testimony, I used information from a variety of sources that would normally be relied upon by a person in my capacity. In connection with the present filing, I considered and relied upon corporate disclosures, publicly available financial reports and filings, and other published information relating to National Grid. In addition, I am familiar with FERC policy generally and have submitted testimony in various proceedings at the Commission dealing with required rates of return for transmission facilities, including Docket No. ER00-3316-000 on behalf of American Transmission Company, LLC, Docket No. ER02-485-000 involving the Midwest Independent Transmission System Operator, Inc., Docket No. ER03-343-000 on behalf of International Transmission Company, and Docket No. ER04-157-000 on behalf of the transmission-owning members of the ISO New England, Inc., the New England Regional Transmission Organization ("New England RTO"). I also reviewed information relating generally to capital markets and specifically to investor perceptions, requirements, and expectations for regulated utilities in a restructured wholesale electric power market. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of ROE issues affecting National Grid and are the basis of my conclusions.

Q. WHAT IS THE ROLE OF THE RETURN ON EQUITY IN SETTING A UTILITY'S RATES?

A. The rate of return on common equity compensates shareholders for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the Supreme Court in the *Bluefield*[2] and *Hope*[3] cases, a utility's allowed return on common equity should be sufficient to: (1) fairly compensate capital invested in the utility, (2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity.

Q. HOW DID YOU GO ABOUT DETERMINING THE ROE RANGE OF REASONABLENESS FOR NATIONAL GRID?

A. In order to calculate the ROE zone of reasonableness for National Grid, I first reviewed the operations and finances of National Grid, as well as the general conditions in the electric utility industry. With this background, I examined current capital market conditions and conducted various quantitative analyses to estimate the current cost of equity. Specifically, I relied on the Discounted Cash Flow ("DCF") methodology currently prescribed by this Commission and applied to a proxy group of electric utilities. In addition, I validated the results of my DCF analysis against supplemental ROE benchmarks prepared utilizing 1) the Capital

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[2] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).
[3] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

Asset Pricing Model ("CAPM") and 2) expected earned rates of return expected for utilities.

C. Summary and Conclusions

Q. WHAT IS YOUR RECOMMENDED BASE ROE FOR NATIONAL GRID?

A. I recommend a base ROE for National Grid of 11.9 percent, which is equal to the midpoint of the 7.9 percent to 15.9 percent zone of reasonableness produced by applying the Commission's DCF approach to a proxy group of electric utilities.

The reasonableness of my recommended base ROE range for National Grid is also supported by the results of the CAPM and expected earnings methods and the need to consider flotation costs.

Q. IS NATIONAL GRID ENTITLED TO AN ROE ADJUSTMENT ATTRIBUTABLE TO ITS PARTICIPATION IN A REGIONAL TRANSMISSION ORGANIZATION?

A. Yes. Under established Commission policy, as affirmed by *Order Nos. 679* and *679-A*, electric utilities that join and remain in a FERC-approved Transmission Organization, including an independent system operator ("ISO"), may request an ROE incentive. Specifically, the Commission has consistently authorized a 50 basis point adder to encourage continued membership in a Transmission Organization, which is in addition to the baseline ROE. Apart from established Commission policy, consideration of an incentive for membership in a Transmission Organization is confirmed by the consensus view of industry stakeholders and investors that higher returns are necessary to facilitate timely investment and stimulate expansion of the transmission infrastructure. Considering National Grid's ongoing membership in an ISO and its active support for and participation in a regional planning process, I recommend that the

Commission incorporate an incentive adder for Transmission Organization participation of 50 basis points, resulting in a midpoint ROE of 12.4 percent.

In evaluating the ROE for jurisdictional transmission operations, it is important to consider the uncertainties associated with National Grid and the challenges National Grid faces in raising capital for transmission investment – including a renewed focus on regulatory uncertainties. In addition, the allowed ROE for National Grid must reflect the need to provide returns that are sufficient to meet the established policy goal of encouraging participation in approved Transmission Organizations and promoting capital investment in transmission, while recognizing investors' renewed focus on the associated risks. Taken together, these considerations confirm the reasonableness of my recommended range and support an ROE for National Grid above the midpoint of the DCF range for the proxy group.

II. FUNDAMENTAL ANALYSES

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. As a predicate to my economic and capital market analyses, this section examines conditions in the utility industry generally, and for National Grid specifically, that investors consider in evaluating their required rate of return. An understanding of these fundamental factors, which drive the risks and prospects of National Grid, is essential to develop an informed opinion about investor expectations and requirements that form the basis of a fair ROE.

A. National Grid

Q. BRIEFLY DESCRIBE NATIONAL GRID AND ITS ELECTRIC UTILITY OPERATIONS.

A. National Grid is a wholly owned subsidiary of National Grid USA, which in turn is an indirect, wholly owned subsidiary of U.K.-based National Grid plc. Headquartered in Syracuse, New York, National Grid is principally engaged in providing regulated electric and gas utility service. The Company provides electric transmission and distribution services to approximately 1.5 million customers and sells, transports, and distributes natural gas to approximately 571,000 customers, all of whom are located in upstate New York. While National Grid formerly operated as an integrated electric utility, the Company restructured its electric utility operations, completing the sale of its generation assets in 1999. As a result, its electric operations now consist of its retail delivery and wholesale transmission operations. In addition to power delivery, as provider of last resort ("POLR") National Grid is also obligated to arrange for electric supply for those retail customers who have not elected an alternative competitive electric energy supplier. National Grid purchases the power supply required to satisfy its POLR obligations under long-term contracts with various suppliers and meets a portion of its energy needs through the wholesale electricity market. At year-end 2006, National Grid had total assets of $12.2 billion, with total revenues amounting to approximately $4.1 billion.

National Grid's electric transmission system consists of approximately 10,500 miles of overhead and underground lines and 706 substations. The Company is a member of the New York Independent System Operator ("NYISO"), a FERC-approved ISO, and has turned over functional control of its transmission facilities to NYISO. The Company provides regional transmission service pursuant to the NYISO Open Access Transmission Tariff ("OATT").

Q. PLEASE DESCRIBE NATIONAL GRID PLC.

A. Based in London, England, National Grid plc is an international electricity and gas company and one of the largest investor-owned energy companies in the world. National Grid plc owns the high-voltage electricity transmission network in England and Wales and operates the system across Great Britain. It also owns and operates the high pressure gas transmission system in Britain and its distribution business delivers gas to 11 million homes and businesses. In the US, National Grid plc's subsidiaries distribute electricity to nearly five million customers in Massachusetts, New Hampshire, New York and Rhode Island. As a result of a recently consummated merger with KeySpan Corporation ("KeySpan"), National Grid plc currently owns 6,650 megawatts of electricity generation.[4] Through its local distribution company subsidiaries, National Grid plc is also the largest distributor of natural gas in the northeastern U.S., providing service to 3.4 million customers in New York, Massachusetts, New Hampshire and Rhode Island.

Q. WHERE DOES NATIONAL GRID OBTAIN THE CAPITAL USED TO FINANCE ITS INVESTMENT IN ELECTRIC UTILITY PLANT?

A. As a wholly-owned subsidiary of National Grid plc, National Grid obtains equity capital solely from its parent, whose common stock is listed on the London Stock Exchange and publicly traded on the New York Stock Exchange through the

[4] As a condition of the merger, National Grid agreed to the divestiture of the Ravenswood Station.

American Depository Receipt system. In addition to capital supplied by National Grid plc, National Grid also issues debt securities directly under its own name.

National Grid will require capital investment to meet customer growth, provide for necessary maintenance and replacements of its utility infrastructure, as well as fund new investment in electric transmission and distribution facilities. National Grid is committed to addressing both economic and reliability needs in New York, whether or not these needs arise in the Company's transmission district. In particular, National Grid has committed to the New York Public Service Commission to invest at least $1.47 billion in its transmission and distribution system over five years in connection with the National Grid plc/KeySpan merger.

Q. WHAT CREDIT RATINGS ARE ASSIGNED TO NATIONAL GRID?

A. Currently, National Grid is assigned a corporate credit rating of "A-" by Standard & Poor's Corporation ("S&P"), with Moody's Investors Service ("Moody's") assigning the Company an issuer rating of "Baa1". While Moody's recently announced its decision to downgrade the ratings of three other sister subsidiaries of National Grid – New England Power Company, Massachusetts Electric Company, and Narragansett Electric Company – it has placed National Grid under review for a possible upgrade, noting the Company's historically lower ratings relative to National Grid plc's other U.S. subsidiaries.[5]

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[5] Moody's Investors Service, "Some National Grid USA Subsidiaries' Ratings Lowered," *Credit Perspectives* (Sep. 3, 2007).

Q. BRIEFLY DESCRIBE THE NYISO.

A. Based near Albany, New York, the NYISO is a not-for-profit corporation established to manage the operation of most of the bulk power electric transmission assets of its member utilities. The NYISO began its oversight responsibilities in 1999 and coordinates the movement of wholesale electricity throughout New York State. Governed by a 10-member Board of Directors, none of who are affiliated with market participants, the NYISO manages a transmission network of approximately 10,775 miles of high-voltage lines over a service area with a peak demand of almost 34,000 megawatts ("MW") and annual load of approximately 166.9 million megawatt hours ("MWh").

The primary objectives of the NYISO include ensuring open access to bulk electric power lines and maintaining and enhancing transmission system reliability. The NYISO performs security coordination, tariff administration, real-time system monitoring, and the other functions of an ISO. The NYISO has authority for operational control of the system under a contract with National Grid and other New York transmission owners ("TOs"), which specifies the specific facilities under its purview. The NYISO TOs retain ownership and maintenance responsibility for their transmission assets and perform many operational functions in coordination with the NYISO. The NYISO is responsible for assessing and identifying reliability needs of the regional bulk power transmission system, while the NYISO TOs are responsible for planning to meet their respective local transmission needs.

B. Electric Power Industry

Q. WHAT GENERAL CONDITIONS HAVE CHARACTERIZED THE ELECTRIC POWER INDUSTRY?

A. Since the 1990s, the industry has experienced significant structural change resulting from market forces and regulatory initiatives. At least initially, this process was largely driven by regulatory reforms at the federal level. The Energy Policy Act of 1992 greatly increased prospective competition for the production and sale of power at the wholesale level, with FERC being a proponent for actions designed to foster greater competition in markets for wholesale power supply.

In April 1996, this Commission adopted Order No. 888,[6] which mandated open access to the wholesale transmission facilities of jurisdictional electric utilities. The Commission later addressed improvements to the transmission system, including the establishment of Transmission Organizations such as ISOs and Regional Transmission Organizations ("RTO"), in Order No. 2000 and has continued to pursue the goal of creating "seamless" wholesale power markets that facilitate transactions across transmission grid boundaries, among other objectives. More recently, in response to the passage of the Energy Policy Act of 2005 ("EPAct"), FERC issued its *Order Nos. 679* and *679-A*, establishing

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[6] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 1991-1996 FERC Stats. & Regs., Regs. Preambles ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 1996-2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *reh'g denied*, Order No. 888-C, 82 FERC ¶ 61.046 (1998), *aff'd in part and remanded in part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002)

incentive-based rate treatments to promote participation in Transmission Organizations and greater capital investment in electric utility infrastructure.

Q. WHAT IMPACTS HAVE RECENT EVENTS HAD ON INVESTORS' RISK PERCEPTIONS FOR FIRMS INVOLVED IN THE ELECTRIC POWER INDUSTRY?

A. Events of the decade caused investors to rethink their assessment of the relative risks associated with the electric power industry. A well-publicized energy crisis in the West wreaked havoc on regional energy markets and had dramatic repercussions for investors and utilities nationwide. Beyond causing state regulators and legislators to re-evaluate industry restructuring plans for the retail sector, the financial implications of the Western experience demonstrated the risks facing the electric power industry.

Q. WAS THERE A CORRESPONDING IMPACT ON THE INDUSTRY'S CREDIT STANDING?

A. Yes. The years following the Western power crisis witnessed steady erosion in credit quality throughout the utility industry, both as a result of revised perceptions of the risks in the industry and the weakened finances of the utilities themselves. For example, during 2002, S&P recorded 182 downgrades in the utility industry, versus only fifteen upgrades,[7] while Moody's downgraded 109 utility issuers and upgraded three.[8] Credit quality continued to decline during 2003, with S&P reporting that downgrades outpaced upgrades by more than

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[7] Standard & Poor's Corporation, "U.S. Power Industry Experiences Precipitous Credit Decline in 2002; Negative Slope Likely to Continue," *RatingsDirect* (Jan. 15, 2003).
[8] Moody's Investors Service, *Credit Perspectives* (Jul. 14, 2003) at 33.

fifteen to one in the fourth quarter of 2003.[9] S&P reported in 2007 that the majority of the companies in the utility sector now fall in the triple-B rating category and noted a continued negative bias in the credit outlook.[10]

Q. IS THE POTENTIAL FOR ENERGY MARKET VOLATILITY AN ONGOING CONCERN FOR INVESTORS?

A. Most definitely. Investors recognize that the prospect of further turmoil in energy markets cannot be discounted. S&P has reported continued spikes in wholesale market prices since the Western power crisis,[11] with average day-ahead prices within certain NYISO zones also experiencing significant fluctuation.[12] Moody's recently noted continued exposure to "extremely volatile" energy commodity costs, including purchased power prices.[13] Similarly, the Commission Staff has continued to recognize the ongoing potential for market disruption, as a 2007 market assessment report concluded:

> Prices are likely to remain a concern. Last year we monitored transactions above the $400 per megawatt hour Western soft cap due to scarcity at peak. Given the likelihood of higher-priced natural gas in

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[9] Standard & Poor's Corporation, "U.S. Utilities' Ratings Decline Continued in 2003, But Pace Slows," *RatingsDirect* (Feb. 2, 2004).

[10] Standard & Poor's Corporation, "U.S. Electric Utilities Continued Their Long Shift To Stability In Third Quarter," *RatingsDirect* (Oct. 23, 2007).

[11] Standard & Poor's Corporation, "Fuel and Purchased Power Cost Recovery In The Wake Of Volatile Gas And Power Markets – U.S. Electric Utilities To Watch," (Mar. 22, 2006).

[12] For example, FERC reported that the 30-day rolling average day-ahead price for the Long Island Zone climbed from approximately $75 per MWh in June 2006 to $150 per MWh in August 2006, with daily average day-ahead prices spiking to over $325 per MWh during August 2006. http://www.ferc.gov/market-oversight/mkt-electric/new-york.asp.

[13] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* at 6 (Aug. 2007).

> the West this year, extreme weather could easily raise prices to the peak level again in summer 2007.[14]

The report noted that electricity markets in the Northeast were experiencing double-digit price increases and expressed ongoing concern regarding tight supply and congestion.[15] FERC continues to warn of load pockets vulnerable to periods of high peak demand and unplanned outages of generation or transmission capacity and ongoing reliability concerns led FERC to establish mandatory standards for the bulk power system.[16]

Additionally, in recent years utilities and their customers have also had to contend with dramatic fluctuations in gas costs due to ongoing price volatility in the spot markets.[17] S&P concluded that "natural gas prices have proven to be very volatile" and warned of a "turbulent journey" due to the uncertainty associated with future fluctuations in energy costs.[18] Fitch also highlighted the challenges that fluctuations in commodity prices can have for utilities and their investors, concluding, "Historically high and volatile commodity prices will continue to affect nearly the entire power and gas sector."[19]

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[14] Federal Energy Regulatory Commission, Office of Market Oversight and Investigations, "Summer Energy Market Assessment 2007," at 14 (May 17, 2007).

[15] *Id.* at 4 and 15.

[16] See *Open Commission Meeting Statement of Chairman Joseph T. Kelliher*, Items E-13: Mandatory Reliability Standards for the Bulk-Power System (Docket No. RM06-16-000) (March 15, 2007).

[17] For example, the Energy Information Administration reported that the average price of gas used by electricity generators (regulated utilities and non-regulated power producers) spiked from an average price of $7.18 per Mcf for the first eight months of 2005 to over $11.00 per Mcf in September and October (http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_ nus_m.htm).

[18] Standard & Poor's Corporation, "Top Ten Credit Issues Facing U.S. Utilities," *RatingsDirect* (Jan. 29, 2007).

[19] Fitch Ratings, Ltd., "U.S. Power and Gas 2007 Outlook," *Global Power North American Special Report* (Dec. 15, 2006) at 1.

In addition, while coal and nuclear power have historically provided relative stability with respect to fuel costs, rising prices have raised investors' concerns. In a 2004 article entitled "Rising Coal Prices May Threaten U.S. Utility Credit Profiles," S&P noted that:

> [S]everal current and structural developments for the coal mining industry have resulted in a dramatic increase in spot coal prices.[20]

More recently, the Energy Information Administration ("EIA"), a statistical agency of the U.S. Department of Energy ("DOE"), reported that average delivered coal prices for electric utilities increased 9.7 percent in 2006, the sixth consecutive annual rise.[21] Similarly, the EIA documented an increase of 30 percent in the weighted-average price paid for uranium oxide equivalent over 2006.[22] At the same time, heightened environmental awareness, particularly over carbon and other emissions, has increased exposure to mandated remediation and other compliance costs.

Q. HAVE INVESTORS RECOGNIZED THAT ELECTRIC UTILITIES FACE ADDITIONAL RISKS BECAUSE OF THE IMPACT OF INDUSTRY RESTRUCTURING ON TRANSMISSION OPERATIONS?

A. Yes. Policy evolution in the transmission area has been wide reaching and investors' focus on regulatory change in their assessment of risks and prospects was exemplified by S&P:

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[20] Standard & Poor's Corporation, "Rising Coal Prices May Threaten U.S. Utility Credit Profiles," *RatingsDirect* (Aug. 12, 2004).
[21] Energy Information Administration, *Annual Coal Report 2006* at 9 (Nov. 2007).
[22] Energy Information Administration, *2006 Uranium Marketing Annual Report* (May 16, 2007).

> The FERC is in the process of changing every aspect of the electric utility landscape, with industry sages anticipating further transmission and wholesale market development guidance, which could affect the segment's credit prospects and quality. ... Uncertainty will exist until operating rules are in place and have stabilized.[23]

More recently, S&P confirmed a "continued lack of clarity from lawmakers and regulators on the regulatory framework surrounding transmission projects."[24]

Transmission operations have become increasingly complex and investors have recognized that difficulties in obtaining permits and uncertainty over the adequacy of allowed rates of return have contributed to heightened risk and fueled concerns regarding the adequacy of investment in the transmission sector of the electric power industry. At the same time, the development of competitive wholesale power markets has resulted in increased demand for transmission resources. Concerns regarding the need to encourage further investment in the transmission sector were exemplified by the Commission's observations in *Order No. 679*.[25] Consistent with these findings, the Commission cited the platform for system expansion provided by regional Transmission Organizations, along with other well-documented benefits, in support of its decision to provide an incentive ROE for utilities that join and remain in organizations such as the NYISO.[26]

The challenges posed by an increasingly complex marketplace heighten the uncertainties associated with transmission operations while requiring the commitment of significant new capital investment to maintain and enhance

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[23] Standard & Poor's Corporation, "Electric Transmission at the Starting Gate," *RatingsDirect* (May 10, 2002).
[24] Standard & Poor's Corporation, "Capital Spending On Electric Transmission Is On The Upswing Around The World," *RatingsDirect* (Aug. 7, 2006).
[25] See, *e.g.*, *Order No. 679* at P 10.
[26] *Order No. 679-A* at P 86 & 87.

service capabilities. Early on, the DOE noted the importance of regulatory policies in supporting economic rewards that stimulate investment in new transmission:

> The economic rewards from improving the transmission system must be greater than the rewards from maintaining the status quo or decreasing the system's ability to reliably support fair and efficient competitive wholesale markets. ...The key to spurring new transmission investment lies in ensuring that the rewards offered by this system of regulation are commensurate with the risks of undertaking these investments and finding innovative approaches to align costs and benefits.[27]

As the Commission has concluded, encouraging membership in Transmission Organizations is consistent with the EPAct and provides further support for expansion of transmission infrastructure.

Q. CAN YOU DESCRIBE MORE FULLY THE REGULATORY RISKS THAT INVESTORS ASSOCIATE WITH TRANSMISSION OPERATIONS?

A. Yes. First, investors understand that there is always the potential that regulators will prevent the recovery of the full costs associated with new investment in transmission. They remember the amount of money that was disallowed by regulators through after-the-fact reviews in connection with the construction of generating projects in the 1980s and 1990s, and factor into their expectations the possibility of future cost disallowances. There is no evidence that this exposure has ended with restructuring, and investors have no reason to believe that regulators and intervenors will be less vigorous in pursuing potential

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[27] U.S. Department of Energy, *National Transmission Grid Study* (May 2002).

disallowances with respect to transmission than they have been in the past with respect to generation projects. As Moody's observed:

> [T]here are concerns arising from the sector's sizeable infrastructure investment plans in the face of an environment of steadily rising operating costs. Combined, these costs and investments can create a continuous need for regulatory rate relief, which in turn can increase the likelihood for political and/or regulatory intervention.[28]

Similarly, S&P concluded, "Any potential for after-the-fact prudence reviews and cost disallowances would stop transmission investment in its tracks by raising risks past the balance with the returns offered by such investments."[29]

Second, investors in transmission take into account the possibility that future regulators might deem long-lived transmission assets to be obsolete because of technological change or competition from alternatives. For example, if distributed generation becomes a major new source of supply, it may reduce the need for existing transmission assets. Thus, investors perceive a long-term risk in the potential for full recovery of costs associated with transmission.

Third, investors recognize that there are federal-state jurisdictional issues involving transmission, and that even if the Commission permits the costs of transmission to be recovered through FERC rates, there is no assurance that utilities will be able to obtain full and timely recovery of these costs from retail customers, which is where the majority of the money must come from to repay National Grid and the other NYISO TOs. Investors believe that operating a

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[28] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* (Aug. 2007).

[29] Standard & Poor's Corporation, "Capital Spending on Electric Transmission Is on the Upswing Around the World," *RatingsDirect* (Aug. 7, 2007).

capital intensive business in a regulatory "no-man's land" created by multiple jurisdictions means higher risk. This is a consideration that is not lost on potential investors as the NYISO TOs undertake the capital investment program contemplated under the regional expansion plan.

Finally, investors recognize that utilities incur substantial up front costs to design transmission projects and then obtain siting approvals for them, and that regulators or customer groups may try to deny these utilities recovery of the associated costs if the projects are unable to obtain the required approvals. The investment community understands that regulation can lead to a significant lag between the time an investment is made and when the costs are reflected in rates and that these up front capital costs may be tied up without earning an actual return for several years before the outcome of siting issues are decided.

Consider New York Regional Interconnection ("NYRI"), for example, which is seeking approval to construct approximately 200 miles of 1,200 MW direct current transmission line to link the New York metropolitan area with upstate New York. NYRI would fall within one of two National Interest Electric Transmission Corridors ("NIETC") designated by the DOE, which allows FERC backstop siting authority to approve transmission lines that have not received state regulatory approval within one year. Despite this designation, NYRI remains bogged down in the face of fierce opposition on multiple fronts, including protracted regulatory and legal disputes.

Virtually all industry stakeholders have recognized that regulatory uncertainties increase the risks associated with the utility industry. For example, the DOE identified "reducing regulatory uncertainty" as critical in stimulating increased investment in the power industry and has noted that lack of clarity in the regulatory structure was inhibiting planning and investment.[30] More recently, Moody's confirmed investors' ongoing concerns regarding the financial and regulatory pressures associated with sizable infrastructure investment and rising capital expenditures.[31]

Q. IS THERE ANY INDICATION THAT THESE UNCERTAINTIES CAN IMPACT INVESTORS' WILLINGNESS TO SUPPLY CAPITAL?

A. Yes. As early as 2003, the *Wall Street Journal* cited the debilitating impact of an "unsteady regulatory environment" and the "chaotic combination of regulated and deregulated markets" in explaining inhibitions to increased investment in the electric utility system.[32] Similarly, S&P warned investors that the partial reforms presently characterizing wholesale power markets invite dysfunction and that elevated risks will discourage new capital, "or at least make it more expensive." S&P observed:

> Investors should not expect that such risk will dissipate any time soon. Instead, credit risk could actually intensify if the politically charged debate over reform continues for years, as it might very well do. And even if policy makers succeed in crafting a comprehensive solution to the problems of the nation's energy grid, the regulatory treatment of the costs needed to upgrade the infrastructure remains uncertain.[33]

In an article sponsored by the electric industry that appeared in Forbes Magazine, a number of investment analysts confirmed that investors perceive

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[30] U.S. Department of Energy, *National Transmission Grid Study* (May 2002), at 24 and 31.

[31] Moody's Investors Service, "Regulatory Pressures Increase For U.S. Electric Utilities," *Special Comment* (March 2007); "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* (August 2007).

[32] Smith, Rebecca, "Overloaded Circuits Blackout Signals Major Weakness in U.S. Power Grid," The Wall Street Journal (Aug. 18, 2003).

[33] Standard & Poor's Corporation, "Electric Utility Blackout Puts Spotlight on Political and Regulatory Credit Risk," *RatingsDirect* (Aug. 21, 2003).

significant risks associated with investing in transmission in the United States.[34] For example, Jeffery R. Holzschuh, the Managing Director of Morgan Stanley's Global Power Group, confirmed that the investment community recognizes that the returns permitted by FERC-approved rates act as a ceiling on the actual returns investors can expect and that there are serious regulatory risks that make cost recovery uncertain. As he summarized, "[t]here is a cap on how much I can earn and no floor on how much I can lose."[35] More recently, S&P recognized continued concerns over the need to overcome obstacles to investment in transmission infrastructure and provide clarity in the regulatory framework:

> Like motherhood and apple pie, everybody favors pouring dollars into the transmission grid to improve reliability and provide a stronger platform for developing the wholesale electricity market, but there is considerably less consensus around how to encourage that investment (or least not discourage it) and how to provide reasonable certainty concerning recovery.[36]

Even when capital is available, transmission must compete with alternative uses and the additional funding necessary to meet the Commission's policy goals will only be allocated if investors anticipate an opportunity to earn a return that is sufficient to compensate for the associated risks.

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[34] "Electric Utilities: Creating the Right Environment For Transmission Investment," Forbes Magazine (Sep. 20, 2004).
[35] *Id.* at 58.
[36] Standard & Poor's Corporation, "Capital Spending On Electric Transmission Is On The Upswing Around The World," *RatingsDirect* (Aug. 7, 2006).

Q. HAS FERC RECOGNIZED THE NEED FOR INCENTIVES FOR INVESTMENT IN TRANSMISSION INFRASTRUCTURE?

A. Yes. To address the requirements of Section 219 of the EPAct, *Order Nos. 679* and *679-A* establish incentive-based rate treatments to achieve greater grid reliability and lower-cost electric power for customers by encouraging membership in Transmission Organizations and increased infrastructure investment. The Commission's rulings recognize the legislative mandate to promote participation in Transmission Organizations as a platform for capital investment, in light of the substantial challenges faced by utilities in constructing new transmission projects. In response to this mandate, and after considering stakeholder comments, FERC provides utilities with the opportunity to seek various incentive rate treatments.

Q. WHAT INCENTIVES DID THE COMMISSION ESTABLISH?

A. *Order Nos. 679 and 679-A* affirmed the Commission's policy of authorizing incentive-based rate treatment for utilities that join and/or continue to be a member of an ISO or other Commission-approved transmission organization. FERC concluded that providing incentives to each utility that joins a Transmission Organization is consistent with the mandate under the EPAct to ensure reliability and reduce the cost of delivered power:

> We consider an inducement for utilities to join, and remain in, Transmission Organizations to be entirely consistent with those purposes. The consumer benefits, including reliability and cost benefits, provided by Transmission Organizations are well documented, and the best way to ensure those benefits are spread to as many consumers as possible it to provide an incentive that is widely available to member utilities of Transmission Organizations and is effective for

> the entire duration of a utility's membership in the Transmission Organization.[37]

In addition to authorizing incentives for utilities that participate in regional Transmission Organizations, such as the NYISO, the Commission also established a number of incentives intended to directly encourage construction of new transmission infrastructure. These include an incentive-based ROE for investments in new transmission facilities, the ability to include 100 percent of transmission-related construction work in progress ("CWIP") in rates, potential recovery of abandoned plant costs that are beyond the utility's control, as well as the possibility of employing a hypothetical capital structure and accelerated depreciation.

III. CAPITAL MARKET ESTIMATES

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, capital market estimates of the cost of equity are developed for a proxy group of electric utilities. First, I discuss the concept of the cost of equity, along with the risk-return trade-off principle fundamental to capital markets. Next, I describe the specific DCF analyses I conducted to estimate the current cost of equity for the reference group of electric utilities. In addition, I present supplemental ROE benchmarks developed using the CAPM and expected earnings approaches. While my ultimate recommendations are based on the

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[37] *Order No. 679-A* at P. 86.

results of the Commission's DCF methodology, these analyses confirm the reasonableness of my conclusions.

A. Cost of Equity Concept

Q. WHAT ROLE DOES THE RETURN ON COMMON EQUITY PLAY IN A UTILITY'S RATES?

A. The return on common equity is the cost of inducing and retaining investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Competition for investor funds is intense and investors are free to invest their funds wherever they choose. They will commit money to a particular investment only if they expect it to produce a return commensurate with those from other investments with comparable risks.

Q. WHAT FUNDAMENTAL ECONOMIC PRINCIPLE UNDERLIES THIS COST OF EQUITY CONCEPT?

A. The fundamental economic principle underlying the cost of equity concept is the notion that investors are risk averse. In capital markets where relatively risk-free assets are available (*e.g.*, U.S. Treasury securities), investors can be induced to hold riskier assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Since all assets compete with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to hold them.

Given this risk-return trade-off, the required rate of return (K) from an asset (i) can generally be expressed as

$$K_i = R_f + RP_i$$

where: R_f = risk-free rate of return, and
RP_i = Risk premium required to hold riskier asset i.

Thus, the required rate of return for a particular asset at any time is a function of: (1) the yield on risk-free assets, and (2) the asset's relative risk, with investors demanding correspondingly larger risk premiums for bearing greater risk.

Q. IS THERE EVIDENCE THAT THE RISK-RETURN TRADE-OFF PRINCIPLE ACTUALLY OPERATES IN THE CAPITAL MARKETS?

A. Yes. The risk-return trade-off can be readily documented in segments of the capital markets where required rates of return can be directly inferred from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. The observed yields on government securities, which are considered free of default risk, and bonds of various rating categories demonstrate that the risk-return trade-off does, in fact, exist in the capital markets.

Q. DOES THE RISK-RETURN TRADE-OFF OBSERVED WITH FIXED INCOME SECURITIES EXTEND TO COMMON STOCKS AND OTHER ASSETS?

A. It is generally accepted that the risk-return trade-off evidenced with long-term debt extends to all assets. Documenting the risk-return trade-off for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets – including common stock – required rates of return cannot be directly observed. Yet there is every reason to believe that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

Q. IS THIS RISK-RETURN TRADE-OFF LIMITED TO DIFFERENCES BETWEEN FIRMS?

A. No. The risk-return trade-off principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. Long-term debt secured by a mortgage on property is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky. Following first mortgage bonds are other debt instruments also holding contractual claims on the utility's net revenues, such as subordinated debentures. The last investors in line are common shareholders. They receive only the net revenues, if any, which remain after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q. WHAT DOES THE ABOVE DISCUSSION IMPLY WITH RESPECT TO ESTIMATING THE COST OF EQUITY OF A UTILITY?

A. Although the cost of equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is unobservable, the cost of equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

Q. WHAT METHOD DID YOU USE TO EVALUATE THE COST OF EQUITY FOR NATIONAL GRID?

A. Consistent with FERC precedent, my recommendations were based on the results of the Commission's one-step DCF methodology for electric utilities.[38] However, in recognition of the fact that no single approach to estimating a utility's cost of equity can be regarded as definitive, I also developed alternative ROE benchmarks using forward-looking applications of the CAPM and expected earnings approaches. As the Federal Communications Commission recognized:

> Equity prices are established in highly volatile and uncertain capital markets... Different forecasting methodologies compete with each other for eminence, only to be superceded by other methodologies as conditions change... In these circumstances, we should not restrict ourselves to one methodology, or even a series of methodologies, that would be applied mechanically. Instead, we conclude that we should adopt a more accommodating and flexible position.[39]

FERC has also recognized that it may be appropriate to consider the results of alternative methods. For example, the Commission concluded in *Distrigas of Massachusetts Corp.* that "no one methodology is preferred to the exclusion of all others. The DCF methodology, which we endorse, is but one analytical tool."[40] FERC made much the same point in another case,

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[38] *See, e.g., Bangor Hydro-Elec. Co.*, 117 FERC ¶ 61,129 (2006) ("*Bangor Hydro*"); *Midwest Indep. Transmission Sys. Operator, Inc.*, 100 FERC ¶ 61,292 (2002) ("*Midwest ISO*"), *reh'g denied*, 102 FERC ¶ 61,143 (2003), *modified on other grounds sub nom. Pub. Serv. Comm'n v. FERC*, 397 F.3d 1004 (D.C. Cir. 2005); *S. Calif. Edison Co.*, 92 FERC ¶ 61,070 (2000) ("*Southern California Edison*"), *reh'g denied*, 108 FERC 61,085 (2004).

[39] Federal Communications Commission, Report and Order 42-43, CC Docket No. 92-133 (1995).

[40] *Distrigas of Massachusetts Corp.*, 41 FERC ¶ 61,205 at 61,550 (1987), *modified on reh'g*, 42 FERC ¶ 61,225 (1988).

acknowledging that "[i]n some instances, the DCF methodology alone may be inappropriate."[41] More recently, while electing not to make "broadly applicable changes to how the Commission has traditionally performed its DCF analysis," *Order No. 679* noted the opinion that "there is a benefit to introducing more information into the analysis process," and indicated FERC's willingness to consider modification to its standard approach on a case-by-case basis.[42] Similarly, in concurring with the Commission's Order in *American Electric Power Company*, Commissioner Wellinghoff concluded, "I have not foreclosed considering variations on the DCF methodology or other methods to determine the cost of equity."[43]

Therefore, I also evaluated a fair rate of return using a forward-looking application of the CAPM method, as well as an expected earnings approach based on investors' current expectations in the capital markets. In my opinion, comparing estimates produced by one method with those produced by other approaches ensures that estimates of the cost of equity pass fundamental tests of reasonableness and economic logic.

B. <u>DCF Model</u>

Q. CAN THE DCF MODEL BE APPLIED DIRECTLY TO ESTIMATE THE COST OF EQUITY FOR NATIONAL GRID?

A. No. Application of the DCF model to estimate the cost of equity requires an observable stock price. Because National Grid is a wholly owned subsidiary of

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[41] *Williston Basin Interstate Pipeline Co.*, 50 FERC ¶ 61,284 at 61,913 n.90 (1990), *vacated on other grounds*, 931 F.2d 949 (D.C. Cir. 1991).
[42] *Order No. 679* at P 102.
[43] *Am. Elec. Power Serv. Co.*, 118 FERC ¶ 61,041 at 61,216 (2007), *reh'g pending*.

National Grid plc and has no publicly traded stock, its cost of equity cannot be estimated directly using the DCF model. And even though National Grid plc's stock is publicly traded, the data required to implement the Commission's DCF model is not available. The Commission has affirmed that this disqualifies National Grid plc from consideration in applying the DCF model.[44]

Q. HOW DID YOU IMPLEMENT THE COMMISSION'S DCF MODEL TO ESTIMATE THE COST OF EQUITY FOR NATIONAL GRID?

A. In estimating the cost of equity, the DCF model is typically applied to publicly traded firms engaged in similar business activities. In the present instance, the formula rates proposed by National Grid apply to transmission facilities operated within the scope of the NYISO. In order to reflect the risks and prospects associated with National Grid's jurisdictional transmission operations, my analyses focused on a group of fifteen transmission-owning utilities located in the Northeast. I refer to this group of utilities as the "Northeast TO Proxy Group".

Following the approach approved by the Commission in *Bangor Hydro*, these companies consisted of the transmission-owning members of the NYISO, the PJM Interconnection, LLC ("PJM"), and the New England RTO with publicly traded stock. Excluded from my analyses were firms that do not pay common dividends or for which no data from I/B/E/S International, Inc. ("IBES") or the Value Line Investment Survey ("Value Line") was currently available, as well as one firm (Energy East Corporation) that has agreed to be acquired. In addition,

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[44] In *Bangor Hydro*, the Presiding Judge concluded (and the Commission affirmed) that National Grid plc and other firms for which necessary data was unavailable should be excluded from the proxy group. 111 FERC ¶ 63,048 at P 72 (2005).

consistent with the Commission's findings in *Bangor Hydro*, UGI Corporation was also eliminated from the proxy group. These criteria resulted in the following proxy group:

Northeast TO Proxy Group

American Electric Power
Central Vermont Public. Service
Consolidated Edison, Inc.
Constellation Energy Group
Dominion Resources
DPL Inc.
Exelon Corp.
FirstEnergy Corp.
FPL Group, Inc.
Northeast Utilities
NSTAR
Pepco Holdings, Inc.
PPL Corp.
Public Service Enterprise Group
UIL Holdings

Consistent with FERC's recent guidance, this proxy group is composed of utilities "with a direct correlation" to the NYISO or to "the broader RTO markets" with which the NYISO interacts.[45] Given the similarities in the regulatory and business environments in which these fifteen utilities operate, investors are likely to regard these firms as having comparable risks and prospects. Like National Grid and the other NYISO members, the PJM and New England RTO utilities operate in markets where an effective wholesale market platform is supported by adoption of independent and regional grid operation pursuant to Commission policies. These utilities have all transferred operational control over most bulk

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[45] *Order Conditionally Granting Declaratory Order, Accepting Proposed Formula Rates, Subject to Conditions and Establishing Hearing and Settlement Procedures*, Docket No. EL06-109, 118 FERC ¶ 61,087 at P 73 (2007) ("*Duquesne Light Co.*").

power transmission assets to an independent entity and provide transmission services pursuant to region-wide open access tariffs. In addition, like the PJM and New England RTO utilities, the NYISO members are subject to independent authority over the identification of reliability needs on the bulk power transmission system. With the exception of Vermont, all of these utilities are also operating in jurisdictions that have undergone regulatory restructuring. As a result, these utilities have unbundled their operations and share the experience of operating in retail markets that have implemented retail choice.

Moreover, the Northeast TO Proxy Group is also consistent with the elimination of seams and the push toward a "virtual single market" in the Northeast, as well as the increased coordination of system operations among regional utilities. It also recognizes that these firms compete for investment funds from the same pool of potential capital. Considering these common traits, the companies in the Northeast TO Proxy Group provide a sound basis on which to estimate investors required returns and establish the range of reasonableness for National Grid.

Q. WOULD IT BE APPROPRIATE TO USE A PROXY GROUP COMPOSED SOLELY OF THE NYISO TRANSMISSION OWNERS TO ESTIMATE THE COST OF EQUITY FOR NATIONAL GRID?

A. No. Eliminating those NYISO TOs for which insufficient data is available to apply the Commission's DCF model would leave only a single firm (Consolidated Edison, Inc.). Estimating the cost of equity using any method is a stochastic process and the potential for misleading findings increases as the proxy group is narrowed. Apart from being consistent with FERC precedent and guidance, expanding the proxy group insulates against unreliable results. The cost of equity is inherently unobservable and can only be inferred indirectly by reference to available capital market data. Any form of analysis that depends on estimates, such as the growth parameter of the DCF model, is subject to measurement error. This potential for error is magnified when the analysis is restricted to a single method, such as the DCF.[46] To the extent that the data used to apply the DCF model does not capture the expectations that investors have incorporated into current stock prices, the resulting cost of equity estimates will be biased.

Q. HAS THE COMMISSION RECOGNIZED THE PROBLEMS ASSOCIATED WITH PROXY GROUPS COMPRISED OF A LIMITED NUMBER OF COMPANIES?

A. Yes. As FERC noted in its July 3, 2003 *Order on Initial Decision* in Docket No. RP00-107-000, even using a limited group of companies increases the potential for error:

> Both Staff and Williston agreed that a proxy group of only three companies presented problems because "a single company will have a magnified influence on the group results." It was with those changing market dynamics in mind that witnesses of both Staff and Williston proposed to expand the group of proxy companies to determine a zone of reasonableness.[47]

Conceptually, the issue of proxy group size is directly analogous to the use of sampling in statistical analyses. In statistics, a "true" value is often estimated by reference to sample observations, with the analyst having greater confidence in the applicability of the estimated results as the size of the sample increases

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[46] As I discuss subsequently, regulators have customarily considered alternative approaches (*e.g.* CAPM) in determining allowed returns. Evaluating DCF results against estimates produced using multiple methods also increases confidence that the implied cost of equity is not spurious.

[47] *Williston Basin Interstate Pipeline Co.*, 104 FERC ¶ 61,036, at pp. 14-15 (2003).

Although the Commission has on occasion accepted proxy groups as small as four companies, the Commission generally recognized that a constrained proxy group "may not be representative of industry conditions."[48] A proxy group consisting of transmission-owning members of NYISO, PJM, and the New England RTO addresses the problems associated with a limited proxy group by providing a greater number of data points for the similarly situated transmission owners. The Northeast TO Proxy Group will provide a large enough sample that the Commission can be assured that it is representative of industry conditions and more likely to reflect investor expectations and requirements for transmission-owning utilities within NYISO and adjacent markets. As noted above, National Grid will compete with transmission owners in PJM and New England RTO (as well as transmission owners elsewhere in the country) for the same limited pool of capital in order to finance transmission system investment. National Grid should be permitted to offer comparable returns to potential investors of equity capital in the NYISO region as are available elsewhere in the country.

Q. WHAT PITFALLS ARE ASSOCIATED WITH RESTRICTING THE PROXY GROUP TO UTILITIES WITHIN A SINGLE TRANSMISSION ORGANIZATION?

A. Following its legislative mandate, the Commission has recognized the benefits to customers of encouraging investment in transmission infrastructure in order to support wholesale electric power markets. This evolution in regulatory policy has

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[48] *Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260 at P 237 (2002) (citing *Transcontinental Gas Pipe Line Corp.*, 60 FERC ¶ 63,001, at 65,041 , *aff'd in part, rev'd in part*, 60 FERC ¶ 61,246, at 61,826 (1992), *rev'd and remanded, North Carolina Utilities v. FERC*, 42 F.3d 659 (1994), Order on rehearing, *Transco*, 71 FERC ¶ 61,305, at 62,195 (1995)).

most recently culminated in *Order Nos. 679* and *679-A* that affirm the importance of encouraging transmission investment and membership in a Transmission Organization, in part through the ability to seek incentive rate treatments. But in implementing its rulemaking, the Commission should resist applying its ROE policies in a manner that could discourage transmission owners in certain regions of the country from entering voluntarily into long-term arrangements for transmission operation that comply with Commission policy or undertaking the capital investment necessary to further wholesale competition.

Considering the imprecision of DCF results, artificially restricting the proxy group to the geographical boundaries of a single Transmission Organization poses just such a risk. Balkanizing the process of proxy group selection based solely on membership within a single Transmission Organization would increase the potential for disparate ROE findings that are entirely unrelated to meaningful differences in investment risk. Such a distortion of the Commission's ROE policies could result in significant deviations in allowed ROEs for utilities that otherwise operate under similar circumstances and in adjacent Transmission Organizations. In turn, this would lead to garbled signals that would stimulate capital investment in one region while artificially stifling grid expansion in another.

In addition, the concept of a "NYISO-only" proxy group is in some respects a fallacy, since it would include utilities engaged in transmission operations beyond the Transmission Organization's regional boundaries. For example, Consolidated Edison, Inc., the parent of Orange & Rockland Utilities, Inc., also owns Consolidated Edison Company of New York, Inc. and Rockland Electric Company, which operate inside the PJM footprint. The Commission should apply its ROE policies in an equitable and even-handed manner. Expanding the proxy group to include utilities operating in adjacent Transmission Organizations and facing similar circumstances helps to avoid regional discrimination with no underlying economic justification and provides greater assurance that the resulting ROEs will further the policy goals of this Commission and of the Congress.

Q. IS THE NORTHEAST TO PROXY GROUP CONSISTENT WITH COMMISSION PRECEDENT?

A. Yes. There is no general policy requiring that proxy companies be chosen from within the same Transmission Organization as the applicant, with ROEs established for other transmission-owning public utilities being determined using proxy groups that include comparable utilities outside the boundaries of a specific geographic region or Transmission Organization. For example, the order that established the Commission's current electric utility DCF model utilized a proxy group for determining Southern California Edison's ROE that included Constellation Energy, the parent company of Baltimore Gas & Electric Company, noting that Constellation Energy was a comparable risk company because Baltimore Gas & Electric also participated in a Commission-approved independent system operator.[49] More recently, the Commission concluded in *Bangor Hydro* that:

> We also found that a proxy group comprised of Northeast utility companies, including transmission-owning companies doing business in the markets operated by ISO New England, the New York Independent System Operator (New York ISO) and PJM Interconnection, L.L.C. (PJM), would provide a sufficiently

[49] 92 FERC ¶ 61,070 at 61,265.

> representative universe of companies for calculating an ROE in this case...[50]

Thus, the rationale used to determine the Northeast TO Proxy Group in this case is consistent with the approach approved by the Commission in *Bangor Hydro*.

Moreover, consistent with FERC's more recent guidance, this Northeast TO Proxy Group is composed of utilities "with a direct correlation" to the NYISO *or to the broader RTO markets*" with which the NYISO interacts.[51] The Commission has also confirmed that a utility should not be eliminated from a proxy group "solely because of geographic or climatic differences."[52] Use of the Northeast TO Proxy Group to determine the ROE for National Grid is therefore fully justified and consistent with the Commission's ongoing efforts to broaden the footprint of regional wholesale power markets.

Q. DID YOUR ANALYSIS ALSO CONSIDER REPORTED RISK MEASURES?

A. Yes. My evaluation of the Northeast TO Proxy Group also included a comparison of three objective measures of the investment risks associated with bonds and common stocks – S&P's corporate credit rating and Value Line's Safety Rank and Financial Strength Rating.

Credit ratings are assigned by independent rating agencies for the purpose of providing investors with a broad assessment of the creditworthiness of a firm. Because the rating agencies' evaluation includes virtually all of the factors normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide a broad measure of overall investment

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[50] *Bangor Hydro* at P 8.
[51] *Duquesne Light Co.*, 118 FERC ¶ 61,087 P 73 (2007) (emphasis added).
[52] *Consumers Energy Co.*, 98 FERC ¶ 61,333 at p. 62,412 (2002).

risk that is readily available to investors. Widely cited in the investment community and referenced by investors as an objective measure of risk, credit ratings are also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of equity. For example, the Commission relied on this measure as the single defining risk indicator in its decision to establish an allowed ROE above the midpoint of the range of reasonableness in *Southern California Edison*.[53]

Apart from the broad assessment of investment risk provided by credit ratings, other quality rankings published by investment advisory services also provide relative assessments of risk that are considered by investors in forming their expectations. Given that Value Line is perhaps the most widely available source of investment advisory information, its rankings provide useful guidance regarding the risk perceptions of investors. The Safety Rank is Value Line's primary risk indicator and ranges from "1" (Safest) to "5" (Riskiest). This overall risk measure is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength. The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps.

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[53] Southern California Edison Company, Opinion No. 445 (Jul. 26, 2000), 92 FERC ¶ 61,070 at p. 22 (*Southern California Edison*).

Q. DO THESE CRITERIA PROVIDE OBJECTIVE EVIDENCE THAT INVESTORS WOULD VIEW THE NORTHEAST TO PROXY GROUP AS RISK-COMPARABLE?

A. Yes. As noted earlier, S&P has assigned a corporate credit rating of "A-" to National Grid, while Moody's rates the Company at "Baa1". This compares with an average S&P credit rating for the utilities in the Northeast TO Proxy Group of "BBB+". Meanwhile, the average Value Line Safety Rank and Financial Strength Rating for the Northeast TO Proxy Group is "2" and "B++", respectively.

Based on these criteria, which reflect objective, published indicators that incorporate consideration of a broad spectrum of risks, including financial and business position, relative size, and exposure to company-specific factors, investors are likely to regard this group as having comparable risks and prospects. Taken together, these objective measures provide additional support for using the Northeast TO Proxy Group as the basis for estimating the ROE for National Grid.[54]

Q. WHEN DEFINING A PROXY GROUP, DO YOU BELIEVE THAT THE COMPOSITION OF A UTILITY'S REVENUES SERVES AS A MEANINGFUL BASIS TO ASSESS RELATIVE INVESTMENT RISK?

A. No. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criteria in establishing a meaningful proxy group to estimate investors' required return is relative risk, not the source of the revenue stream. Due to

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[54] As noted earlier, National Grid is a wholly-owned subsidiary of National Grid plc. While I reviewed Value Line's risk indicators for the Northeast TO Proxy Group, no comparable information is available for National Grid plc, which is not covered by Value Line.

differences in business segment definition and reporting between utilities, it is often impossible to accurately apportion financial measures, such as total revenues, between utility segments (*e.g.*, distribution, transmission, or generation) or regulated and non-regulated sources. As a result, even ignoring the fact that there is no clear link between the source of a utility's revenues and investors' risk perceptions, it is not generally possible to accurately apply revenue-based criteria.

Moreover, the Commission on multiple occasions has rejected the notion that relative participation in non-transmission operations is a meaningful criterion in identifying a proxy group. In adopting my recommended proxy group in *Midwest ISO*, for example, the Commission concluded that "[w]e are unpersuaded...that transmission investments are less risky than the other investments of the Midwest ISO TO proxy companies."[55] Similarly, in *Bangor Hydro*, the Commission specifically rejected arguments that PPL "should be excluded from the proxy group given the risk factors associated with its unregulated, non-utility business operations."[56] Indeed, as discussed above, reference to objective indicators of investment risk demonstrates that there is no basis to distinguish between the investment risks of National Grid and the Northeast TO Proxy Group.

[55] *Midwest ISO*, 100 FERC ¶ 61,292 at P 12 (2002).
[56] *Bangor Hydro* at PP 17, 26.

Q. HOW DID YOU CALCULATE THE DIVIDEND YIELD COMPONENT OF THE DCF MODEL FOR THE ELECTRIC UTILITY PROXY GROUP?

A. Following Commission policy, average low and high indicated dividend yields were calculated for each electric utility during the six months July through December 2007. These six-month average low and high historical dividend yields were also increased by one-half of the low and high growth rates discussed subsequently ($1 + 0.5g$) to convert them to adjusted dividend yields.

Q. WHAT GROWTH RATES ARE USED IN THE COMMISSION'S ONE-STEP DCF METHOD FOR ELECTRIC UTILITIES?

A. The one-step DCF method for electric utilities adopted by the Commission employs two growth rates for each firm. The first growth rate is a "sustainable" growth rate calculated by the following formula:

$$g = br + sv$$

where: b = expected retention ratio;
r = expected earned rate of return;
s = percent of common equity expected to be issued annually as new common stock;
v = equity accretion ratio.

The second growth rate is the consensus 5-year earnings growth forecast published by IBES. These two growth rates are combined with the adjusted dividend yields to develop a cost of equity range for each company.

Q. HOW DID YOU CALCULATE THE SUSTAINABLE GROWTH RATE FOR THE ELECTRIC UTILITY PROXY GROUP?

A. For each electric utility in the Northeast TO Proxy Group, the expected retention ratio (b) was calculated based on projected dividends and earnings per share from Value Line for 2007, 2008, and their 2010-2012 forecast horizon. Likewise, each firm's expected earned rate of return (r) was computed by dividing projected earnings per share by Value Line's corresponding figure for net book value. In *Southern California Edison*, the Commission correctly recognized that if the rate of return, or "r" component of the br+sv growth rate, is based on end-of-year book values, such as those reported by Value Line, it will understate actual returns because of growth in common equity over the year.[57] Accordingly, consistent with the Commission's findings and the theory underlying this approach to estimating investors' growth expectations, an adjustment was incorporated to compute an average rate of return.[58] Finally, the percent of common equity expected to be issued annually as new common stock (s) was equal to the product of the projected market-to-book ratio and growth in common shares outstanding over Value Line's forecast horizon, while the equity accretion rate (v) was computed as 1 minus the inverse of the projected market-to-book ratio. The resulting sustainable growth rate for each electric utility is shown in column (c) of Exhibit No. NMP-4.

Q. WHAT ARE INVESTMENT ANALYSTS' PROJECTED GROWTH RATES FOR THE COMPANIES IN THE NORTHEAST TO PROXY GROUP?

A. The 5-year earnings growth forecasts published by IBES for each electric utility in the Northeast TO Proxy Group are shown in column (d) of Exhibit No. NMP-4.

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[57] *Southern California Edison* at 61,263 & n. 38.

[58] Use of an average return in developing the sustainable growth rate is well supported. See, *e.g.*, Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," Public Utilities Reports, Inc. (1994), which discusses the need to adjust Value Line's end-of-year data, consistent with the Commission's findings in *Southern California Edison*.

Q. WHAT WERE THE RESULTS OF APPLYING THE COMMISSION'S ONE-STEP DCF APPROACH TO THE NORTHEAST TO PROXY GROUP?

A. As shown on Exhibit No. NMP-4, application of the Commission's DCF model to the Northeast TO Proxy Group resulted in current cost of equity estimates ranging from 6.1 percent to 21.0 percent.

Q. HAS THE COMMISSION RECOGNIZED THAT IT MAY BE APPROPRIATE TO ELIMINATE COST OF EQUITY ESTIMATES THAT FAIL TO MEET THRESHOLD TESTS OF ECONOMIC LOGIC?

A. Yes. In *Southern California Edison* the Commission noted that adjustments to the zone of reasonableness are justified where applications of its preferred DCF approach produce illogical results:

> An adjustment to this data is appropriate in the case of PG&E's low-end return of 8.42 percent, which is comparable to the average Moody's "A" grade public utility bond yield of 8.06 percent, for October 1999. Because investors cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low-end return cannot be considered reliable in this case.[59]

More recently, in its October 2006 decision in *Kern River Gas Transmission Company*, the Commission noted that:

> [T]he 7.31 and 7.32 percent costs of equity for El Paso and Williams found by the ALJ are only 110 and 122 basis points above that average yield for public utility debt.[60]

The Commission upheld the opinion of Commission Staff and the Presiding Judge that cost of equity estimates for these two proxy group companies "were too low to be credible."[61]

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[59] *Southern California Edison Company* at 61,266 (footnote omitted).
[60] *Kern River Gas Transmission Company*, 117 FERC ¶ 61,077 at P 140 & n. 227 (2006).

As noted earlier, the average bond rating associated with the firms in the proxy group is triple-B, with Moody's monthly yields on triple-B public utility bonds averaging approximately 6.4 percent over the six-month period ending December 2007.[62] As highlighted on Exhibit No. NMP-4, low-end cost of equity estimates for three of the firms in the Northeast TO Proxy Group exceeded this threshold by 70 basis points or less.[63] In light of the risk-return trade-off principle and the test applied in *Kern River Gas Transmission Company*, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock, which is the riskiest of a utility's securities. As a result, these values provide little guidance as to the returns investors require from the common stock of an electric utility.

Q. DO YOU BELIEVE THAT THE CURRENT YIELD TO MATURITY FOR OUTSTANDING BOND ISSUES SPECIFIC TO EACH UTILITY SHOULD SERVE AS THE BASIS FOR APPLYING THIS TEST OF REASONABLENESS?

A. No. As in *Kern River Gas Transmission*, the Commission has not customarily referenced company-specific debt issues but instead employs an average yield on long-term utility bonds of corresponding risk – and for good reason. As explained earlier, because common equity is a perpetual asset, investors are concerned with expectations for the firm's long-term risks and prospects. This does not mean that every investor will buy and hold a particular common stock

(. . . continued)

[61] *Id.* (citation omitted).

[62] Based on data from Moody's *Credit Perspectives* (Oct. 8, & Dec. 10, 2007, Jan. 7, 2008).

[63] As highlighted on Exhibit No. NMP-4, low-end estimates for Central Vermont Public Service, Dominion Resources, and UIL Holdings ranged from 6.1 percent to 7.1 percent.

forever. Rather, it recognizes that even an investor with a relatively short holding period will consider the long-term because of its influence on the price that he or she ultimately receives from the stock when it is sold. In order to mirror this long-term horizon in evaluating the reasonableness of DCF cost of equity estimates, the appropriate comparison is with long-term debt instruments.

Meanwhile, the yield for the embedded debt issues of a specific utility will typically reflect a ladder of shorter-term maturities, which does not match the long-term horizon relevant to an evaluation of common equity returns. In addition to different terms to maturity, using yields on company-specific bonds as a benchmark is fraught with other problems. The yield to maturity on any particular bond is influenced by specific attributes of the securities, such as coupon rate, call provisions or convertibility, and size of the issue. Indeed, the Financial Analysis Branch of the Commission previously noted some of these problems in a 1992 study:

> Determining the bond cost has proven more difficult, however. Ideally, all utilities would have a bond: with identical terms and conditions; maturing in 30 years ... and bear a coupon similar to the market rate, thus accurately reflecting the debt cost of the company. For most companies bonds with identical terms were not available.[64]

Because of these attributes, the yields for company-specific debt issues do not provide a reliable basis on which to evaluate the results of the Commission's DCF model. These measurement problems are avoided by using average yields

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[64] Financial Analysis Branch, *Risk Premium Study* at 3 (Aug. 4, 1992).

for risk-comparable long-term utility bonds, such as the Moody's triple-B rate averages referenced by Commission Staff in Docket No. ER06-787-002.[65]

Q. DO YOU ALSO RECOMMEND EXCLUDING COST OF EQUITY ESTIMATES AT THE HIGH END OF THE RANGE OF REASONABLENESS FOR THE NORTHEAST TO PROXY GROUP?

A. Yes. In a November 2004 Order in *Bangor Hydro*, the Commission determined that a cost of equity estimate at the high end of the range of reasonableness might also be excluded if it is determined to be an extreme outlier.[68] As noted earlier, the upper end of the cost of equity range produced by the DCF analysis presented in Exhibit No. NMP-4 was based on a cost of equity estimate of 21.0 percent for Public Service Enterprise Group Inc., with the high-end DCF estimate Constellation Energy Group Inc. being 18.2 percent. Accordingly, these high-end cost of equity estimates are clearly extreme outliers and are properly excluded under the rationale adopted by the Commission in *Bangor Hydro*.

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[65] *Prepared Answering Testimony of Commission Staff Witness Edward Alvarez III*, Docket No. ER06-787-002, Exhibit S-11 at 15 (filed Jan. 19, 2007).

[68] *ISO New England, Inc.*, 109 FERC ¶ 61,147 at P 205 (2004) ("*November 2004 Bangor Hydro Order*"), *reh'g denied*, 110 FERC ¶ 61,111 at P 23 & n.19 (2005).

Q. WHAT ROE RANGE DO YOUR DCF RESULTS IMPLY FOR THE NORTHEAST TO PROXY GROUP?

A. As shown on Exhibit No. NMP-4, eliminating illogical low- and high-end outliers resulted in an adjusted range of reasonableness for the Northeast TO Proxy Group ranging from 7.9 percent to 15.9 percent, with a midpoint of 11.9 percent.

Q. DID YOU REMOVE A UTILITY FROM THE PROXY GROUP IF ONE OF THE DCF ESTIMATES WAS EXCLUDED AS A LOW- OR HIGH-END OUTLIER?

A. No. I do not believe that it is necessary or appropriate to remove a company from the proxy group altogether when just one of its DCF values fails the test of logic. This is consistent with the Commission's approach in *Southern California Edison*, where FERC eliminated the low-end return for one of the firms in the proxy group, while retaining the high-end value.[69]

Q. WHY DID YOU REFERENCE THE MIDPOINT OF THE DCF RANGE IN EVALUATING YOUR DCF RESULTS?

A. Reliance on the midpoint – the average of the high and low boundaries of the DCF range of reasonableness – as the measure of central tendency for electric utilities is well-established Commission policy. The Commission has been consistent in using the midpoint of the zone of reasonableness as the basis for allowed ROEs for electric utilities – both for transmission-owning members of a Transmission Organization and for individual utilities – as reflected in *Bangor Hydro, Midwest ISO, Southern California Edison,* and in previous electric cases. For example, in *Consumers Energy* the Commission reversed an initial decision

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[69] *Southern California Edison Company* at 61,266.

in which the Presiding Judge had relied on the median of the zone of reasonableness, rather than the midpoint. The Commission concluded that:

> The precedent on which the judge and Staff rely in this instance was developed in the context of setting the rata of return for gas pipelines. In this case, there has been no reason provided to depart from our precedent in Opinion Nos. 445 and 446, setting the return at the midpoint of the zone of reasonableness.[70]

The Commission followed the same approach in *Consumers Energy* Co.[71] and *Utah Power & Light* Co.,[72] finding the midpoint to be the appropriate return for an electric utility. The courts have also recognized that other proposed measures of central tendency (*e.g.*, the median) are not inherently superior to the use of the midpoint.[73]

C. ROE Benchmarks

Q. WHAT OTHER ANALYSES DID YOU CONDUCT TO ESTIMATE THE COST OF EQUITY?

A. I also evaluated the cost of equity for National Grid against ROE benchmarks developed using the CAPM and expected earnings methods. While *Order Nos. 679* and *679-A* did not establish a requirement to implement alternatives to FERC's DCF approach, the Commission stated its willingness to consider other methods on a case-by-case basis. As noted previously, the Commission has

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[70] *Consumers Energy,*, 98 FERC ¶ 61,333 at 62,416 (2002).
[71] 85 FERC ¶ 61,100 (1998).
[72] 44 FERC ¶ 61,166 (1988).
[73] *Canadian Ass'n of Petroleum Producers v. FERC*, 254 F.3d 289, 298 (D.C. Cir. 2001). Arguments against reliance on the midpoint frequently contend that this value relies on only the top and bottom numbers in the range and ignores the rest. The Court rejected this argument, holding that "[t]he midpoint doesn't 'completely disregard the middle three numbers'; the highest and lowest numbers achieve their status by reference to all five numbers." *Id.*

also recognized that it may be appropriate to consider the results of alternative methods. Moreover, in contrast to applications of the CAPM using historical, realized rates of return, which have been largely rejected by the Commission in the past, my CAPM analysis specifically incorporated forward-looking expectations that are consistent with the assumptions of this approach.

Q. WHAT OTHER EVIDENCE SUPPORTS YOUR REFERENCE TO ALTERNATIVE ROE BENCHMARKS?

A. Because the cost of equity is unobservable, no single method should be viewed in isolation. While the DCF model has been routinely relied on in regulatory proceedings as one guide to investors' required return, it is a blunt tool that should never be used exclusively. Regulators have customarily considered the results of alternative approaches in determining allowed returns.[74] It is widely recognized that no single method can be regarded as a panacea; all approaches having advantages and shortcomings. For example, a publication of the Society of Utility and Financial Analysts (formerly the National Society of Rate of Return Analysts), concluded that:

> Each model requires the exercise of judgment as to the reasonableness of the underlying assumptions of the methodology and on the reasonableness of the proxies used to validate the theory. Each model has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises, most of which cannot be validated empirically. Investors clearly do not subscribe to any singular method,

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[74] For example, a NARUC survey reported that 26 regulatory jurisdictions ascribe to no specific method for setting allowed ROEs, with the results of all approaches being considered. "Utility Regulatory Policy in the U.S. and Canada, 1995-1996," National Association of Regulatory Utility Commissioners (December 1996).

> nor does the stock price reflect the application of any one single method by investors.[75]

Moreover, evidence suggests that reliance on the DCF model as a tool for estimating investors' required rate of return has declined outside the regulatory sphere, with the CAPM being "the dominant model for estimating the cost of equity."[76] *Regulatory Finance: Utilities Cost of Capital* noted the inherent difficulties of the DCF approach:

> [C]aution and judgment are required in interpreting the results of DCF models because of (1) the questionable applicability of the DCF model to utility stocks in certain market environments, (2) the effect of declining earnings and dividends on financial inputs to the DCF model and biases caused by the effect of changes in risk and growth, and (3) the conceptual and practical difficulties associated with the growth component of the DCF model.[77]

The publication concluded, "If the cost of equity estimation process is limited to one methodology, such as DCF, it may severely bias the results."[78]

Q. PLEASE DESCRIBE THE CAPM.

A. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. The CAPM assumes that investors are fully diversified, so the relevant risk of an individual asset (e.g., common stock) is its volatility relative to the market as a whole. Beta reflects the tendency of a stock's price to follow changes in the market. A stock that tends to respond relatively less to market

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[75] Parcell, David C., "The Cost of Capital – A Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* (1997) at Part 2, p. 4.
[76] See, *e.g.*, Bruner, R.F., Eades, K.M., Harris, R.S., and Higgins, R.C., "Best Practices in Estimating Cost of Capital: Survey and Synthesis," Financial Practice and Education (1998).
[77] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports, Inc.* (1994) at 238.
[78] *Id.*

movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

where: R_j = required rate of return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and,
β_j = beta, or systematic risk, for stock j.

Like the DCF model, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using data that reflect the expectations of actual investors in the market.

Q. HOW DID YOU APPLY THE CAPM TO ESTIMATE THE COST OF EQUITY FOR THE FIRMS IN THE NORTHEAST TO PROXY GROUP?

A. Application of the CAPM to the utilities in the Northeast TO Proxy Group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Exhibit No. NMP-5. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500.

The dividend yield for each firm was obtained from Value Line, with the growth rate being equal to the average of the earnings growth projections for each firm published by IBES and Value Line, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections for the 354 individual firms, current estimates imply an average growth rate over the next five years of 11.0 percent. Combining this average growth rate with a dividend yield of 2.2 percent results in a current cost of equity estimate for the market as a whole of approximately 13.2 percent. Subtracting a 4.8 percent risk-free rate based on the average yield on 20-year Treasury bonds for the six months ended December 2007 produced a market equity risk premium of 8.4 percent. Multiplying this risk premium by the respective Value Line betas for the utilities in the Northeast TO Proxy Group, and then adding the resulting risk premiums to the average long-term Treasury bond yield, indicated a base ROE in the range of 11.1 to 13.2 percent, with a midpoint of 12.1 percent.

Q. WHAT OTHER BENCHMARKS DID YOU DEVELOP TO EVALUATE THE ROE?

A. As I noted earlier, I also evaluated the ROE using the expected earnings method. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This expected earnings approach is consistent with the economic underpinnings for a fair rate of return established by the Supreme Court in *Hope* and *Bluefield*. Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on expected earned returns on book equity, which are more readily available to investors.

Q. WHAT RATES OF RETURN ARE INDICATED FOR UTILITIES BASED ON THIS APPROACH?

A. With respect to expectations for electric utilities generally, the December 28, 2007 edition of Value Line reports that its analysts anticipate an average rate of return on common equity for the electric utility industry of 11.5 percent in 2007, 2008, and over its three-to-five year forecast horizon.[79] Meanwhile, Value Line expects that natural gas utilities will earn an average rate of return on common equity of 11.5 percent in 2007 and 2008, and 12.0 percent over the years 2010 through 2012.[80] Considering the Commission's policy goal of promoting increased infrastructure investment, these expected earned returns for electric and gas utilities provide a meaningful benchmark in establishing an ROE for jurisdictional transmission operations that is sufficient to successfully compete for necessary capital investment.

For the firms in the Northeast TO Proxy Group specifically, the returns on common equity projected by Value Line over its three-to-five year forecast horizon are shown on Exhibit No. NMP-6. Consistent with the rationale underlying the development of the br+sv growth rates, these year-end values were converted to average returns using the same adjustment factor discussed earlier. While the four Value Line projections highlighted on Exhibit No. NMP-6 may accurately reflect expectations for actual earned rates of return on common equity over the forecast horizon, they are unlikely to be representative of investors' required rate of return. As shown on Exhibit No. NMP-6, after eliminating potential outliers, Value Line's projections suggested an ROE in the range of 8.1 percent to 15.4 percent, with the midpoint being 11.8 percent.

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[79] The Value Line Investment Survey (Dec. 28, 2007) at 695.
[80] The Value Line Investment Survey (Dec. 14, 2007) at 445.

D. Flotation Costs

Q. WHAT OTHER CONSIDERATIONS ARE RELEVANT IN SETTING THE ROE FOR A UTILITY?

A. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds a utility nets when it issues common equity.

Q. IS THERE AN ESTABLISHED MECHANISM FOR A UTILITY TO RECOGNIZE EQUITY ISSUANCE COSTS?

A. No While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. Alternatively, no rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant. In other words, equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for indirectly, with an upward adjustment to the cost of equity being the most logical mechanism.

Q. IS THE NEED FOR A FLOTATION COST ADJUSTMENT TO COMPENSATE FOR PAST EQUITY ISSUES RECOGNIZED IN THE FINANCIAL LITERATURE?

A. Yes. In a *Public Utilities Fortnightly* article, Brigham, Aberwald, and Gapenski demonstrated that even if no further stock issues are contemplated, a flotation cost adjustment in all future years is required to keep shareholders whole, and that the flotation cost adjustment must consider total equity, including retained earnings.[81] Similarly, *Regulatory Finance: Utilities' Cost of Capital* contains the following discussion:

> Another controversy is whether the underpricing allowance should still be applied when the utility is not contemplating an imminent common stock issue. Some argue that flotation costs are real and should be recognized in calculating the fair rate of return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. ... The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered.[82]

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[81] Brigham, E.F., Aberwald, D.A., and Gapenski, L.C., "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly* (May, 2, 1985).
[82] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," Public Utilities Reports (1994) at 175.

Q. WHAT IS THE MAGNITUDE OF THE ADJUSTMENT TO THE "BARE BONES" COST OF EQUITY TO ACCOUNT FOR ISSUANCE COSTS?

A. One of the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. Based on a review of the finance literature, *Regulatory Finance: Utilities' Cost of Capital* concluded:

> The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue.[83]

Alternatively, a study of data from Morgan Stanley regarding issuance costs associated with utility common stock issuances suggests an average flotation cost percentage of 3.6 percent.[84]

Applying these expense percentages to a representative dividend yield for a utility of 3.5 percent implies a flotation cost adjustment on the order of 13 to 35 basis points. While my ROE recommendation for National Grid does not include an adjustment for flotation costs, this is a legitimate consideration that supports the reasonableness of my conclusions in this case.

IV. RETURN ON EQUITY FOR NATIONAL GRID

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. This section presents my conclusions regarding a reasonable ROE range of reasonableness for National Grid. It examines other factors properly considered

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[83] Id. at 166.

[84] *Application of Yankee Gas Services Company for a Rate Increase*, DPUC Docket No. 04-06-01, Direct Testimony of George J. Eckenroth (Jul. 2, 2004) at Exhibit GJE-11.1. Updating the results presented by Mr. Eckenroth through April 2005 also resulted in an average flotation cost percentage of 3.6%.

in determining a fair rate of return, including the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital.

A. Implications for Financial Integrity

Q. WHY IS IT IMPORTANT TO ALLOW NATIONAL GRID AN ADEQUATE ROE?

A. Given the social and economic importance of the utility industry, it is essential to maintain reliable and economical service to all consumers. While National Grid remains committed to deliver reliable service, a utility's ability to fulfill its mandate can be compromised if it lacks the necessary financial wherewithal or is unable to earn a return sufficient to attract capital. Coupled with the ongoing potential for energy market volatility, National Grid's plans for infrastructure investment and ongoing exposure to regulatory uncertainty pose a number of potential challenges that might require the relatively swift commitment of significant capital resources in order to maintain the high level of service that customers deserve.

As documented earlier, the major rating agencies have warned of exposure to unrecovered power costs associated with political and regulatory developments, especially in view of the potential for high and volatile commodity costs in competitive energy markets. Investors understand just how swiftly unforeseen circumstances can lead to deterioration in a utility's financial condition, and stakeholders have discovered first hand how difficult and complex it can be to remedy the situation after the fact. While providing the infrastructure necessary to further the goals of enhancing the bulk power transmission system and meeting the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on National Grid. For a utility with an obligation to provide reliable service, investors' increased reticence to supply additional capital during times of crisis highlights the necessity of preserving the flexibility needed to overcome periods of adverse capital market conditions.

Q. DO CUSTOMERS ALSO BENEFIT BY ENHANCING THE UTILITY'S FINANCIAL FLEXIBILITY?

A. Yes. While providing an ROE that is sufficient to maintain National Grid's ability to attract capital, even under duress, is consistent with the economic requirements embodied in the Supreme Court's *Hope* and *Bluefield* decisions, it is also in customers' best interests. Ultimately, it is customers and the service area economy that enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure a reliable energy supply. By the same token, customers also bear a significant burden when the ability of the utility to attract capital is impaired and service quality is compromised.

Q. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING A REASONABLE ROE FOR NATIONAL GRID?

A. National Grid and other participating transmission owners face risks simply by transferring functional control of their transmission assets to the NYISO, which participates in an industry that is in the process of restructuring and where business practices and regulatory policy continue to experience dramatic change. By participating in an ISO, National Grid has given up significant control over decisions about whether to invest in new transmission and how its transmission assets will be operated. At a financial conference hosted by the Fitch IBCA, Duff & Phelps rating agency, one speaker summarized the uncertain environment faced by ISO and RTO participants:

> [Y]ou can put on all the new technology you like, spend all your money, and the rate you will get in return is unclear and someone else is going to manage it for you.[85]

More recently, S&P observed that, despite the problems and uncertainties associated with transmission operations, investment has been "encouraged by financial incentives offered by [the Commission]."[86] The corollary is that, absent a commitment to follow through on expectations for meaningful incentives embodied in the EPAct and the Commission's rulemaking, the flow of capital will diminish.

Q. NATIONAL GRID IS PROPOSING TO MOVE TO A FORMULA RATE. DO FORMULA RATES ELIMINATE RISK FROM AN INVESTOR'S PERSPECTIVE?

A. No. Formula rates are a two-edged sword. Formula rates might modify risk at the wholesale level to the extent that they eliminate the need for utilities to file rate cases when costs are increasing, but they also put utilities at risk for retroactive downward rate adjustments under Section 206 of the Federal Power Act – a risk that does not exist under fixed rates. In addition, under formula rates that are tied to cost, there is no opportunity to earn in excess of the allowed rate of return in between rate cases, as may be the case with stated rates. Investors therefore see very limited strategic opportunity to earn higher returns to balance the risks associated with potential disallowances by regulators. Also, most of the money for transmission must still be recovered from consumers at the retail level,

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[85] Fitch IBCA, Duff & Phelps, "Electric Markets: The Past Year and the Next 10", *Special Report* at 8 (Dec. 12, 2001).
[86] *Id.*

which typically (and in the case of National Grid) has a greater impact on financial performance.

B. Capital Structure

Q. IS AN EVALUATION OF THE CAPITAL STRUCTURE MAINTAINED BY A UTILITY RELEVANT IN ASSESSING ITS RETURN ON EQUITY?

A. Yes. Other things equal, a higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive his contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow, if any, that will remain.

Q. WHAT COMMON EQUITY RATIO WILL BE USED TO ESTABLISH THE COMPANY'S OVERALL RATE OF RETURN?

A. Under the proposed formula, National Grid's capitalization will be established from the same data source that supports the Company's Form 1 Electric Utility Annual Report ("Form 1") filed with the Commission. Rates will initially reflect a common equity ratio in the range of approximately 56 percent to 60 percent.

Q. HOW DOES THIS COMPARE WITH COMMON EQUITY RATIOS MAINTAINED BY THE NORTHEAST TO PROXY GROUP?

A. As shown on Exhibit No. NMP-7, common equity ratios for the individual firms in the Northeast TO Proxy Group ranged from a low of 28.3 percent to a high of 58.4 percent at year-end 2006.

Q. WHAT IMPLICATION DOES THE INCREASING RISK OF THE UTILITY INDUSTRY HAVE FOR THE CAPITAL STRUCTURES MAINTAINED BY UTILITIES?

A. As discussed earlier, the average credit rating associated with firms in the electric industry has fallen to triple-B, the lowest rung on the ladder of the investment grade scale.[87] This decline in credit quality is indicative of the need for utilities to strengthen their balance sheets to deal with an increasingly uncertain and competitive market. A more conservative financial profile is consistent with increasing uncertainties and the need to maintain the continuous access to capital that is required to fund operations and necessary system investment, even during times of adverse capital market conditions. This is especially the case if electric utilities are to be successful in raising the substantial funds necessary to boost investments for network reliability and transmission projects. Moody's recently noted the financial pressures associated with planned infrastructure investments in an environment of rising costs. Moody's went on to warn of the risks associated with increasing debt leverage and fixed obligations

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[87] The Commission has recognized that a triple-B rating is a "minimum investment rating for an electric utility." *Duquesne*, 118 FERC ¶ 61,087 at P 53 (2007).

and advised utilities not to squander the opportunity to strengthen the balance sheet as a buffer against future uncertainties.[88]

Q. WHAT CAPITALIZATION IS REPRESENTATIVE FOR THE PROXY GROUP GOING FORWARD?

A. As shown on Exhibit No. NMP-7, Value Line expects that the average common equity ratio for the Northeast TO Proxy Group will increase to 50.8 percent over the next three to five years, with the individual common equity ratios ranging from 42.5 percent to 58.0 percent.

Q. WHAT OTHER FACTORS DO INVESTORS CONSIDER IN THEIR ASSESSMENT OF CAPITAL STRUCTURE?

A. Depending on their specific attributes, contractual agreements that obligate the utility to make specified payments may be treated as debt in evaluating a utility's financial risk. Because power purchase agreements typically obligate the utility to make specified minimum contractual payments akin to those associated with traditional debt financing, investors consider a portion of these commitments as debt in evaluating total financial risks. The implications of purchased power commitments and other off-balance-sheet obligations have been repeatedly cited by major bond rating agencies in connection with assessments of utility financial risks. Because bond ratings agencies and investors consider the debt impact of

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[88] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* (Aug. 2007).

such fixed obligations in assessing a utility's financial position, they imply greater risk and reduced financial flexibility.[89]

Q. WHAT DOES THIS EVIDENCE SUGGEST WITH RESPECT TO NATIONAL GRID'S PROPOSED CAPITAL STRUCTURE?

A. Based on my evaluation, I concluded that an equity ratio in the range of 56 percent to 60 percent represents a reasonable mix of capital sources from which to calculate National Grid's overall rate of return. Although the Company's common equity ratio currently exceeds the average currently maintained by the Northeast TO Proxy Group, it is consistent with the trend towards lower financial leverage expected for the industry and within the range of individual results projected for this proxy group.

While industry averages provide one benchmark for comparison, each firm must select its capitalization based on the risks and prospects it faces, as well its specific needs to access the capital markets. A public utility with an obligation to serve must maintain ready access to capital so that it can meet the service requirements of its customers. The need for access becomes even more important when the company has large capital requirements over a period of years, and financing must be continuously available, even during unfavorable capital market conditions. National Grid's capital structure reflects the Company's ongoing efforts to maintain its credit standing and support access to capital on reasonable terms. The reasonableness of National Grid's capital structure is reinforced by the ongoing uncertainties associated with the electric

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[89] The capital structure ratios presented earlier do not include imputed debt associated with power purchase agreements or the impact of other off-balance sheet obligations.

power industry, the need to accommodate ongoing regulatory risks, and the importance of supporting continued system investment, even during times of adverse industry or market conditions.

Q. IS NATIONAL GRID'S PROPOSED CAPITAL STRUCTURE CONSISTENT WITH COMMISSION PRECEDENT?

A. Yes. As noted earlier, the proposed formula relies on National Grid's actual capitalization, as reflected in the same data sources supporting the Company's Form 1 filing. This is consistent with Commission precedent, which reflects a long and clear preference for using the actual capital structure of the utility in establishing the overall rate of return.[90] As the Commission stated in *Kentucky West Virginia,* for example, "In our opinion a utility should be regulated on the basis of its being an independent entity; that is, a utility should be considered as nearly as possible on its own merits."[91]

Moreover, the Commission has specifically rejected the notion that a utility's capital structure must fall within the range of the proxy group to be considered reasonable. In *Transcontinental Gas Pipeline Corp.* the Commission noted that an appropriate capital structure "can fall within a very broad range," and concluded, "[T]he Commission has determined that it will not continue to require that a pipeline's equity ratio be within the range established by the proxy companies in order to use the pipeline's own capital structure."[92] The

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[90] See, *e.g.*, *Kentucky West Virginia*, 2 FERC ¶ 61,139 (1978); *Transcontinental Gas Pipeline Corp.*, 84 FERC ¶ 61,084 (1998).
[91] *Kentucky West Virginia*, 2 FERC ¶ 61,139 at p. 61,325 (1978); quoting *Florida Gas Transmission Co.*, 47 FPC 341 at p. 363 (1972).
[92] Transcontinental *Gas Pipeline Corp.*, 84 FERC ¶ 61,084 at pp. 16-17 (1998).

Commission has affirmed application of these guidelines in evaluating the capital structure of electric utilities.[93] Similarly, National Grid's use of its actual capital structure in implementing formula rates is consistent with past practice approved by the Commission for other utilities.

C. Transmission Organization Participation Adder

Q. HAS THE COMMISSION RECOGNIZED THAT AN ROE ADDER FOR PARTICIPATION IN A TRANSMISSION ORGANIZATION LIKE THE NYISO IS APPROPRIATE?

A. Yes. The EPAct specifically required the Commission to "provide for incentives to each transmitting utility or electric utility that joins a Transmission Organization."[94] The decision to provide this incentive is well supported, both from policy and capital attraction reasons, and the Commission has consistently affirmed its support for an ROE incentive for participation in a Transmission Organization (ISO or RTO).[95] The Commission has determined that the public interest is better served if functional control of the grid is performed by an independent entity like an ISO or RTO and if new transmission investment is undertaken with the wider focus and enhanced stakeholder participation provided through an independently-driven process, rather than under isolated, utility-by-utility planning.

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[93] See, *e.g.*, *Allegheny Power*, 106 FERC ¶ 61,241 (2004); *Milford Power Company, LLC*, 110 FERC ¶61,299 at P73 (2005) (ruling that actual debt/equity ratios that can be substantiated are preferred over a proxy capital structures).

[94] *EPAct* at Sect. 219 (c), 119 STAT. 962.

[95] See, *e.g.*, *Bangor Hydro* at P 2; *ISO New England, Inc.*, 106 FERC ¶ 61,280 at P 246; *PJM Interconnection, L.L.C.*, 104 FERC ¶ 61,124 at P 74 (2003); *Allegheny Power Sys. Operating Cos.*, 106 FERC ¶ 61,003 (2004).

In *Order No. 679*, the Commission stated that it will authorize, when justified, an incentive-based rate treatment, in the form of a higher ROE, for public utilities that join and/or continue to be a member of an ISO, RTO, or other Commission-approved Transmission Organization.[96] As the Commission noted:

> A regional planning process is very important to meeting regional transmission needs, and, we believe it will produce benefits for customers.[97]

While FERC elected to consider the incentive request on a case-by-case basis, rather than creating a generic adder, the Commission concluded that:

> [E]ntities that have already joined, and that remain members of, an RTO, ISO, or other Commission-approved Transmission Organization, are eligible to receive this incentive. The basis for the incentive is a recognition of the benefits that flow from membership in such an organization and the fact that continuing membership is generally voluntary.[98]

In *Pepco Holdings*,[99] the Commission affirmed its policy of allowing an ROE adder to recognize the consumer benefits provided through membership in a Transmission organization, and noted that a 50 basis point incentive was consistent with the level approved in recent proceedings.[100]

Comprehensive operations, planning and decision making under the framework of a Transmission Organization should be encouraged, fostered, and

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[96] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 326.
[97] *Order No. 679* at P 332.
[98] *Order No. 679* at P. 331. Similarly, the Commission concluded in *Order No. 679-A*, "We affirm the finding in the Final Rule that the incentive applies to all utilities joining Transmission Organizations, irrespective of the date they join, based on a reading of section 219 in its entirety." [P. 86]
[99] *Pepco Holdings, Inc.*, 121 FERC ¶ 61,169 (2007).
[100] *Id.* at P 15 & 16.

rewarded in order to achieve the public policy goals mandated by Congress. Moreover, given past precedent authorizing incentive returns for Transmission Organization participants, investors have come to expect such added returns when they fund projects for which the utility is no longer the sole operational or planning entity. Incentive rate treatment to recognize National Grid's active support of regional transmission planning and ongoing participation in an ISO is consistent with past precedent, the Commission's guidelines, and investors' expectations and should be approved.

D. ROE Range of Reasonableness

Q. WHAT BASE ROE RANGE OF REASONABLENESS DOES YOUR EVALUATION INDICATE FOR NATIONAL GRID?

A. Because the transmission facilities of National Grid are operated within the scope of the NYISO, investors' required rate of return on equity was estimated by reference to a group of electric utilities comprised of TOs participating in the NYISO and the broader markets with which the NYISO interacts. Based on the adjusted range of reasonableness produced by applying the Commission's DCF approach to the Northeast TO Proxy Group, I recommend a base ROE range of reasonableness of 7.9 percent to 15.9 percent, with the midpoint of this range being 11.9 percent. This recommendation is supported by the results of the CAPM and expected earnings approaches.

Q. DOES NATIONAL GRID QUALIFY FOR AN INCENTIVE FOR MEMBERSHIP IN A TRANSMISSION ORGANIZATION?

A. Yes. I recommend increasing National Grid's ROE by a 50 basis-point incentive adder to recognize its membership in NYISO. This recommendation is consistent with the Commission's past practice of incorporating a 50 basis-point incentive return for participation in a Transmission Organization.

Q. WHAT ROE IS INDICATED FOR NATIONAL GRID AFTER INCORPORATING AN INCENTIVE FOR PARTICIPATION IN A TRANSMISSION ORGANIZATION?

A. Increasing National Grid's ROE by a 50 basis-point incentive adder to recognize its membership in NYISO results in an ROE of 12.4 percent. As noted earlier, applying the Commission's DCF model to the Northeast TO Proxy Group resulted in an adjusted range of reasonableness of 7.9 percent to 15.9 percent, with the midpoint being 11.9 percent. Thus, this 12.4 percent ROE falls well within the range of reasonableness, as required by established Commission policy.

In evaluating a reasonable ROE for National Grid, it is important to consider investors' continued focus on the unsettled conditions in restructured power markets, as well as other development in the electric utility industry, such as heightened exposure to regulatory risks. In addition, uncertainties associated with National Grid – including renewed focus on regulatory actions, potential exposure to energy procurement, and the need for significant capital investment – are clearly evident to investors. Considering these factors, along with the incentives for National Grid' ongoing participation in an ISO, it is my conclusion that an ROE of 12.4 percent is warranted for National Grid.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY IN THIS CASE?

A. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Niagara Mohawk Power Corporation d/b/a National Grid	)))	Docket No. ER08-___-000

VERIFICATION

I, William E. Avera, President of FINCAP, Inc., being duly sworn, depose and state that that the foregoing testimony was prepared by me or under my direction; that I have read such testimony and am familiar with the contents thereof, and that the contents is true, correct, accurate and complete to the best of my knowledge, information, and belief.

William E. Avera

SUBSCRIBED AND SWORN to before me, the undersigned notary public, on this 6th day of February, 2008.

Notary Public

ADRIEN MCKENZIE
Notary Public
STATE OF TEXAS
My Comm Exp Jan 10, 2011

WILLIAM E. AVERA

FINCAP, INC.
Financial Concepts and Applications
Economic and Financial Counsel

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Austin, Texas 78751
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Summary of Qualifications

Ph.D. in economics and finance; Chartered Financial Analyst (CFA ®) designation; extensive expert witness testimony before courts, alternative dispute resolution panels, regulatory agencies and legislative committees; lectured in executive education programs around the world on ethics, investment analysis, and regulation; undergraduate and graduate teaching in business and economics; appointed to leadership positions in government, industry, academia, and the military.

Employment

Principal, FINCAP, Inc. (Sep. 1979 to present)	Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (over 150 entities valued), estimation of damages, statistical and industry studies. Provide strategy advice and educational services in public and private sectors, and serve as expert witness before regulatory agencies, legislative committees, arbitration panels, and courts.
Director, Economic Research Division, Public Utility Commission of Texas (Dec. 1977 to Aug. 1979)	Responsible for research and testimony preparation on rate of return, rate structure, and econometric analysis dealing with energy, telecommunications, water and sewer utilities. Testified in major rate cases and appeared before legislative committees and served as Chief Economist for agency. Administered state and federal grant funds. Communicated frequently with political leaders and representatives from consumer groups, media, and investment community.
Manager, Financial Education, International Paper Company New York City (Feb. 1977 to Nov. 1977)	Directed corporate education programs in accounting, finance, and economics. Developed course materials, recruited and trained instructors, liaison within the company and with academic institutions. Prepared operating budget and designed financial controls for corporate professional development program.

Lecturer in Finance,
The University of Texas at Austin
(Sep. 1979 to May 1981)
Assistant Professor of Finance,
(Sep. 1975 to May 1977)

Taught graduate and undergraduate courses in financial management and investment theory. Conducted research in business and public policy. Named Outstanding Graduate Business Professor and received various administrative appointments.

Assistant Professor of Business,
University of North Carolina at Chapel Hill
(Sep. 1972 to Jul. 1975)

Taught in BBA, MBA, and Ph.D. programs. Created project course in finance, Financial Management for Women, and participated in developing Small Business Management sequence. Organized the North Carolina Institute for Investment Research, a group of financial institutions that supported academic research. Faculty advisor to the Media Board, which funds student publications and broadcast stations.

Education

Ph.D., Economics and Finance,
University of North Carolina at Chapel Hill
(Jan. 1969 to Aug. 1972)

Elective courses included financial management, public finance, monetary theory, and econometrics. Awarded the Stonier Fellowship by the American Bankers' Association and University Teaching Fellowship. Taught statistics, macroeconomics, and microeconomics.

Dissertation: *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice*

B.A., Economics,
Emory University, Atlanta, Georgia
(Sep. 1961 to Jun. 1965)

Active in extracurricular activities, president of the Barkley Forum (debate team), Emory Religious Association, and Delta Tau Delta chapter. Individual awards and team championships at national collegiate debate tournaments.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1977; Vice President for Membership, Financial Management Association; President, Austin Chapter of Planning Executives Institute; Board of Directors, North Carolina Society of Financial Analysts; Candidate Curriculum Committee, Association for Investment Management and Research; Executive Committee of Southern Finance Association; Vice Chair, Staff Subcommittee on Economics and National Association of Regulatory Utility Commissioners (NARUC); Appointed to NARUC Technical Subcommittee on the National Energy Act.

Teaching in Executive Education Programs

University-Sponsored Programs: Central Michigan University, Duke University, Louisiana State University, National Defense University, National University of Singapore, Texas A&M University, University of Kansas, University of North Carolina, University of Texas.

Business and Government-Sponsored Programs: Advanced Seminar on Earnings Regulation, American Public Welfare Association, Association for Investment Management and Research, Congressional Fellows Program, Cost of Capital Workshop, Electricity Consumers Resource Council, Financial Analysts Association of Indonesia, Financial Analysts Review, Financial Analysts Seminar at Northwestern University, Governor's Executive Development Program of Texas, Louisiana Association of Business and Industry, National Association of Purchasing Management, National Association of Tire Dealers, Planning Executives Institute, School of Banking of the South, State of Wisconsin Investment Board, Stock Exchange of Thailand, Texas Association of State Sponsored Computer Centers, Texas Bankers' Association, Texas Bar Association, Texas Savings and Loan League, Texas Society of CPAs, Tokyo Association of Foreign Banks, Union Bank of Switzerland, U.S. Department of State, U.S. Navy, U.S. Veterans Administration, in addition to Texas state agencies and major corporations.

Presented papers for Mills B. Lane Lecture Series at the University of Georgia and Heubner Lectures at the University of Pennsylvania. Taught graduate courses in finance and economics in evening program at St. Edward's University in Austin from January 1979 through 1998.

Expert Witness Testimony

Testified in 240 cases before regulatory agencies addressing cost of capital, regulatory policy, rate design, and other economic and financial issues.

Federal Agencies: Federal Communications Commission, Federal Energy Regulatory Commission, Surface Transportation Board, Interstate Commerce Commission, and the Canadian Radio-Television and Telecommunications Commission.

State Regulatory Agencies: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware. Florida, Hawaii, Idaho, Illinois, Indiana, Kansas, Maryland, Michigan, Missouri, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, Wisconsin, and Wyoming.

Testified in 40 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (80 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Co-chair, Synchronous Interconnection Committee, appointed by Public Utility Commission of Texas and approved by governor; Operator of AAA Ranch, a certified organic producer of agricultural products; Appointed to Organic Livestock Advisory Committee by Texas Agricultural Commissioner Susan Combs; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas;* Appointed by Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

Community Activities

Board Member, Sustainable Food Center; Chair, Board of Deacons, Finance Committee, and Elder, Central Presbyterian Church of Austin; Founding Member, Orange-Chatham County (N.C.) Legal Aid Screening Committee.

Military

Captain, U.S. Naval Reserve (retired after 28 years service); Commanding Officer, Naval Special Warfare Engineering Support Unit; Officer-in-charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

Bibliography

Monographs

Ethics and the Investment Professional (video, workbook, and instructor's guide) and *Ethics Challenge Today* (video), Association for Investment Management and Research (1995)

"Definition of Industry Ethics and Development of a Code" and "Applying Ethics in the Real World," in *Good Ethics: The Essential Element of a Firm's Success*, Association for Investment Management and Research (1994)

"On the Use of Security Analysts' Growth Projections in the DCF Model," with Bruce H. Fairchild in *Earnings Regulation Under Inflation*, J. R. Foster and S. R. Holmberg, eds. Institute for Study of Regulation (1982)

An Examination of the Concept of Using Relative Customer Class Risk to Set Target Rates of Return in Electric Cost-of-Service Studies, with Bruce H. Fairchild, Electricity Consumers Resource Council (ELCON) (1981); portions reprinted in *Public Utilities Fortnightly* (Nov. 11, 1982)

"Usefulness of Current Values to Investors and Creditors," *Research Study on Current-Value Accounting Measurements and Utility*, George M. Scott, ed., Touche Ross Foundation (1978)

"The Geometric Mean Strategy and Common Stock Investment Management," with Henry A. Latané in *Life Insurance Investment Policies*, David Cummins, ed. (1977)

Investment Companies: Analysis of Current Operations and Future Prospects, with J. Finley Lee and Glenn L. Wood, American College of Life Underwriters (1975)

Articles

"Should Analysts Own the Stocks they Cover?" *The Financial Journalist*, (March 2002)

"Liquidity, Exchange Listing, and Common Stock Performance," with John C. Groth and Kerry Cooper, *Journal of Economics and Business* (Spring 1985); reprinted by National Association of Security Dealers

"The Energy Crisis and the Homeowner: The Grief Process," *Texas Business Review* (Jan.–Feb. 1980); reprinted in *The Energy Picture: Problems and Prospects*, J. E. Pluta, ed., Bureau of Business Research (1980)

"Use of IFPS at the Public Utility Commission of Texas," *Proceedings of the IFPS Users Group Annual Meeting* (1979)

"Production Capacity Allocation: Conversion, CWIP, and One-Armed Economics," *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"Some Thoughts on the Rate of Return to Public Utility Companies," with Bruce H. Fairchild in *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"A New Capital Budgeting Measure: The Integration of Time, Liquidity, and Uncertainty," with David Cordell in *Proceedings of the Southwestern Finance Association* (1977)

"Usefulness of Current Values to Investors and Creditors," in *Inflation Accounting/Indexing and Stock Behavior* (1977)

"Consumer Expectations and the Economy," *Texas Business Review* (Nov. 1976)

"Portfolio Performance Evaluation and Long-run Capital Growth," with Henry A. Latané in *Proceedings of the Eastern Finance Association* (1973)

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *CFA Digest*. Articles in *Carolina Financial Times*.

Selected Papers and Presentations

"The Who, What, When, How, and Why of Ethics", San Antonio Financial Analysts Society (Jan. 16, 2002). Similar presentation given to the Austin Society of Financial Analysts (Jan. 17, 2002)

"Ethics for Financial Analysts," Sponsored by Canadian Council of Financial Analysts: delivered in Calgary, Edmonton, Regina, and Winnipeg, June 1997. Similar presentations given to Austin Society of Financial Analysts (Mar. 1994), San Antonio Society of Financial Analysts (Nov. 1985), and St. Louis Society of Financial Analysts (Feb. 1986)

"Cost of Capital for Multi-Divisional Corporations," Financial Management Association, New Orleans, Louisiana (Oct. 1996)

"Ethics and the Treasury Function," Government Treasurers Organization of Texas, Corpus Christi, Texas (Jun. 1996)

"A Cooperative Future," Iowa Association of Electric Cooperatives, Des Moines (December 1995). Similar presentations given to National G & T Conference, Irving, Texas (June 1995), Kentucky Association of Electric Cooperatives Annual Meeting, Louisville (Nov. 1994), Virginia, Maryland, and Delaware Association of Electric Cooperatives Annual Meeting, Richmond (July 1994), and Carolina Electric Cooperatives Annual Meeting, Raleigh (Mar. 1994)

"Information Superhighway Warnings: Speed Bumps on Wall Street and Detours from the Economy," Texas Society of Certified Public Accountants Natural Gas, Telecommunications and Electric Industries Conference, Austin (Apr. 1995)

"Economic/Wall Street Outlook," Carolinas Council of the Institute of Management Accountants, Myrtle Beach, South Carolina (May 1994). Similar presentation given to Bell Operating Company Accounting Witness Conference, Santa Fe, New Mexico (Apr. 1993)

"Regulatory Developments in Telecommunications," Regional Holding Company Financial and Accounting Conference, San Antonio (Sep. 1993)

"Estimating the Cost of Capital During the 1990s: Issues and Directions," The National Society of Rate of Return Analysts, Washington, D.C. (May 1992)

"Making Utility Regulation Work at the Public Utility Commission of Texas," Center for Legal and Regulatory Studies, University of Texas, Austin (June 1991)

"Can Regulation Compete for the Hearts and Minds of Industrial Customers," Emerging Issues of Competition in the Electric Utility Industry Conference, Austin (May 1988)

"The Role of Utilities in Fostering New Energy Technologies," Emerging Energy Technologies in Texas Conference, Austin (Mar. 1988)

"The Regulators' Perspective," Bellcore Economic Analysis Conference, San Antonio (Nov. 1987)

"Public Utility Commissions and the Nuclear Plant Contractor," Construction Litigation Superconference, Laguna Beach, California (Dec. 1986)

"Development of Cogeneration Policies in Texas," University of Georgia Fifth Annual Public Utilities Conference, Atlanta (Sep. 1985)

"Wheeling for Power Sales," Energy Bureau Cogeneration Conference, Houston (Nov. 1985).

"Asymmetric Discounting of Information and Relative Liquidity: Some Empirical Evidence for Common Stocks" (with John Groth and Kerry Cooper), Southern Finance Association, New Orleans (Nov. 1982)

"Used and Useful Planning Models," Planning Executive Institute, 27th Corporate Planning Conference, Los Angeles (Nov. 1979)

"Staff Input to Commission Rate of Return Decisions," The National Society of Rate of Return Analysts, New York (Oct. 1979)

"Electric Rate Design in Texas," Southwestern Economics Association, Fort Worth (Mar. 1979)

"Discounted Cash Life: A New Measure of the Time Dimension in Capital Budgeting," with David Cordell, Southern Finance Association, New Orleans (Nov. 1978)

"The Relative Value of Statistics of Ex Post Common Stock Distributions to Explain Variance," with Charles G. Martin, Southern Finance Association, Atlanta (Nov. 1977)

"An ANOVA Representation of Common Stock Returns as a Framework for the Allocation of Portfolio Management Effort," with Charles G. Martin, Financial Management Association, Montreal (Oct. 1976)

"A Growth-Optimal Portfolio Selection Model with Finite Horizon," with Henry A. Latané, American Finance Association, San Francisco (Dec. 1974)

"An Optimal Approach to the Finance Decision," with Henry A. Latané, Southern Finance Association, Atlanta (Nov. 1974)

"A Pragmatic Approach to the Capital Structure Decision Based on Long-Run Growth," with Henry A. Latané, Financial Management Association, San Diego (Oct. 1974)

"Multi-period Wealth Distributions and Portfolio Theory," Southern Finance Association, Houston (Nov. 1973)

"Growth Rates, Expected Returns, and Variance in Portfolio Selection and Performance Evaluation," with Henry A. Latané, Econometric Society, Oslo, Norway (Aug. 1973)

NORTHEAST TO PROXY GROUP

FERC DCF MODEL

		(a)		(b)		(c)	(d)	(e)		(f)
		6 Mo.Div. Yield		Adjusted Div. Yield		Growth Rates		Implied Cost of Equity		
	Company	Low	High	Low	High	br + sv	IBES	Low		High
1	American Elec Pwr	3.3%	3.6%	3.4%	3.7%	6.0%	6.0%	9.4%	--	9.8%
2	Central Vermont PS	2.5%	3.1%	2.5%	3.2%	3.5%	9.0%	$\boxed{6.1\%}$	--	12.2%
3	Consolidated Edison	4.8%	5.2%	4.9%	5.2%	3.3%	3.0%	7.9%	--	8.5%
4	Constellation Energy	1.8%	2.0%	1.9%	2.2%	11.2%	16.0%	13.2%	--	$\boxed{18.2\%}$
5	Dominion Resources	3.2%	3.4%	3.2%	3.6%	2.8%	8.0%	$\boxed{6.1\%}$	--	11.6%
6	DPL Inc.	3.5%	3.9%	3.6%	4.1%	10.8%	6.0%	9.6%	--	14.9%
7	Exelon Corp.	2.1%	2.4%	2.2%	2.6%	12.6%	9.0%	11.2%	--	15.2%
8	FirstEnergy Corp.	2.9%	3.2%	3.0%	3.4%	6.7%	8.0%	9.8%	--	11.4%
9	FPL Group	2.5%	2.7%	2.6%	2.9%	8.3%	10.0%	10.9%	--	12.9%
10	Northeast Utilities	2.6%	2.9%	2.7%	3.0%	6.5%	11.0%	9.2%	--	14.0%
11	NSTAR	3.8%	4.1%	3.9%	4.2%	5.5%	7.0%	9.4%	--	11.2%
12	Pepco Holdings	3.6%	4.0%	3.7%	4.2%	4.2%	9.0%	7.9%	--	13.2%
13	PPL Corp.	2.4%	2.6%	2.4%	2.8%	7.6%	12.0%	10.0%	--	14.8%
14	PS Enterprise Group	2.5%	2.8%	2.6%	3.0%	10.9%	18.0%	13.5%	--	$\boxed{21.0\%}$
15	UIL Holdings	4.9%	5.6%	5.0%	5.9%	2.1%	10.0%	$\boxed{7.1\%}$	--	15.9%
	Range of Reasonableness							6.1%	--	21.0%
	Midpoint								13.5%	
	Adjusted Range of Reasonableness							7.9%	--	15.9%
	Midpoint								11.9%	

(a) Six-month average dividend yield for July - December 2007.
(b) Six-month dividend yield adjusted for one-half years' growth.
(c) Average of projections based on data from The Value Line Investment Survey (Nov. 30 & Dec. 28, 2007).
(d) S&P's Earnings Guide (November 2007).
(e) Sum of low growth rate and corresponding adjusted dividend yield.
(f) Sum of high growth rate and corresponding adjusted dividend yield.

NORTHEAST TO PROXY GROUP

Exhibit No. NMP-5

CAPM MODEL

	Company	(a) Div Yield	(b) Proj. Growth	(c) Cost of Equity	(d) Risk-Free Rate	(e) Risk Premium	(f) Beta	(g) Implied Cost of Equity
		S&P 500						
1	American Elec Pwr	2.2%	11.0%	13.2%	4.8%	8.4%	0.95	12.8%
2	Central Vermont PS	2.2%	11.0%	13.2%	4.8%	8.4%	1.00	13.2%
3	Consolidated Edison	2.2%	11.0%	13.2%	4.8%	8.4%	0.75	11.1%
4	Constellation Energy	2.2%	11.0%	13.2%	4.8%	8.4%	0.85	11.9%
5	Dominion Resources	2.2%	11.0%	13.2%	4.8%	8.4%	0.75	11.1%
6	DPL Inc.	2.2%	11.0%	13.2%	4.8%	8.4%	0.85	11.9%
7	Exelon Corp.	2.2%	11.0%	13.2%	4.8%	8.4%	0.90	12.3%
8	FirstEnergy Corp.	2.2%	11.0%	13.2%	4.8%	8.4%	0.85	11.9%
9	FPL Group	2.2%	11.0%	13.2%	4.8%	8.4%	0.75	11.1%
10	Northeast Utilities	2.2%	11.0%	13.2%	4.8%	8.4%	0.80	11.5%
11	NSTAR	2.2%	11.0%	13.2%	4.8%	8.4%	0.75	11.1%
12	Pepco Holdings	2.2%	11.0%	13.2%	4.8%	8.4%	0.95	12.8%
13	PPL Corp.	2.2%	11.0%	13.2%	4.8%	8.4%	0.90	12.3%
14	PS Enterprise Group	2.2%	11.0%	13.2%	4.8%	8.4%	0.95	12.8%
15	UIL Holdings	2.2%	11.0%	13.2%	4.8%	8.4%	0.95	12.8%
	Range of Reasonableness							**11.1% -- 13.2%**
	Midpoint							**12.1%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Dec. 11, 2007).

(b) Weighted average of IBES and Value Line growth rates for the dividend paying firms in the S&P 500 based on data from Standard & Poor's Earnings Guide (Nov. 2007) and www.valueline.com (Dec. 11, 2007).

(c) (a) + (b).

(d) Average yield on 20-year Treasury bonds for July - December 2007 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data.htm.

(e) (c) - (d).

(f) The Value Line Investment Survey (Nov. 30, & Dec. 28, 2007).

(g) (d) + (e) x (f).

NORTHEAST TO PROXY GROUP

Exhibit No. NMP-6
Page 1 of 1

COMPARABLE EARNINGS APPROACH

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity		
1	American Elec Pwr	12.5%	1.0299		12.9%	
2	Central Vermont PS	8.0%	1.0180		8.1%	
3	Consolidated Edison	8.5%	1.0267		8.7%	
4	Constellation Energy	17.5%	1.0604		18.6%	
5	Dominion Resources	15.0%	1.0281		15.4%	
6	DPL Inc.	21.0%	1.0557		22.2%	
7	Exelon Corp.	24.0%	1.0487		25.2%	
8	FirstEnergy Corp.	13.5%	1.0314		13.9%	
9	FPL Group	13.5%	1.0395		14.0%	
10	Northeast Utilities	10.5%	1.0202		10.7%	
11	NSTAR	14.5%	1.0287		14.9%	
12	Pepco Holdings	11.0%	1.0135		11.1%	
13	PPL Corp.	23.5%	1.0395		24.4%	
14	PS Enterprise Group	14.5%	1.0532		15.3%	
15	UIL Holdings	10.5%	1.0074		10.6%	
	Range of Reasonableness			8.1%	--	25.2%
	Midpoint				16.7%	
	Adjusted Range of Reasonableness			8.1%	--	15.4%
	Midpoint				11.8%	

(a) 3-5 year projections from The Value Line Investment Survey (Nov 30 & Dec. 28, 2007).

(b) Adjustment to convert year-end "r" to an average rate of return, consistent with *Southern California Edison*.

(c) (a) x (b).

NORTHEAST TO PROXY GROUP

CAPITAL STRUCTURE

		At December 31, 2006 (a)			Value Line Projected 2010-12 (b)		
	Company	Long-term Debt	Preferred	Common Equity	Long-term Debt	Other	Common Equity
1	American Elec Pwr	59.1%	0.3%	40.6%	56.5%	0.5%	43.0%
2	Central Vermont PS	38.1%	3.6%	58.4%	39.0%	3.0%	58.0%
3	Consolidated Edison	51.2%	1.3%	47.5%	47.0%	0.5%	52.5%
4	Constellation Energy	51.0%	1.9%	47.1%	41.0%	1.0%	58.0%
5	Dominion Resources	53.7%	0.9%	45.4%	49.5%	1.0%	49.5%
6	DPL Inc.	70.7%	0.9%	28.3%	53.5%	0.5%	46.0%
7	Exelon Corp.	47.6%	0.5%	51.9%	45.0%	0.5%	54.5%
8	FirstEnergy Corp.	53.5%	0.0%	46.5%	48.0%	0.0%	52.0%
9	FPL Group	53.1%	0.0%	46.9%	48.5%	0.0%	51.5%
10	Northeast Utilities	50.4%	2.0%	47.6%	56.5%	1.0%	42.5%
11	NSTAR	52.7%	1.3%	46.1%	48.0%	1.0%	51.0%
12	Pepco Holdings	56.0%	0.0%	44.0%	50.0%	0.5%	49.5%
13	PPL Corp.	58.6%	2.3%	39.2%	48.5%	2.0%	49.5%
14	PS Enterprise Group	57.1%	1.6%	41.3%	46.0%	0.5%	53.5%
15	UIL Holdings	51.4%	0.0%	48.6%	49.5%	0.0%	50.5%
	Average	53.6%	**1.1%**	**45.3%**	**48.4%**	**0.8%**	**50.8%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Nov. 30 & Dec. 28, 2007).

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Niagara Mohawk Power Corporation — Docket No. ER08-____ ____

Direct Testimony

of

Thomas F. Killeen

I. Introduction and Qualifications:

Q. Please state your name and business address.

A. My name is Thomas F. Killeen. My business address is 25 Research Drive, Westborough, Massachusetts 01582.

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

A. I am employed by National Grid USA Service Company, Inc. ("Company") as a Principal Financial Analyst in the Treasury Services Department. My responsibilities include providing certain financial services to all National Grid USA companies, including Niagara Mohawk Power Corporation ("NMPC").

Q. Please describe your educational background and training.

A. I have a Bachelor of Arts degree in economics from Columbia University and a Master of Business Administration degree with a concentration in finance from Babson College. I joined the Company in 1985 and have held various positions in the Corporate Finance, Internal Audit, Financial Forecasting, and Treasury Services Departments. I have submitted testimony in FERC Docket No. ER07-694 regarding capital structure, in New Hampshire PUC Docket No. 95-169 regarding capital structure and rate of return and in New Hampshire PUC Docket No. 00-148 regarding financing, and have also submitted testimony and testified in Massachusetts Docket No. 00-53 regarding financing.

II. Testimony:

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe and support the cost of capital to be used in NMPC's filing to update certain NMPC specific components of the Wholesale TSC formula under the New York Independent System Operator's Open Access Transmission Tariff, FERC Electric Tariff in Original Volume No. 1.

Q. Are you supporting any statements included with this filing?

A. Yes, I am supporting Statement AV which demonstrates the rate of return.

Q. Please describe the proposed capital structure to be used in NMPC's filing.

A. The proposed formula relies on NMPC's actual capitalization, established from the same data source that supports the Company's Form 1 Electric Utility Annual Report. The capital structure is supported by the testimony of NMPC Witness Avera.

Q. What are the cost rates to be applied to this capital structure?

A. The cost rate for long term debt is 5.48%. This is based on the weighted average cost rate of NMPC's actual long term debt outstanding during the year ending December 31, 2006, as shown in Statement AV Schedule A, Sheet 1. The weighted average cost rate of NMPC's actual long term debt outstanding for each of the twelve months in the year ended December 31, 2006 are shown in Statement AV Schedule A, Sheets 2 through 13. The cost rate for the preferred stock is 3.95% based on the weighted average cost rate of NMPC's actual preferred stock outstanding during the year ending December 31, 2006, as shown on Statement AV Schedule A, Sheet 14. These same series of preferred stock remained outstanding in these same amounts and at these same cost rates for the entire year. The proposed return on common equity is 12.4%, which is supported by the testimony of NMPC Witness Avera.

Q. What is the resulting weighted average overall cost of capital rate to be used in the proposed formula?

A. As shown in Statement AV Schedule A, Sheet 1, the weighted average cost of capital rate is 9.62%. This cost of capital rate will be applied in the testimony of NMPC Witness Viapiano to determine the return under the proposed formula.

Q.. Does this conclude your testimony?

A. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Niagara Mohawk Power Corporation Docket No. ER08-__________

DECLARATION OF THOMAS F. KILLEEN

I, Thomas F. Killeen, do hereby declare under penalty of perjury under the laws of the United States of America that I am the Thomas F. Killeen referred to in the document entitled "Direct Testimony of Thomas F. Killeen;" that I have read such testimony and am familiar with the contents thereof; and that the facts set forth therein are true and correct to the best of my knowledge, information, and belief.

Thomas F. Killeen

Thomas F. Killeen