EXHIBITS TO THE DIRECT TESTIMONY
OF
MATTHEW I. KAHAL

EXHIBIT A

MATTHEW I. KAHAL

Since 2001, Mr. Kahal has worked as an independent consulting economist, specializing in energy economics, public utility regulation, and utility financial studies. Over the past three decades, his work has encompassed electric utility integrated resource planning (IRP), power plant licensing, environmental compliance, and utility financial issues. In the financial area, he has conducted numerous cost of capital studies and addressed other financial issues for electric, gas, telephone, and water utilities. Mr. Kahal's work in recent years has expanded to electric power markets, mergers, and various aspects of regulation.

Mr. Kahal has provided expert testimony in more than 400 cases before state and federal regulatory commissions, federal courts, and the U.S. Congress. His testimony has covered need for power, integrated resource planning, cost of capital, purchased power practices and contracts, merger economics, industry restructuring, and various other regulatory and public policy issues.

Education

B.A. (Economics) – University of Maryland, 1971

M.A. (Economics) – University of Maryland, 1974

Ph.D. candidacy – University of Maryland, completed all course work and qualifying examinations.

Previous Employment

1981-2001	Founding Principal, Vice President, and President Exeter Associates, Inc. Columbia, MD
1980-1981	Member of the Economic Evaluation Directorate The Aerospace Corporation Washington, D.C.
1977-1980	Consulting Economist Washington, D.C. consulting firm
1972-1977	Research/Teaching Assistant and Instructor (part time) Department of Economics, University of Maryland (College Park) Lecturer in Business and Economics Montgomery College (Rockville and Takoma Park, MD)

Professional Experience

Mr. Kahal has more than thirty-five years' experience managing and conducting consulting assignments relating to public utility economics and regulation. In 1981, he and five colleagues founded the firm of Exeter Associates, Inc., and for the next 20 years he served as a Principal and corporate officer of the firm. During that time, he supervised multi-million dollar support contracts with the State of Maryland and directed the technical work conducted by both Exeter professional staff and numerous subcontractors. Additionally, Mr. Kahal took the lead role at Exeter in consulting to the firm's other governmental and private clients in the areas of financial analysis, utility mergers, electric restructuring, and utility purchase power contracts.

At the Aerospace Corporation, Mr. Kahal served as an economic consultant to the Strategic Petroleum Reserve (SPR). In that capacity, he participated in a detailed financial assessment of the SPR, and developed an econometric forecasting model of U.S. petroleum industry inventories. That study has been used to determine the extent to which private sector petroleum stocks can be expected to protect the U.S. from the impacts of oil import interruptions.

Before entering consulting, Mr. Kahal held faculty positions with the Department of Economics at the University of Maryland and with Montgomery College, teaching courses on economic principles, business, and economic development.

Publications and Consulting Reports

Projected Electric Power Demands of the Baltimore Gas and Electric Company, Maryland Power Plant Siting Program, 1979.

Projected Electric Power Demands of the Allegheny Power System, Maryland Power Plant Siting Program, January 1980.

An Econometric Forecast of Electric Energy and Peak Demand on the Delmarva Peninsula, Maryland Power Plant Siting Program, March 1980 (with Ralph E. Miller).

A Benefit/Cost Methodology of the Marginal Cost Pricing of Tennessee Valley Authority Electricity, prepared for the Board of Directors of the Tennessee Valley Authority, April 1980.

An Evaluation of the Delmarva Power and Light Company Generating Capacity Profile and Expansion Plan, (Interim Report), prepared for the Delaware Office of the Public Advocate, July 1980 (with Sharon L. Mason).

Rhode Island-DOE Electric Utilities Demonstration Project, Third Interim Report on Preliminary Analysis of the Experimental Results, prepared for the Economic Regulatory Administration, U.S. Department of Energy, July 1980.

Petroleum Inventories and the Strategic Petroleum Reserve, The Aerospace Corporation, prepared for the Strategic Petroleum Reserve Office, U.S. Department of Energy, December

1980.

Alternatives to Central Station Coal and Nuclear Power Generation, prepared for Argonne National Laboratory and the Office of Utility Systems, U.S. Department of Energy, August 1981.

"An Econometric Methodology for Forecasting Power Demands," Conducting Need-for-Power Review for Nuclear Power Plants (D.A. Nash, ed.), U.S. Nuclear Regulatory Commission, NUREG-0942, December 1982.

State Regulatory Attitudes Toward Fuel Expense Issues, prepared for the Electric Power Research Institute, July 1983 (with Dale E. Swan).

"Problems in the Use of Econometric Methods in Load Forecasting," Adjusting to Regulatory, Pricing and Marketing Realities (Harry Trebing, ed.), Institute of Public Utilities, Michigan State University, 1983.

Proceedings of the Maryland Conference on Electric Load Forecasting (editor and contributing author), Maryland Power Plant Siting Program, PPES-83-4, October 1983.

"The Impacts of Utility-Sponsored Weatherization Programs: The Case of Maryland Utilities" (with others), in Government and Energy Policy (Richard L. Itteilag, ed.), 1983.

Power Plant Cumulative Environmental Impact Report, contributing author (Paul E. Miller, ed.) Maryland Department of Natural Resources, January 1984.

Projected Electric Power Demands for the Potomac Electric Power Company, three volumes (with Steven L. Estomin), prepared for the Maryland Power Plant Siting Program, March 1984.

"An Assessment of the State-of-the-Art of Gas Utility Load Forecasting" (with Thomas Bacon, Jr. and Steven L. Estomin), published in the Proceedings of the Fourth NARUC Biennial Regulatory Information Conference, 1984.

"Nuclear Power and Investor Perceptions of Risk" (with Ralph E. Miller), published in The Energy Industries in Transition: 1985-2000 (John P. Weyant and Dorothy Sheffield, eds.), 1984.

The Financial Impact of Potential Department of Energy Rate Recommendations on the Commonwealth Edison Company, prepared for the U.S. Department of Energy, October 1984.

"Discussion Comments," published in Impact of Deregulation and Market Forces on Public Utilities: The Future of Regulation (Harry Trebing, ed.), Institute of Public Utilities, Michigan State University, 1985.

An Econometric Forecast of the Electric Power Loads of Baltimore Gas and Electric Company, two volumes (with others), prepared for the Maryland Power Plant Siting Program, 1985.

A Survey and Evaluation of Demand Forecast Methods in the Gas Utility Industry, prepared for the Public Utilities Commission of Ohio, Forecasting Division, November 1985 (with Terence Manuel).

A Review and Evaluation of the Load Forecasts of Houston Lighting & Power Company and Central Power & Light Company – Past and Present, prepared for the Texas Public Utility Commission, December 1985 (with Marvin H. Kahn).

Power Plant Cumulative Environmental Impact Report for Maryland, principal author of three of the eight chapters in the report (Paul E. Miller, ed.), PPSP-CEIR-5, March 1986.

"Potential Emissions Reduction from Conservation, Load Management, and Alternative Power," published in Acid Deposition in Maryland: A Report to the Governor and General Assembly, Maryland Power Plant Research Program, AD-87-1, January 1987.

Determination of Retrofit Costs at the Oyster Creek Nuclear Generating Station, March 1988, prepared for Versar, Inc., New Jersey Department of Environmental Protection.

Excess Deferred Taxes and the Telephone Utility Industry, April 1988, prepared on behalf of the National Association of State Utility Consumer Advocates.

Toward a Proposed Federal Policy for Independent Power Producers, comments prepared on behalf of the Indiana Consumer Counselor, FERC Docket EL87-67-000, November 1987.

Review and Discussion of Regulations Governing Bidding Programs, prepared for the Pennsylvania Office of Consumer Advocate, June 1988.

A Review of the Proposed Revisions to the FERC Administrative Rules on Avoided Costs and Related Issues, prepared for the Pennsylvania Office of Consumer Advocate, April 1988.

Review and Comments on the FERC NOPR Concerning Independent Power Producers, prepared for the Pennsylvania Office of Consumer Advocate, June 1988.

The Costs to Maryland Utilities and Ratepayers of an Acid Rain Control Strategy – An Updated Analysis, prepared for the Maryland Power Plant Research Program, October 1987, AD-88-4.

"Comments," in New Regulatory and Management Strategies in a Changing Market Environment (Harry M. Trebing and Patrick C. Mann, editors), Proceedings of the Institute of Public Utilities Eighteenth Annual Conference, 1987.

Electric Power Resource Planning for the Potomac Electric Power Company, prepared for the Maryland Power Plant Research Program, July 1988.

Power Plant Cumulative Environmental Impact Report for Maryland (Thomas E. Magette, ed.), authored two chapters, November 1988, PPRP-CEIR-6.

Resource Planning and Competitive Bidding for Delmarva Power & Light Company, October 1990, prepared for the Maryland Department of Natural Resources (with M. Fullenbaum).

Electric Power Rate Increases and the Cleveland Area Economy, prepared for the Northeast Ohio Areawide Coordinating Agency, October 1988.

An Economic and Need for Power Evaluation of Baltimore Gas & Electric Company's Perryman Plant, May 1991, prepared for the Maryland Department of Natural Resources (with M. Fullenbaum).

The Cost of Equity Capital for the Bell Local Exchange Companies in a New Era of Regulation, October 1991, presented at the Atlantic Economic Society 32nd Conference, Washington, D.C.

A Need for Power Review of Delmarva Power & Light Company's Dorchester Unit 1 Power Plant, March 1993, prepared for the Maryland Department of National Resources (with M. Fullenbaum).

The AES Warrior Run Project: Impact on Western Maryland Economic Activity and Electric Rates, February 1993, prepared for the Maryland Power Plant Research Program (with Peter Hall).

An Economic Perspective on Competition and the Electric Utility Industry, November 1994, prepared for the Electric Consumers' Alliance.

PEPCO's Clean Air Act Compliance Plan: Status Report, prepared for the Maryland Power Plant Research Plan, January 1995 (w/Diane Mountain, Environmental Resources Management, Inc.).

The FERC Open Access Rulemaking: A Review of the Issues, prepared for the Indiana Office of Utility Consumer Counselor and the Pennsylvania Office of Consumer Advocate, June 1995.

A Status Report on Electric Utility Restructuring: Issues for Maryland, prepared for the Maryland Power Plant Research Program, November 1995 (with Daphne Psacharopoulos).

Modeling the Financial Impacts on the Bell Regional Holding Companies from Changes in Access Rates, prepared for MCI Corporation, May 1996.

The CSEF Electric Deregulation Study: Economic Miracle or the Economists' Cold Fusion?, prepared for the Electric Consumers' Alliance, Indianapolis, Indiana, October 1996.

Reducing Rates for Interstate Access Service: Financial Impacts on the Bell Regional Holding Companies, prepared for MCI Corporation, May 1997.

The New Hampshire Retail Competition Pilot Program: A Preliminary Evaluation, July 1997, prepared for the Electric Consumers' Alliance (with Jerome D. Mierzwa).

Electric Restructuring and the Environment: Issue Identification for Maryland, March 1997, prepared for the Maryland Power Plant Research Program (with Environmental Resource Management, Inc.).

An Analysis of Electric Utility Embedded Power Supply Costs, prepared for Power-Gen International Conference, Dallas, Texas, December 1997.

Market Power Outlook for Generation Supply in Louisiana, December 2000, prepared for the Louisiana Public Service Commission (with others).

A Review of Issues Concerning Electric Power Capacity Markets, prepared for the Maryland Power Plant Research Program, December 2001 (with B. Hobbs and J. Inon).
The Economic Feasibility of Air Emissions Controls at the Brandon Shores and Morgantown Coal-fired Power Plants, February 2005 (prepared for the Chesapeake Bay Foundation).

The Economic Feasibility of Power Plant Retirements on the Entergy System, September 2005, with Phil Hayet (prepared for the Louisiana Public Service Commission).

Expert Report on Capital Structure, Equity and Debt Costs, prepared for the Edmonton Regional Water Customers Group, August 30, 2006.

Maryland's Options to Reduce and Stabilize Electric Power Prices Following Restructuring, with Steven L. Estomin, prepared for the Power Plant Research Program, Maryland Department of Natural Resources, September 2006.

Expert Report of Matthew I. Kahal, on behalf of the U. S. Department of Justice, August 2008, Civil Action No. IP-99-1693C-MIS.

Conference and Workshop Presentations

Workshop on State Load Forecasting Programs, sponsored by the Nuclear Regulatory Commission and Oak Ridge National Laboratory, February 1982 (presentation on forecasting methodology).

Fourteenth Annual Conference of the Michigan State University Institute for Public Utilities, December 1982 (presentation on problems in forecasting).

Conference on Conservation and Load Management, sponsored by the Massachusetts Energy Facilities Siting Council, May 1983 (presentation on cost-benefit criteria).

Maryland Conference on Load Forecasting, sponsored by the Maryland Power Plant Siting Program and the Maryland Public Service Commission, June 1983 (presentation on overforecasting power demands).

The 5th Annual Meetings of the International Association of Energy Economists, June 1983 (presentation on evaluating weatherization programs).

The NARUC Advanced Regulatory Studies Program (presented lectures on capacity planning for electric utilities), February 1984.

The 16th Annual Conference of the Institute of Public Utilities, Michigan State University (discussant on phase-in and excess capacity), December 1984.

U.S. Department of Energy Utilities Conference, Las Vegas, Nevada (presentation of current and future regulatory issues), May 1985.

The 18th Annual Conference of the Institute of Public Utilities, Michigan State University, Williamsburg, Virginia, December 1986 (discussant on cogeneration).

The NRECA Conference on Load Forecasting, sponsored by the National Rural Electric Cooperative Association, New Orleans, Louisiana, December 1987 (presentation on load forecast accuracy).

The Second Rutgers/New Jersey Department of Commerce Annual Conference on Energy Policy in the Middle Atlantic States, Rutgers University, April 1988 (presentation on spot pricing of electricity).

The NASUCA 1988 Mid-Year Meeting, Annapolis, Maryland, June 1988, sponsored by the National Association of State Utility Consumer Advocates (presentation on the FERC electricity avoided cost NOPRs).

The Thirty-Second Atlantic Economic Society Conference, Washington, D.C., October 1991 (presentation of a paper on cost of capital issues for the Bell Operating Companies).

The NASUCA 1993 Mid-Year Meeting, St. Louis, Missouri, sponsored by the National Association of State Utility Consumer Advocates, June 1993 (presentation on regulatory issues concerning electric utility mergers).

The NASUCA and NARUC annual meetings in New York City, November 1993 (presentations and panel discussions on the emerging FERC policies on transmission pricing).

The NASUCA annual meetings in Reno, Nevada, November 1994 (presentation concerning the FERC NOPR on stranded cost recovery).

U.S. Department of Energy Utilities/Energy Management Workshop, March 1995 (presentation concerning electric utility competition).

The 1995 NASUCA Mid-Year Meeting, Breckenridge, Colorado, June 1995 (presentation concerning the FERC rulemaking on electric transmission open access).

The 1996 NASUCA Mid-Year Meeting, Chicago, Illinois, June 1996 (presentation concerning electric utility merger issues).

Conference on “Restructuring the Electric Industry,” sponsored by the National Consumers League and Electric Consumers Alliance, Washington, D.C., May 1997 (presentation on retail access pilot programs).

The 1997 Mid-Atlantic Conference of Regulatory Utilities Commissioners (MARUC), Hot Springs, Virginia, July 1997 (presentation concerning electric deregulation issues).

Power-Gen ‘97 International Conference, Dallas, Texas, December 1997 (presentation concerning utility embedded costs of generation supply).

Consumer Summit on Electric Competition, sponsored by the National Consumers League and Electric Consumers’ Alliance, Washington, D.C., March 2001 (presentation concerning generation supply and reliability).

National Association of State Utility Consumer Advocates, Mid-Year Meetings, Austin, Texas, June 16-17, 2002 (presenter and panelist on RTO/Standard Market Design issues).

Louisiana State Bar Association, Public Utility Section, Baton Rouge, Louisiana, October 2, 2002 (presentation on Performance-Based Ratemaking and panelist on RTO issues).

Virginia State Corporation Commission/Virginia State Bar, Twenty-Second National Regulatory Conference, Williamsburg, Virginia, May 10, 2004 (presentation on Electric Transmission System Planning).

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
1.	27374 & 27375 October 1978	Long Island Lighting Company	New York Counties	Nassau & Suffolk	Economic Impacts of Proposed Rate Increase
2.	6807 January 1978	Generic	Maryland	MD Power Plant Siting Program	Load Forecasting
3.	78-676-EL-AIR February 1978	Ohio Power Company	Ohio	Ohio Consumers' Counsel	Test Year Sales and Revenues
4.	17667 May 1979	Alabama Power Company	Alabama	Attorney General	Test Year Sales, Revenues, Costs, and Load Forecasts
5.	None April 1980	Tennessee Valley Authority	TVA Board	League of Women Voters	Time-of-Use Pricing
6.	R-80021082	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Load Forecasting, Marginal Cost pricing
7.	7259 (Phase I) October 1980	Potomac Edison Company	Maryland	MD Power Plant Siting Program	Load Forecasting
8.	7222 December 1980	Delmarva Power & Light Company	Maryland	MD Power Plant Siting Program	Need for Plant, Load Forecasting
9.	7441 June 1981	Potomac Electric Power Company	Maryland	Commission Staff	PURPA Standards
10.	7159 May 1980	Baltimore Gas & Electric	Maryland	Commission Staff	Time-of-Use Pricing
11.	81-044-E-42T	Monongahela Power	West Virginia	Commission Staff	Time-of-Use Rates
12.	7259 (Phase II) November 1981	Potomac Edison Company	Maryland	MD Power Plant Siting Program	Load Forecasting, Load Management
13.	1606 September 1981	Blackstone Valley Electric and Narragansett	Rhode Island	Division of Public Utilities	PURPA Standards
14.	RID 1819 April 1982	Pennsylvania Bell	Pennsylvania	Office of Consumer Advocate	Rate of Return
15.	82-0152 July 1982	Illinois Power Company	Illinois	U.S. Department of Defense	Rate of Return, CWIP

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
16.	7559 September 1982	Potomac Edison Company	Maryland	Commission Staff	Cogeneration
17.	820150-EU September 1982	Gulf Power Company	Florida	Federal Executive Agencies	Rate of Return, CWIP
18.	82-057-15 January 1983	Mountain Fuel Supply Company	Utah	Federal Executive Agencies	Rate of Return, Capital Structure
19.	5200 August 1983	Texas Electric Service Company	Texas	Federal Executive Agencies	Cost of Equity
20.	28069 August 1983	Oklahoma Natural Gas	Oklahoma	Federal Executive Agencies	Rate of Return, deferred taxes, capital structure, attrition
21.	83-0537 February 1984	Commonwealth Edison Company	Illinois	U.S. Department of Energy	Rate of Return, capital structure, financial capability
22.	84-035-01 June 1984	Utah Power & Light Company	Utah	Federal Executive Agencies	Rate of Return
23.	U-1009-137 July 1984	Utah Power & Light Company	Idaho	U.S. Department of Energy	Rate of Return, financial condition
24.	R-842590 August 1984	Philadelphia Electric Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
25.	840086-EI August 1984	Gulf Power Company	Florida	Federal Executive Agencies	Rate of Return, CWIP
26.	84-122-E August 1984	Carolina Power & Light Company	South Carolina	South Carolina Consumer Advocate	Rate of Return, CWIP, load forecasting
27.	CGC-83-G & CGC-84-G October 1984	Columbia Gas of Ohio	Ohio	Ohio Division of Energy	Load forecasting
28.	R-842621 October 1984	Western Pennsylvania Water Company	Pennsylvania	Office of Consumer Advocate	Test year sales
29.	R-842710 January 1985	ALLTEL Pennsylvania Inc.	Pennsylvania	Office of Consumer Advocate	Rate of Return
30.	ER-504 February 1985	Allegheny Generating Company	FERC	Office of Consumer Advocate	Rate of Return

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
31.	R-842632 March 1985	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Rate of Return, conservation, time-of-use rates
32.	83-0537 & 84-0555 April 1985	Commonwealth Edison Company	Illinois	U.S. Department of Energy	Rate of Return, incentive rates, rate base
33.	Rulemaking Docket No. 11, May 1985	Generic	Delaware	Delaware Commission Staff	Interest rates on refunds
34.	29450 July 1985	Oklahoma Gas & Electric Company	Oklahoma	Oklahoma Attorney General	Rate of Return, CWIP in rate base
35.	1811 August 1985	Bristol County Water Company	Rhode Island	Division of Public Utilities	Rate of Return, capital Structure
36.	R-850044 & R-850045 August 1985	Quaker State & Continental Telephone Companies	Pennsylvania	Office of Consumer Advocate	Rate of Return
37.	R-850174 November 1985	Philadelphia Suburban Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return, financial conditions
38.	U-1006-265 March 1986	Idaho Power Company	Idaho	U.S. Department of Energy	Power supply costs and models
39.	EL-86-37 & EL-86-38 September 1986	Allegheny Generating Company	FERC	PA Office of Consumer Advocate	Rate of Return
40.	R-850287 June 1986	National Fuel Gas Distribution Corp.	Pennsylvania	Office of Consumer Advocate	Rate of Return
41.	1849 August 1986	Blackstone Valley Electric	Rhode Island	Division of Public Utilities	Rate of Return, financial condition
42.	86-297-GA-AIR November 1986	East Ohio Gas Company	Ohio	Ohio Consumers' Counsel	Rate of Return
43.	U-16945 December 1986	Louisiana Power & Light Company	Louisiana	Public Service Commission	Rate of Return, rate phase-in plan
44.	Case No. 7972 February 1987	Potomac Electric Power Company	Maryland	Commission Staff	Generation capacity planning, purchased power contract
45.	EL-86-58 & EL-86-59 March 1987	System Energy Resources and Middle South Services	FERC	Louisiana PSC	Rate of Return

	Docket Number	Utility	Jurisdiction	Client	Subject
46.	ER-87-72-001 April 1987	Orange & Rockland	FERC	PA Office of Consumer Advocate	Rate of Return
47.	U-16945 April 1987	Louisiana Power & Light Company	Louisiana	Commission Staff	Revenue requirement update phase-in plan
48.	P-870196 May 1987	Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Cogeneration contract
49.	86-2025-EL-AIR June 1987	Cleveland Electric Illuminating Company	Ohio	Ohio Consumers' Counsel	Rate of Return
50.	86-2026-EL-AIR June 1987	Toledo Edison Company	Ohio	Ohio Consumers' Counsel	Rate of Return
51.	87-4 June 1987	Delmarva Power & Light Company	Delaware	Commission Staff	Cogeneration/small power
52.	1872 July 1987	Newport Electric Company	Rhode Island	Commission Staff	Rate of Return
53.	WO 8606654 July 1987	Atlantic City Sewerage Company	New Jersey	Resorts International	Financial condition
54.	7510 August 1987	West Texas Utilities Company	Texas	Federal Executive Agencies	Rate of Return, phase-in
55.	8063 Phase I October 1987	Potomac Electric Power Company	Maryland	Power Plant Research Program	Economics of power plant site selection
56.	00439 November 1987	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Cogeneration economics
57.	RP-87-103 February 1988	Panhandle Eastern Pipe Line Company	FERC	Indiana Utility Consumer Counselor	Rate of Return
58.	EC-88-2-000 February 1988	Utah Power & Light Co. PacifiCorp	FERC	Nucor Steel	Merger economics
59.	87-0427 February 1988	Commonwealth Edison Company	Illinois	Federal Executive Agencies	Financial projections
60.	870840 February 1988	Philadelphia Suburban Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
61.	870832 March 1988	Columbia Gas of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Rate of Return
62.	8063 Phase II July 1988	Potomac Electric Power Company	Maryland	Power Plant Research Program	Power supply study
63.	8102 July 1988	Southern Maryland Electric Cooperative	Maryland	Power Plant Research Program	Power supply study
64.	10105 August 1988	South Central Bell Telephone Co.	Kentucky	Attorney General	Rate of Return, incentive regulation
65.	00345 August 1988	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Need for power
66.	U-17906 September 1988	Louisiana Power & Light Company	Louisiana	Commission Staff	Rate of Return, nuclear power costs Industrial contracts
67.	88-170-EL-AIR October 1988	Cleveland Electric Illuminating Co.	Ohio	Northeast-Ohio Areawide Coordinating Agency	Economic impact study
68.	1914 December 1988	Providence Gas Company	Rhode Island	Commission Staff	Rate of Return
69.	U-12636 & U-17649 February 1989	Louisiana Power & Light Company	Louisiana	Commission Staff	Disposition of litigation proceeds
70.	00345 February 1989	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Load forecasting
71.	RP88-209 March 1989	Natural Gas Pipeline of America	FERC	Indiana Utility Consumer Counselor	Rate of Return
72.	8425 March 1989	Houston Lighting & Power Company	Texas	U.S. Department of Energy	Rate of Return
73.	EL89-30-000 April 1989	Central Illinois Public Service Company	FERC	Soyland Power Coop, Inc.	Rate of Return
74.	R-891208 May 1989	Pennsylvania American Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
75.	89-0033 May 1989	Illinois Bell Telephone Company	Illinois	Citizens Utility Board	Rate of Return
76.	881167-EI May 1989	Gulf Power Company	Florida	Federal Executive Agencies	Rate of Return
77.	R-891218 July 1989	National Fuel Gas Distribution Company	Pennsylvania	Office of Consumer Advocate	Sales forecasting
78.	8063, Phase III Sept. 1989	Potomac Electric Power Company	Maryland	Depart. Natural Resources	Emissions Controls
79.	37414-S2 October 1989	Public Service Company of Indiana	Indiana	Utility Consumer Counselor	Rate of Return, DSM, off-system sales, incentive regulation
80.	October 1989	Generic	U.S. House of Reps. Comm. on Ways & Means	N/A	Excess deferred income tax
81.	38728 November 1989	Indiana Michigan Power Company	Indiana	Utility Consumer Counselor	Rate of Return
82.	RP89-49-000 December 1989	National Fuel Gas Supply Corporation	FERC	PA Office of Consumer Advocate	Rate of Return
83.	R-891364 December 1989	Philadelphia Electric Company	Pennsylvania	PA Office of Consumer Advocate	Financial impacts (surrebuttal only)
84.	RP89-160-000 January 1990	Trunkline Gas Company	FERC	Indiana Utility Consumer Counselor	Rate of Return
85.	EL90-16-000 November 1990	System Energy Resources, Inc.	FERC	Louisiana Public Service Commission	Rate of Return
86.	89-624 March 1990	Bell Atlantic	FCC	PA Office of Consumer Advocate	Rate of Return
87.	8245 March 1990	Potomac Edison Company	Maryland	Depart. Natural Resources	Avoided Cost
88.	000586 March 1990	Public Service Company of Oklahoma	Oklahoma	Smith Cogeneration Mgmt.	Need for Power

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
89.	38868 March 1990	Indianapolis Water Company	Indiana	Utility Consumer Counselor	Rate of Return
90.	1946 March 1990	Blackstone Valley Electric Company	Rhode Island	Division of Public Utilities	Rate of Return
91.	000776 April 1990	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration Mgmt.	Need for Power
92.	890366 May 1990, December 1990	Metropolitan Edison Company	Pennsylvania	Office of Consumer Advocate	Competitive Bidding Program Avoided Costs
93.	EC-90-10-000 May 1990	Northeast Utilities	FERC	Maine PUC, et al.	Merger, Market Power, Transmission Access
94.	ER-891109125 July 1990	Jersey Central Power & Light	New Jersey	Rate Counsel	Rate of Return
95.	R-901670 July 1990	National Fuel Gas Distribution Corp.	Pennsylvania	Office of Consumer Advocate	Rate of Return Test year sales
96.	8201 October 1990	Delmarva Power & Light Company	Maryland	Depart. Natural Resources	Competitive Bidding, Resource Planning
97.	EL90-45-000 April 1991	Entergy Services, Inc.	FERC	Louisiana PSC	Rate of Return
98.	GR90080786J January 1991	New Jersey Natural Gas	New Jersey	Rate Counsel	Rate of Return
99.	90-256 January 1991	South Central Bell Telephone Company	Kentucky	Attorney General	Rate of Return
100.	U-17949A February 1991	South Central Bell Telephone Company	Louisiana	Louisiana PSC	Rate of Return
101.	ER90091090J April 1991	Atlantic City Electric Company	New Jersey	Rate Counsel	Rate of Return
102.	8241, Phase I April 1991	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	Environmental controls

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
103.	8241, Phase II May 1991	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	Need for Power, Resource Planning
104.	39128 May 1991	Indianapolis Water Company	Indiana	Utility Consumer Counselor	Rate of Return, rate base, financial planning
105.	P-900485 May 1991	Duquesne Light Company	Pennsylvania	Office of Consumer Advocate	Purchased power contract and related ratemaking
106.	G900240 P910502 May 1991	Metropolitan Edison Company Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Purchased power contract and related ratemaking
107.	GR901213915 May 1991	Elizabethtown Gas Company	New Jersey	Rate Counsel	Rate of Return
108.	91-5032 August 1991	Nevada Power Company	Nevada	U.S. Dept. of Energy	Rate of Return
109.	EL90-48-000 November 1991	Entergy Services	FERC	Louisiana PSC	Capacity transfer
110.	000662 September 1991	Southwestern Bell Telephone	Oklahoma	Attorney General	Rate of Return
111.	U-19236 October 1991	Arkansas Louisiana Gas Company	Louisiana	Louisiana PSC Staff	Rate of Return
112.	U-19237 December 1991	Louisiana Gas Service Company	Louisiana	Louisiana PSC Staff	Rate of Return
113.	ER91030356J October 1991	Rockland Electric Company	New Jersey	Rate Counsel	Rate of Return
114.	GR91071243J February 1992	South Jersey Gas Company	New Jersey	Rate Counsel	Rate of Return
115.	GR91081393J March 1992	New Jersey Natural Gas Company	New Jersey	Rate Counsel	Rate of Return
116.	P-870235, et al. March 1992	Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Cogeneration contracts

	Docket Number	Utility	Jurisdiction	Client	Subject
117.	8413 March 1992	Potomac Electric Power Company	Maryland	Dept. of Natural Resources	IPP purchased power contracts
118.	39236 March 1992	Indianapolis Power & Light Company	Indiana	Utility Consumer Counselor	Least-cost planning Need for power
119.	R-912164 April 1992	Equitable Gas Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
120.	ER-91111698J May 1992	Public Service Electric & Gas Company	New Jersey	Rate Counsel	Rate of Return
121.	U-19631 June 1992	Trans Louisiana Gas Company	Louisiana	PSC Staff	Rate of Return
122.	ER-91121820J July 1992	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Rate of Return
123.	R-00922314 August 1992	Metropolitan Edison Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
124.	92-049-05 September 1992	US West Communications	Utah	Committee of Consumer Services	Rate of Return
125.	92PUE0037 September 1992	Commonwealth Gas Company	Virginia	Attorney General	Rate of Return
126.	EC92-21-000 September 1992	Entergy Services, Inc.	FERC	Louisiana PSC	Merger Impacts (Affidavit)
127.	ER92-341-000 December 1992	System Energy Resources	FERC	Louisiana PSC	Rate of Return
128.	U-19904 November 1992	Louisiana Power & Light Company	Louisiana	Staff	Merger analysis, competition competition issues
129.	8473 November 1992	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	QF contract evaluation
130.	IPC-E-92-25 January 1993	Idaho Power Company	Idaho	Federal Executive Agencies	Power Supply Clause

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
131.	E002/GR-92-1185 February 1993	Northern States Power Company	Minnesota	Attorney General	Rate of Return
132.	92-102, Phase II March 1992	Central Maine Power Company	Maine	Staff	QF contracts prudence and procurements practices
133.	EC92-21-000 March 1993	Entergy Corporation	FERC	Louisiana PSC	Merger Issues
134.	8489 March 1993	Delmarva Power & Light Company	Maryland	Dept. of Natural Resources	Power Plant Certification
135.	11735 April 1993	Texas Electric Utilities Company	Texas	Federal Executives Agencies	Rate of Return
136.	2082 May 1993	Providence Gas Company	Rhode Island	Division of Public Utilities	Rate of Return
137.	P-00930715 December 1993	Bell Telephone Company of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Rate of Return, Financial Projections, Bell/TCI merger
138.	R-00932670 February 1994	Pennsylvania-American Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
139.	8583 February 1994	Conowingo Power Company	Maryland	Dept. of Natural Resources	Competitive Bidding for Power Supplies
140.	E-015/GR-94-001 April 1994	Minnesota Power & Light Company	Minnesota	Attorney General	Rate of Return
141.	CC Docket No. 94-1 May 1994	Generic Telephone	FCC	MCI Comm. Corp.	Rate of Return
142.	92-345, Phase II June 1994	Central Maine Power Company	Maine	Advocacy Staff	Price Cap Regulation Fuel Costs
143.	93-11065 April 1994	Nevada Power Company	Nevada	Federal Executive Agencies	Rate of Return
144.	94-0065 May 1994	Commonwealth Edison Company	Illinois	Federal Executive Agencies	Rate of Return
145.	GR94010002J June 1994	South Jersey Gas Company	New Jersey	Rate Counsel	Rate of Return

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
146.	WR94030059 July 1994	New Jersey-American Water Company	New Jersey	Rate Counsel	Rate of Return
147.	RP91-203-000 June 1994	Tennessee Gas Pipeline Company	FERC	Customer Group	Environmental Externalities (oral testimony only)
148.	ER94-998-000 July 1994	Ocean State Power	FERC	Boston Edison Company	Rate of Return
149.	R-00942986 July 1994	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Rate of Return, Emission Allowances
150.	94-121 August 1994	South Central Bell Telephone Company	Kentucky	Attorney General	Rate of Return
151.	35854-S2 November 1994	PSI Energy, Inc.	Indiana	Utility Consumer Counsel	Merger Savings and Allocations
152.	IPC-E-94-5 November 1994	Idaho Power Company	Idaho	Federal Executive Agencies	Rate of Return
153.	November 1994	Edmonton Water	Alberta, Canada	Regional Customer Group	Rate of Return (Rebuttal Only)
154.	90-256 December 1994	South Central Bell Telephone Company	Kentucky	Attorney General	Incentive Plan True-Ups
155.	U-20925 February 1995	Louisiana Power & Light Company	Louisiana	PSC Staff	Rate of Return Industrial Contracts Trust Fund Earnings
156.	R-00943231 February 1995	Pennsylvania-American Water Company	Pennsylvania	Consumer Advocate	Rate of Return
157.	8678 March 1995	Generic	Maryland	Dept. Natural Resources	Electric Competition Incentive Regulation (oral only)
158.	R-000943271 April 1995	Pennsylvania Power & Light Company	Pennsylvania	Consumer Advocate	Rate of Return Nuclear decommissioning Capacity Issues
159.	U-20925 May 1995	Louisiana Power & Light Company	Louisiana	Commission Staff	Class Cost of Service Issues

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
160.	2290 June 1995	Narragansett Electric Company	Rhode Island	Division Staff	Rate of Return
161.	U-17949E June 1995	South Central Bell Telephone Company	Louisiana	Commission Staff	Rate of Return
162.	2304 July 1995	Providence Water Supply Board	Rhode Island	Division Staff	Cost recovery of Capital Spending Program
163.	ER95-625-000, et al. August 1995	PSI Energy, Inc.	FERC	Office of Utility Consumer Counselor	Rate of Return
164.	P-00950915, et al. September 1995	Paxton Creek Cogeneration Assoc.	Pennsylvania	Office of Consumer Advocate	Cogeneration Contract Amendment
165.	8702 September 1995	Potomac Edison Company	Maryland	Dept. of Natural Resources	Allocation of DSM Costs (oral only)
166.	ER95-533-001 September 1995	Ocean State Power	FERC	Boston Edison Co.	Cost of Equity
167.	40003 November 1995	PSI Energy, Inc.	Indiana	Utility Consumer Counselor	Rate of Return Retail wheeling
168.	P-55, SUB 1013 January 1996	BellSouth	North Carolina	AT&T	Rate of Return
169.	P-7, SUB 825 January 1996	Carolina Tel.	North Carolina	AT&T	Rate of Return
170.	February 1996	Generic Telephone	FCC	MCI	Cost of capital
171.	95A-531EG April 1996	Public Service Company of Colorado	Colorado	Federal Executive Agencies	Merger issues
172.	ER96-399-000 May 1996	Northern Indiana Public Service Company	FERC	Indiana Office of Utility Consumer Counselor	Cost of capital
173.	8716 June 1996	Delmarva Power & Light Company	Maryland	Dept. of Natural Resources	DSM programs
174.	8725 July 1996	BGE/PEPCO	Maryland	Md. Energy Admin.	Merger Issues

	Docket Number	Utility	Jurisdiction	Client	Subject
175.	U-20925 August 1996	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Rate of Return Allocations Fuel Clause
176.	EC96-10-000 September 1996	BGE/PEPCO	FERC	Md. Energy Admin.	Merger issues competition
177.	EL95-53-000 November 1996	Entergy Services, Inc.	FERC	Louisiana PSC	Nuclear Decommissioning
178.	WR96100768 March 1997	Consumers NJ Water Company	New Jersey	Ratepayer Advocate	Cost of Capital
179.	WR96110818 April 1997	Middlesex Water Co.	New Jersey	Ratepayer Advocate	Cost of Capital
180.	U-11366 April 1997	Ameritech Michigan	Michigan	MCI	Access charge reform/financial condition
181.	97-074 May 1997	BellSouth	Kentucky	MCI	Rate Rebalancing financial condition
182.	2540 June 1997	New England Power	Rhode Island	PUC Staff	Divestiture Plan
183.	96-336-TP-CSS June 1997	Ameritech Ohio	Ohio	MCI	Access Charge reform Economic impacts
184.	WR97010052 July 1997	Maxim Sewerage Corp.	New Jersey	Ratepayer Advocate	Rate of Return
185.	97-300 August 1997	LG&E/KU	Kentucky	Attorney General	Merger Plan
186.	Case No. 8738 August 1997	Generic (oral testimony only)	Maryland	Dept. of Natural Resources	Electric Restructuring Policy
187.	Docket No. 2592 September 1997	Eastern Utilities	Rhode Island	PUC Staff	Generation Divestiture
188.	Case No.97-247 September 1997	Cincinnati Bell Telephone	Kentucky	MCI	Financial Condition

	Docket Number	Utility	Jurisdiction	Client	Subject
189.	Docket No. U-20925 November 1997	Entergy Louisiana	Louisiana	PSC Staff	Rate of Return
190.	Docket No. D97.7.90 November 1997	Montana Power Co.	Montana	Montana Consumers Counsel	Stranded Cost
191.	Docket No. EO97070459 November 1997	Jersey Central Power & Light Co.	New Jersey	Ratepayer Advocate	Stranded Cost
192.	Docket No. R-00974104 November 1997	Duquesne Light Co.	Pennsylvania	Office of Consumer Advocate	Stranded Cost
193.	Docket No. R-00973981 November 1997	West Penn Power Co.	Pennsylvania	Office of Consumer Advocate	Stranded Cost
194.	Docket No. A-1101150F0015 November 1997	Allegheny Power System DQE, Inc.	Pennsylvania	Office of Consumer Advocate	Merger Issues
195.	Docket No. WR97080615 January 1998	Consumers NJ Water Company	New Jersey	Ratepayer Advocate	Rate of Return
196.	Docket No. R-00974149 January 1998	Pennsylvania Power Company	Pennsylvania	Office of Consumer Advocate	Stranded Cost
197.	Case No. 8774 January 1998	Allegheny Power System DQE, Inc.	Maryland	Dept. of Natural Resources MD Energy Administration	Merger Issues
198.	Docket No. U-20925 (SC) March 1998	Entergy Louisiana, Inc.	Louisiana	Commission Staff	Restructuring, Stranded Costs, Market Prices
199.	Docket No. U-22092 (SC) March 1998	Entergy Gulf States, Inc.	Louisiana	Commission Staff	Restructuring, Stranded Costs, Market Prices
200.	Docket Nos. U-22092 (SC) and U-20925(SC) May 1998	Entergy Gulf States and Entergy Louisiana	Louisiana	Commission Staff	Standby Rates
201.	Docket No. WR98010015 May 1998	NJ American Water Co.	New Jersey	Ratepayer Advocate	Rate of Return
202.	Case No. 8794 December 1998	Baltimore Gas & Electric Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
203.	Case No. 8795 December 1998	Delmarva Power & Light Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan
204.	Case No. 8797 January 1998	Potomac Edison Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan
205.	Docket No. WR98090795 March 1999	Middlesex Water Co.	New Jersey	Ratepayer Advocate	Rate of Return
206.	Docket No. 99-02-05 April 1999	Connecticut Light & Power	Connecticut	Attorney General	Stranded Costs
207.	Docket No. 99-03-04 May 1999	United Illuminating Company	Connecticut	Attorney General	Stranded Costs
208.	Docket No. U-20925 (FRP) June 1999	Entergy Louisiana, Inc.	Louisiana	Staff	Capital Structure
209.	Docket No. EC-98-40-000, et al. May 1999	American Electric Power/ Central & Southwest	FERC	Arkansas PSC	Market Power Mitigation
210.	Docket No. 99-03-35 July 1999	United Illuminating Company	Connecticut	Attorney General	Restructuring
211.	Docket No. 99-03-36 July 1999	Connecticut Light & Power Co.	Connecticut	Attorney General	Restructuring
212.	WR99040249 Oct. 1999	Environmental Disposal Corp.	New Jersey	Ratepayer Advocate	Rate of Return
213.	2930 Nov. 1999	NEES/EUA	Rhode Island	Division Staff	Merger/Cost of Capital
214.	DE99-099 Nov. 1999	Public Service New Hampshire	New Hampshire	Consumer Advocate	Cost of Capital Issues
215.	00-01-11 Feb. 2000	Con Ed/NU	Connecticut	Attorney General	Merger Issues
216.	Case No. 8821 May 2000	Reliant/ODEC	Maryland	Dept. of Natural Resources	Need for Power/Plant Operations

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
217.	Case No. 8738 July 2000	Generic	Maryland	Dept. of Natural Resources	DSM Funding
218.	Case No. U-23356 June 2000	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Fuel Prudence Issues Purchased Power
219.	Case No. 21453, et al. July 2000	SWEPCO	Louisiana	PSC Staff	Stranded Costs
220.	Case No. 20925 (B) July 2000	Entergy Louisiana	Louisiana	PSC Staff	Purchase Power Contracts
221.	Case No. 24889 August 2000	Entergy Louisiana	Louisiana	PSC Staff	Purchase Power Contracts
222.	Case No. 21453, et al. February 2001	CLECO	Louisiana	PSC Staff	Stranded Costs
223.	P-00001860 and P-0000181 March 2001	GPU Companies	Pennsylvania	Office of Consumer Advocate	Rate of Return
224.	CVOL-0505662-S March 2001	ConEd/NU	Connecticut Superior Court	Attorney General	Merger (Affidavit)
225.	U-20925 (SC) March 2001	Entergy Louisiana	Louisiana	PSC Staff	Stranded Costs
226.	U-22092 (SC) March 2001	Entergy Gulf States	Louisiana	PSC Staff	Stranded Costs
227.	U-25533 May 2001	Entergy Louisiana/ Gulf States	Louisiana Interruptible Service	PSC Staff	Purchase Power
228.	P-00011872 May 2001	Pike County Pike	Pennsylvania	Office of Consumer Advocate	Rate of Return
229.	8893 July 2001	Baltimore Gas & Electric Co.	Maryland	MD Energy Administration	Corporate Restructuring
230.	8890 September 2001	Potomac Electric/Connectivity	Maryland	MD Energy Administration	Merger Issues

	Docket Number	Utility	Jurisdiction	Client	Subject
231.	U-25533 August 2001	Entergy Louisiana / Gulf States	Louisiana	Staff	Purchase Power Contracts
232.	U-25965 November 2001	Generic	Louisiana	Staff	RTO Issues
233.	3401 March 2002	New England Gas Co.	Rhode Island	Division of Public Utilities	Rate of Return
234.	99-833-MJR April 2002	Illinois Power Co.	U.S. District Court	U.S. Department of Justice	New Source Review
235.	U-25533 March 2002	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Nuclear Uprates Purchase Power
236.	P-00011872 May 2002	Pike County Power & Light	Pennsylvania	Consumer Advocate	POLR Service Costs
237.	U-26361, Phase I May 2002	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Purchase Power Cost Allocations
238.	R-00016849C001, et al. June 2002	Generic	Pennsylvania	Pennsylvania OCA	Rate of Return
239.	U-26361, Phase II July 2002	Entergy Louisiana/ Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contracts
240.	U-20925(B) August 2002	Entergy Louisiana	Louisiana	PSC Staff	Tax Issues
241.	U-26531 October 2002	SWEPCO	Louisiana	PSC Staff	Purchase Power Contract
242.	8936 October 2002	Delmarva Power & Light	Maryland	Energy Administration Dept. Natural Resources	Standard Offer Service
243.	U-25965 November 2002	SWEPCO/AEP	Louisiana	PSC Staff	RTO Cost/Benefit
244.	8908 Phase I November 2002	Generic	Maryland	Energy Administration Dept. Natural Resources	Standard Offer Service
245.	02S-315EG November 2002	Public Service Company of Colorado	Colorado	Fed. Executive Agencies	Rate of Return

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
246.	EL02-111-000 December 2002	PJM/MISO	FERC	MD PSC	Transmission Ratemaking
247.	02-0479 February 2003	Commonwealth Edison	Illinois	Dept. of Energy	POLR Service
248.	PL03-1-000 March 2003	Generic	FERC	NASUCA	Transmission Pricing (Affidavit)
249.	U-27136 April 2003	Entergy Louisiana	Louisiana	Staff	Purchase Power Contracts
250.	8908 Phase II July 2003	Generic	Maryland	Energy Administration Dept. of Natural Resources	Standard Offer Service
251.	U-27192 June 2003	Entergy Louisiana and Gulf States	Louisiana	LPSC Staff	Purchase Power Contract Cost Recovery
252.	C2-99-1181 October 2003	Ohio Edison Company	U.S. District Court	U.S. Department of Justice, et al.	Clean Air Act Compliance Economic Impact (Report)
253.	RP03-398-000 December 2003	Northern Natural Gas Co.	FERC	Municipal Distributors Group/Gas Task Force	Rate of Return
254.	8738 December 2003	Generic	Maryland	Energy Admin Department of Natural Resources	Environmental Disclosure (oral only)
255.	U-27136 December 2003	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Purchase Power Contracts
256.	U-27192, Phase II October/December 2003	Entergy Louisiana & Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contracts
257.	WC Docket 03-173 December 2003	Generic	FCC	MCI	Cost of Capital (TELRIC)
258.	ER 030 20110 January 2004	Atlantic City Electric	New Jersey	Ratepayer Advocate	Rate of Return
259.	E-01345A-03-0437 January 2004	Arizona Public Service Company	Arizona	Federal Executive Agencies	Rate of Return
260.	03-10001 January 2004	Nevada Power Company	Nevada	U.S. Dept. of Energy	Rate of Return

	Docket Number	Utility	Jurisdiction	Client	Subject
261.	R-00049255 June 2004	PPL Elec. Utility	Pennsylvania	Office of Consumer Advocate	Rate of Return
262.	U-20925 July 2004	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Rate of Return Capacity Resources
263.	U-27866 September 2004	Southwest Electric Power Co.	Louisiana	PSC Staff	Purchase Power Contract
264.	U-27980 September 2004	Cleco Power	Louisiana	PSC Staff	Purchase Power Contract
265.	U-27865 October 2004	Entergy Louisiana, Inc. Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contract
266.	RP04-155 December 2004	Northern Natural Gas Company	FERC	Municipal Distributors Group/Gas Task Force	Rate of Return
267.	U-27836 January 2005	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Power plant Purchase and Cost Recovery
268.	U-199040 et al. February 2005	Entergy Gulf States/ Louisiana	Louisiana	PSC Staff	Global Settlement, Multiple rate proceedings
269.	EF03070532 March 2005	Public Service Electric & Gas	New Jersey	Ratepayers Advocate	Securitization of Deferred Costs
270.	05-0159 June 2005	Commonwealth Edison	Illinois	Department of Energy	POLR Service
271.	U-28804 June 2005	Entergy Louisiana	Louisiana	LPSC Staff	QF Contract
272.	U-28805 June 2005	Entergy Gulf States	Louisiana	LPSC Staff	QF Contract
273.	05-0045-EI June 2005	Florida Power & Lt.	Florida	Federal Executive Agencies	Rate of Return
274.	9037 July 2005	Generic	Maryland	MD. Energy Administration	POLR Service
275.	U-28155 August 2005	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Independent Coordinator of Transmission Plan

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
276.	U-27866-A September 2005	Southwestern Electric Power Company	Louisiana	LPSC Staff	Purchase Power Contract
277.	U-28765 October 2005	Cleco Power LLC	Louisiana	LPSC Staff	Purchase Power Contract
278.	U-27469 October 2005	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Avoided Cost Methodology
279.	A-313200F007 October 2005	Sprint (United of PA)	Pennsylvania	Office of Consumer Advocate	Corporate Restructuring
280.	EM05020106 November 2005	Public Service Electric & Gas Company	New Jersey	Ratepayer Advocate	Merger Issues
281.	U-28765 December 2005	Cleco Power LLC	Louisiana	LPSC Staff	Plant Certification, Financing, Rate Plan
282.	U-29157 February 2006	Cleco Power LLC	Louisiana	LPSC Staff	Storm Damage Financing
283.	U-29204 March 2006	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Purchase power contracts
284.	A-310325F006 March 2006	Alltel	Pennsylvania	Office of Consumer Advocate	Merger, Corporate Restructuring
285.	9056 March 2006	Generic	Maryland	Maryland Energy Administration	Standard Offer Service Structure
286.	C2-99-1182 April 2006	American Electric Power Utilities	U. S. District Court Southern District, Ohio	U. S. Department of Justice	New Source Review Enforcement (expert report)
287.	EM05121058 April 2006	Atlantic City Electric	New Jersey	Ratepayer Advocate	Power plant Sale
288.	ER05121018 June 2006	Jersey Central Power & Light Company	New Jersey	Ratepayer Advocate	NUG Contracts Cost Recovery
289.	U-21496, Subdocket C June 2006	Cleco Power LLC	Louisiana	Commission Staff	Rate Stabilization Plan
290.	GR0510085 June 2006	Public Service Electric & Gas Company	New Jersey	Ratepayer Advocate	Rate of Return (gas services)

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
291.	R-000061366 July 2006	Metropolitan Ed. Company Penn. Electric Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
292.	9064 September 2006	Generic	Maryland	Energy Administration	Standard Offer Service
293.	U-29599 September 2006	Cleco Power LLC	Louisiana	Commission Staff	Purchase Power Contracts
294.	WR06030257 September 2006	New Jersey American Water Company	New Jersey	Rate Counsel	Rate of Return
295.	U-27866/U-29702 October 2006	Southwestern Electric Power Company	Louisiana	Commission Staff	Purchase Power/Power Plant Certification
296.	9063 October 2006	Generic	Maryland	Energy Administration Department of Natural Resources	Generation Supply Policies
297.	EM06090638 November 2006	Atlantic City Electric	New Jersey	Rate Counsel	Power Plant Sale
298.	C-2000065942 November 2006	Pike County Light & Power	Pennsylvania	Consumer Advocate	Generation Supply Service
299.	ER06060483 November 2006	Rockland Electric Company	New Jersey	Rate Counsel	Rate of Return
300.	A-110150F0035 December 2006	Duquesne Light Company	Pennsylvania	Consumer Advocate	Merger Issues
301.	U-29203, Phase II January 2007	Entergy Gulf States Entergy Louisiana	Louisiana	Commission Staff	Storm Damage Cost Allocation
302.	06-11022 February 2007	Nevada Power Company	Nevada	U.S. Dept. of Energy	Rate of Return
303.	U-29526 March 2007	Cleco Power	Louisiana	Commission Staff	Affiliate Transactions
304.	P-00072245 March 2007	Pike County Light & Power	Pennsylvania	Consumer Advocate	Provider of Last Resort Service
305.	P-00072247 March 2007	Duquesne Light Company	Pennsylvania	Consumer Advocate	Provider of Last Resort Service

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
306.	EM07010026 May 2007	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Power Plant Sale
307.	U-30050 June 2007	Entergy Louisiana Entergy Gulf States	Louisiana	Commission Staff	Purchase Power Contract
308.	U-29956 June 2007	Entergy Louisiana	Louisiana	Commission Staff	Black Start Unit
309.	U-29702 June 2007	Southwestern Electric Power Company	Louisiana	Commission Staff	Power Plant Certification
310.	U-29955 July 2007	Entergy Louisiana Entergy Gulf States	Louisiana	Commission Staff	Purchase Power Contracts
311.	2007-67 July 2007	FairPoint Communications	Maine	Office of Public Advocate	Merger Financial Issues
312.	P-00072259 July 2007	Metropolitan Edison Co.	Pennsylvania	Office of Consumer Advocate	Purchase Power Contract Restructuring
313.	EO07040278 September 2007	Public Service Electric & Gas	New Jersey	Rate Counsel	Solar Energy Program Financial Issues
314.	U-30192 September 2007	Entergy Louisiana	Louisiana	Commission Staff	Power Plant Certification Ratemaking, Financing
315.	9117 (Phase II) October 2007	Generic (Electric)	Maryland	Energy Administration	Standard Offer Service Reliability
316.	U-30050 November 2007	Entergy Gulf States	Louisiana	Commission Staff	Power Plant Acquisition
317.	IPC-E-07-8 December 2007	Idaho Power Co.	Idaho	U.S. Department of Energy	Cost of Capital
318.	U-30422 (Phase I) January 2008	Entergy Gulf States	Louisiana	Commission Staff	Purchase Power Contract
319.	U-29702 (Phase II) February, 2008	Southwestern Electric Power Co.	Louisiana	Commission Staff	Power Plant Certification
320.	March 2008	Delmarva Power & Light	Delaware State Senate	Senate Committee	Wind Energy Economics

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
321.	U-30192 (Phase II) March 2008	Entergy Louisiana	Louisiana	Commission Staff	Cash CWIP Policy, Credit Ratings
322.	U-30422 (Phase II) April 2008	Entergy Gulf States - LA	Louisiana	Commission Staff	Power Plant Acquisition
323.	U-29955 (Phase II) April 2008	Entergy Gulf States - LA Entergy Louisiana	Louisiana	Commission Staff	Purchase Power Contract
324.	GR-070110889 April 2008	New Jersey Natural Gas Company	New Jersey	Rate Counsel	Cost of Capital
325.	WR-08010020 July 2008	New Jersey American Water Company	New Jersey	Rate Counsel	Cost of Capital
326.	U-28804-A August 2008	Entergy Louisiana	Louisiana	Commission Staff	Cogeneration Contract
327.	IP-99-1693C-M/S August 2008	Duke Energy Indiana	Federal District Court	U.S. Department of Justice/ Environmental Protection Agency	Clean Air Act Compliance (Expert Report)
328.	U-30670 September 2008	Entergy Louisiana	Louisiana	Commission Staff	Nuclear Plant Equipment Replacement
329.	9149 October 2008	Generic	Maryland	Department of Natural Resources	Capacity Adequacy/Reliability
330.	IPC-E-08-10 October 2008	Idaho Power Company	Idaho	U.S. Department of Energy	Cost of Capital
331.	U-30727 October 2008	Cleco Power LLC	Louisiana	Commission Staff	Purchased Power Contract
332.	U-30689-A December 2008	Cleco Power LLC	Louisiana	Commission Staff	Transmission Upgrade Project
333.	IP-99-1693C-M/S February 2009	Duke Energy Indiana	Federal District Court	U.S. Department of Justice/EPA	Clean Air Act Compliance (Oral Testimony)
334.	U-30192, Phase II February 2009	Entergy Louisiana, LLC	Louisiana	Commission Staff	CWIP Rate Request Plant Allocation
335.	U-28805-B February 2009	Entergy Gulf States, LLC	Louisiana	Commission Staff	Cogeneration Contract

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
336.	P-2009-2093055, et al. May 2009	Metropolitan Edison Pennsylvania Electric	Pennsylvania	Office of Consumer Advocate	Default Service
337.	U-30958 July 2009	Cleco Power	Louisiana	Commission Staff	Purchase Power Contract
338.	EO08050326 August 2009	Jersey Central Power Light Co.	New Jersey	Rate Counsel	Demand Response Cost Recovery
339.	GR09030195 August 2009	Elizabethtown Gas	New Jersey	New Jersey Rate Counsel	Cost of Capital
340.	U-30422-A August 2009	Entergy Gulf States	Louisiana	Staff	Generating Unit Purchase
341.	CV 1:99-01693 August 2009	Duke Energy Indiana	Federal District Court – Indiana	U. S. DOJ/EPA, et al.	Environmental Compliance Rate Impacts (Expert Report)
342.	4065 September 2009	Narragansett Electric	Rhode Island	Division Staff	Cost of Capital
343.	U-30689 September 2009	Cleco Power	Louisiana	Staff	Cost of Capital, Rate Design, Other Rate Case Issues
344.	U-31147 October 2009	Entergy Gulf States Entergy Louisiana	Louisiana	Staff	Purchase Power Contracts
345.	U-30913 November 2009	Cleco Power	Louisiana	Staff	Certification of Generating Unit
346.	M-2009-2123951 November 2009	West Penn Power	Pennsylvania	Office of Consumer Advocate	Smart Meter Cost of Capital (Surrebuttal Only)
347.	GR09050422 November 2009	Public Service Electric & Gas Company	New Jersey	Rate Counsel	Cost of Capital
348.	D-09-49 November 2009	Narragansett Electric	Rhode Island	Division Staff	Securities Issuances
349.	U-29702, Phase II November 2009	Southwestern Electric Power Company	Louisiana	Commission Staff	Cash CWIP Recovery
350.	U-30981 December 2009	Entergy Louisiana Entergy Gulf States	Louisiana	Commission Staff	Storm Damage Cost Allocation

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
351.	U-31196 (ITA Phase) February 2010	Entergy Louisiana	Louisiana	Staff	Purchase Power Contract
352.	ER09080668 March 2010	Rockland Electric	New Jersey	Rate Counsel	Rate of Return
353.	GR10010035 May 2010	South Jersey Gas Co.	New Jersey	Rate Counsel	Rate of Return
354.	P-2010-2157862 May 2010	Pennsylvania Power Co.	Pennsylvania	Consumer Advocate	Default Service Program
355.	10-CV-2275 June 2010	Xcel Energy	U.S. District Court Minnesota	U.S. Dept. Justice/EPA	Clean Air Act Enforcement
356.	WR09120987 June 2010	United Water New Jersey	New Jersey	Rate Counsel	Rate of Return
357.	U-30192, Phase III June 2010	Entergy Louisiana	Louisiana	Staff	Power Plant Cancellation Costs
358.	31299 July 2010	Cleco Power	Louisiana	Staff	Securities Issuances
359.	App. No. 1601162 July 2010	EPCOR Water	Alberta, Canada	Regional Customer Group	Cost of Capital
360.	U-31196 July 2010	Entergy Louisiana	Louisiana	Staff	Purchase Power Contract
361.	2:10-CV-13101 August 2010	Detroit Edison	U.S. District Court Eastern Michigan	U.S. Dept. of Justice/EPA	Clean Air Act Enforcement
362.	U-31196 August 2010	Entergy Louisiana Entergy Gulf States	Louisiana	Staff	Generating Unit Purchase and Cost Recovery
363.	Case No. 9233 October 2010	Potomac Edison Company	Maryland	Energy Administration	Merger Issues
364.	2010-2194652 November 2010	Pike County Light & Power	Pennsylvania	Consumer Advocate	Default Service Plan
365.	2010-2213369 April 2011	Duquesne Light Company	Pennsylvania	Consumer Advocate	Merger Issues

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
366.	U-31841 May 2011	Entergy Gulf States	Louisiana	Staff	Purchase Power Agreement
367.	11-06006 September 2011	Nevada Power	Nevada	U. S. Department of Energy	Cost of Capital
368.	9271 September 2011	Exelon/Constellation	Maryland	MD Energy Administration	Merger Savings
369.	4255 September 2011	United Water Rhode Island	Rhode Island	Division of Public Utilities	Rate of Return
370.	P-2011-2252042 October 2011	Pike County Light & Power	Pennsylvania	Consumer Advocate	Default service plan
371.	U-32095 November 2011	Southwestern Electric Power Company	Louisiana	Commission Staff	Wind energy contract
372.	U-32031 November 2011	Entergy Gulf States Louisiana	Louisiana	Commission Staff	Purchased Power Contract
373.	U-32088 January 2012	Entergy Louisiana	Louisiana	Commission Staff	Coal plant evaluation
374.	R-2011-2267958 February 2012	Aqua Pa.	Pennsylvania	Office of Consumer Advocate	Cost of capital
375.	P-2011-2273650 February 2012	FirstEnergy Companies	Pennsylvania	Office of Consumer Advocate	Default service plan
376.	U-32223 March 2012	Cleco Power	Louisiana	Commission Staff	Purchase Power Contract and Rate Recovery
377.	U-32148 March 2012	Entergy Louisiana Energy Gulf States	Louisiana	Commission Staff	RTO Membership
378.	ER11080469 April 2012	Atlantic City Electric	New Jersey	Rate Counsel	Cost of capital
379.	R-2012-2285985 May 2012	Peoples Natural Gas Company	Pennsylvania	Office of Consumer Advocate	Cost of capital
380.	U-32153 July 2012	Cleco Power	Louisiana	Commission Staff	Environmental Compliance Plan

	Docket Number	Utility	Jurisdiction	Client	Subject
381.	U-32435 August 2012	Entergy Gulf States Louisiana LLC	Louisiana	Commission Staff	Cost of equity (gas)
382.	ER-2012-0174 August 2012	Kansas City Power & Light Company	Missouri	U. S. Department of Energy	Rate of return
383.	U-31196 August 2012	Entergy Louisiana/ Entergy Gulf States	Louisiana	Commission Staff	Power Plant Joint Ownership
384.	ER-2012-0175 August 2012	KCP&L Greater Missouri Operations	Missouri	U.S. Department of Energy	Rate of Return
385.	4323 August 2012	Narragansett Electric Company	Rhode Island	Division of Public Utilities and Carriers	Rate of Return (electric and gas)
386.	D-12-049 October 2012	Narragansett Electric Company	Rhode Island	Division of Public Utilities and Carriers	Debt issue
387.	GO12070640 October 2012	New Jersey Natural Gas Company	New Jersey	Rate Counsel	Cost of capital
388.	GO12050363 November 2012	South Jersey Gas Company	New Jersey	Rate Counsel	Cost of capital
389.	R-2012-2321748 January 2013	Columbia Gas of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Cost of capital
390.	U-32220 February 2013	Southwestern Electric Power Co.	Louisiana	Commission Staff	Formula Rate Plan
391.	CV No. 12-1286 February 2013	PPL et al.	Federal District Court	MD Public Service Commission	PJM Market Impacts (deposition)
392.	EL13-48-000 February 2013	BGE, PHI subsidiaries	FERC	Joint Customer Group	Transmission Cost of Equity
393.	EO12080721 March 2013	Public Service Electric & Gas	New Jersey	Rate Counsel	Solar Tracker ROE
394.	EO12080726 March 2013	Public Service Electric & Gas	New Jersey	Rate Counsel	Solar Tracker ROE
395.	CV12-1286MJG March 2013	PPL, PSEG	U.S. District Court for the District of Md.	Md. Public Service Commission	Capacity Market Issues (trial testimony)

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
396.	U-32628 April 2013	Entergy Louisiana and Gulf States Louisiana	Louisiana	Staff	Avoided cost methodology
397.	U-32675 June 2013	Entergy Louisiana and Entergy Gulf States	Louisiana	Staff	RTO Integration Issues
398.	ER12111052 June 2013	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Cost of capital
399.	PUE-2013-00020 July 2013	Dominion Virginia Power	Virginia	Apartment & Office Building Assoc. of Met. Washington	Cost of capital
400.	U-32766 August 2013	Cleco Power	Louisiana	Staff	Power plant acquisition
401.	U-32764 September 2013	Entergy Louisiana and Entergy Gulf States	Louisiana	Staff	Storm Damage Cost Allocation
402.	P-2013-237-1666 September 2013	Pike County Light and Power Co.	Pennsylvania	Office of Consumer Advocate	Default Generation Service
403.	E013020155 and G013020156 October 2013	Public Service Electric and Gas Company	New Jersey	Rate Counsel	Cost of capital
404.	U-32507 November 2013	Cleco Power	Louisiana	Staff	Environmental Compliance Plan
405.	DE11-250 December 2013	Public Service Co. New Hampshire	New Hampshire	Consumer Advocate	Power plant investment prudence
406.	4434 February 2014	United Water Rhode Island	Rhode Island	Staff	Cost of Capital
407.	U-32987 February 2014	Atmos Energy	Louisiana	Staff	Cost of Capital
408.	EL 14-28-000 February 2014	Entergy Louisiana Entergy Gulf States	FERC	LPSC	Avoided Cost Methodology (affidavit)
409.	ER13111135 May 2014	Rockland Electric	New Jersey	Rate Counsel	Cost of Capital

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
410.	13-2385-SSO, et al. May 2014	AEP Ohio	Ohio	Ohio Consumers' Counsel	Default Service Issues
411.	U-32779 May 2014	Cleco Power, LLC	Louisiana	Staff	Formula Rate Plan
412.	CV-00234-SDD-SCR June 2014	Entergy Louisiana Entergy Gulf	U.S. District Court Middle District Louisiana	Louisiana Public Service Commission	Avoided Cost Determination Court Appeal
413.	U-32812 July 2014	Entergy Louisiana	Louisiana	Louisiana Public Service Commission	Nuclear Power Plant Prudence
414.	14-841-EL-SSO September 2014	Duke Energy Ohio	Ohio	Ohio Consumer' Counsel	Default Service Issues
415.	EM14060581 November 2014	Atlantic City Electric Company	New Jersey	Rate Counsel	Merger Financial Issues
416.	EL15-27 December 2014	BGE, PHI Utilities	FERC	Joint Complainants	Cost of Equity
417.	14-1297-EL-SSO December 2014	First Energy Utilities	Ohio	Ohio Consumer's Counsel and NOPEC	Default Service Issues
418.	EL-13-48-001 January 2015	BGE, PHI Utilities	FERC	Joint Complainants	Cost of Equity
419.	EL13-48-001 and EL15-27-000 April 2015	BGE and PHI Utilities	FERC	Joint Complainants	Cost of Equity
420.	U- 33592 November 2015	Entergy Louisiana	Louisiana Public Service Commission	Commission Staff	PURPA PPA Contract
421.	GM15101196 April 2016	AGL Resources	New Jersey	Rate Counsel	Financial Aspects of Merger
422.	U-32814 April 2016	Southwestern Electric Power	Louisiana	Staff	Wind Energy PPAs
423.	A-2015-2517036, et.al. April 2016	Pike County	Pennsylvania	Office of Consumer Advocate	Merger Issues

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
424.	EM15060733 August 2016	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Transmission Divestiture
425.	16-395-EL-SSO November 2016	Dayton Power & Light Company	Ohio	Ohio Consumer's Counsel	Electric Security Plan
426.	PUE-2016-00001 January 2017	Washington Gas Light	Virginia	AOBA	Cost of Capital
427.	U-34200 April 2017	Southwestern Electric Power Co.	Louisiana	Commission Staff	Design of Formula Rate Plan
428.	ER-17030308 August 2017	Atlantic City Electric Co.	New Jersey	Rate Counsel	Cost of Capital
429.	U-33856 October 2017	Southwestern Electric Power Co.	Louisiana	Commission Staff	Power Plant Prudence
430.	4:11 CV77RWS December 2017	Ameren Missouri	U.S. District Court	U.S. Department of Justice	Expert Report FGD Retrofit
431.	D-17-36 January 2018	Narragansett Electric Co.	Rhode Island	Division Staff	Debt Issuance Authority
432.	4770 April 2018	Narragansett Electric Co.	Rhode Island	Division Staff	Cost of Capital
433.	4800 June 2018	Suez Water	Rhode Island	Division Staff	Cost of Capital
434.	17-32-EL-AIR et.al. June 2018	Duke Ohio	Ohio	Ohio Consumer's Counsel	Electric Security Plan
435.	Docket No. ER18010029/ GR18010030 August 2018	Public Service Electric & Gas Co.	New Jersey	Division of Rate Counsel	Rate of Return
436.	4:11 CV77RWS April 2019	Ameren Missouri	U.S. District Court	U.S. Department of Justice	Oral Trial Testimony— Environmental Compliance
437.	A-2018-3006061 April 2019	Aqua American/Peoples Gas	Pennsylvania	Office of Consumer Advocate	Merger Issues

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
438.	4929 April 2019	Narragansett Electric	Rhode Island	Division Staff	Wind Energy PPA
439.	ER19050552 October 2019	Rockland Electric Co.	New Jersey	Division of Rate Counsel	Rate of Return
440.	19-00170-UT November 2019	Southwest Public Service Co.	New Mexico	Attorney General	Rate of Return
441.	D-19-17 November 2019	Narragansett Electric	Rhode Island	Division of Public Utilities	Debt Issuance
442.	ER-20-1074-000 March 2020	Marsh Landing	FERC	California PUC	Capital Structure
443.	19-00317-UT July 2020	New Mexico Gas Company	New Mexico	Attorney General	Rate of Return
444.	EO1801115 August 2020	Public Service Electric & Gas Co.	New Jersey	Rate Counsel	Rate of Return
445.	20-00104-UT October 2020	El Paso Electric Company	New Mexico	Attorney General	Rate of Return
446.	20-680-EL-UNC October 2020	Dayton Power & Light Co.	Ohio	Consumers' Counsel	Electric Security Case
447.	ER16-2320-002 December 2020	Pacific Gas & Electric Co.	FERC	California PUC	Cost of Equity
448.	18-857-EL-UNC April 2021	FirstEnergy Ohio	Ohio	Consumers' Counsel	Excess Earnings Refunds
449.	20-00238-UT May 2021	Southwest Public Service Co.	New Mexico	Attorney General	Rate of Return
450.	D-21-09 November 2021	Narragansett Electric Co.	Rhode Island	Division of Public Utilities	Merger Financial Issues

EXHIBIT B

National Grid USA and The Narragansett Electric Company
Division 8-2

Request:

Please provide a schedule or workpaper showing Narragansett's actual cost of long-term debt as of June 30, 2021. This schedule should identify each long-term debt issue outstanding including: the balance outstanding at that date, the interest or cost rate, date of issue, date of maturity, issuance cost, and debt discount/premium.

Response:

Please refer to the table below for a schedule of The Narragansett Electric Company's cost of debt information as of June 30, 2021.

Description	Issuance Date	Maturity Date	Interest Rate	Principal	Interest	Amortized DD&E
Providence Gas First Mortgage Bond Series O	9/1/1992	9/30/2022	8.4600%	$ 12,500,000	$ 1,057,500	$ 4,311
Providence Gas FMB First Mortgage Bond Series P (sinking fund $625k Sept)	9/1/1992	9/30/2022	8.0900%	$ 1,250,000	$ 101,125	$ 3,449
Providence Gas FMB First Mortgage Bond Series R (sinking fund $750k Dec)	12/1/1995	12/15/2025	7.5000%	$ 3,750,000	$ 281,250	$ 4,071
30 YR Senior Unsecured Note $300M @ 5.638%	3/22/2010	3/15/2040	5.6380%	$ 300,000,000	$ 16,914,000	$ 188,787
30 YR Senior Unsecured Note $250M @ 4.170%	12/10/2012	12/10/2042	4.1700%	$ 250,000,000	$ 10,425,000	$ 283,517
10 YR Senior Unsecured Note $350M @ 3.919%	7/27/2018	8/1/2028	3.9190%	$ 350,000,000	$ 13,716,500	$ 82,255
10 YR Senior Unsecured Note $600M @ 3.395%	4/9/2020	4/9/2030	3.3950%	$ 600,000,000	$ 20,370,000	$ 68,396
			Total	$ 1,517,500,000	$ 62,865,375	$ 634,786

Prepared by or under the supervision of: Christopher McCusker

---

National Grid USA and The Narragansett Electric Company
Division 8-3

Request:

Please provide a detailed description of how Narragansett will acquire its needed short-term debt and liquidity post-Transaction. The response should describe any plans or arrangements for Narragansett to have its own credit facility, operate under a PPL affiliate credit facility, and/or use a commercial paper program.

Response:

PPL Corporation and PPL Rhode Island Holdings, LLC have responded to this request in their response to Data Request Division 8-3.

Prepared by or under the supervision of: Pamela Viapiano

National Grid USA and The Narragansett Electric Company
Division 8-5

Request:

To the extent not already provided, please provide all Narragansett credit rating reports issued since January 1, 2019.

Response:

Please refer to the following attachments for The Narragansett Electric Company's credit rating reports issued since January 1, 2019:

- Please see Attachment NG-DIV 8-5-1 for Moody's Investors Service ("Moody's) September 12, 2019 published credit rating report;
- Please see Attachment NG-DIV 8-5-2 for Moody's October 8, 2020 published credit rating report; and
- Please see Attachment NG-DIV 8-5-3 for Moody's March 18, 2021 published credit rating report.

In addition, please see the table below for the S&P Global Ratings ("S&P") credit ratings for Narragansett issued since January 1, 2019[1]:

Year	**Credit Rating**
2019	A-
2020	A-
2021*	BBB+

**As of September 28, 2021*

[1] S&P does not issue separate, individual credit rating reports for Narragansett.

MOODY'S INVESTORS SERVICE

CREDIT OPINION
12 September 2019

Update

Rate this Research

RATINGS

Narragansett Electric Company

Domicile	Providence, Rhode Island, United States
Long Term Rating	A3
Type	LT Issuer Rating
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

Contacts

Philip Cope +44.20.7772.5229
AVP-Analyst
philip.cope@moodys.com

Joao Pereira +44.20.7772.5227
Associate Analyst
joao.pereira@moodys.com

Neil Griffiths-Lambeth +44.20.7772.5543
Associate Managing Director
neil.griffiths-lambeth@moodys.com

CLIENT SERVICES

Americas 1-212-553-1653

Asia Pacific 852-3551-3077

Japan 81-3-5408-4100

EMEA 44-20-7772-5454

Narragansett Electric Company

Update to credit analysis

Summary

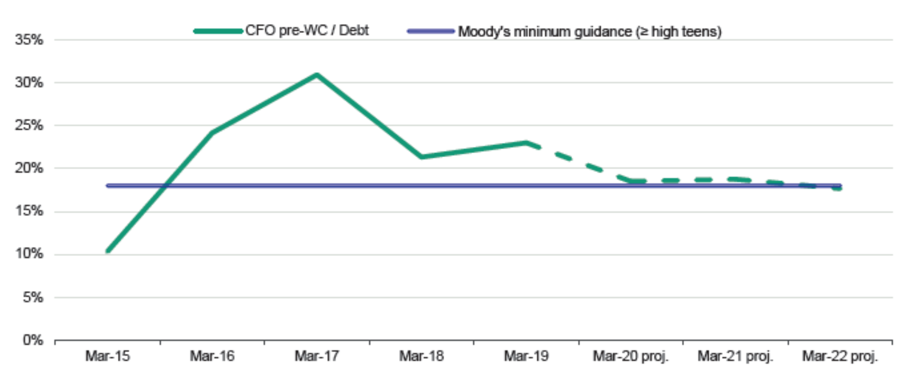
The credit quality of Narragansett Electric Company (NECO, A3 stable) is supported by the low business risk profile of its distribution and transmission operations, which are governed by different regulatory frameworks and thus provide some cash flow diversification. We view the regulatory framework for its electricity transmission operations, which accounts for around 30% of its rate base, as particularly supportive to credit quality, reflecting the well-established and transparent framework and a tariff formula that allows for timely recovery of operating and capital spending. We consider the regulatory environment in Rhode Island generally supportive, where a wide variety of de-risking provisions have been incorporated in recent rate cases, including NECO's for its distribution operations.

NECO's credit quality is constrained by its material investment programme over the next few years. Nonetheless, we expect the impact on NECO's key credit metrics, in particular cash flow from operations pre-working capital (CFO pre-WC)/debt, to be manageable. This view principally reflects the higher allowed revenue under NECO's current rate plan for its distribution operations, whose primary term commenced in September 2018 and runs for a further two years, and a financial profile that has been supported by modest dividend payment in recent years.

Exhibit 1

We expect NECO to maintain a financial profile in line with guidance despite a material investment programme

Evolution of NECO's CFO pre-WC/debt versus the minimum guidance for the A3 rating



Sources: National Grid, Moody's Investors Service

Credit strengths

» Cash flow diversification from activities governed by two different regulatory frameworks

» Very low business risk of electricity transmission operations, reflecting a well-established and transparent regulatory framework and a tariff formula that allows for the timely recovery of operating and capital spending

» Low-risk electricity and gas distribution operations in Rhode Island, governed by a supportive regulatory environment with improved ability and timeliness of cost recovery under the current rate plan, whose primary term runs for another two years

Credit challenges

» Lower revenue increases under the current rate plan because of the federal tax reform and material investment programme, averaging almost 15% per year of the rate base over the next few years, we estimate, will increase leverage and reduce financial flexibility.

» Substantial additional debt at the parent holding companies and the absence of significant ring-fencing provisions at NECO to restrict higher leverage.

Rating outlook

The stable outlook reflects our expectation that NECO will continue to meet the minimum ratio guidance over the medium term, with CFO pre-WC/debt at least in the high teens in percentage terms.

Factors that could lead to an upgrade

» Although not currently expected, upward rating pressure would arise if (1) CFO pre-WC/debt was above the low 20s in percentage terms, on a sustained basis; and (2) significant regulatory ring-fencing provisions were introduced to restrict higher leverage at NECO.

» Any rating upgrade would also take into consideration the credit quality of the wider National Grid group.

Factors that could lead to a downgrade

» Downward rating pressure would arise if (1) weaker-than-expected financial performance caused CFO pre-WC/debt to fall below the high teens in percentage terms, on an underlying basis, without any prospect of a speedy recovery; or (2) there were material adverse changes in the regulators' overall supportiveness to utilities.

» Any rating downgrade would also take into consideration the credit quality of the wider National Grid group.

Key indicators

Exhibit 2
Narragansett Electric Company

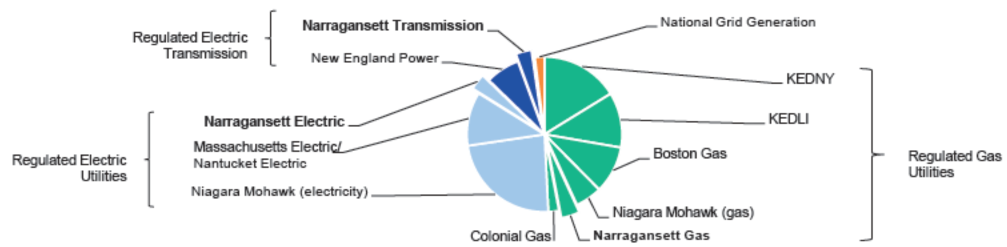
	Mar-15	Mar-16	Mar-17	Mar-18	Mar-19	Mar-20 proj.	Mar-21 proj.	Mar-22 proj.
CFO pre-WC + Interest / Interest	3.4x	6.6x	7.5x	6.3x	6.2x	5 8x	5.7x	5.2x
CFO pre-WC / Debt	10.3%	24.1%	30.9%	21.3%	23.0%	18.5%	18.8%	17.7%
CFO pre-WC – Dividends / Debt	10.3%	24.1%	30.9%	21.3%	16.4%	16.3%	16.1%	15.1%
Debt / Capitalization	35.6%	32.9%	29.6%	33.4%	34.8%	35.5%	36.1%	36 3%

All figures and ratios are calculated using Moody's estimates and standard adjustments. Moody's Forecasts (f) or Projections (proj.) are Moody's opinion and do not represent the views of the issuer. Periods are financial year-end unless indicated. LTM = Last 12 months.
Source: Moody's Financial Metrics™

Profile

Narragansett Electric Company (NECO) is a retail distribution company providing electric service to around 506,000 customers and gas service to around 273,000 customers in 38 cities and towns in Rhode Island. It also owns electricity transmission assets in Rhode Island, which are operated by its sister company New England Power Company (NEP, A3 positive). NECO's electricity transmission operations are regulated by the Federal Energy Regulatory Commission (FERC) and its electricity and gas distribution activities by the Rhode Island Public Utilities Commission (RIPUC). The company is ultimately owned by National Grid plc (NG plc, Baa1 stable) via intermediate holding companies National Grid North America Inc. (NGNA, Baa1 negative) and National Grid USA (NG USA, Baa1 stable). NECO's rate base of around $2.4 billion as of 31 March 2019 is almost equally distributed across its three business segments and represents around 11% of National Grid's rate base in the US.

Exhibit 3
National Grid's rate base in the US by asset type
Rate base as of 31 March 2019



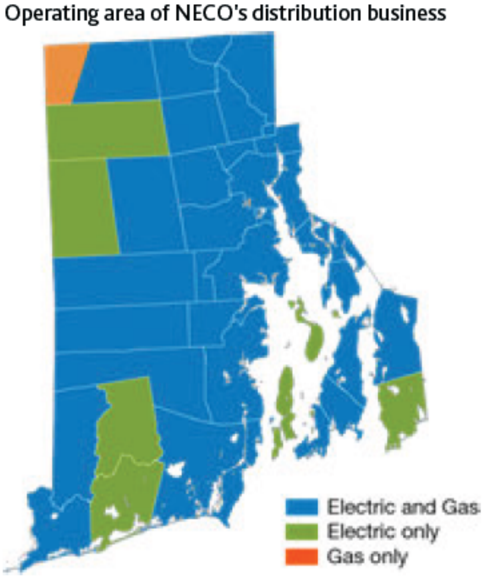
Rate bases for Boston Gas and its sister company (Colonial Gas Company) are estimates reflecting the fact that National Grid, since March 2019, has not provided a split of the Massachusetts Gas business' rate base between the two companies. We have assumed the same proportions as of March 2018.
Sources: National Grid, Moody's Investors Service

Detailed credit considerations

Low-risk distribution activities under a supportive regulatory environment

Around two-thirds of NECO's business, as measured by its rate base, pertains to the distribution of electricity and gas to consumers within its specific geographic area in Rhode Island, an activity that we view as having low business risk, and is regulated under a transparent and established regulatory regime, providing stable and predictable cash flow generation.

Exhibit 4
Operating area of NECO's distribution business



Source: National Grid

Exhibit 5
Rate case summary

Regulated Business	Narragansett Electric	Narragansett Gas	Narragansett Transmission
Regulator	RIPUC		FERC
Primary term of rate plan	Sep 2018 - Aug 2021		-
Allowed return on equity (RoE)	9.3%		10.6%
Achieved RoE (fiscal 2019)	10.7%	4.7%	11.3%
Rate Base at March 2019	$0 8 billion	$0.9 billion	$0.7 billion

Source: National Grid, Moody's Investors Service

The primary term of NECO's rate plan for its distribution operations commenced on 1 September 2018 and runs for a further two years (until August 2021). This was the first multiyear plan approved for NECO, providing the company with increased cash flow predictability. The plan provides an allowed RoE of 9.3%, which could increase by 30-50 basis points through upside only performance incentive mechanisms, on an assumed equity/total capitalisation of 51%.

NECO's rate plan benefits from a number of de-risking provisions that improve the likelihood and timing of cost recovery. They include full revenue decoupling and capital trackers, a pension adjustment mechanism and an annual property tax recovery mechanism within the annual capital programme that more closely aligns rate recovery and costs related to property tax expenses. The plan also permits NECO to file for a base-rate increase for the recovery of advanced metering and grid-modernisation investment costs if these are approved by the RIPUC during the primary term of the plan.

Despite this, we view the regulatory environment in Rhode Island as tougher than that in some other US states where National Grid operates, in particular New York. This view reflects the fact that when rates are set by the RIPUC, most weight is still placed on a "historical test year" (albeit some consideration is given to forecast capital investment, volume and operating costs with some other cost categories increased by inflation) rather than solely projected costs.

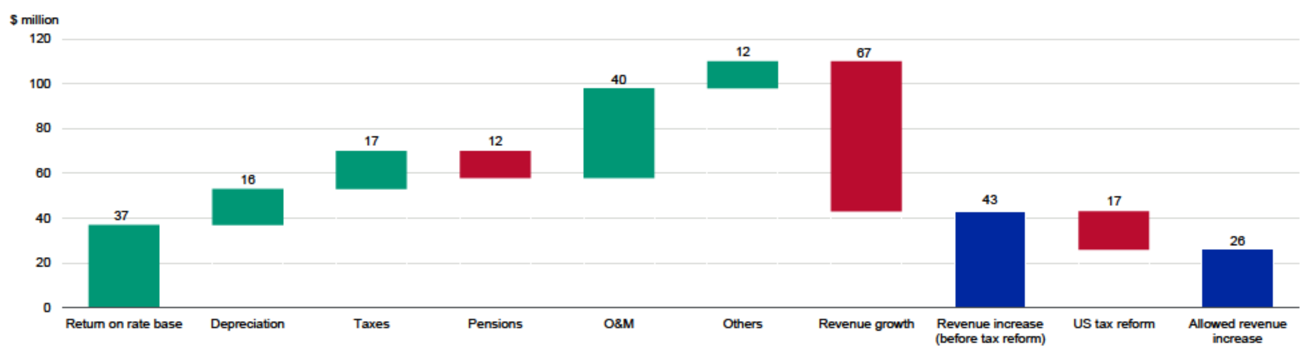
US tax reform resulted in a materially lower revenue increase under NECO's current rate plan

Following the passage of the Tax Cuts and Jobs Act of 2017 in the US, the RIPUC opened a docket to address the change in the federal corporate income tax rate and other changes resulting from this act. Because of NECO's ongoing rate-case proceedings at the time, the company was allowed to defer the effect of this tax reduction until the effective date of the new rate plan (1 September 2018), provided the company adjusted its revenue accordingly. This resulted in a combined increase in allowed revenue for both electric and gas distribution of only $26 million in the first year of the plan, which would have been $43 million if not for the negative adjustment related to the tax reform (see Exhibit 6). Additionally, in May 2019 the RIPUC approved a settlement agreement filed by NECO to return to customers around $8 million of excess deferred income tax collected before the start of the new rate plan.

Exhibit 6

Increase in allowed revenue under the current rate plan was significantly reduced by the US tax reform

Combined revenue increases for electricity and gas distribution businesses effective 1 September 2018



Note: "Revenue growth" relates to revenue increases previously allowed to NECO. These were approved by the RIPUC following several filings made through the Infrastructure, Safety and Reliability mechanism to recover capital spending since the last full rate case in 2013.
Source: National Grid

The US tax reform also affected NECO's transmission business, discussed below, but the impact is still unknown. The FERC initiated an inquiry in this area for public utilities in March 2018 and NECO, along with other utilities, made recommendations as to how to reflect this in tariffs but a final ruling from the FERC is still pending with no timeline provided.

Very low business risk of transmission operations ensures stable and predictable cash flow

NECO's transmission facilities are operated in combination with the transmission facilities of its New England affiliates, Massachusetts Electric Company (A3 stable) and NEP, as a single integrated system, with NEP designated as the combined operator. NEP collects the costs of the combined transmission asset pool, including a current RoE of 10.57%, and subsequently reimburses the transmission owners (TOs). The amount reimbursed to NECO for the fiscal year ended March 2019 (fiscal 2019) was around $145 million. The transmission business has no exposure to the end consumer, and therefore has no commodity price risk.

The highly supportive regulatory environment is likely to continue

NECO's transmission business is wholly regulated by the FERC, which we view as highly credit supportive. The FERC-regulated rates are set based on a formulaic, forward-looking rate setting mechanism, designed to reimburse the company for all prudently incurred operating and maintenance spending, tax, depreciation and a fair return on assets employed in the provision of transmission services. The formula contains an automatic annual true-up for operating and capital costs, and allows NECO to include construction work in progress for new transmission projects in the rate base. These features are intended to ensure that the company recovers its allowed costs and returns within a two-year period. In addition, to encourage greater investment in transmission infrastructure, the FERC allows independent TOs to earn RoEs that tend to be above those allowed by state regulators. In line with NEP and other transmission owners in New England, NECO is allowed to earn a base RoE of 10.57% on an assumed equity-to-total capitalisation ratio of 50% (in line with state regulators, but lower than 66% at NEP). In addition, NECO benefits from additional incentive mechanisms that could increase the allowed RoE up to 11.74%. While the FERC is currently undertaking a review of the base and maximum allowed RoE, we expect the RoEs to remain above the level set by other state regulators (see the highlighted box below for more details).

The Section 206 dispute triggered a wider review of the FERC's RoE methodology; final level uncertain but RoEs likely to remain above the level set by other regulators

Allowed returns for TOs in the Independent System Operator - New England region have been the subject of administrative law proceedings for several years. In 2014, the FERC reduced the rate of return to 10.57% from 11.14% after appeals from the Massachusetts Attorney General and other customer representatives. The FERC also reduced the maximum allowable RoE, including incentives, to 11.74% — the top of the revised zone of reasonableness.

However, in April 2017, this decision was overturned by an appeals court, which found that the FERC had not established that the existing 11.14% return was unreasonable and that “FERC failed to provide any reasoned basis for selecting 10.57 percent as the new base RoE.” The case was sent back to the FERC for reconsideration.

In October 2018, the FERC issued an order proposing fundamental changes in its methodology for determining the appropriate RoE for TOs in the Independent System Operator - New England region, by giving equal weight to the results of four financial models in determining an appropriate RoE, instead of primarily relying on the discounted cash flow model that the commission has historically used. The suggested approach is, according to the FERC, arguably more stable, transparent (providing more certainty for TOs) and legally defensible than the current approach, which has previously resulted in fluctuating RoE outcomes with each new formulation.

The FERC’s proposal, with calculations still being preliminary, would result in a base RoE of 10.41% versus the current 10.57%. While the change is negative, more important is the increase in the “zone of reasonableness,” which would move from 11.74% to 13.08%, allowing the TOs to possibly have a higher all-in RoE, including incentives. In March 2019, the FERC launched a broad review of RoE policies for electric utilities in a Notice of Inquiry and is currently seeking comments on the proposed modifications.

Because the rate-setting process is not contested before state commissions, and given its design to ensure timely cost recovery, we consider the regulatory framework more stable and predictable than that for state-regulated utility businesses. The transmission business continued to perform strongly, with an achieved ROE of 11.3% in fiscal 2019, well above the allowed base level, as has been the case for the last several years (see Exhibit 7).

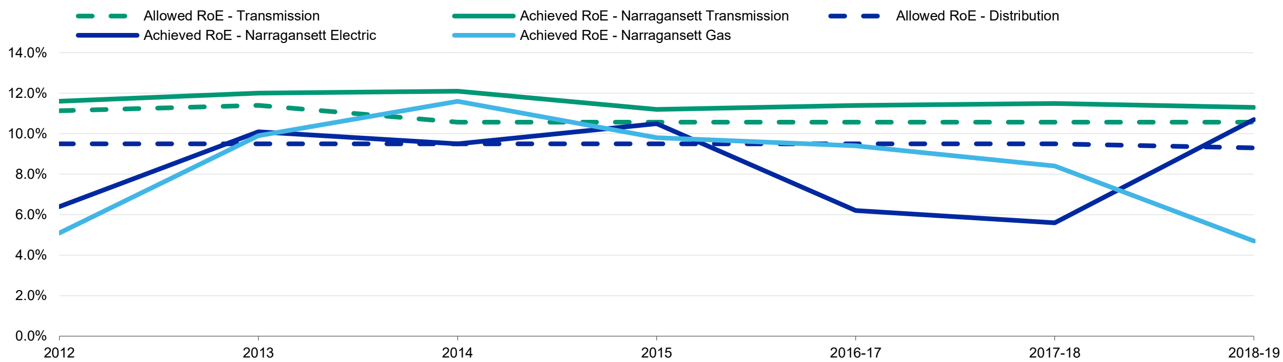
Overall achieved RoEs expected to improve in fiscal 2020 with the completion of the first full year of the current rate plan for distribution operations

NECO's achieved RoE for its distribution businesses fell over the period from 2014 to fiscal 2018, with the gap between achieved and allowed RoEs particularly large in electricity towards the end of this period (see Exhibit 7). This reflected the absence of updated rates in the intervening period (the primary term of the prior rate plan expired in January 2014) because no new rate cases were filed following problems with an IT system implementation programme and inflationary cost pressures.

Fiscal 2019 encompasses just over half a year of the higher allowed rates under the current rate plan. We believe this was the main driver of the material improvement in electricity distribution RoE to above 10%. However, despite the higher rates, the achieved RoE for gas distribution deteriorated substantially to 4.7% in fiscal 2019 from 8.4% in fiscal 2018. We believe the main driver of this deterioration were the costs associated with restoring gas service to around 7,100 customers (2.6% of all its customers) on Aquidneck Island, following a gas transmission supply issue in January 2019, which took nine days to complete. We expect NECO's achieved RoE to be around the allowed levels in fiscal 2020, absent the RIPUC concluding in its final report on the incident, expected in the next few months, that NECO was at fault and levying a fine. We note that the status report published by the RIPUC in June 2019 said there may have been multiple contributing factors leading to the outage.

Exhibit 7

Fiscal 2020 will benefit from the first full year of updated rates, but gas distribution RoE will depend on the outcome of the regulator's investigation



During 2017, National Grid changed the reporting period of its RoEs for the US business from calendar year to fiscal year.
Source: National Grid

Delivery of a material capital spending programme will increase leverage but impact on key financial metrics should be manageable

NECO continues to undertake a material investment programme intended to fund the replacement of several ageing operational systems and gas pipelines, with annual capital spending likely to exceed our estimates of CFO pre-WC of $260 million-$280 million per year over the period to fiscal 2022. While the resulting negative free cash flow will increase gearing, the increase in leverage in recent years has been moderated by National Grid extracting dividends from other US operating companies to service interest payments at the holding companies above NECO. Indeed, until fiscal 2019, when a dividend of $85 million was distributed, NECO had paid no dividends since fiscal 2010. Consequently, as shown in Exhibit 1, we expect NECO to retain a financial profile in line with the guidance for the current rating because the benefit of higher rates under the current rate plan will offset some of the increase in leverage, assuming distributions from NECO remain modest.

However, the absence of significant ring-fencing provisions increases the risk from high parent company leverage

The period of no dividends until fiscal 2019 has contributed to NECO's historical financial metrics being towards the upper end of the guidance for the current rating, with CFO pre-WC/debt averaging around 25% over fiscal 2017-19. However, the presence of high levels of additional debt at the holding companies, coupled with the absence of significant ring-fencing provisions, constrains NECO's credit quality at the level of the wider National Grid group, which we assess as commensurate with a low-A rating.

The absence of significant ring-fencing provisions contrasts with other US regulated utilities within the National Grid group, principally those operating in New York, where a number of provisions exist, such as (1) specific leverage restrictions at conservative levels (usually defined by a debt-to-capitalisation ratio); (2) a special class of preferred stock (the Golden Share), which is subordinated to all other existing preferred stock and limits a regulated utility's ability to commence any voluntary bankruptcy (or similar) proceedings without the consent of the holder; and (3) a requirement to maintain an investment-grade rating. Together, these provisions provide a material benefit to creditors and may allow regulated utilities to be rated more highly than the group to which they belong. Of these restrictions, we view an explicit leverage restriction at conservative leverage levels as having the greatest benefit for protecting a single-A rating, while other measures have power only at lower rating levels.

Liquidity analysis

Given group funding arrangements, although NECO has inadequate liquidity on a standalone basis, with limited cash and cash equivalents and no revolving credit facilities in its own name, we regard its liquidity risk as manageable.

National Grid manages its financing and liquidity on an overall group basis, with a central finance committee setting the rules by which individual entities can raise capital. For the US subsidiaries, including NECO, short-term liquidity requirements are managed via the group's regulated money pool. All of the regulated subsidiaries can lend and borrow from the pool; however, the unregulated holding companies — NG USA and NGNA — may only act as lenders. The interest rate for borrowing under the money pool is determined by reference to the cost of meeting the group's funding needs, typically a mix of 30-day A2 commercial paper and any other long- and short-term funding sources.

To support the regulated money pool, the parent holding companies have in place bilateral facilities totalling $3.7 billion, with maturity dates ranging from June 2021 out to June 2024, for which NG Plc, NGNA and NG USA are named borrowers. We understand the facilities were undrawn as of March 2019. NG USA also has two commercial paper programmes totalling $4 billion, denominated equally in US dollars and euros. Support for these programmes comes from the holding companies being named as borrowers under the aforementioned revolving credit facilities. As of March 2019, $200 million and $944 million were outstanding on the US and euro commercial paper programmes, respectively.

Viewed in this wider context, NECO's liquidity appears much stronger. NECO's rating relies on continued access to liquidity from the wider National Grid group via this money pool arrangement.

Rating methodology and scorecard factors

We assess NECO under our Regulated Electric and Gas Utilities rating methodology, published in June 2017. The scorecard-indicated outcome for NECO is A3 on a forward-looking basis, in line with the assigned rating.

Exhibit 8
Rating factors
Narragansett Electric Company

Regulated Electric and Gas Utilities Industry Grid [1][2]	Current FY 3/31/2019		Moody's 12-18 Month Forward View As of September 2019 [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.7x	Aa	5.5x - 6x	A
b) CFO pre-WC / Debt (3 Year Avg)	24.8%	A	18% - 20%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	22.3%	A	16% - 18%	A
d) Debt / Capitalization (3 Year Avg)	32.7%	Aa	35% - 36%	Aa
Rating:				
Scorecard-indicated Outcome Before Notching Adjustment		A2		A3
HoldCo Structural Subordination Notching		0		0
a) Scorecard-indicated Outcome from Grid		A2		A3
b) Actual Rating Assigned				A3

(1) All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. (2) As of 31 March 2019. (3) This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics™

Appendix

Exhibit 9

Peer comparison

Narragansett Electric Company

	Narragansett Electric Company			Delmarva Power & Light Company			Potomac Electric Power Company			Jersey Central Power & Light Company		
	A3 Stable			Baa1 Stable			Baa1 Stable			Baa1 Positive		
(in USD Millions)	FYE Mar-17	FYE Mar-18	FYE Mar-19	FYE Dec-16	FYE Dec-17	FYE Dec-18	FYE Dec-16	FYE Dec-17	FYE Dec-18	FYE Dec-16	FYE Dec-17	FYE Dec-18
Revenue	1,263	1,445	1,557	1,277	1,300	1,332	2,186	2,158	2,239	1,833	1,828	1,864
CFO Pre - W/C	317	252	296	289	329	352	502	431	463	422	479	427
Interest Expense	49	48	56	55	58	62	142	137	133	145	113	115
Gross Debt	1,026	1,180	1,286	1,467	1,631	1,598	2,540	2,681	2,912	2,481	2,109	1,899
Net Debt	1,018	1,174	1,278	1,421	1,629	1,575	2,531	2,676	2,896	2,481	2,109	1,899
Book capitalization	3,463	3,530	3,694	3,841	3,557	3,725	6,708	6,235	6,684	6,382	5,859	6,095
(CFO Pre-W/C + Interest) / Interest	7.5x	6.3x	6.2x	6.2x	6.7x	6.7x	4.5x	4.1x	4 5x	3 9x	5 2x	4.7x
(CFO Pre-W/C) / Debt	30 9%	21 3%	23 0%	19.7%	20.1%	22.1%	19 8%	16.1%	15 9%	17 0%	22.7%	22 5%
(CFO Pre - W/C - Dividends) / Debt	30 9%	21 3%	16.4%	16 0%	13 3%	16 0%	14.4%	11.1%	10.1%	17 0%	22.7%	22 5%
Debt / Book Capitalization	29 6%	33.4%	34 8%	38 2%	45 9%	42 9%	37 9%	43 0%	43 6%	38 9%	36 0%	31 2%

All metrics are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. FYE = Financial year-end. LTM = Last 12 months.
Source: Moody's Financial Metrics™

Exhibit 10

Moody's-adjusted debt calculation

Narragansett Electric Company

(in USD Millions)	FYE Mar-15	FYE Mar-16	FYE Mar-17	FYE Mar-18	FYE Mar-19
As Reported Debt	**1,084.7**	**1,039.7**	**969.0**	**1,149.8**	**1,231.5**
Pensions	128.2	94.2	51.9	25.3	20.6
Operating Leases	0.0	0.0	0.0	0.0	27.2
Hybrid Securities	1.2	1.2	1.2	1.2	1.2
Non-Standard Adjustments	0.0	4.4	4.1	3.8	5.3
Moody's-Adjusted Debt	**1,214.1**	**1,139.5**	**1,026.3**	**1,180.1**	**1,285.8**

All metrics are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. FYE = Financial year-end. LTM = Last 12 months.
Source: Moody's Financial Metrics™

Exhibit 11

Moody's-adjusted CFO pre-WC calculation

Narragansett Electric Company

(in USD Millions)	FYE Mar-15	FYE Mar-16	FYE Mar-17	FYE Mar-18	FYE Mar-19
As Reported CFO pre-WC	**125.5**	**264.5**	**317.4**	**232.0**	**280.4**
Pensions	0.0	10.6	0.0	19.9	15.5
Operating Leases	0.0	0.0	0.0	0.0	0.0
Hybrid Securities	-0.1	-0.1	-0.1	-0.1	-0.1
Non-Standard Adjustments	0.0	0.0	0.0	0.0	0.0
Moody's-Adjusted CFO pre-WC	**125.5**	**275.0**	**317.3**	**251.8**	**295.8**

All metrics are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. FYE = Financial year-end. LTM = Last 12 months.
Source: Moody's Financial Metrics™

Exhibit 12

Select historical Moody's-adjusted financial data

Narragansett Electric Company

(in USD Millions)	FYE Mar-15	FYE Mar-16	FYE Mar-17	FYE Mar-18	FYE Mar-19
INCOME STATEMENT					
Revenue	1,500.0	1,306 2	1,263.4	1,445 0	1,556.6
EBIT	153.1	193 8	188.6	192.4	190.1
EBITDA	243.9	290.7	292 5	298.1	301 2
Interest expense	52.5	48.6	48 8	47 8	56.5
BALANCE SHEET					
Total Debt	1,214.1	1,139 5	1,026 3	1,180.1	1,285 8
Net Debt	1,194.8	1,125.1	1,018 5	1,173 8	1,277.6
Total Liabilities	2,457.9	2,449 5	2,444.6	2,662 5	2,852 8
Fixed Assets	2,358.0	2,576.6	2,785 8	2,984 3	3,241 9
Total Assets	4,179.1	4,259 5	4,343.6	4,688 3	4,901 9
CASH FLOW					
CFO Pre - W/C	125.4	275 0	317 3	251 8	295 8
Cash Dividends - Common	0.0	0 0	0 0	0 0	-85.3
Cash Dividends - Preference	-0.1	-0.1	-0.1	-0.1	-0.1
Capital Expenditures	-295.3	-296 0	-313 5	-290.4	-331.7
(CFO Pre-W/C) / Debt	10 3%	24.1%	30.9%	21.3%	23.0%
(CFO Pre - W/C - Dividends) / Debt	10 3%	24.1%	30.9%	21.3%	16.4%
PROFITABILITY					
EBIT Margin %	10 2%	14.8%	14.9%	13.3%	12.2%
EBITDA Margin %	16 3%	22.3%	23.2%	20.6%	19.3%
INTEREST COVERAGE					
(CFO Pre-W/C + Interest) / Interest	3.4x	6.7x	7.5x	6.3x	6.2x
LEVERAGE					
Debt / EBITDA	5.0x	3.9x	3.5x	4.0x	4.3x
Net Debt / EBITDA	4.9x	3.9x	3.5x	3.9x	4.2x
Debt / Book Capitalization	35.7%	32.9%	29.6%	33.4%	34.8%

All metrics are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. FYE = Financial year-end. LTM = Last 12 months.
Source: Moody's Financial Metrics™

Ratings

Exhibit 13

Category	Moody's Rating
NARRAGANSETT ELECTRIC COMPANY	
Outlook	Stable
Issuer Rating	A3
First Mortgage Bonds	A1
Senior Unsecured	A3
Pref. Stock	Baa2
ULT PARENT: NATIONAL GRID PLC	
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured	Baa1
Commercial Paper	P-2
Other Short Term	(P)P-2
PARENT: NATIONAL GRID NORTH AMERICA INC.	
Outlook	Negative
Issuer Rating	Baa1
Senior Unsecured	Baa1
Commercial Paper	P-2
ST Issuer Rating	P-2
PARENT: NATIONAL GRID USA	
Outlook	Stable
Issuer Rating	Baa1
Commercial Paper	P-2

Source: Moody's Investors Service

REPORT NUMBER 1190848

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

MOODY'S INVESTORS SERVICE

CREDIT OPINION
8 October 2020

Update

RATINGS

Narragansett Electric Company

Domicile	Providence, Rhode Island, United States
Long Term Rating	A3
Type	LT Issuer Rating
Outlook	Negative

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

Contacts

Philip Cope +44.20.7772.5229
AVP-Analyst
philip.cope@moodys.com

Matthew Brown +44.20.7772.1043
Associate Analyst
matthew.brown@moodys.com

Neil Griffiths-Lambeth +44.20.7772.5543
Associate Managing Director
neil.griffiths-lambeth@moodys.com

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

Narragansett Electric Company

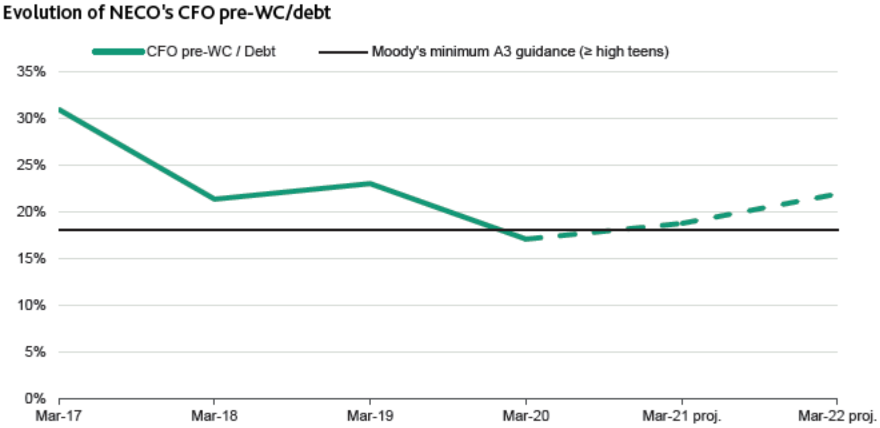
Update following outlook change to negative

Summary

The credit quality of Narragansett Electric Company (NECO, A3 negative) is supported by the low business risk profile of its distribution and transmission operations, which are governed by different regulatory frameworks and thus provide some cash flow diversification. We view the regulatory framework for its electricity transmission operations, which accounts for around 30% of its rate base, as particularly supportive to credit quality, reflecting the well-established and transparent framework and a tariff formula that allows for timely recovery of operating and capital spending. NECO has increased cash flow visibility for its distribution businesses in Rhode Island for a further one year under the primary term of its current rate plans. We expect NECO to maintain a solid financial profile, with cash flow from operations pre-working capital (CFO pre-WC) / debt around 20% over the next two years despite a material investment programme.

Credit quality is constrained by the weaker consolidated credit quality of the wider National Grid group, which we currently assess as commensurate as a weak A3, and the absence of significant ring-fencing provisions to allow NECO's credit quality to be delinked from that of the wider National Grid group. Like other FERC regulated transmission companies, a dividend lock-up only applies at debt / capitalisation of 70%. Despite this, and the substantial additional debt at parent holding companies above NECO, we expect NECO to retain a capital structure closely aligned to regulatory assumptions.

Exhibit 1
We expect NECO to maintain a financial profile in line with guidance
Evolution of NECO's CFO pre-WC/debt



Source: National Grid, Moody's Investors Service

Credit strengths

» Cash flow diversification from activities governed by two different regulatory frameworks

» Very low business risk of electricity transmission operations, reflecting a well-established and transparent regulatory framework and a tariff formula that allows for the timely recovery of operating and capital spending

» Low-risk electricity and gas distribution operations in Rhode Island, governed by a supportive regulatory environment with improved ability and timeliness of cost recovery under the current rate plans, whose primary term runs for another year

Credit challenges

» Material investment programme, averaging almost 15% per year of the rate base over the next few years

» Possible cuts to Narrangansett transmission's base return on equity (RoE), if FERC's latest RoE methodology is applied, albeit impact manageable given solid financial profile

» Substantial additional debt at the parent holding companies and the absence of significant ring-fencing provisions at NECO to restrict higher leverage.

Rating outlook

The negative outlook is tied to that on the National Grid group. NECO's credit quality is constrained by the weaker consolidated credit quality of the wider National Grid group, which we currently assess as commensurate as a weak A3, and the absence of significant ring-fencing provisions to allow NECO's credit quality to be delinked from that of the wider National Grid group. On a standalone basis, we expect NECO to meet minimum guidance for the current rating (CFO pre-WC / debt at least in the high teens in percentage terms).

Factors that could lead to an upgrade

» The outlook could be stabilised if the outlook on National Grid plc were stabilised

» Although not currently expected, upward rating pressure would arise if (1) CFO pre-WC/debt was above the low 20s in percentage terms, on a sustained basis; and (2) stronger regulatory ring-fencing provisions, e.g. a lower leverage cap for dividend lock-up, were introduced

Factors that could lead to a downgrade

» A downgrade of National Grid plc

» Whilst not currently expected, downward rating pressure would also arise if weaker-than-expected financial performance caused CFO pre-WC/debt to fall below the high teens in percentage terms, without prospect of a speedy recovery

Key indicators

Exhibit 2
Narragansett Electric Company

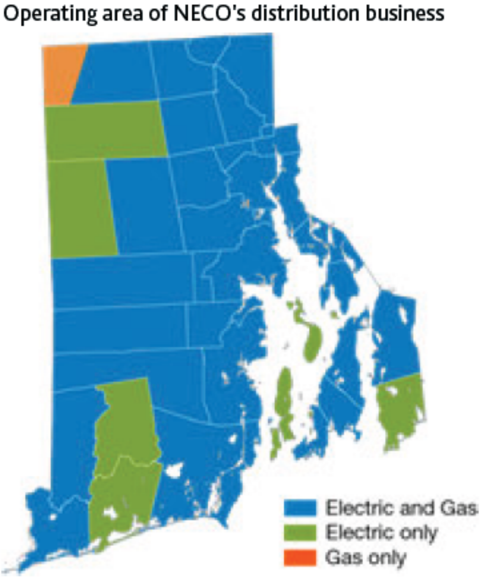
	Mar-16	Mar-17	Mar-18	Mar-19	Mar-20	Mar-21 proj.	Mar-22 proj.
CFO pre-WC + Interest / Interest	6.6x	7.5x	6.3x	6.2x	4.8x	5.7x	6.1x
CFO pre-WC / Debt	24.1%	30.9%	21.3%	23.0%	17.1%	19 0%	21.9%
CFO pre-WC – Dividends / Debt	24.1%	30.9%	21.3%	16.4%	17.1%	17 5%	19.4%
Debt / Capitalization	32.9%	29.6%	33.4%	34.8%	34.3%	35.1%	33.3%

All figures and ratios are calculated using Moody's estimates and standard adjustments. Moody's Forecasts (f) or Projections (proj.) are Moody's opinion and do not represent the views of the issuer. Periods are financial year-end unless indicated. LTM = Last 12 months.
Source: Moody's Financial Metrics™

Profile

Narragansett Electric Company (NECO) is a retail distribution company providing electric service to around 507,000 customers and gas service to around 273,000 customers in 38 cities and towns in Rhode Island. It also owns electricity transmission assets in Rhode Island, which are operated by its sister company New England Power Company (NEP, A3 stable). NECO's electricity transmission operations are regulated by the Federal Energy Regulatory Commission (FERC) and its electricity and gas distribution activities by the Rhode Island Public Utilities Commission (RIPUC). The company is ultimately owned by National Grid plc (NG plc, Baa1 negative) via intermediate holding companies National Grid North America Inc. (NGNA, Baa1 negative) and National Grid USA (NG USA, Baa1 negative). NECO's rate base of around $2.6 billion as of 31 March 2020 is broadly equally distributed across its three business segments, see Exhibit 4 below, and represents around 10% of National Grid's rate base in the US.

Exhibit 3
Operating area of NECO's distribution business



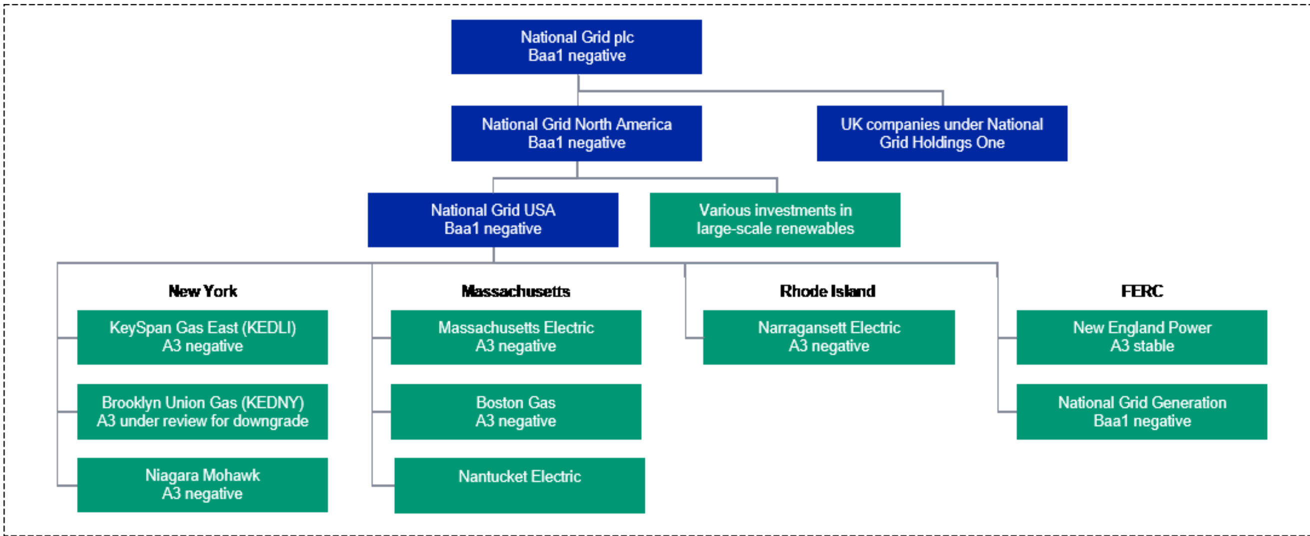
Source: National Grid

Exhibit 4
Rate case summary

Regulated Business	Narragansett Electric	Narragansett Gas	Narragansett Transmission
Regulator	RIPUC		FERC
Primary term of rate plan	Sep 2018 - Aug 2021		-
Allowed return on equity (RoE)	9.275%		10.57%
Achieved RoE (fiscal 2020)	11.9%	8.8%	11.1%
Rate Base at March 2020	$895 million	$944 million	$788 million

Source: National Grid, Moody's Investors Service

Exhibit 5
National Grid's simplified organisation structure for the US business



Source: Moody's Investors Service

Detailed credit considerations

Low-risk distribution activities under a supportive regulatory environment

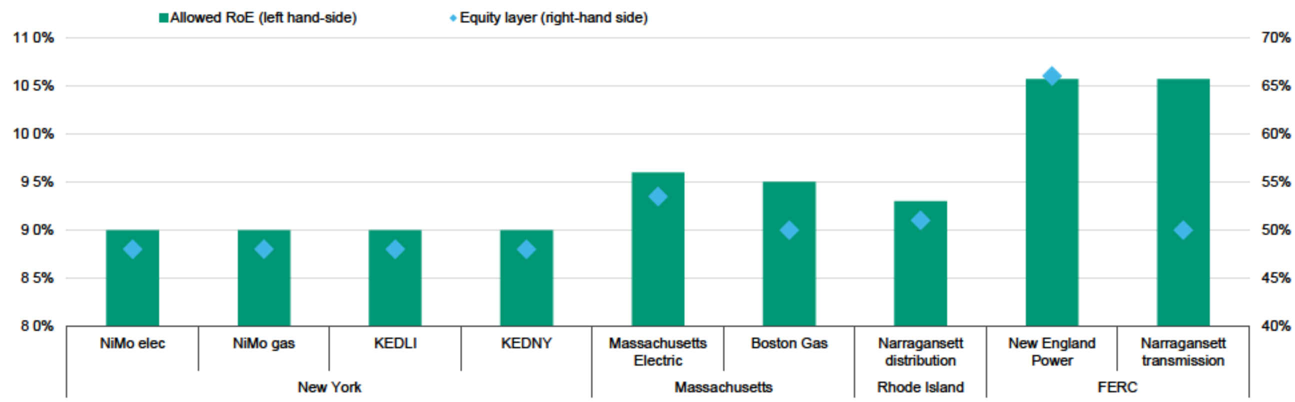
Around 70% of NECO's business, as measured by its rate base, pertains to the distribution of electricity and gas to consumers within its specific geographic area in Rhode Island, an activity that we view as having low business risk, and is regulated under a transparent and established regulatory regime, providing stable and predictable cash flow generation.

The primary term of NECO's rate plans for its distribution operations commenced on 1 September 2018 and runs for another year (until August 2021). This was the first multiyear plan approved for NECO, providing the company with increased cash flow predictability. The plan provides an allowed ROE of 9.275%, which can increase by 30-50 basis points through upside only performance incentive mechanisms, on an assumed equity layer in its capital structure of 51%. Compared to National Grid's other US distribution businesses, Narragansett distribution has an above average allowed ROE although it is below the national average. However, this benefit is partly offset by the RIPUC still placing most weight on historic costs[1], rather than using solely projected costs as in New York, when setting rates which means that cost pressures from a growing asset base are not taken into account.

Exhibit 6

Rhode Island provides aboveaverage return on equity levels compared to National Grid's other regulated US distribution businesses

Base allowed ROE and assumed equity layer in most recent rate case order



(1) Massachussets Electric comprises Massachusetts Electric Company (MECO, A3 negative) and Nantucket Electric Company. The series reflects its 2019 rate case order. (2) NEP is remunerated based on its capital structure, which has had a thicker equity layer in recent years; (3) As per latest formula rates rather than rate case settlements for FERC regulated businesses

Source: National Grid; Regulatory settlements; Moody's Investors Service

NECO's rate plan benefits from a number of de-risking provisions that improve the likelihood and timing of cost recovery. They include full revenue decoupling and capital trackers, a pension adjustment mechanism and an annual property tax recovery mechanism within the annual capital programme that more closely aligns rate recovery and costs related to property tax expenses. The plan also permits NECO to file for a base-rate increase for the recovery of advanced metering and grid-modernisation investment costs if these are approved by the RIPUC during the primary term of the plan. Finally, full revenue decoupling and weather normalization for gas, protect margins of NECO from variations in sales volumes, particularly important in FY2021 given the lower than expected consumption volumes due to the coronavirus outbreak.

Lower revenues resulting from US tax reform fully reflected in Narragansett distribution's rate plans

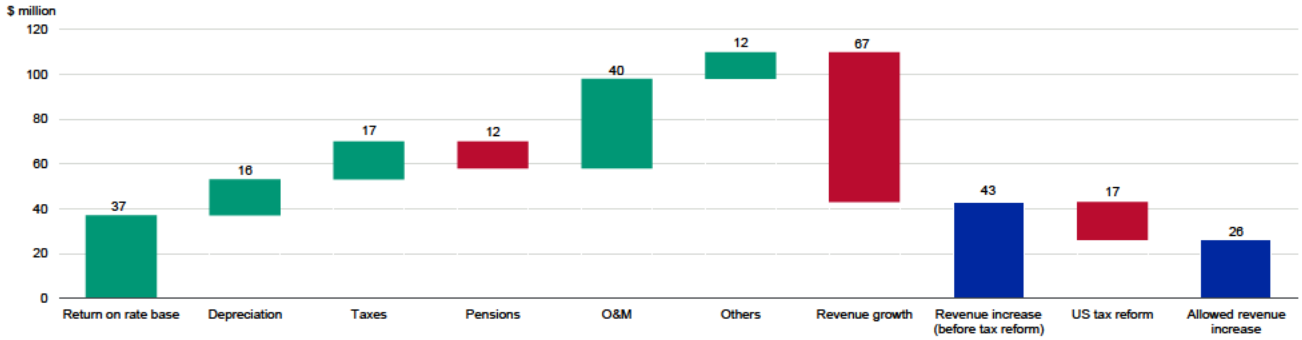
Following the passage of the US Tax Cuts and Jobs Act of 2017 in the US, regulators initiated proceedings to address the change in the federal corporate income tax rate and other changes resulting from this act. From an earnings perspective, the change in tax rates has no impact on regulated utilities because regulation results in the benefit of the lower tax rate being passed to customers. However, and because the utilities typically pay much less tax in cash, the legislation is credit negative.

For Narragansett distribution, the revenue reductions attributable to this tax reduction ($17 million across electricity and gas) took effect from 1 September 2018 and the start of the current rate plans.[2] As the exhibit below shows, without this negative adjustment the combined rate increase would have been $43 million. Additionally, in May 2019 the RIPUC approved a settlement agreement filed by NECO to return to customers around $8 million, over July 2019 - October 2020, of excess deferred income tax collected before the start of the new rate plan.

Exhibit 7

Increase in allowed revenue under the current rate plan was significantly reduced by the US tax reform

Combined revenue increases for electricity and gas distribution businesses effective 1 September 2018



Note: "Revenue growth" relates to revenue increases previously allowed to NECO. These were approved by the RIPUC following several filings made through the Infrastructure, Safety and Reliability mechanism to recover capital spending since the last full rate case in 2013.
Source: National Grid

The US tax reform also affected Narragansett's transmission business, discussed below, but the impact is still unknown. The FERC initiated an inquiry in this area for public utilities in March 2018 and NEP (on behalf of its affiliates), along with other utilities, made recommendations as to how to reflect this in tariffs but a final ruling from the FERC is still pending with no timeline provided. [3]

Very low business risk of transmission operations ensures stable and predictable cash flow

NECO's transmission facilities are operated in combination with the transmission facilities of its New England affiliates, MECO and NEP, as a single integrated system, with NEP designated as the combined operator. NEP collects the costs of the combined transmission asset pool, including a current RoE of 10.57%, and subsequently reimburses the transmission owners (TOs). The amount reimbursed to NECO for the fiscal year ended March 2020 (fiscal 2020) was around $142 million. The transmission business has no exposure to the end consumer, and therefore has no commodity price risk.

Very supportive regulatory environment expected to continue

NECO's transmission business is wholly regulated by the FERC, which we view as highly credit supportive. The FERC-regulated rates are set based on a formulaic, forward-looking rate setting mechanism that adjusts for changes in network load that impacts demand. This ensures the utility's ability to earn the allowed RoE and enhances the stability and predictability of cash flow, a significant credit positive.

The FERC's rate-setting mechanism is designed to reimburse the company for all efficiently incurred operating and maintenance spending, tax, depreciation, amortisation, and to provide a fair return on assets employed in the provision of transmission services. The formula contains an automatic annual true-up for operating and capital costs. Transmission projects generally enter rate base after they are placed in commercial operation; however, certain FERC-approved projects can recover construction-work-in-progress costs in the rate base, another credit positive. These features are intended to ensure that the company recovers its allowed costs and returns within a two-year period. In addition, to encourage greater investment in transmission infrastructure, the FERC allows independent TOs to earn RoEs that tend to be above those allowed by state regulators. In line with NEP and other transmission owners in New England, and shown in Exhibit 6 above, Narragansett transmission is allowed to earn a base RoE of 10.57% on an assumed equity-to-total capitalisation ratio of 50% (in line with state regulators, but lower than 66% at NEP). In addition, Narragansett transmission benefits from incentive adder mechanisms that can increase the allowed RoE up to 11.74%. Indeed, the majority of the company's transmission plant provide regional transmission services ("pool transmission facilities") with these receiving a 50 basis point higher RoE.

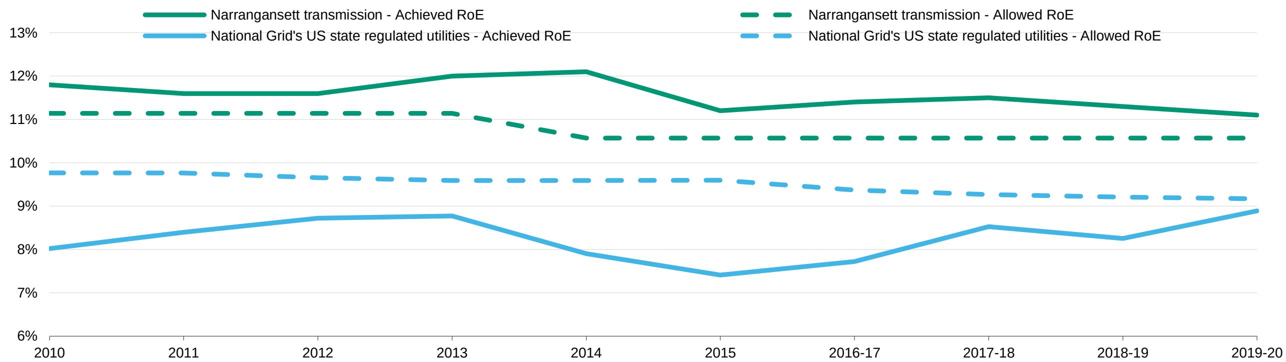
Since the rate-setting process is not contested before state commissions, and given its design to ensure timely cost recovery, we consider the regulatory framework more stable and predictable than for state-regulated utility businesses.

Despite many changes in FERC RoE methodologies and complaints on allowed returns, base RoEs are expected to remain above those of state regulated utilities

Despite the shifting RoE policy landscape at the FERC since 2014, with the rate of change accelerating in the last two years, base RoEs for transmission companies remain significantly above recent authorisations for state regulated utilities (averaging in the low-to-mid 9s in percentage terms across the US in H1 2020). The differential in achieved RoEs is even wider, as shown in the exhibit below, because of incentive adders for TOs that have meant Narragansett's achieved RoE has been above 11.0% in each of the last ten years - over half of its transmission assets earn an RoE of 11.74, with the vast majority of this pertaining to the New England East-West Solution (NEEWS) project.[4]

Exhibit 8

Narragansett's achieved ROE continues to be above base ROE, supported by incentive adders, and is well above that for National Grid's US business as a whole



(1) During 2017 National Grid changed the reported period of its RoEs for the US business from calendar year to fiscal year. (2) The cut in Narragansett transmission's base RoE from 11.14% to 10.57% took effect from 15 October 2014
Source: National Grid

Although four separate complaints have been filed over 2011-16 against allowed returns for TOs operating in the Independent System Operator - New England (ISO-NE) region, Narragansett transmission's (and NEP's) base RoE has only changed once in the last ten years (lowered from 11.14% to 10.57% in October 2014). With regulators reflecting the sustained low interest rate environment since the global financial crisis in lower authorised RoEs in rate case settlements, the cut in allowed equity returns for state regulated utilities has been larger over this period.

Within the last year, November 2019 and May 2020, the FERC have issued orders on the Midcontinent ISO transmission owners (MISO) ROE complaints. The November 2019 order proposed the application of the average of two models to judge whether ROEs are just and reasonable which resulted in a reduced RoE of 9.88%, from 10.32%, when the proposed methodology is applied to the two MISO RoE complaints. [5] The May 2020 order proposes using three, rather than two models, to make this assessment and resulted in a base RoE of 10.02%. The FERC orders on the MISO ROE complaint proceedings, and the proposed revised ROE methodology, are specific to MISO. However, the FERC could order the revised methodology to be applied to all transmission companies, including NEP's own RoE complaint proceedings.

Transmission Incentive Policy Inquiry ongoing but proposals are credit positive if enacted

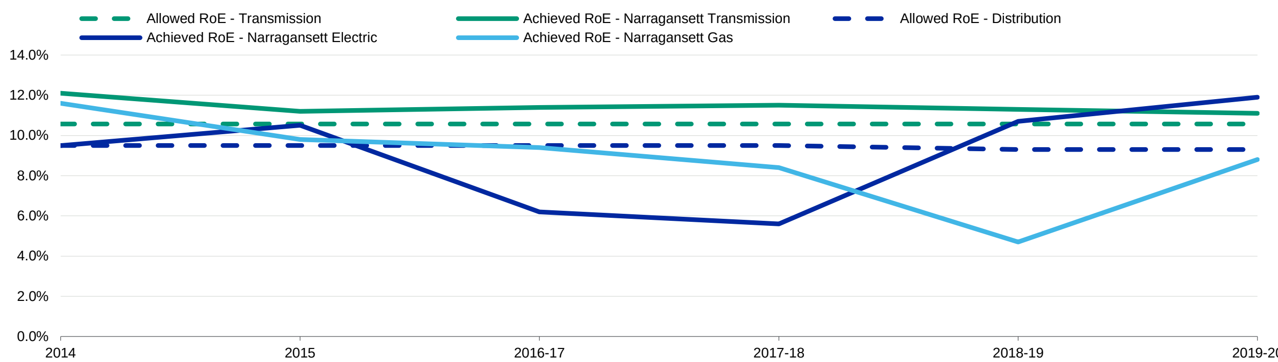
Since March 2019, when the FERC published a notice of inquiry, the FERC has been reviewing electricity transmission incentives. On 19 March 2020, the Commission issued a Notice of Proposed Rulemaking (NOPR). In the NOPR, the commission proposes to shift the test for transmission incentives from risks and challenges to an approach based on benefits to customers. On each of the four tests (around participating companies, benefits to reliability and pre-construction benefit-to-cost ratio), TOs would receive either a 50 or 100 basis point incentive adder with a proposed 250 basis point cap on total ROE incentives, rather than being limited at the zone of reasonableness under current arrangements. NEP, on behalf of its affiliates, filed comments in response to the NOPR on 1 July with a final ruling pending. We expect a decision either later this year or in 2021.

Improved achieved RoEs under current distribution rate plans support financial profile

NECO's financial profile has been supported by the continued strong performance of its transmission operations, which has partially offset the fall in achieved RoEs since 2014 for its distribution business prior to the current rate plans taken effect in September 2018. The declining ROE primarily reflected the absence of updated rates in the intervening period (the primary term of the prior rate plan expired in January 2014) because no new rate cases were filed following problems with an IT system implementation programme and inflationary cost pressures.

Fiscal 2020 was the first year that Narrangansett had the full benefit of higher rates under its current distribution plans. This, coupled with no exceptional one-off costs (in January 2019 the gas distribution business had to restoring gas service to around 7,500 customers [2.7% of all its customers] on Aquidneck Island, following a gas transmission supply issue in January 2019, which took nine days to complete), was the main driver for the improvement in achieved RoE in this year.[6] We expect Narragansett distribution's achieved RoE to be close to allowed levels in fiscal 2021 and 2022, supported by annual rate increases under the rate settlement but with fiscal 2021 metrics adversely affected by the coronavirus pandemic (discussed below). This, allied to the strong performance of transmission business, means we expect NECO to exhibit CFO pre-WC / debt at or above 20%, above minimum guidance for the current rating as shown in Exhibit 1.

Exhibit 9
Strong achieved RoE in fiscal 2020 reflecting first full year of updated rates for distribution businesses and no material one-off costs



During 2017, National Grid changed the reporting period of its RoEs for the US business from calendar year to fiscal year.
Source: National Grid

Modest dividend distributions expected to continue whilst NECO undertakes material investment programme

NECO continues to undertake a material investment programme intended to fund the replacement of several ageing operational systems and gas pipelines. Under its rate case settlement, Narragansett distribution has a $240 million capital programme fully funded annually via the Infrastructure, Safety and Reliability plans. Whilst NECO's investment programme has meant the company has been free cash flow negative in recent years, the increase in leverage in recent years has been moderated by National Grid typically extracting dividends from other US operating companies to service interest payments at the holding companies above NECO. Indeed, aside from a dividend distribution of $85 million, NECO had paid no dividends since fiscal 2010. We expect that National Grid will continue to gear NECO at or close to regulatory assumptions which will result in a continuation of only modest distributions.

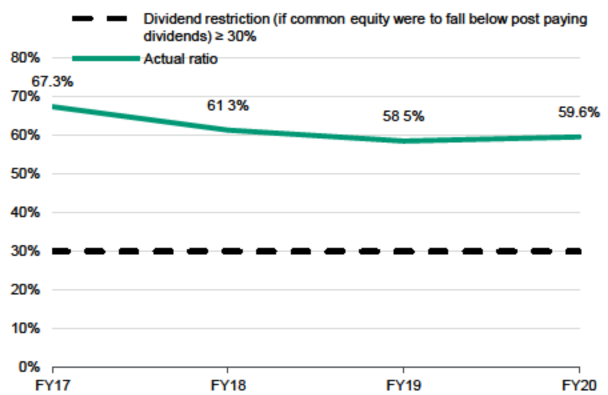
Credit quality constrained by that of the National Grid group

Whilst we expect NECO to maintain a financial profile at least in line with minimum guidance for the current rating, the presence of high levels of additional debt at the holding companies (including NG USA and NGNA), coupled with the absence of significant ring-fencing provisions, currently constrains NECO's credit quality at the level of the wider National Grid group, which we assess as commensurate with an A3 negative rating.

As Exhibit 9 shows, NECO's current ring-fencing provisions only restrict dividends if leverage is over twice current levels (debt to capitalisation were to exceed 70%, around 30% at March 2020)[7]

Exhibit 10

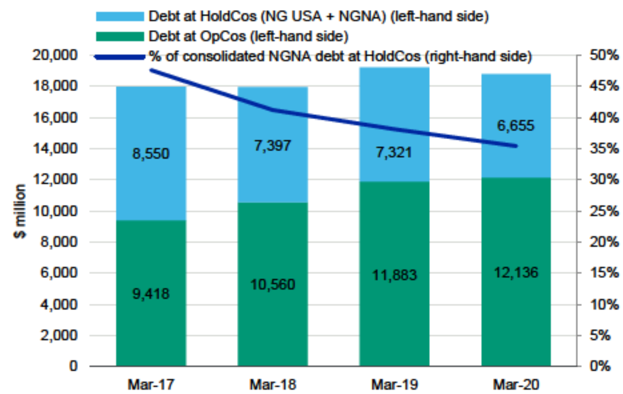
NECO has significant headroom before dividend restrictions apply
Debt / capitalisation compared to covenant levels



Source: Annual report; Moody's Investors Service

Exhibit 11

Material level of holding company debt above NECO
Breakdown of NGNA's reported debt by source



(1) Lending by NG USA to the regulated money pool reallocated to OpCos. (2) Genco's promissory notes to NGNA reallocated to OpCos
Source: Annual reports; Moody's Investors Service

The absence of significant ring-fencing provisions contrasts with other US regulated utilities within the National Grid group, principally those operating in New York, where a number of provisions exist, such as (1) specific leverage restrictions at conservative levels (usually defined by a debt-to-capitalisation ratio); (2) a special class of preferred stock (the Golden Share), which is subordinated to all other existing preferred stock and limits a regulated utility's ability to commence any voluntary bankruptcy (or similar) proceedings without the consent of the holder; and (3) a requirement to maintain an investment-grade rating. Together, these provisions provide a material benefit to creditors and may allow regulated utilities to be rated more highly than the group to which they belong. Of these restrictions, we view an explicit leverage restriction at conservative leverage levels as having the greatest benefit for protecting a single-A rating, while other measures have power only at lower rating levels.

ESG considerations

NECO has low carbon transition risk within the regulated utility sector, particularly compared to vertically integrated electric utilities, mainly due to its lack of generation asset ownership. All commodity costs, including carbon, associated with power procurement for customers is fully passed through to customers with an effective cost recovery mechanism.

In the US, regulatory frameworks are driving the decarbonisation of the energy industry, although at different scales depending on the state. In order to deliver this decarbonisation, significant investment is needed on safety (replacing leak prone pipe) and asset health (improving system reliability, which is also required to accommodate uptake of electric vehicles), and to support the significant growth in renewables whilst keeping the affordability of tariffs. This long-term capital expenditure and resource planning is already usually incorporated into regulatory tariff setting to reflect demand expectations driven by population growth, consumption efficiency initiatives, and required investment to maintain reliability and security of supply. Narragansett's current distribution rate plans include a reopener in base rates in rate years 2 and 3 (September 2019 - August 2021) for the recovery of advanced metering and grid modernization costs approved by the RIPUC during the primary term of the rate plan.

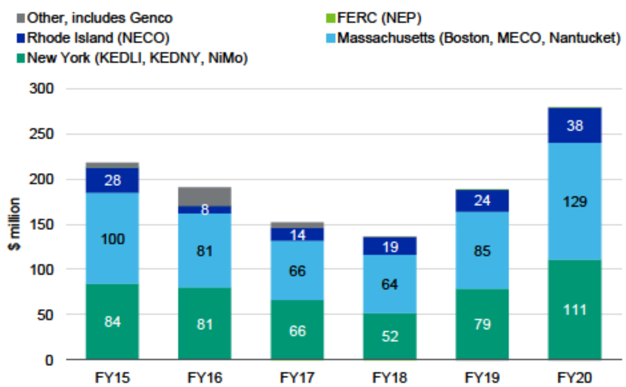
Coronavirus pandemic will depress operating cash flows for NECO's distribution business but have negligible impact on its transmission business

We regard the coronavirus outbreak as a social risk under our ESG framework, given the substantial implications for public health and safety.

For its US operations, NECO's ultimate parent, National Grid plc, has suspended debt collections and customer termination activities, which will result in near term lower customer receipts and likely increases in bad debt and associated provisions. In its current distribution rate plans, NECO does have (1) full revenue decoupling; and (2) commodity-related bad debt true-ups. We view the regulatory protections for the latter as weaker than with volume risk, where the company is protected against lower than expected gas consumption (albeit with a delay in recovery of revenues).

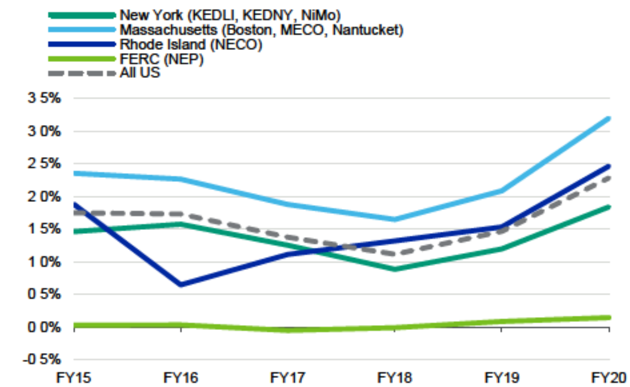
We expect the resulting fall in operating cash flows in fiscal 2021 to be larger for NECO's distribution business than for its transmission business. Whilst the fall in energy consumption (particularly by industrial and commercial customers) will impact all network volumes, the recovery happens on a more timely basis for NECO's transmission operations reflecting that their rates are set based on a formulaic, forward-looking rate-setting mechanism, with a monthly formula that adjusts for changes in network load that impacts demand. Similarly, bad debt rates are much lower for transmission companies than for state regulated utilities reflecting the limited exposure to the end consumer. Whilst NECO only reports bad debt expense for all its business, in FY2020 bad debt expense for NEP, standalone electricity transmission, was 0.15% of revenue compared to 2.3% for National Grid's US business as a whole.

Exhibit 12
Like National Grid's other businesses, NECO's bad debt expense was higher in FY2020
Breakdown by state of regulated operations



Source: Company reports; Moody's Investors Service

Exhibit 13
Bad debt expense, as a % of revenue, for National Grid's US operations
Breakdown by state of regulated operations



Source: Company reports; Moody's Investors Service

Liquidity analysis

Given group funding arrangements, although NECO has inadequate liquidity on a standalone basis, with limited cash and cash equivalents and no revolving credit facilities in its own name, we regard its liquidity risk as manageable.

National Grid manages its financing and liquidity on an overall group basis, with a central finance committee setting the rules by which individual entities can raise capital. For the US subsidiaries, including NECO, short-term liquidity requirements are managed via the group's regulated money pool. All of the regulated subsidiaries can lend and borrow from the pool; however, the unregulated holding companies — NG USA and NGNA — may only act as lenders. The interest rate for borrowing under the money pool is determined by reference to the cost of meeting the group's funding needs, typically a mix of 30-day P-2 commercial paper and any other long- and short-term funding sources.

To support the regulated money pool, the parent holding companies have in place bilateral facilities totalling $3.8 billion, with maturity dates now ranging from May 2022 out to June 2025, for which NG plc, NGNA and NG USA are named borrowers. The facilities were undrawn as of March 2020. NGNA and NG USA also have two commercial paper programmes, denominated equally in US dollars and euros. Support for these programmes comes from the holding companies being named as borrowers under the aforementioned revolving credit facilities. As of March 2020, $483 million and $328 million were outstanding on the US and euro commercial paper programmes, respectively.

Viewed in this wider context, NECO's liquidity appears much stronger. NECO's rating relies on continued access to liquidity from the wider National Grid group via this money pool arrangement.

The company has remaining long-term debt authorization of $300 million over the period to March 2023.[8]

Rating methodology and scorecard factors

We assess NECO under our Regulated Electric and Gas Utilities rating methodology, published in June 2017. The scorecard-indicated outcome for NECO is A2 both a historic and a forward-looking basis, one notch higher than the assigned rating.

Exhibit 14
Rating factors
Narragansett Electric Company

Regulated Electric and Gas Utilities Industry Grid [1][2]	Current FY 3/31/2020		Moody's 12-18 Month Forward View As of October 2020 [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	5.7x	A	5.7x - 6.1x	A
b) CFO pre-WC / Debt (3 Year Avg)	20.4%	A	19% - 22%	A
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	18.2%	A	17% - 20%	A
d) Debt / Capitalization (3 Year Avg)	34.2%	Aa	34% - 36%	Aa
Rating:				
Scorecard-indicated Outcome Before Notching Adjustment		A2		A2
HoldCo Structural Subordination Notching		0		0
a) Scorecard-indicated Outcome from Grid		A2		A2
b) Actual Rating Assigned				A3

(1) All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. (2) As of 31 March 2020. (3) This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics™

Appendix

Exhibit 15
Peer comparison
Narragansett Electric Company

	Narragansett Electric Company			Delmarva Power & Light Company			Potomac Electric Power Company			Jersey Central Power & Light Company		
	A3 Negative			Baa1 Stable			Baa1 Stable			A3 Stable		
(in USD Millions)	FYE Mar-18	FYE Mar-19	FYE Mar-20	FYE Dec-17	FYE Dec-18	FYE Dec-19	FYE Dec-17	FYE Dec-18	FYE Dec-19	FYE Dec-17	FYE Dec-18	FYE Dec-19
Revenue	1,445	1,557	1,557	1,300	1,332	1,306	2,158	2,232	2,260	1,828	1,864	1,837
CFO Pre - W/C	252	296	233	329	352	306	431	463	588	479	427	459
Interest Expense	48	56	62	58	62	64	137	133	137	113	115	95
Gross Debt	1,180	1,286	1,366	1,631	1,598	1,730	2,681	2,912	3,085	2,109	1,899	1,975
Net Debt	1,174	1,278	1,363	1,629	1,575	1,717	2,676	2,896	3,055	2,109	1,899	1,975
Book capitalization	3,530	3,694	3,980	3,557	3,725	3,954	6,235	6,652	7,090	5,859	6,095	6,258
(CFO Pre-W/C + Interest) / Interest	6.3x	6.2x	4.8x	6.7x	6.7x	5.7x	4.1x	4.5x	5.3x	5.2x	4.7x	5.8x
(CFO Pre-W/C) / Debt	21 3%	23 0%	17.1%	20.1%	22.1%	17.7%	16.1%	15.9%	19.1%	22.7%	22.5%	23.2%
(CFO Pre - W/C - Dividends) / Debt	21 3%	16.4%	17.1%	13 3%	16.0%	9.7%	11.1%	10.1%	12.1%	22.7%	22.5%	18.7%
Debt / Book Capitalization	33.4%	34 8%	34 3%	45 9%	42.9%	43.7%	43.0%	43.8%	43.5%	36.0%	31.2%	31.6%

All metrics are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. FYE = Financial year-end. LTM = Last 12 months.
Source: Moody's Financial Metrics™

Exhibit 16
Moody's-adjusted debt calculation
Narragansett Electric Company

(in USD Millions)	FYE Mar-16	FYE Mar-17	FYE Mar-18	FYE Mar-19	FYE Mar-20
As Reported Debt	**1,039.7**	**969.0**	**1,149.8**	**1,231.5**	**1,275.5**
Pensions	94 2	51 9	25.3	20.6	62.6
Operating Leases	0 0	0 0	0.0	27.2	21.9
Hybrid Securities	1 2	1 2	1.2	1.2	1.2
Non-Standard Adjustments	4.4	4.1	3.8	5.3	4.8
Moody's-Adjusted Debt	**1,139.5**	**1,026.3**	**1,180.1**	**1,285.8**	**1,366.1**

All metrics are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. FYE = Financial year-end. LTM = Last 12 months.
Source: Moody's Financial Metrics™

Exhibit 17
Moody's-adjusted CFO pre-WC calculation
Narragansett Electric Company

(in USD Millions)	FYE Mar-16	FYE Mar-17	FYE Mar-18	FYE Mar-19	FYE Mar-20
As Reported CFO pre-WC	**264.5**	**317.4**	**232.0**	**280.4**	**223.0**
Pensions	10.6	0.0	19.9	15.5	3.0
Operating Leases	0.0	0.0	0.0	0.0	7.3
Capitalized Interest	0.0	0.0	0.0	0.0	0.0
Hybrid Securities	-0.1	-0.1	-0.1	-0.1	-0.1
Non-Standard Adjustments	0.0	0.0	0.0	0.0	0.0
Moody's-Adjusted CFO pre-WC	**275.0**	**317.3**	**251.8**	**295.8**	**233.3**

All metrics are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. FYE = Financial year-end. LTM = Last 12 months.
Source: Moody's Financial Metrics™

Exhibit 18

Select historical Moody's-adjusted financial data

Narragansett Electric Company

(in USD Millions)	FYE Mar-16	FYE Mar-17	FYE Mar-18	FYE Mar-19	FYE Mar-20
INCOME STATEMENT					
Revenue	1,306.2	1,263.4	1,445.0	1,556.6	1,556.6
EBIT	193.8	188.6	202.3	199.9	216.7
EBITDA	290.7	292.5	308.2	309.4	342.9
Interest expense	48.6	48.8	47.8	56.5	62.1
BALANCE SHEET					
Total Debt	1,139.5	1,026.3	1,180.1	1,285.8	1,366.1
Net Debt	1,125.1	1,018.5	1,173.8	1,277.6	1,362.7
Total Liabilities	2,449.5	2,444.6	2,662.5	2,852.8	2,917.8
Fixed Assets	2,576.6	2,785.8	2,984.3	3,241.9	3,470.8
Total Assets	4,259.5	4,343.6	4,688.3	4,901.9	5,164.9
CASH FLOW					
CFO Pre - W/C	275.0	317.3	251.8	295.8	233.3
Cash Dividends - Common	0.0	0.0	0.0	-85.3	0.0
Cash Dividends - Preference	-0.1	-0.1	-0.1	-0.1	-0.1
Capital Expenditures	-295.3	-296.0	-313.5	-331.7	-348.3
(CFO Pre-W/C) / Debt	24.1%	30.9%	21.3%	23.0%	17.1%
(CFO Pre - W/C - Dividends) / Debt	24.1%	30.9%	21.3%	16.4%	17.1%
PROFITABILITY					
EBIT Margin %	14.8%	14.9%	14.0%	12.8%	13.9%
EBITDA Margin %	22.3%	23.2%	21.3%	19.9%	22.0%
INTEREST COVERAGE					
(CFO Pre-W/C + Interest) / Interest	6.7x	7.5x	6 3x	6.2x	4 8x
LEVERAGE					
Debt / EBITDA	3.9x	3.5x	3 8x	4.2x	4 0x
Net Debt / EBITDA	3.9x	3.5x	3 8x	4.1x	4 0x
Debt / Book Capitalization	32.9%	29.6%	33.4%	34.8%	34.3%

All metrics are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. FYE = Financial year-end.
Source: Moody's Financial Metrics™

Ratings

Exhibit 19

Category	Moody's Rating
NARRAGANSETT ELECTRIC COMPANY	
Outlook	Negative
Issuer Rating	A3
Senior Unsecured	A3
Pref. Stock	Baa2
ULT PARENT: NATIONAL GRID PLC	
Outlook	Negative
Issuer Rating	Baa1
Senior Unsecured -Dom Curr	Baa1
Commercial Paper	P-2
Other Short Term	(P)P-2
PARENT: NATIONAL GRID NORTH AMERICA INC.	
Outlook	Negative
Issuer Rating	Baa1
Senior Unsecured	Baa1
Commercial Paper	P-2
ST Issuer Rating	P-2
PARENT: NATIONAL GRID USA	
Outlook	Negative
Issuer Rating	Baa1
Commercial Paper	P-2

Source: Moody's Investors Service

Endnotes

1 Albeit some consideration is given to forecast capital investment, volume and operating costs with some other cost categories increased by inflation.

2 Due to NECO's ongoing rate-case proceedings at the time, the company was allowed to defer the effect of this tax reduction until the effective date of the new rate plan.

3 In line with a FERC order published in November 2019, NEP made a compliance filing (on behalf of its affiliates) on accumulated deferred income tax (ADIT) in July 2020. If accepted, the result would be a reduction in revenues and cash flow of approximately $1.5 million per annum as NEP's amortizes the ADIT balance back to customers. However, it will not affect earned RoE. We understand that the FERC has not yet ruled on any ADIT filings for any companies in the US. The timing of their ultimate decision on whether they accept NEP's amortization schedules is unknown.

4 The NEEWS project, built by Narragansett transmission, NEP and Northeast Utilities, consists of a series of inter-related transmission upgrades identified in the New England Regional System Plan to improve system reliability in the surrounding area. Narragansett transmission's share of the investment costs was around $560 million which it is fully reimbursed for its transmission revenue requirements on a monthly basis by NEP. Since the FERC capped the maximum RoE at 11.74% the NEEWS incentive RoE has been effectively capped at this level (the project was initially granted an incentive RoE of 12.89%, 125 basis points above the then prevailing RoE.

5 See FERC order reducing MISO base ROE is credit negative for transmission owners, November 2019 for more information.

6 RIPUC investigated the issue and found there were multiple contributing factors leading to the outage, some of which were outside the company's control. In January 2020, Narragansett paid the $39,000 fine levied by the RIPUC for failing "to provide a telephonic notification to RIPUC of the emergency shutdown of an LNG facility" although it did not admit liability. The company has also been served with amended class action complaints, one on behalf of business owners of Aquidneck and one on behalf of individuals in the affected areas.

7 FERC, 89; FERC 61266. Under NECO's First Mortgage Bonds, which total less than $20 million (just over 1%) of the company's outstanding external debt and mature between September 2022 and December 2025, if debt / capitalization exceeds 60% then bondholders receive a 0.2% increase in the coupon paid from the first date of such occurrence.

8 In January 2020 the RIPUC authorized NECO to issue up to $900 million of long-term debt in one or more transactions through 31 March 2023. Under the authorization, in April 2020, NECO issued $600 billion. As of the date of this report, $300 million of debt authorization remains under the RIPUC order.

REPORT NUMBER 1245994

MOODY'S
INVESTORS SERVICE

MOODY'S
INVESTORS SERVICE

Rating Action: Moody's places NECO's Baa1/Baa3 ratings on review for upgrade

18 Mar 2021

London, 18 March 2021 -- Moody's Investors Serv ce (Moody's) has today p aced on rev ew for upgrade the Baa1 ong-term ssuer and sen or unsecured rat ngs of Narragansett E ectr c Company (NECO), and the Baa3 rat ng of ts preferred stock secur t es. Concurrent y, Moody's has changed NECO's ssuer out ook to rat ngs under rev ew from stab e. NECO, wh ch s u t mate y owned by Nat ona Gr d p c (Nat ona Gr d, Baa2 stab e), s a reta d str but on company prov d ng e ectr c and gas serv ces to customers n Rhode Is and, where t a so owns e ectr c ty transm ss on assets.

The rat ng rev ew was prompted by the 18 March announcement [1] that Nat ona Gr d and PPL Corporat on (PPL, Baa2 pos t ve) have agreed that NECO w be so d to PPL fo ow ng the purchase of PPL's UK regu ated assets by Nat ona Gr d.

RATINGS RATIONALE / FACTORS THAT COULD LEAD TO AN UPGRADE OR DOWNGRADE OF THE RATINGS

The asset sa e, f conc uded, w remove an ex st ng cap on NECO's Baa1 rat ngs. Moody's current y v ews the conso dated cred t qua ty of the Nat ona Gr d group, commensurate w th a Baa1 rat ng, as a constra nt n ts assessment of NECO. The rev ew w cons der NECO's ke y future cred t qua ty n the context of ts membersh p of the PPL group. In part cu ar, t w cons der whether NECO w ma nta n f nanc a metr cs cons stent w th an A3 rat ng w th cash f ow from operat ons pre-work ng cap ta (CFO pre-WC) to debt of at east 18%, nc ud ng after the pr mary term of ts current d str but on rate p ans has exp red.

The current constra nt on NECO's rat ng as part of the Nat ona Gr d group ref ects the substant a add t ona debt at the parent ho d ng compan es, Nat ona Gr d USA (Baa2 stab e) and Nat ona Gr d North Amer ca Inc. (NGNA, Baa2 stab e), and the absence of s gn f cant r ng-fenc ng prov s ons. NECO's d v dend ock-up on y app es f ts debt to cap ta zat on w exceed 70% - a eve much h gher than for the group's New York ut t es (n the m d-50s n percentage terms). A though Nat ona Gr d manages ts f nanc ng and qu d ty on a group bas s, Moody's cons ders the nkages for US subs d ar es to be greater than for those n the UK. None of the group's US operat ng subs d ar es, for examp e, have revo v ng cred t fac t es n the r own names. Short-term qu d ty requ rements are managed v a the group's regu ated money poo .

NECO's f nanc a prof e has been supported by the cont nued strong performance of ts transm ss on operat ons, wh ch account for around 30% of ts rate base, w th ach eved return on equ ty (ROE) over 11% n each of the ast ten years. Th s h gh eve ref ects base ROE above those of state regu ated ut t es (current y 10.57%, n ne w th that for other transm ss on owners n New Eng and), desp te many changes n the regu ator's (FERC) ROE methodo og es and comp a nts on a owed returns n recent years, and the support prov ded by ncent ve adders. The company's f nanc a prof e has a so benef tted from the mproved performance of ts d str but on bus nesses, whose rate base s sp t broad y equa y between e ectr c ty and gas, under the current three-year rate p ans wh ch took effect n September 2018. These p ans nc ude de-r sk ng prov s ons that mprove the ke hood and t m ng of cost recovery.

Under the agreement between Nat ona Gr d and PPL, PPL w assume NECO's outstand ng debt, $1,396 m on, at 31 December 2020, and pay Nat ona Gr d $3.8 b on for NECO's equ ty upon successfu comp et on of the transact on. There are severa steps to the announced dea , wh ch a so nvo ves Nat ona Gr d acqu r ng PPL's UK e ectr c ty d str but on assets (the Western Power D str but on group), but a the customary approva s perta n ng to NECO are expected to be rece ved no ater than March 2022.

Based on prev ous precedent, the Rhode Is and regu ator (the Pub c Ut t es Comm ss on, PUC) may, as a cond t on of approv ng the change n ownersh p, requ re PPL to stay-out from mak ng a fresh rate case f ng for NECO's d str but on operat ons for a pre-def ned per od. If the stay out per od (1) does not conta n any mechan sms for ncreas ng revenues to ref ect ncreas ng operat ng costs or cost pressure from a grow ng rate base; and (2) s for severa years, NECOs ab ty to ma nta n a f nanc a prof e commensurate w th an A3 rat ng may be dependent on PPL's ab ty to rea se operat ona eff c enc es.

Rates for NECO's transm ss on operat ons are set based on a formu a c, forward- ook ng rate-sett ng mechan sm, under an ndef n te rate p an so t wou d on y be f the FERC app es ts rev sed ROE methodo ogy to a transm ss on compan es, rather than just n the MISO reg on that there wou d be cut n author zed ROE.

NECO's rat ngs are supported by the d vers f cat on of ts revenues across d str but on and transm ss on, ts stab e and pred ctab e cash f ows, and the genera y support ve regu atory env ronment n Rhode Is and. Moody's v ews the regu atory framework for ts e ectr c ty transm ss on operat ons, wh ch accounts for around 30% of the rate base, as part cu ar y support ve to cred t qua ty, g ven the we -estab shed and transparent framework and a tar ff formu a that a ows for t me y recovery of operat ng and cap ta spend ng.

The rat ngs cou d be upgraded f t appears ke y that, fo ow ng successfu comp et on of the asset sa e, NECO w ma nta n CFO pre-WC/debt of at east 18%.

The rat ngs cou d be conf rmed f t appears ke y that NECO's CFO pre-WC/debt w fa be ow 18% or there was a deter orat on n the support veness of the regu atory frameworks that govern NECO's bus nesses.

The pr nc pa methodo ogy used n these rat ngs was Regu ated E ectr c and Gas Ut t es pub shed n June 2017 and ava ab e at https://www.moodys.com/researchdocumentcontentpage.aspx?doc d=PBC_1072530 . A ternat ve y, p ease see the Rat ng Methodo og es page on www.moodys.com for a copy of th s methodo ogy.

The Nat ona Gr d group owns a range of arge y regu ated bus nesses focus ng on the e ectr c ty and gas transm ss on networks n the UK and transm ss on and d str but on ut t es n the US. The company reported tota revenue of GBP14.5 b on n 2019-20 and tota regu ated and other assets of GBP45.2 b on as of 31 March 2020. NECO's rate base of around $2.6 b on as of 31 March 2020 s broad y equa y d str buted across e ectr c ty d str but on and transm ss on, and gas d str but on and represents around 10% of Nat ona Gr d's rate base n the US.

REGULATORY DISCLOSURES

For further spec f cat on of Moody's key rat ng assumpt ons and sens t v ty ana ys s, see the sect ons Methodo ogy Assumpt ons and Sens t v ty to Assumpt ons n the d sc osure form. Moody's Rat ng Symbo s and Def n t ons can be found at: https://www.moodys.com/researchdocumentcontentpage.aspx?doc d=PBC_79004.

For rat ngs ssued on a program, ser es, category/c ass of debt or secur ty th s announcement prov des certa n regu atory d sc osures n re at on to each rat ng of a subsequent y ssued bond or note of the same ser es, category/c ass of debt, secur ty or pursuant to a program for wh ch the rat ngs are der ved exc us ve y from ex st ng rat ngs n accordance w th Moody's rat ng pract ces. For rat ngs ssued on a support prov der, th s announcement prov des certa n regu atory d sc osures n re at on to the cred t rat ng act on on the support prov der and n re at on to each part cu ar cred t rat ng act on for secur t es that der ve the r cred t rat ngs from the support prov der's cred t rat ng. For prov s ona rat ngs, th s announcement prov des certa n regu atory d sc osures n re at on to the prov s ona rat ng ass gned, and n re at on to a def n t ve rat ng that may be ass gned subsequent to the f na ssuance of the debt, n each case where the transact on structure and terms have not changed pr or to the ass gnment of the def n t ve rat ng n a manner that wou d have affected the rat ng. For further nformat on p ease see the rat ngs tab on the ssuer/ent ty page for the respect ve ssuer on www.moodys.com.

For any affected secur t es or rated ent t es rece v ng d rect cred t support from the pr mary ent ty(es) of th s cred t rat ng act on, and whose rat ngs may change as a resu t of th s cred t rat ng act on, the assoc ated regu atory d sc osures w be those of the guarantor ent ty. Except ons to th s approach ex st for the fo ow ng d sc osures, f app cab e to jur sd ct on: Anc ary Serv ces, D sc osure to rated ent ty, D sc osure from rated ent ty.

The rat ngs have been d sc osed to the rated ent ty or ts des gnated agent(s) and ssued w th no amendment resu t ng from that d sc osure.

These rat ngs are so c ted. P ease refer to Moody's Po cy for Des gnat ng and Ass gn ng Unso c ted Cred t Rat ngs ava ab e on ts webs te www.moodys.com.

Regu atory d sc osures conta ned n th s press re ease app y to the cred t rat ng and, f app cab e, the re ated rat ng out ook or rat ng rev ew.

Moody's genera pr nc p es for assess ng env ronmenta , soc a and governance (ESG) r sks n our cred t ana ys s can be found at https://www.moodys.com/researchdocumentcontentpage.aspx?doc d=PBC_1243406 .

The G oba Sca e Cred t Rat ng on th s Cred t Rat ng Announcement was ssued by one of Moody's aff ates outs de the EU and s endorsed by Moody's Deutsch and GmbH, An der We e 5, Frankfurt am Ma n 60322, Germany, n accordance w th Art.4 paragraph 3 of the Regu at on (EC) No 1060/2009 on Cred t Rat ng Agenc es. Further nformat on on the EU endorsement status and on the Moody's off ce that ssued the cred t rat ng s ava ab e on www.moodys.com.

REFERENCES/CITATIONS

[1] https://otp.too s. nvest s.com/Ut t es/PDFDown oad.aspx?News d=1461911

P ease see www.moodys.com for any updates on changes to the ead rat ng ana yst and to the Moody's ega ent ty that has ssued the rat ng.

P ease see the rat ngs tab on the ssuer/ent ty page on www.moodys.com for add t ona regu atory d sc osures for each cred t rat ng.

Ph p Cope
Asst V ce Pres dent - Ana yst
Infrastructure F nance Group
Moody's Investors Serv ce Ltd.
One Canada Square
Canary Wharf
London E14 5FA
Un ted K ngdom
JOURNALISTS: 44 20 7772 5456
C ent Serv ce: 44 20 7772 5454

Ne Gr ff ths-Lambeth
Assoc ate Manag ng D rector
Infrastructure F nance Group
JOURNALISTS: 44 20 7772 5456
C ent Serv ce: 44 20 7772 5454

Re eas ng Off ce:
Moody's Investors Serv ce Ltd.
One Canada Square
Canary Wharf
London E14 5FA
Un ted K ngdom
JOURNALISTS: 44 20 7772 5456
C ent Serv ce: 44 20 7772 5454

MOODY'S PUBLICATIONS ARE NOT STATEMENTS OF CURRENT OR HISTORICAL FACT. MOODY'S PUBLICATIONS MAY ALSO INCLUDE QUANTITATIVE MODEL-BASED ESTIMATES OF CREDIT RISK AND RELATED OPINIONS OR COMMENTARY PUBLISHED BY MOODY'S ANALYTICS, INC. AND/OR ITS AFFILIATES. MOODY'S CREDIT RATINGS, ASSESSMENTS, OTHER OPINIONS AND PUBLICATIONS DO NOT CONSTITUTE OR PROVIDE INVESTMENT OR FINANCIAL ADVICE, AND MOODY'S CREDIT RATINGS, ASSESSMENTS, OTHER OPINIONS AND PUBLICATIONS ARE NOT AND DO NOT PROVIDE RECOMMENDATIONS TO PURCHASE, SELL, OR HOLD PARTICULAR SECURITIES. MOODY'S CREDIT RATINGS, ASSESSMENTS, OTHER OPINIONS AND PUBLICATIONS DO NOT COMMENT ON THE SUITABILITY OF AN INVESTMENT FOR ANY PARTICULAR INVESTOR. MOODY'S ISSUES ITS CREDIT RATINGS, ASSESSMENTS AND OTHER OPINIONS AND PUBLISHES ITS PUBLICATIONS WITH THE EXPECTATION AND UNDERSTANDING THAT EACH INVESTOR WILL, WITH DUE CARE, MAKE ITS OWN STUDY AND EVALUATION OF EACH SECURITY THAT IS UNDER CONSIDERATION FOR PURCHASE, HOLDING, OR SALE.

MOODY S CREDIT RATINGS, ASSESSMENTS, OTHER OPINIONS, AND PUBLICATIONS ARE NOT INTENDED FOR USE BY RETAIL INVESTORS AND IT WOULD BE RECKLESS AND INAPPROPRIATE FOR RETAIL INVESTORS TO USE MOODY S CREDIT RATINGS, ASSESSMENTS, OTHER OPINIONS OR PUBLICATIONS WHEN MAKING AN INVESTMENT DECISION. IF IN DOUBT YOU SHOULD CONTACT YOUR FINANCIAL OR OTHER PROFESSIONAL ADVISER.

ALL INFORMATION CONTAINED HEREIN IS PROTECTED BY LAW, INCLUDING BUT NOT LIMITED TO, COPYRIGHT LAW, AND NONE OF SUCH INFORMATION MAY BE COPIED OR OTHERWISE REPRODUCED, REPACKAGED, FURTHER TRANSMITTED, TRANSFERRED, DISSEMINATED, REDISTRIBUTED OR RESOLD, OR STORED FOR SUBSEQUENT USE FOR ANY SUCH PURPOSE, IN WHOLE OR IN PART, IN ANY FORM OR MANNER OR BY ANY MEANS WHATSOEVER, BY ANY PERSON WITHOUT MOODY S PRIOR WRITTEN CONSENT.

MOODY S CREDIT RATINGS, ASSESSMENTS, OTHER OPINIONS AND PUBLICATIONS ARE NOT INTENDED FOR USE BY ANY PERSON AS A BENCHMARK AS THAT TERM IS DEFINED FOR REGULATORY PURPOSES AND MUST NOT BE USED IN ANY WAY THAT COULD RESULT IN THEM BEING CONSIDERED A BENCHMARK.

A nformat on conta ned here n s obta ned by MOODY S from sources be eved by t to be accurate and re ab e. Because of the poss b ty of human or mechan ca error as we as other factors, however, a nformat on conta ned here n s prov ded "AS IS" w thout warranty of any k nd. MOODY'S adopts a necessary measures so that the nformat on t uses n ass gn ng a cred t rat ng s of suff c ent qua ty and from sources MOODY'S cons ders to be re ab e nc ud ng, when appropr ate, ndependent th rd-party sources. However, MOODY S s not an aud tor and cannot n every nstance ndependent y ver fy or va date nformat on rece ved n the rat ng process or n prepar ng ts Pub cat ons.

To the extent perm tted by aw, MOODY S and ts d rectors, off cers, emp oyees, agents, representat ves, censors and supp ers d sc a m ab ty to any person or ent ty for any nd rect, spec a , consequent a , or nc denta osses or damages whatsoever ar s ng from or n connect on w th the nformat on conta ned here n or the use of or nab ty to use any such nformat on, even f MOODY S or any of ts d rectors, off cers, emp oyees, agents, representat ves, censors or supp ers s adv sed n advance of the poss b ty of such osses or damages, nc ud ng but not m ted to: (a) any oss of present or prospect ve prof ts or (b) any oss or damage ar s ng where the re evant f nanc a nstrument s not the subject of a part cu ar cred t rat ng ass gned by MOODY S.

To the extent perm tted by aw, MOODY S and ts d rectors, off cers, emp oyees, agents, representat ves, censors and supp ers d sc a m ab ty for any d rect or compensatory osses or damages caused to any person or ent ty, nc ud ng but not m ted to by any neg gence (but exc ud ng fraud, w fu m sconduct or any other type of ab ty that, for the avo dance of doubt, by aw cannot be exc uded) on the part of, or any cont ngency w th n or beyond the contro of, MOODY S or any of ts d rectors, off cers, emp oyees, agents, representat ves, censors or supp ers, ar s ng from or n connect on w th the nformat on conta ned here n or the use of or nab ty to use any such nformat on.

NO WARRANTY, EXPRESS OR IMPLIED, AS TO THE ACCURACY, TIMELINESS, COMPLETENESS, MERCHANTABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE OF ANY CREDIT RATING,

ASSESSMENT, OTHER OPINION OR INFORMATION IS GIVEN OR MADE BY MOODY S IN ANY FORM OR MANNER WHATSOEVER.

Moody s Investors Serv ce, Inc., a who y-owned cred t rat ng agency subs d ary of Moody s Corporat on ("MCO"), hereby d sc oses that most ssuers of debt secur t es (nc ud ng corporate and mun c pa bonds, debentures, notes and commerc a paper) and preferred stock rated by Moody s Investors Serv ce, Inc. have, pr or to ass gnment of any cred t rat ng, agreed to pay to Moody s Investors Serv ce, Inc. for cred t rat ngs op n ons and serv ces rendered by t fees rang ng from $1,000 to approx mate y $5,000,000. MCO and Moody s Investors Serv ce a so ma nta n po c es and procedures to address the ndependence of Moody s Investors Serv ce cred t rat ngs and cred t rat ng processes. Informat on regard ng certa n aff at ons that may ex st between d rectors of MCO and rated ent t es, and between ent t es who ho d cred t rat ngs from Moody s Investors Serv ce and have a so pub c y reported to the SEC an ownersh p nterest n MCO of more than 5%, s posted annua y at www.moodys.com under the head ng "Investor Re at ons — Corporate Governance — D rector and Shareho der Aff at on Po cy."

Add t ona terms for Austra a on y: Any pub cat on nto Austra a of th s document s pursuant to the Austra an F nanc a Serv ces L cense of MOODY S aff ate, Moody s Investors Serv ce Pty L m ted ABN 61 003 399 657AFSL 336969 and/or Moody s Ana yt cs Austra a Pty Ltd ABN 94 105 136 972 AFSL 383569 (as app cab e). Th s document s ntended to be prov ded on y to "who esa e c ents" w th n the mean ng of sect on 761G of the Corporat ons Act 2001. By cont nu ng to access th s document from w th n Austra a, you represent to MOODY S that you are, or are access ng the document as a representat ve of, a "who esa e c ent" and that ne ther you nor the ent ty you represent w d rect y or nd rect y d ssem nate th s document or ts contents to "reta c ents" w th n the mean ng of sect on 761G of the Corporat ons Act 2001. MOODY S cred t rat ng s an op n on as to the cred tworth ness of a debt ob gat on of the ssuer, not on the equ ty secur t es of the ssuer or any form of secur ty that s ava ab e to reta nvestors.

Add t ona terms for Japan on y: Moody's Japan K.K. ("MJKK") s a who y-owned cred t rat ng agency subs d ary of Moody's Group Japan G.K., wh ch s who y-owned by Moody s Overseas Ho d ngs Inc., a who y-owned subs d ary of MCO. Moody s SF Japan K.K. ("MSFJ") s a who y-owned cred t rat ng agency subs d ary of MJKK. MSFJ s not a Nat ona y Recogn zed Stat st ca Rat ng Organ zat on ("NRSRO"). Therefore, cred t rat ngs ass gned by MSFJ are Non-NRSRO Cred t Rat ngs. Non-NRSRO Cred t Rat ngs are ass gned by an ent ty that s not a NRSRO and, consequent y, the rated ob gat on w not qua fy for certa n types of treatment under U.S. aws. MJKK and MSFJ are cred t rat ng agenc es reg stered w th the Japan F nanc a Serv ces Agency and the r reg strat on numbers are FSA Comm ss oner (Rat ngs) No. 2 and 3 respect ve y.

MJKK or MSFJ (as app cab e) hereby d sc ose that most ssuers of debt secur t es (nc ud ng corporate and mun c pa bonds, debentures, notes and commerc a paper) and preferred stock rated by MJKK or MSFJ (as app cab e) have, pr or to ass gnment of any cred t rat ng, agreed to pay to MJKK or MSFJ (as app cab e) for cred t rat ngs op n ons and serv ces rendered by t fees rang ng from JPY125,000 to approx mate y JPY550,000,000.

MJKK and MSFJ a so ma nta n po c es and procedures to address Japanese regu atory requ rements.

nationalgrid

Jennifer Brooks Hutchinson
Senior Counsel

October 6, 2021

VIA ELECTRONIC MAIL

Luly E. Massaro, Division Clerk
Rhode Island Division of Public Utilities and Carriers
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket D-21-09 – Petition of PPL Corporation, PPL Rhode Island Holdings, LLC, National Grid USA, and The Narragansett Electric Company for Authority to Transfer Ownership of The Narragansett Electric Company to PPL Rhode Island Holdings, LLC and Related Approvals
<u>Responses to Division Advocacy Section Data Requests – Set 8</u>

Dear Ms. Massaro:

On behalf of National Grid USA and The Narragansett Electric Company (together, "National Grid"), enclosed is National Grid's response to Division 8-15 of the eighth set of data requests issued by the Rhode Island Division of Public Utilities and Carriers ("Division") Advocacy Section (the "Advocacy Section") in the above-referenced proceeding.[1]

This transmittal completes National Grid's responses to the Advocacy Section's Set 8.

Thank you for your attention to this matter. If you have any questions, please contact me at 401-784-7288.

Very truly yours,

Jennifer Brooks Hutchinson

[1] Although this is a Division filing, consistent with Public Utilities Commission's filing requirements during the COVID-19 emergency period, National Grid is submitting an electronic version of this filing. National Grid will provide the Division Clerk with five hard copies within 24 hours and, if needed, additional hard copies of the enclosures upon request.

280 Melrose Street, Providence, RI 02907
T: 401-784-7288 ■ jennifer.hutchinson@nationalgrid.com ■ www.nationalgrid.com

Enclosures

cc: Docket D-21-09 Service List (electronic only)
John Bell, Division
Leo Wold, Esq.
Christy Hetherington, Esq.
Scott H. Strauss, Esq. (electronic only)
Latif M. Nurani, Esq. (electronic only)
Amber L. Martin Stone, Esq. (electronic only)
Anree G. Little, Esq. (electronic only)

National Grid USA and The Narragansett Electric Company
Division 8-15

Request:

Please provide Narragansett's balance sheet (with footnotes) as of June 30, 2021.

Response:

Please refer to Attachment NG-DIV 8-15-1 for The Narragansett Electric Company's ("Narragansett") balance sheet as of June 30, 2021. Note, however, the June 30 financial statements are quarterly statements that are unaudited and do not include footnotes. Footnotes are included for calendar year and fiscal year financial statements. Please refer to Attachment NG-DIV 8-15-2 for Narragansett's audited balance sheet (with footnotes) as of the most recent fiscal year end, March 31, 2021.

nationalgrid

The Narragansett Electric Company

Financial Statements

For the three months ended June 30, 2021, 2020 and 2019

(Unaudited)

THE NARRAGANSETT ELECTRIC COMPANY

FINANCIAL STATEMENTS

FOR THE THREE MONTHS ENDED

JUNE 30, 2021
(unaudited)

I hereby certify that I am Vice-President, NE Controller of The Narragansett Electric Company and that the enclosed financial statements for the three months ended June 30, 2021, have been prepared in accordance with generally accepted accounting principles, and are, in my opinion, correct, subject to year-end audit adjustments and footnote disclosure. These financial statements should be read in conjunction with the audited financial statements for the year ended March 31, 2021.

Christopher McCusker, Vice-President, NE Controller

9/27/2021
Date

THE NARRAGANSETT ELECTRIC COMPANY
STATEMENTS OF INCOME
(unaudited, in thousands of dollars)

	Three Months Ended June 30,		
	2021	2020	2019
Operating revenues	**$ 341,035**	$ 325,567	$ 335,948
Operating expenses:			
Purchased electricity	**73,836**	80,591	92,971
Purchased gas	**26,144**	26,457	27,246
Operations and maintenance	**146,043**	113,595	113,778
Depreciation	**35,064**	30,909	28,804
Other taxes	**32,816**	33,133	32,170
Total operating expenses	**313,903**	284,685	294,969
Operating income	**27,132**	40,882	40,979
Other income and (deductions):			
Interest on long-term debt	**(15,749)**	(15,529)	(13,850)
Other interest, including affiliate interest, net	**59**	(718)	(756)
Other income, net	**1,341**	4,339	2,263
Total other deductions, net	**(14,349)**	(11,908)	(12,343)
Income before income taxes	**12,783**	28,974	28,636
Income tax expense	**1,349**	5,148	4,260
Net income	**$ 11,434**	$ 23,826	$ 24,376

THE NARRAGANSETT ELECTRIC COMPANY
STATEMENTS OF CASH FLOWS
(unaudited, in thousands of dollars)

	Three Months Ended June 30,		
	2021	2020	2019
Operating activities:			
Net income	**$ 11,434**	$ 23,826	$ 24,376
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation	**35,064**	30,909	28,804
Regulatory amortizations	**107**	107	107
Deferred income tax (benefit) expense	**3,040**	2,479	4,321
Bad debt expense	**25,360**	8,252	2,054
Amortization of debt discount and issuance costs	**158**	154	118
Pension and postretirement benefits expenses, net	**(1,106)**	(307)	684
Pension and postretirement benefits contributions	**(1,871)**	(1,093)	(1,127)
Environmental remediation payments	**(4,842)**	(414)	(600)
Changes in operating assets and liabilities:			
Accounts receivable, net and unbilled revenues	**32,193**	7,453	75,861
Accounts receivable from/payable to affiliates, net	**(17,283)**	(13,095)	(5,420)
Inventory	**(1,511)**	(56)	(2,582)
Regulatory assets and liabilities, net	**19,925**	(1,341)	(27,826)
Derivative instruments	**(21,611)**	(1,625)	11,301
Prepaid and accrued taxes	**(6,666)**	412	(211)
Accounts payable and other liabilities	**(4,930)**	(8,633)	(33,755)
Other, net	**(11,036)**	4,839	2,757
Net cash provided by operating activities	**56,425**	51,867	78,862
Investing activities:			
Capital expenditures	**(79,053)**	(69,777)	(75,049)
Intercompany money pool	**18,158**	(210,706)	-
Cost of removal	**(4,993)**	(6,646)	(8,423)
Financial Investments	**7,820**	(668)	(384)
Other	**1**	(2)	789
Net cash used in investing activities	**(58,067)**	(287,799)	(83,067)
Financing activities:			
Preferred stock dividends	**(28)**	(28)	(28)
Payments on long-term debt	**-**	(10,000)	-
Issuance of long-term debt	**-**	600,000	-
Payment of debt issuance costs	**-**	(2,834)	-
Intercompany money pool	**-**	(351,415)	1,409
Net cash (used) provided by financing activities	**(28)**	235,723	1,381
Net decrease in cash, cash equivalents, restricted cash and special deposits	**(1,670)**	(209)	(2,824)
Cash, cash equivalents, restricted cash and special deposits, beginning of year	**6,356**	3,871	8,653
Cash, cash equivalents, restricted cash and special deposits, end of year	**$ 4,686**	$ 3,662	$ 5,829

THE NARRAGANSETT ELECTRIC COMPANY
BALANCE SHEETS
(unaudited, in thousands of dollars)

	June 30, 2021	March 31, 2021
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 4,300**	$ 5,990
Restricted cash and special deposits	**386**	366
Accounts receivable	**284,336**	314,047
Allowance for doubtful accounts	**(84,468)**	(63,390)
Accounts receivable from affiliates	**29,596**	17,386
Intercompany money pool	**140,392**	158,550
Unbilled revenues	**55,531**	62,295
Inventory	**35,462**	44,015
Regulatory assets	**63,413**	71,917
Derivative Instruments	**19,918**	5,010
Other	**9,123**	11,324
Total current assets	**557,989**	627,510
Property, plant and equipment, net	**3,796,857**	3,734,291
Non-current assets:		
Regulatory assets	**453,896**	451,963
Goodwill	**724,810**	724,810
Other	**28,833**	30,038
Total non-current assets	**1,207,539**	1,206,811
Total assets	**$ 5,562,385**	$ 5,568,612

THE NARRAGANSETT ELECTRIC COMPANY
BALANCE SHEETS
(unaudited, in thousands of dollars)

	June 30, 2021	March 31, 2021
LIABILITIES AND CAPITALIZATION		
Current liabilities:		
Accounts payable	**$ 137,026**	$ 147,033
Accounts payable to affiliates	**55,314**	60,387
Current portion of long-term debt	**1,375**	1,375
Taxes accrued	**48,478**	55,149
Customer deposits	**11,958**	11,519
Interest accrued	**16,079**	16,072
Regulatory liabilities	**126,868**	108,573
Derivative instruments	**4,288**	6,084
Renewable energy certificate obligations	**11,360**	31,372
Environmental remediation costs	**20,828**	22,588
Other	**88,564**	77,453
Total current liabilities	**522,138**	537,605
Other non-current liabilities:		
Regulatory liabilities	**564,412**	565,774
Asset retirement obligations	**9,437**	9,399
Deferred income tax liabilities, net	**396,943**	392,222
Environmental remediation costs	**87,759**	89,247
Other	**70,157**	74,419
Total other non-current liabilities	**1,128,708**	1,131,061
Capitalization:		
Shareholders' equity	**2,402,279**	2,390,844
Long-term debt	**1,509,260**	1,509,102
Total capitalization	**3,911,539**	3,899,946
Total liabilities and capitalization	**$ 5,562,385**	$ 5,568,612

THE NARRAGANSETT ELECTRIC COMPANY
STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(unaudited, in thousands of dollars)

				Accumulated Other Comprehensive Income (Loss)					
	Common Stock	Cumulative Preferred Stock	Additional Paid-in Capital	Unrealized Gain (Loss) on Available-For-Sale Securities	Pension and Other Postretirement Benefits	Hedging Activity	Total Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total
Balance as of March 31, 2019	$ 56,624	$ 2,454	$ 1,358,057	$ 23	$ 618	$ (2,719)	$ (2,078)	$ 640,481	$ 2,055,538
Net income	-	-	-	-	-	-	-	24,376	24,376
Other comprehensive income									
Unrealized gains on securities, net of $8 tax expense	-	-	-	30	-	-	30	-	30
Change in pension and other postretirement									
obligations, net of $5 tax benefit	-	-	-	-	17	-	17	-	17
Unrealized gains on hedges, net of $17 tax expense	-	-	-	-	-	63	63	-	63
Total comprehensive income									24,486
Preferred stock dividends	-	-	-	-	-	-	-	(28)	(28)
Impact of adoption of recognition and measurement of	-	-	-	-	-	-	-	-	-
financial assets and liabilities standard	-	-	-	8	(1,409)	(664)	(2,065)	2,065	-
Balance as of June 30, 2019	$ 56,624	$ 2,454	$ 1,358,057	$ 61	$ (774)	$ (3,320)	$ (4,033)	$ 666,894	$ 2,079,996
Balance as of March 31, 2020	$ 56,624	$ 2,454	$ 1,433,057	$ 189	$ (918)	$ (3,133)	$ (3,862)	$ 764,842	$ 2,253,115
Net income	-	-	-	-			-	23,826	23,826
Other comprehensive income									
Unrealized gains on securities, net of $13 tax benefit	-	-	-	(48)	-	-	(48)	-	(48)
Change in pension and other postretirement									
obligations, net of $5 tax expense	-	-	-	-	18	-	18	-	18
Unrealized gains on hedges, net of $11 tax expense	-	-	-	-	-	40	40	-	40
Total comprehensive income									23,836
Preferred stock dividends	-	-	-	-	-	-	-	(28)	(28)
Balance as of June 30, 2020	$ 56,624	$ 2,454	$ 1,433,057	$ 141	$ (900)	$ (3,093)	$ (3,852)	$ 788,640	$ 2,276,923
Balance as of March 31, 2021	$ 56,624	$ 2,454	$ 1,435,732	$ 204	$ (904)	$ (2,974)	(3,674)	$ 899,708	2,390,844
Net income	-	-	-	-			-	11,434	11,434
Other comprehensive income (loss)									
Unrealized losses on securities, net of $3 tax benefit	-	-	-	(10)	-	-	(10)	-	(10)
Change in pension and other postretirement									
obligations, net of $0 tax benefit	-	-	-	-	(1)	-	(1)	-	(1)
Unrealized gains on hedges, net of $11 tax expense	-	-	-	-	-	40	40	-	40
Total comprehensive income									11,463
Parent tax loss allocation	-	-	-	-	-	-	-	-	-
Preferred stock dividends	-	-	-	-	-	-	-	(28)	(28)
Balance as of June 30, 2021	$ 56,624	$ 2,454	$ 1,435,732	$ 194	$ (905)	$ (2,934)	$ (3,645)	$ 911,114	$ 2,402,279

The Company had 1,132,487 shares of common stock authorized, issued and outstanding, with a par value of $50 per share and 49,089 shares of cumulative preferred stock authorized, issued and outstanding, with a par value of $50 per share at June 30, 2021 and 2020.

The Narragansett Electric Company

Financial Statements

For the years ended March 31, 2021, 2020, and 2019

THE NARRAGANSETT ELECTRIC COMPANY

TABLE OF CONTENTS

Deloitte.

Deloitte & Touche LLP
30 Rockefeller Plaza
New York, NY 10112
USA

Tel: +1 212 492 4000
Fax: +1 212 489 1687
www.deloitte.com

INDEPENDENT AUDITORS' REPORT

To the Board of Directors of
The Narragansett Electric Company

We have audited the accompanying financial statements of The Narragansett Electric Company (the "Company"), which comprise the balance sheets and statements of capitalization as of March 31, 2021 and 2020 and the related statements of income, cash flows, and changes in shareholders' equity for each of the three years in the period ended March 31, 2021, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of The Narragansett Electric Company as of March 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended March 31, 2021 in accordance with accounting principles generally accepted in the United States of America.

Emphasis of Matter

As discussed in Note 1 and Note 5 to the financial statements, National Grid USA has agreed to sell 100 percent of the outstanding shares of common stock in the Company to PPL Rhode Island Holdings, LLC, a wholly owned indirect subsidiary of PPL Corporation. Our opinion is not modified with respect to this matter.

September 27, 2021

THE NARRAGANSETT ELECTRIC COMPANY
STATEMENTS OF INCOME
(in thousands of dollars)

	Years Ended March 31,		
	2021	2020	2019
Operating revenues	**$ 1,547,789**	$ 1,556,566	$ 1,556,597
Operating expenses:			
Purchased electricity	**360,686**	406,596	439,140
Purchased gas	**162,502**	158,387	173,829
Operations and maintenance	**520,548**	530,156	507,911
Depreciation	**133,770**	118,428	111,095
Other taxes	**142,387**	136,976	135,020
Total operating expenses	**1,319,893**	1,350,543	1,366,995
Operating income	**227,896**	206,023	189,602
Other income and (deductions):			
Interest on long-term debt	**(63,654)**	(55,433)	(51,573)
Other interest, including affiliate interest, net	**(1,930)**	(4,385)	(4,060)
Other income, net	**2,490**	3,096	468
Total other deductions, net	**(63,094)**	(56,722)	(55,165)
Income before income taxes	**164,802**	149,301	134,437
Income tax expense	**29,826**	26,895	24,001
Net income	**$ 134,976**	$ 122,406	$ 110,436

The accompanying notes are an integral part of these financial statements.

THE NARRAGANSETT ELECTRIC COMPANY
STATEMENTS OF CASH FLOWS
(in thousands of dollars)

	Years Ended March 31,		
	2021	2020	2019
Operating activities:			
Net income	$ **134,976**	$ 122,406	$ 110,436
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation	**133,770**	118,428	111,095
Regulatory amortizations	**426**	427	(1,580)
Deferred income tax	**10,657**	2,975	36,399
Bad debt expense	**33,140**	38,360	23,856
Amortization of debt discount and issuance costs	**630**	471	412
Pension and postretirement benefit expenses, net	**(1,510)**	1,562	(3,203)
Pension and postretirement benefit contributions	**(4,273)**	(4,542)	(12,294)
Environmental remediation payments	**(5,684)**	(1,932)	(1,847)
Changes in operating assets and liabilities:			
Accounts receivable, net and unbilled revenues	**(98,413)**	18,340	(35,717)
Accounts receivable from/payable to affiliates, net	**8,244**	2,692	42,975
Inventory	**1,160**	(526)	(4,406)
Regulatory assets and liabilities, net	**18,514**	(86,207)	66,431
Derivative instruments	**(7,935)**	15,089	(3,511)
Prepaid and accrued taxes	**6,240**	12,551	14,707
Accounts payable and other liabilities	**55,639**	(25,728)	30,294
Other, net	**14,558**	3,272	(15,375)
Net cash provided by operating activities	**300,139**	217,638	358,672
Investing activities:			
Capital expenditures	**(346,413)**	(314,935)	(305,013)
Intercompany money pool	**(158,550)**	-	-
Cost of removal	**(24,910)**	(26,043)	(26,652)
Other	**(2,042)**	175	(480)
Net cash used in investing activities	**(531,915)**	(340,803)	(332,145)
Financing activities:			
Common stock dividends to Parent	**-**	-	(85,250)
Preferred stock dividends	**(110)**	(110)	(110)
Payments on long-term debt	**(11,375)**	(251,375)	(15,839)
Issuance of long-term debt	**600,000**	-	350,000
Payment of debt issuance costs	**(2,839)**	-	(1,893)
Intercompany money pool	**(351,415)**	294,868	(271,647)
Equity infusion from Parent	**-**	75,000	-
Net cash provided by (used in) financing activities	**234,261**	118,383	(24,739)
Net increase (decrease) in cash, cash equivalents, restricted cash and special deposits	**2,485**	(4,782)	1,788
Cash, cash equivalents, restricted cash and special deposits, beginning of year	**3,871**	8,653	6,865
Cash, cash equivalents, restricted cash and special deposits, end of year	$ **6,356**	$ 3,871	$ 8,653
Supplemental disclosures:			
Interest paid	$ **(53,243)**	$ (55,612)	$ (50,639)
Income taxes (paid) refunded	**(220)**	(11,107)	15,746
Significant non-cash items:			
Capital-related accruals included in accounts payable	**11,070**	10,516	12,625
Parent tax loss allocation	**2,675**	-	-

The accompanying notes are an integral part of these financial statements.

THE NARRAGANSETT ELECTRIC COMPANY
BALANCE SHEETS
(in thousands of dollars)

	March 31, 2021	March 31, 2020
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 5,990**	$ 3,420
Restricted cash and special deposits	**366**	451
Accounts receivable	**314,047**	233,444
Allowance for doubtful accounts	**(63,390)**	(43,288)
Accounts receivable from affiliates	**17,386**	19,674
Intercompany moneypool asset	**158,550**	-
Unbilled revenues	**62,295**	57,523
Inventory	**44,015**	41,702
Regulatory assets	**71,917**	98,179
Derivative instruments	**5,010**	154
Other	**11,324**	2,873
Total current assets	**627,510**	414,132
Property, plant and equipment, net	**3,734,291**	3,470,757
Non-current assets:		
Regulatory assets	**451,963**	513,869
Goodwill	**724,810**	724,810
Other	**30,038**	41,318
Total non-current assets	**1,206,811**	1,279,997
Total assets	**$ 5,568,612**	$ 5,164,886

The accompanying notes are an integral part of these financial statements.

THE NARRAGANSETT ELECTRIC COMPANY
BALANCE SHEETS
(in thousands of dollars)

	March 31, 2021	March 31, 2020
LIABILITIES AND CAPITALIZATION		
Current liabilities:		
Accounts payable	**$ 147,033**	$ 139,474
Accounts payable to affiliates	**60,387**	54,431
Intercompany moneypool liability	**-**	351,415
Current portion of long-term debt	**1,375**	11,375
Taxes accrued	**55,149**	43,022
Customer deposits	**11,519**	11,733
Interest accrued	**16,072**	6,676
Regulatory liabilities	**108,573**	94,664
Derivative instruments	**6,084**	11,768
Renewable energy certificate obligations	**31,372**	19,878
Environmental remediation costs	**22,588**	13,938
Other	**77,453**	43,662
Total current liabilities	**537,605**	802,036
Other non-current liabilities:		
Regulatory liabilities	**565,774**	556,768
Asset retirement obligations	**9,399**	9,738
Deferred income tax liabilities, net	**392,222**	367,318
Postretirement benefits	**32,420**	122,176
Environmental remediation costs	**89,247**	105,841
Other	**41,999**	35,208
Total other non-current liabilities	**1,131,061**	1,197,049
Commitments and contingencies (Note 13)		
Capitalization:		
Shareholders' equity	**2,390,844**	2,253,115
Long-term debt	**1,509,102**	912,686
Total capitalization	**3,899,946**	3,165,801
Total liabilities and capitalization	**$ 5,568,612**	$ 5,164,886

The accompanying notes are an integral part of these financial statements.

THE NARRAGANSETT ELECTRIC COMPANY
STATEMENTS OF CAPITALIZATION
(in thousands of dollars)

			March 31,	
			2021	2020
Total shareholders' equity			**$ 2,390,844**	$ 2,253,115
Long-term debt:	Interest Rate	Maturity Date		
Unsecured notes:				
Senior Notes	5.64%	March 15, 2040	**300,000**	300,000
Senior Notes	4.17%	December 10, 2042	**250,000**	250,000
Senior Notes	3.92%	August 1, 2028	**350,000**	350,000
Senior Notes	3.40%	April 9, 2030	**600,000**	-
			1,500,000	900,000
First Mortgage Bonds ("FMB"):				
FMB Series N	9.63%	May 30, 2020	**-**	10,000
FMB Series O	8.46%	September 30, 2022	**12,500**	12,500
FMB Series P	8.09%	September 30, 2022	**1,250**	1,875
FMB Series R	7.50%	December 15, 2025	**3,750**	4,500
			17,500	28,875
Total debt			**1,517,500**	928,875
Unamortized debt discount			**(1,551)**	(1,646)
Unamortized debt issuance costs			**(5,472)**	(3,168)
Total debt less unamortized costs			**1,510,477**	924,061
Current portion of long-term debt			**1,375**	11,375
Total long-term debt			**1,509,102**	912,686
Total capitalization			**$ 3,899,946**	$ 3,165,801

The accompanying notes are an integral part of these financial statements.

THE NARRAGANSETT ELECTRIC COMPANY
STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(in thousands of dollars)

				Accumulated Other Comprehensive Income (Loss)					
	Common Stock	Cumulative Preferred Stock	Additional Paid-in Capital	Unrealized Gain (Loss) on Available-For-Sale Securities	Pension and Other Postretirement Benefits	Hedging Activity	Total Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total
Balance as of March 31, 2018	**$ 56,624**	**$ 2,454**	**$ 1,358,057**	**$ 931**	**$ 1,301**	**$ (2,973)**	**$ (741)**	**$ 614,509**	**$ 2,030,903**
Net income	-	-	-	-	-	-	-	110,436	110,436
Other comprehensive income (loss):									
Unrealized loss on securities, net of $3 tax benefit	-	-	-	(12)	-	-	(12)	-	(12)
Change in pension and other postretirement obligations, net of $182 tax benefit	-	-	-	-	(683)	-	(683)	-	(683)
Unrealized gains on hedges, net of $67 tax expense	-	-	-	-	-	254	254	-	254
Total comprehensive income									109,995
Common stock dividends to Parent	-	-	-	-	-	-	-	(85,250)	(85,250)
Preferred stock dividends	-	-	-	-	-	-	-	(110)	(110)
Impact of adoption of recognition and measurement of financial assets and liabilities standard	-	-	-	(896)	-	-	(896)	896	-
Balance as of March 31, 2019	**$ 56,624**	**$ 2,454**	**$ 1,358,057**	**$ 23**	**$ 618**	**$ (2,719)**	**$ (2,078)**	**$ 640,481**	**$ 2,055,538**
Net income	-	-	-	-			-	122,406	122,406
Other comprehensive income (loss):									
Unrealized gain on securities, net of $42 tax expense	-	-	-	158	-	-	158	-	158
Change in pension and other postretirement obligations, net of $34 tax benefit	-	-	-	-	(127)	-	(127)	-	(127)
Unrealized gains on hedges, net of $66 tax expense	-	-	-	-	-	250	250	-	250
Total comprehensive income									122,687
Equity infusion from Parent	-	-	75,000	-	-	-	-	-	75,000
Preferred stock dividends	-	-	-	-	-	-	-	(110)	(110)
Impact of adoption of reclassification of certain tax from accumulated other comprehensive income standard	-	-	-	8	(1,409)	(664)	(2,065)	2,065	-
Balance as of March 31, 2020	**$ 56,624**	**$ 2,454**	**$ 1,433,057**	**$ 189**	**$ (918)**	**$ (3,133)**	**$ (3,862)**	**$ 764,842**	**$ 2,253,115**
Net income	-	-	-	-			-	134,976	134,976
Other comprehensive income:									
Unrealized gain on securities, net of $4 tax expense	-	-	-	15	-	-	15	-	15
Change in pension and other postretirement obligations, net of $4 tax expense	-	-	-	-	14	-	14	-	14
Unrealized gains on hedges, net of $42 tax expense	-	-	-	-	-	159	159	-	159
Total comprehensive income									135,164
Parent tax loss allocation	-	-	2,675	-	-	-	-	-	2,675
Preferred stock dividends	-	-	-	-	-	-	-	(110)	(110)
Balance as of March 31, 2021	**$ 56,624**	**$ 2,454**	**$ 1,435,732**	**$ 204**	**$ (904)**	**$ (2,974)**	**$ (3,674)**	**$ 899,708**	**$ 2,390,844**

The Company had 1,132,487 shares of common stock authorized, issued and outstanding, with a par value of $50 per share and 49,089 shares of cumulative preferred stock authorized, issued and outstanding, with a par value of $50 per share at March 31, 2021 and 2020.

THE NARRAGANSETT ELECTRIC COMPANY
NOTES TO THE FINANCIAL STATEMENTS

1. NATURE OF OPERATIONS AND BASIS OF PRESENTATION

The Narragansett Electric Company ("the Company") is a retail distribution company providing electric service to approximately 509,000 customers and gas service to approximately 274,000 customers in 38 cities and towns in Rhode Island. The Company's service area covers substantially all of Rhode Island.

The Company is a wholly-owned subsidiary of National Grid USA ("NGUSA" or the "Parent"), a public utility holding company with regulated subsidiaries engaged in the generation of electricity and the transmission, distribution, and sale of both natural gas and electricity. NGUSA is a direct wholly-owned subsidiary of National Grid North America Inc. ("NGNA") and an indirect wholly-owned subsidiary of National Grid plc, a public limited company incorporated under the laws of England and Wales.

On March 18, 2021 it was announced that the Company will be sold to PPL Corporation, as part of a transaction with National Grid PLC in which National Grid PLC will acquire PPL Corporation's Western Power Distribution. The expected sale proceeds is $3.8 billion, and the sale is expected to be completed in March 2022 once all regulatory approvals are obtained.

The accompanying financial statements are prepared in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP"), including the accounting principles for rate-regulated entities. The financial statements reflect the ratemaking practices of the applicable regulatory authorities.

The novel coronavirus ("COVID-19") pandemic has disrupted the U.S. and global economies and continues to have a significant impact on global health. In March 2020, COVID-19 was declared a pandemic by the World Health Organization ("WHO") and the Centers for Disease Control and Prevention. In March 2020, the Company ceased certain customer cash collection activities in response to regulatory instructions and to changes in State, Federal and City level regulations and guidance, and actions to minimize risk to employees. The Company has also ceased customer termination activities as requested by relevant local authorities.

The Company has seen adverse impacts from COVID-19 on earnings and cash flow. Earnings are impacted by increased incremental costs, increased bad debt expense, lower capitalization rates of workforce costs, and reduced late payment revenues, slightly offset by reduced costs and other mitigation efforts by the Company. Cash flow is negatively impacted by the higher level of operating costs, and lower cash collections from customers because of the moratorium on disconnections and the economic slowdown resulting from the COVID-19 pandemic, including: (1) increase in aged receivables and bad debt expenses, (2) lost revenue from unassessed late payment charges, and (3) changes to the Company for other fees that the Company has waived pursuant to the PUC's orders. As of March 31, 2021, the Company recorded additional reserves for uncollectible accounts related to the COVID-19 pandemic's impact on the Company's electric and gas businesses.

Despite the negative impacts on cash flow, the Company has maintained access to National Grid's money pool, which has insulated the Company from immediate impacts on liquidity. Similarly, there has also been no impact on access to capital at present.

The Company has evaluated subsequent events and transactions through September 27, 2021, the date of issuance of these financial statements, and concluded that there were no events or transactions that require adjustment to, or disclosure in, the financial statements as of and for the year ended March 31, 2021. The Company continues to evaluate the ongoing impact of COVID-19 on both customers and financial performance and is complying with the request from the Rhode Island Public Utilities Commission ("RIPUC") to share relevant information.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

In preparing financial statements that conform to U.S. GAAP, the Company must make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, and expenses, and the disclosure of contingent assets and liabilities included in the financial statements. Such estimates and assumptions include the impact of the ongoing COVID-19 pandemic and are reflected in the accompanying financial statements. Actual results could differ from those estimates.

Regulatory Accounting

The Federal Energy Regulatory Commission ("FERC"), the RIPUC, and the Rhode Island Division of Public Utilities and Carriers ("Division") regulate the rates the Company charges its customers. In certain cases, the rate actions of the FERC, RIPUC and Division can result in accounting that differs from non-regulated companies. In these cases, the Company defers costs (as regulatory assets) or recognizes obligations (as regulatory liabilities) if it is probable that such amounts will be recovered from, or refunded to, customers through future rates. In accordance with Accounting Standards Codification ("ASC") 980, "Regulated Operations," regulatory assets and liabilities are reflected on the balance sheet consistent with the treatment of the related costs in the ratemaking process.

Revenue Recognition

Revenues are recognized for energy service billed on a monthly cycle basis, together with unbilled revenues for the estimated amount of services rendered from the time meters were last read to the end of the accounting period (See Note 3, "Revenue" for additional details).

Other Taxes

The Company collects taxes and fees from customers such as sales taxes, other taxes, surcharges, and fees that are levied by state or local governments on the sale or distribution of gas and electricity. The Company accounts for taxes that are imposed on customers (such as sales taxes) on a net basis (excluded from revenues), while taxes imposed on the Company, such as excise taxes, are recognized on a gross basis. Excise taxes collected and expected to be paid for the years ended March 31, 2021, 2020, and 2019 were $54.7 million, $54.8 million, and $54.9 million, respectively.

The Company's policy is to accrue for property taxes on a calendar year basis.

Income Taxes

Federal income taxes have been computed utilizing the asset and liability approach that requires the recognition of deferred tax assets and liabilities for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. Deferred income taxes also reflect the tax effect of net operating losses, capital losses, and general business credit carryforwards. The Company assesses the available positive and negative evidence to estimate whether enough future taxable income of the appropriate tax character will be generated to realize the benefits of existing deferred tax assets. When the evaluation of the evidence indicates that the Company will not be able to realize the benefits of existing deferred tax assets, a valuation allowance is recorded to reduce existing deferred tax assets to the net realizable amount.

The effects of tax positions are recognized in the financial statements when it is more likely than not that the position taken, or expected to be taken, in a tax return will be sustained upon examination by taxing authorities based on the technical merits of the position. The financial effect of changes in tax laws or rates is accounted for in the period of enactment. Deferred investment tax credits are amortized over the useful life of the underlying property.

NGNA files consolidated federal tax returns including all of the activities of its subsidiaries. Each subsidiary determines its tax provision based on the separate return method, modified by a benefits-for-loss allocation pursuant to a tax sharing agreement between NGNA and its subsidiaries. The benefit of consolidated tax losses and credits are allocated to the NGNA subsidiaries giving rise to such benefits in determining each subsidiary's tax expense in the year that the loss or credit arises. In a year that a consolidated loss or credit carryforward is utilized, the tax benefit utilized in consolidation is paid proportionately to the subsidiaries that gave rise to the benefit regardless of whether that subsidiary would have utilized the benefit. The tax sharing agreement also requires NGNA to allocate its parent tax losses, excluding deductions from acquisition indebtedness, to each subsidiary in the consolidated federal tax return with taxable income. The allocation of NGNA's parent tax losses to its subsidiaries is accounted for as a capital contribution and is performed in conjunction with the annual intercompany cash settlement process following the filing of the federal tax return.

Cash and Cash Equivalents

Cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less. Cash and cash equivalents are carried at cost which approximates fair value.

Restricted Cash and Special Deposits

Restricted cash and special deposits consists of collateral paid to the Company's counterparties for outstanding derivative instruments. The Company had restricted cash and special deposits of $0.4 million and $0.5 million as of March 31, 2021 and 2020, respectively.

Accounts Receivable and Allowance for Doubtful Accounts

The Company recognizes an allowance for doubtful accounts to record accounts receivable at estimated net realizable value. The allowance is determined based on a variety of factors including, for each type of receivable, applying an estimated reserve percentage to each aging category, taking into account historical collection and write-off experience, and management's assessment of collectability from individual customers, as appropriate. The collectability of receivables is continuously assessed and, if circumstances change, the allowance is adjusted accordingly. Receivable balances are written off against the allowance for doubtful accounts when the accounts are disconnected and/or terminated and the balances are deemed to be uncollectible. The Company recorded bad debt expense of $33.1 million, $38.4 million and $23.9 million for the years ended March 31, 2021, 2020 and 2019, respectively, within operation and maintenance expenses in the accompanying statements of income. For the years ended March 31, 2021 and 2020, bad debt expense reflects the estimated impact of COVID-19.

Inventory

Inventory is composed of materials and supplies, purchased Renewable Energy Certificates ("RECs"), and gas in storage. Materials and supplies are stated at weighted average cost, which represents net realizable value, and are expensed or capitalized as used. Purchased RECs are stated at cost. There were no significant write-offs of obsolete inventory for the years ended March 31, 2021, 2020, or 2019.

Gas in storage is stated at weighted average cost and the related cost is recognized when delivered to customers. Existing rate orders allow the Company to pass directly through to customers the cost of gas purchased, along with any applicable authorized delivery surcharge adjustments. Gas costs passed through to customers are subject to regulatory approvals and are reported periodically to the RIPUC.

The Company had materials and supplies of $12.8 million and $12.0 million, purchased RECs of $22.0 million and $18.5 million, and gas in storage of $9.3 million and $11.2 million as of March 31, 2021 and 2020, respectively.

Renewable Energy Standard Obligation

RECs are stated at cost and are used to measure compliance with State renewable energy standards. RECs support new renewable generation standards and are held primarily to be utilized in fulfillment of the Company's compliance obligations. As of March 31, 2021, and 2020, the Company recorded a renewable energy standard obligation of $31.4 million and $19.9 million, respectively, within renewable energy certificate obligations.

Derivative Instruments

The Company uses derivative instruments to manage commodity price risk. All derivative instruments, except those that qualify for the normal purchase normal sale exception, are recorded on the balance sheet at fair value. All commodity costs, including the impact of derivative instruments, are passed on to customers through the Company's commodity rate adjustment mechanisms. Regulatory assets or regulatory liabilities are recorded to defer the recognition of unrealized losses or gains on derivative instruments, respectively. The gains or losses on the settlement of these contracts are recognized as purchased gas on the statements of income and then refunded to, or collected from, customers consistent with regulatory requirements.

The Company has certain non-trading instruments for the physical purchase of electricity that qualify for the normal purchase normal sale exception and are accounted for upon settlement. If the Company were to determine that a contract no longer qualifies for the normal purchase normal sale exception, then the Company would recognize the fair value of the contract and account for the gains and losses using the regulatory accounting described above.

The Company's accounting policy is to not offset fair value amounts recognized for derivative instruments and related cash collateral receivable or payable with the same counterparty under a master netting agreement, but rather to record and present the fair value of the derivative instrument on a gross basis, with related cash collateral recorded within restricted cash and special deposits on the balance sheet.

Fair Value Measurements

The Company measures derivative instruments, securities and pension and postretirement benefit other than pension plan assets at fair value. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The following is the fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value:

- Level 1: quoted prices (unadjusted) in active markets for identical assets or liabilities that a company has the ability to access as of the reporting date;
- Level 2: inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data;
- Level 3: unobservable inputs, such as internally-developed forward curves and pricing models for the asset or liability due to little or no market activity for the asset or liability with low correlation to observable market inputs; and
- Not categorized: Investments in certain funds, that meet certain conditions of ASC 820, are not required to be categorized within the fair value hierarchy. These investments are typically in commingled funds or limited partnerships that are not publicly traded and have ongoing subscription and redemption activity. As a practical expedient, the fair value of these investments is the Net Asset Value ("NAV") per fund share.

The asset or liability's fair value measurement level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. The Company uses valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

Property, Plant and Equipment

Property, plant and equipment is stated at original cost. The capitalized cost of additions to property, plant and equipment includes costs such as direct material, labor and benefits, and an allowance for funds used during construction ("AFUDC"). The cost of repairs and maintenance is charged to expense and the cost of renewals and betterments that extend the useful life of property, plant and equipment is capitalized.

Depreciation is computed over the estimated useful life of the asset using the composite straight-line method. Depreciation studies are conducted periodically to update the composite rates and are approved by the FERC and RIPUC. The average composite rates for the years ended March 31, 2021, 2020 and 2019 are as follows:

	Composite Rates		
	March 31,		
	2021	2020	2019
Electric	**3.0%**	2.9%	3.0%
Gas	**3.1%**	3.1%	3.4%

Depreciation expense includes a component for the estimated cost of removal, which is recovered through rates charged to customers. Any difference in cumulative costs recovered and costs incurred is recognized as a regulatory liability. When property, plant and equipment is retired, the original cost, less salvage, is charged to accumulated depreciation, and the related cost of removal is removed from the associated regulatory liability. The Company recognized a regulatory liability for the amount that was in excess of costs incurred of $238.9 million and $226.3 million as of March 31, 2021 and 2020, respectively.

Allowance for Funds Used During Construction

The Company records AFUDC, which represents the debt and equity costs of financing the construction of new property, plant and equipment. The equity component of AFUDC is reported in the accompanying statements of income as non-cash income in other income, net. The debt component of AFUDC is reported as a non-cash offset to other interest, including affiliate interest. After construction is completed, the Company is permitted to recover these costs through their inclusion in rates. The Company recorded AFUDC related to equity of $5.8 million, $1.7 million, and $4.3 million, and AFUDC related to debt of $2.3 million, $2.0 million, and $2.5 million, for the years ended March 31, 2021, 2020, and 2019, respectively. The average AFUDC rates for the years ended March 31, 2021, 2020, and 2019 were 7.5%, 4.4%, and 5.7% respectively.

Impairment of Long-Lived Assets

The Company tests the impairment of long-lived assets when events or changes in circumstances indicate that the carrying amount of the asset (or asset group) may not be recoverable. If identified, the recoverability of an asset is determined by comparing its carrying value to the estimated undiscounted cash flows that the asset is expected to generate. If the comparison indicates that the carrying value is not recoverable, an impairment loss is recognized for the excess of the carrying value over the estimated fair value. For the years ended March 31, 2021, 2020, and 2019, there were no impairment losses recognized for long-lived assets.

Goodwill

The Company tests goodwill for impairment annually on January 1, or more frequently if events occur or circumstances exist that indicate it is more likely than not that the fair value of the Company is below its carrying amount. The Company has early adopted Accounting Standards Update ("ASU") No. 2017-04, "Intangibles—Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment," which eliminates step two from the two-step goodwill impairment test previously required under the former standard. The goodwill impairment test requires a recoverability test performed based on the comparison of the Company's estimated fair value with its carrying value, including goodwill. If the estimated fair value exceeds the carrying value, then goodwill is not considered impaired. If the carrying value exceeds the estimated fair value, the Company is required to recognize an impairment charge for such excess, limited to the carrying amount of goodwill.

The Company elected to perform a qualitative assessment to determine whether it is more likely than not that the carrying value of the Company exceeds its estimated fair value and an impairment exists. The qualitative assessment is commonly referred to as the "Step 0" test and requires the Company to evaluate relevant events and circumstances including, but not limited to, macroeconomic conditions, industry and market considerations, cost factors, and other relevant entity-specific events that may indicate the existence of a decline in fair value that is other than temporary. The qualitative assessment indicated that it was more likely than not that the fair value of the Company exceeds its carrying value and, as such, no impairment loss exists for the year ended March 31, 2021. The Company did not record any goodwill impairment during the years ended March 31, 2021, 2020 and 2019.

Employee Benefits

The Company participates with other NGUSA subsidiaries in defined benefit pension plans and postretirement benefit other than pension ("PBOP") plans for its employees, administered by NGUSA. The Company recognizes its portion of the pension and PBOP plans' funded status on the balance sheet as a net liability or asset. The cost of providing these plans is recovered through rates; therefore, the net funded status is offset by a regulatory asset or liability. The pension and PBOP plans' assets are commingled and allocated to measure and record pension and PBOP funded status at each year-end date. Pension and PBOP plan assets are measured at fair value, using the year-end market value of those assets.

Supplemental Executive Retirement Plans

The Company has corporate assets included in other non-current assets on the balance sheet representing funds designated for Supplemental Executive Retirement Plans, nonqualified retirement and deferred compensation benefits. These funds are invested in corporate owned life insurance policies and securities primarily consisting of equity investments and investments in municipal and corporate bonds. The corporate owned life insurance investments are measured at cash surrender value or at fair value, with increases and decreases in the value of these assets recorded in the accompanying statements of income.

Leases

The Company adopted Topic 842 during the year ended March 31, 2020. The Company elected the practical expedient "package" in which any expired contracts were not reassessed to determine whether they met the definition of a lease; classification of leases that commenced prior to the adoption of this standard was not reassessed; and any initial direct costs for existing leases were not reassessed. Additionally, the Company elected the practical expedient to not reassess existing easements that were not previously accounted for as leases under Topic 840.

The Company has elected to not evaluate whether sales tax and other similar taxes are lessor and lessee costs. Instead, such costs are deemed lessee costs. The Company does not combine lease and non-lease components for contracts in which the Company is the lessee or the lessor.

Certain building leases provide the Company with an option to extend the lease term. The Company has included the periods covered by an extension options in its determination of the lease term when management believes it is reasonably certain the Company will exercise its option.

Lease liabilities are recognized based on the present value of the lease payments over the lease term at the commencement date. For any leases that do not provide an implicit rate, the Company uses an estimate of its collateralized incremental borrowing rate based on the information available at the commencement date to determine the present value of future payments. In measuring lease liabilities, the Company excludes variable lease payments, other than those that depend on an index or a rate, or are in substance fixed payments, and includes lease payments made at or before the commencement date. Variable lease payments were not material for the years ended March 31, 2021 and 2020. The Company does not reflect short-term leases on the balance sheets. Expense related to short-term leases was not material for the years ended March 31, 2021 and 2020.

Right-of-use assets consist of the lease liability, together with any payments made to the lessor prior to commencement of the lease (less any lease incentives) and any initial direct costs. Right-of-use assets are amortized over the lease term.

The Company recognizes lease expense based on a pattern that conforms to the regulatory ratemaking treatment.

New and Recent Accounting Guidance

Accounting Guidance Recently Adopted

Fair Value

In August 2018, the Financial Accounting Standards Board ("FASB") issued ASU No. 2018-13 "Fair Value Measurement (Topic 820): Disclosure Framework–Changes to the Disclosure Requirements for Fair Value Measurement" which modifies certain disclosure requirements on fair value measurements in Topic 820, Fair Value Measurement, including certain disclosure requirements relating to Level 3 fair value measurements, and eliminates disclosure requirements for transfers between Level 1 and Level 2 fair value measurements. The standard also added certain other disclosure requirements for Level 3 fair value measurements. The Company adopted this new guidance on April 1, 2020 requiring certain revisions to disclosures related to recurring fair value measurements in Note 8, "Fair Value Measurements. Upon adoption, the amendments in the standard were applied retrospectively to all periods presented, except the amendments on changes in unrealized gains and losses, the range and weighted average of significant unobservable inputs used to develop Level 3 fair value measurements, and the narrative description of measurement uncertainty, which were applied prospectively for only the most recent annual period presented. The amendments did not materially affect the Company's disclosures and did not affect the Company's financial position, results of operations, or cash flows.

Pension and Postretirement Benefits

In August 2018, the FASB issued ASU No. 2018-14 "Compensation—Retirement Benefits—Defined Benefit Plans—General (Subtopic 715-20): Disclosure Framework—Changes to the Disclosure Requirements for Defined Benefit Plans," which modifies the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans and eliminates certain disclosure requirements. The Company adopted this new guidance on April 1, 2020 using a retrospective basis to all periods presented, resulting in certain revisions to disclosures related to the Company's defined benefit plans in Note 9, "Employee Benefits". The amendments did not materially affect the Company's disclosures related to its defined benefit postretirement benefit plans and did not affect the Company's financial position, results of operations, or cash flows.

Internal-Use Software

In August 2018, the FASB issued ASU No. 2018-15 "Intangibles–Goodwill and Other–Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that Is a Service Contract" to help entities evaluate the accounting for fees paid by a customer under a cloud computing arrangement that is a service contract. The amendment aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. Under this standard, the Company applies Subtopic 350-40 to determine which implementation costs related to a hosting arrangement should be capitalized or expensed. The Company expenses the capitalized implementation costs of a hosting arrangement that is a service contract over the term of the arrangement. The Company adopted this new guidance prospectively on April 1, 2020. The amendments did not materially impact the Company's financial position, results of operations, or cash flows.

Accounting Guidance Not Yet Adopted

Income Taxes

In December 2019, the FASB issued ASU No. 2019-12 "Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes" which simplifies various aspects of the accounting for income taxes by eliminating certain exceptions to current requirements. The standard also enhances and simplifies other requirements, including tax basis step-up in goodwill obtained in a transaction that is not a business combination, ownership changes in investments, and interim-period accounting for enacted changes in tax law. For public business entities, the standard is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2020. For all other entities, the standard is effective for fiscal years beginning after December 15, 2021, and interim periods within fiscal years beginning after December 15, 2022. Early adoption is permitted.

The Company plans to early adopt this standard on April 1, 2021, and interim periods within. The Company does not expect the adoption to have a material impact on its financial statements.

Investments – Equity Securities

In January 2020, the FASB issued ASU No. 2020-01 "Investments—Equity Securities (Topic 321), Investments—Equity Method and Joint Ventures (Topic 323), and Derivatives and Hedging (Topic 815): Clarifying the Interactions between Topic 321, Topic 323, and Topic 815 (a consensus of the FASB Emerging Issues Task Force)" which clarifies that an entity should consider transaction prices for purposes of measuring the fair value of certain equity securities immediately before applying or upon discontinuing the equity method. This accounting standard also clarifies that when accounting for contracts entered into to purchase equity securities, an entity should not consider whether, upon the settlement of the forward contract or exercise of the purchased option, the underlying securities would be accounted for under the equity method or the fair value option. For public business entities, the standard is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2020. For all other entities, the standard is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2021. Early adoption is permitted. The Company plans to early adopt this standard on April 1, 2021, and interim periods within. The Company does not expect the adoption to have a material impact on its financial statements.

Callable Debt Securities

In October 2020, the FASB issued ASU No. 2020-08 "Codification Improvements to Subtopic 310-20, Receivables – Nonrefundable Fees and Other Costs" to clarify that an entity must reevaluate whether a callable debt security with multiple call dates is within the scope of paragraph ASC 310-20-35-33 for each reporting period such that the premium should be amortized over the period ending at the earliest call date. For public business entities, the standard is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2020. Early application is not permitted for public business entities. The Company will adopt this standard prospectively on April 1, 2021, and interim periods within. The Company does not expect the adoption to have a material impact on its financial statements.

Financial Instruments – Credit Losses

In June 2016, the FASB issued ASU No. 2016-13 "Financial Instruments–Credit Losses (Topic 326): Measurement of Credit Losses on Financial Statements" which requires a financial asset (or a group of financial assets) measured at amortized cost basis to be presented at the net amount expected to be collected. The accounting standard provides a new model for recognizing credit losses on financial instruments based on an estimate of current expected credit losses that replaces existing incurred loss impairment methodology requiring delayed recognition of credit losses. A broader range of reasonable and supportable information must be considered in developing estimates of credit losses. The allowance for credit losses is a valuation account that is deducted from the amortized cost basis of the financial asset(s) to present the net carrying value at the amount expected to be collected on the financial asset. Credit losses relating to available-for-sale debt securities should be recorded through an allowance for credit losses. In May 2019, the FASB issued ASU 2019-05, "Financial Instruments—Credit Losses (Topic 326): Targeted Transition Relief", permitting entities to irrevocably elect the fair value option for financial instruments that were previously recorded at amortized cost basis within the scope of Topic 326, except for held-to-maturity debt securities. For the Company, the requirements in these updates, as amended in November 2019 by ASU 2019-10 "Financial Instruments—Credit Losses (Topic 326), Derivatives and Hedging (Topic 815), and Leases (Topic 842): Effective Dates", will be effective for fiscal years beginning after December 15, 2022 (beginning April 1, 2023 for the Company), including interim periods within those fiscal years. The Company is currently assessing the application of this standard to determine if it will have a material impact on the presentation, results of operations, cash flows, and financial position of the Company.

Reclassifications

Certain reclassifications have been made to the financial statements to conform the prior period's balances to the current period's presentation. These reclassifications had no effect on reported income, statement of cash flows, total assets, or shareholders' equity as previously reported.

3. REVENUE

The following table presents, for the years ended March 31, 2021, 2020 and 2019, revenue from contracts with customers, as well as additional revenue from sources other than contracts with customers, disaggregated by major source:

	Years ended March 31		
	2021	2020	2019
		(in thousands of dollars)	
Revenue from contracts with customers:			
Electric services	**$ 1,135,865**	$ 1,055,161	1,130,618
Gas distribution	**457,123**	416,015	482,793
Total revenue from contracts with customers	**1,592,988**	1,471,176	1,613,411
Revenue from regulatory mechanisms	**(45,199)**	85,390	(56,814)
Total operating revenues	**$ $1,547,789**	$ 1,556,566	1,556,597

Electric Services and Gas Distribution: Revenue from contracts with customers, includes electric services and gas distribution. Electric services are comprised of electric distribution and transmission services.

The Company owns and maintains an electric and natural gas distribution network in Rhode Island. Distribution revenues are primarily from the sale of electricity, gas, and related services to retail customers. Distribution sales are regulated by the RIPUC, which is responsible for determining the prices and other terms of services as part of the rate making process. The arrangement where a utility provides a service to a customer in exchange for a price approved by a regulator is referred to as a tariff sales contract. Gas and electric distribution revenues are derived from the regulated sale and distribution of electricity and natural gas to residential, commercial, and industrial customers within the Company's service territory under the tariff rates. The tariff rates approved by the regulator are designed to recover the costs incurred by the Company for products and services provided and along with a return on investment.

The performance obligation related to distribution sales is to provide electricity and natural gas to customers on demand. The electricity and natural gas supplied under the respective tariff each represents a single performance obligation as it is a series of distinct goods or services that are substantially the same. The performance obligation is satisfied over time because the customer simultaneously receives and consumes the electricity or natural gas as the Company provides these services. The Company records revenues related to the distribution sales based upon the approved tariff rate and the volume delivered to the customers, which corresponds with the amount the Company has the right to invoice.

The distribution revenue also includes estimated unbilled amounts, which represent the estimated amounts due from retail customers for electricity and natural gas provided to customers by the Company, but not yet billed. Unbilled revenues are determined based on estimated unbilled sales volumes for the respective customer classes and then applying the applicable tariff rate to those volumes. Actual amounts billed to customers when the meter readings occur, may be different from the estimated amounts.

Certain customers have the option to obtain electricity or natural gas from other suppliers. In those circumstances, revenue is only recognized for providing delivery of the commodity to the customer.

Additionally, the Company owns an electric transmission system in Rhode Island. Transmission systems generally include overhead lines, underground cables, and substations, connecting generation and interconnectors to the distribution system. The Company's transmission services are regulated by both the Independent System Operator ("ISO") – New England and by the FERC. Additionally, the Company makes available its transmission facilities to New England Power ("NEP," an NGUSA affiliate), for operation and control pursuant to an integrated facilities agreement, Service Agreement No. 23 (Integrated Facilities Agreement or "IFA"). See Note 15 "Related Party Transactions" for additional details. These revenues arise under tariff/rate agreements and are collected primarily from the Company's Rhode Island distribution customers.

Revenue from Regulatory Mechanisms: The Company records revenues in accordance with accounting principles for rate-regulated operations for arrangements between the Company and the regulator, which are not accounted for as contracts with customers. These include various deferral mechanisms such as capital trackers, energy efficiency programs, and other programs that also qualify as Alternative Revenue Programs ("ARPs"). ARPs enable the Company to adjust rates in the future, in response to past activities or completed events. The Company's electric and gas distribution rates both have a revenue decoupling mechanism ("RDM"), which allows for annual adjustments to the Company's delivery rates as a result of the reconciliation between allowed revenue and billed revenue. The Company also has other ARPs related to the achievement of certain objectives, demand side management initiatives, and certain other rate making mechanisms. The Company recognizes ARPs with a corresponding offset to a regulatory asset or liability account when the regulatory specified events or conditions have been met, when the amounts are determinable, and are probable of recovery (or payment) through future rate adjustments.

4. REGULATORY ASSETS AND LIABILITIES

The Company records regulatory assets and liabilities that result from the ratemaking process. The following table presents the regulatory assets and regulatory liabilities recorded on the balance sheets:

	March 31, 2021	March 31, 2020
	(in thousands of dollars)	
Regulatory assets		
Current:		
Derivative instruments	**$ 6,221**	$ 14,157
Rate adjustment mechanisms	**52,648**	72,805
Renewable energy certificates	**9,416**	1,395
Revenue decoupling mechanism	**-**	8,474
Other	**3,632**	1,348
Total	**71,917**	98,179
Non-current:		
Environmental response costs	**110,009**	119,020
Net metering	**37,669**	26,252
Postretirement benefits	**122,878**	214,448
Storm costs	**131,382**	120,207
Other	**50,025**	33,942
Total	**$ 451,963**	$ 513,869
Regulatory liabilities		
Current:		
Energy efficiency	**$ 21,154**	$ 20,654
Gas cost adjustment	**-**	2,894
Rate adjustment mechanisms	**66,867**	44,561
Revenue decoupling mechanism	**14,448**	11,237
Transmission service	**4,491**	15,318
Other	**1,613**	-
Total	**108,573**	94,664
Non-current:		
Cost of removal	**238,863**	226,279
Energy efficiency	**36,330**	15,715
Environmental response costs	**16,155**	18,839
Regulatory tax liability, net	**258,705**	272,901
Other	**15,721**	23,034
Total	**$ 565,774**	$ 556,768

Other than $159.1 million of the regulatory assets summarized above ($120.4 million of Postretirement benefits, $37.7 million of Net metering deferral costs and $1 million other costs), all regulatory assets earn a rate of return.

Cost of removal: Represents cumulative amounts collected, but not yet spent, to dispose of property, plant and equipment. This liability is discharged as removal costs are incurred.

Derivative instruments: The Company evaluates open derivative instruments for regulatory deferral by determining if they are probable of recovery from, or refund to, customers through future rates. Derivative instruments that qualify for recovery are recorded at fair value, with changes in fair value recorded as regulatory assets or regulatory liabilities in the period in which the change occurs.

Energy efficiency: Represents the difference between revenue billed to customers through the Company's energy efficiency charge and the costs of the Company's energy efficiency programs as approved by the RIPUC.

Environmental response costs: The regulatory asset represents deferred costs associated with the Company's share of the estimated costs to investigate and perform certain remediation activities at sites with which it may be associated. The Company's rate plans provide for specific rate allowances for these costs, with variances deferred for future recovery from, or return to, customers. The Company believes future costs, beyond the expiration of current rate plans, will continue to be recovered through rates. The regulatory liability represents the excess of amounts received in rates over the Company's actual site investigation and remediation costs.

Gas costs adjustment: The Company is subject to rate adjustment mechanisms for commodity costs, whereby an asset or liability is recognized resulting from differences between billed revenues and the underlying cost being recovered, as approved by the RIPUC. These amounts will be refunded to, or recovered from, customers over the next year.

Net metering: Net metering deferral reflects the recovery mechanism for costs associated with customer installed on-site generation facilities, including the costs of renewable generation credits. This surcharge provides the Company with a mechanism to recover such amounts.

Postretirement benefits: The regulatory asset represents the Company's unamortized non-cash accrual of net actuarial gains and losses, offset by the excess amounts received in rates over actual costs of the Company's pension and PBOP plans, that are to be recovered from or passed back to customers in future periods.

Rate adjustment mechanisms: In addition to commodity costs, the Company is subject to a number of additional rate adjustment mechanisms whereby an asset or liability is recognized resulting from differences between actual revenues and the underlying cost being recovered or differences between actual revenues and targeted amounts as approved by the RIPUC.

Regulatory tax liability, net: Represents over-recovered federal deferred taxes of the Company primarily as a result of regulatory flow through accounting treatment and excess federal deferred taxes as a result of the Tax Cuts and Jobs Act of 2017 ("Tax Act").

Renewable energy certificates: Represents deferred costs associated with the Company's compliance obligation with the Rhode Island Renewable Portfolio Standard ("RPS"). The RPS is legislation established to foster the development of new renewable energy sources. The regulatory asset will be recovered over the next year.

Revenue decoupling mechanism: As approved by the RIPUC, the Company has electric and gas RDMs which allow for an annual adjustment to the Company's delivery rates as a result of the reconciliation between allowed and billed revenues. Any difference is recorded as a regulatory asset or regulatory liability.

Storm costs: The Company is allowed to recover storm costs from all retail delivery service customers. This balance reflects costs yet to be recovered.

Transmission service: The Company arranges transmission service on behalf of its customers and bills the costs of those services to customers, pursuant to the Company's Transmission Service Cost Adjustment Provision. Any over or under recoveries of these costs are passed on to customers receiving transmission service over the subsequent year.

The Company records carrying charges on regulatory balances for which cash expenditures have been made and are subject to recovery, or for which cash has been collected and is subject to refund, as approved in accordance with the RIPUC. Carrying charges are not recorded on items for which expenditures have not yet been made.

5. RATE MATTERS

General Rate Case

On August 24, 2018 and pursuant to Report and Order No. 23823 issued May 5, 2020, the RIPUC approved the terms of an Amended Settlement Agreement (ASA). The ASA reflects an allowed return on equity ("ROE") rate of 9.275% based on a common equity ratio of approximately 51%. We are currently in year three of the multi-year rate plan (Rate Plan). On June 30, 2021, the Division consented to an extension of the term of the Rate Plan such that the Company is not required to file its next rate case so that new rates take effect no later than September 1, 2022. The ASA will remain in effect and the Company will continue to operate under the current Rate Plan until a new Rate Plan is approved by the RIPUC. The Company filed a copy of the Division consent letter with the RIPUC on July 15, 2021. Base distribution rates will remain at the existing Rate Year 3 levels until the next base rate case.

The ASA includes an Electric Transportation Initiative (the ET Initiative or Program) to facilitate the growth of Electric Vehicle (EV) adoption and scaling of the market for EV charging equipment to advance Rhode Island's zero emission vehicles and greenhouse gas emissions policy goals. The ET Initiative includes the following five components (i) Off-Peak Charging Rebate Pilot, (ii) Charging Station Demonstration Program, (iii) Discount Pilot for Direct Current Fast Charging (DCFC) Station Accounts, (iv) Fleet Advisory Services, and (v) Electric Transportation Initiative Evaluation. As of the end of Rate Year 2 The Charging Station Demonstration Program achieved 72% of ET Initiative targets for Level 2 ports and 7% of the target for DCFC ports. The ASA also includes two energy storage demonstration projects because storage is critical for achieving Rhode Island's clean energy future as it provides the ability to optimize system performance over time and allows intermittent renewable resources to make a larger contribution to overall generation; both projects are on track for timely completion.

The ASA also introduces a new incentive-only performance incentive for System Efficiency: Annual Megawatt ("MW") Capacity Savings, with maximum earnings ranging from approximately $0.4 million in 2019 to $0.9 million in 2021. In addition, the ASA identifies several additional metrics for tracking and reporting purposes only.

Recovery of Transmission Costs

The Company's transmission facilities are operated in combination with the transmission facilities of its New England affiliates, Massachusetts Electric Company ("MECO") and NEP, as a single integrated system with NEP designated as the combined operator. NEP collects the costs of the combined transmission asset pool including a return on those facilities under NEP's Tariff No. 1 from the ISO. The ISO allocates these costs among transmission customers in New England, in accordance with the ISO Open Access Transmission Tariff ("ISO-NE OATT").

According to the FERC order, the Company is compensated for its actual monthly transmission costs, with its authorized maximum ROE of 11.74% on its transmission assets. The amounts remitted by NEP to the Company for the years ended March 31, 2021, 2020 and 2019 were $159.9 million, $141.8 million, and $144.8 million, respectively, which are eliminated as operating revenues and operations and maintenance expenses within the accompanying statements of income.

On October 16, 2014, the FERC issued an order, Opinion No. 531-A, resetting the base ROE applicable to transmission assets under the ISO-NE OATT from 11.14% to 10.57% effective as of October 16, 2014 and establishing a maximum ROE of 11.74%. On March 3, 2015, the FERC issued an Order on Rehearing, Opinion No. 531-B, affirming the 10.57% base ROE and clarifying that the 11.74% maximum ROE applies to all individual transmission projects with ROE incentives previously granted by the FERC. On April 14, 2017, the U.S. Court of Appeals for the D.C. Circuit (Court of Appeals) vacated and remanded FERC's Opinion No. 531 (and successor orders), through which the FERC had lowered the New England Transmission Owners ("NETO") return on equity from 11.14% to 10.57% and capped the total incentives at 11.74%.

On October 16, 2018, the FERC issued an order on all four complaints describing how it intends to address the issues that were remanded by the Court. The FERC proposed a new framework to determine whether an existing ROE is unjust and unreasonable and, if so, how to calculate a replacement ROE. The FERC stated that these calculations were merely preliminary and asked the parties to the New England ("NE") Complaint cases to brief FERC and check the numbers. National Grid along with other NETOs filed a brief supporting FERC's new methodology and confirming the illustrative numbers that FERC arrived at in the October 2018 order—a 10.41% base ROE. FERC has not issued a final order on our briefs and the base ROE in NE remains at a 10.57%. In November 2019, FERC issued an order in the Midcontinent Independent System Operator ("MISO") ROE complaint dockets changing the way it arrives at a just and reasonable ROE. The effects of these changes result in drastically reduced base ROEs in the MISO region. In that MISO order, FERC made statements that it is setting new ROE policy nationwide. In December 2019, the NETOs filed a supplemental brief in the NE ROE complaint dockets showing FERC the detrimental effects on NE if the MISO order were applied to NE. In that brief, the NETOs ask FERC to reopen the record in NE so that we can submit more testimony. Other stakeholders had an opportunity to reply to our supplemental brief by January 21st and did so, arguing that our request should be denied, and that the record in NE should not be reopened.

On January 21, 2020, the FERC issued an order granting rehearing for further consideration to give the FERC more time to act on the substantive issues of the MISO ROE proceedings. On May 21, 2020, FERC revised the methodology to determine MISO transmission owner ROEs. FERC's November order proposed to create "zones of reasonableness" based on averages of two (rather than four) models to judge whether ROEs are just and reasonable. ROEs were reduced from 10.32% to 9.88% when FERC applied the revised methodology in two MISO ROE complaints. The May order relies on three models to estimate ROEs. The application of this new methodology increased ROEs in the MISO complaints from 9.88% to 10.02%. The Company does not believe the outcomes of these complaints will have a material impact on the Company's financial condition, results of operations or cash flows.

Tax Act

On March 15, 2018, the FERC initiated multiple proceedings intended to adjust FERC-jurisdictional rates to reflect the corporate tax changes as a result of the passage of the Tax Act. Of the proceedings initiated relevant to the Company is the Notice of Inquiry ("NOI") seeking comments on the effects of the Tax Act on all FERC-jurisdiction rates and a Notice of Proposed Rulemaking (NOPR) issued as a result of the NOI. In response to the FERC NOI, the Company made recommendations designed to mitigate the cash flow impacts of the expected refunds including providing flexibility regarding the methods used to refund accumulated deferred income tax ("ADIT") to customers and providing flexibility regarding the time period of the flow back. In the NOPR, FERC proposed to give the flexibility the Company proposed.

On November 21, 2019, the FERC issued Order 864 to address ratemaking and regulatory reporting of excess or deficient ADIT related to the Tax Act. The order applies to public utility transmission providers with formula rates and stated rates and provides that public utilities with formula rates submit a compliance filing within 30 days of the effective date of the final rule or in the public utilities next annual informational filing following the issuance of the final rule. The compliance filing must demonstrate how the public utilities formula rate adjusts rate base via a Rate Adjustment mechanism, returns or recovers excess or deficient ADIT via an Income Tax Allowance Mechanism, and must include an ADIT worksheet to support the excess or deficient ADIT calculation and amortization. The ADIT worksheet must be populated and will be a new and permanent worksheet. The mechanisms and worksheet must remain applicable to any future changes to tax rates that give rise to excess or deficient ADIT, including changes to state and local tax rates. Excess or deficient ADIT associated with future tax rate changes will automatically be included in a public utility's formula rate without the need for a Section 205 filing. The order does not prescribe a recovery/refund period for deficient/excess ADIT for unprotected excess/deficient ADIT that is not subject to the normalization requirements. FERC will evaluate proposed amortization periods on a case by case basis. On April 16, 2020, the FERC issued Order No. 864-A addressing requests for clarification, or in the alternative, rehearing, submitted in the proceeding. FERC will evaluate proposed amortization periods on a case by case basis.

On June 29,2020, NEP, on behalf of NECO, submitted a compliance filing to address the application of Order 864 in NEP Tariff No. 1. The filing proposes changes to various revenue requirement calculations in the tariff for the inclusion of the Rate Adjustment and Income Tax Allowance Mechanism. The filing also includes the populated permanent ADIT worksheet to be provided with the issuance of final bills pursuant to the provisions of the tariff. NEP has proposed for NECO to amortize transmission related protected property related excess or deficient ADIT associated with the 2017 Tax Act using the Average Rate Adjustment Mechanism ("ARAM") and a 30-year amortization period on unprotected property related excess or deficient balances. Other unprotected excess or deficient ADIT is proposed to be amortized over 10 years consistent with periods approved in the RIPUC Docket addressing the Tax Act. NECO's transmission related net excess ADIT balance associated with the Tax Act is $99.6 million.

The RIPUC opened a docket to address the change in the federal corporate income tax rate and other changes resulting from the Tax Act that was signed into law in December 2017. Specifically, the RIPUC requested the Company's proposal for how it planned to reduce rates associated with the income taxes recovered from customers on the equity component of the return on investment included in revenue taxed at the new lower income tax rate of 21% effective January 1, 2018, and how it planned to return to customers the reduction in its net deferred income tax liabilities resulting from the 14% decrease in the federal income tax rate from 35%. Effective September 1, 2018, the Company reduced its revenue requirement for electric and gas distribution rates in effect for the impacts of the Tax Act as appropriate. On January 24, 2019, the Company filed with the RIPUC a settlement agreement among the Company, the Division, the Office of Energy Resources, and the State of Rhode Island Office of the Lieutenant Governor, pursuant to which approximately $4.8 million and $3.1 million will be provided to electric and gas customers, respectively, which reflect the benefits of the Company's reduced federal corporate income tax payment obligations for the period January 1, 2018 through August 31, 2018. The RIPUC approved the settlement agreement on May 17, 2019, as filed.

New England East-West Solution ("NEEWS") Project

In September 2008, the Company, NEP, and Northeast Utilities jointly filed an application with the FERC to recover financial incentives for the NEEWS project, pursuant to the FERC's Transmission Pricing Policy Order No. 679. NEEWS consists of a series of inter-related transmission upgrades identified in the New England Regional System Plan and is being undertaken to address several reliability problems in Connecticut, Massachusetts, and Rhode Island. The Company's share of the NEEWS-related transmission investment was approximately $560 million. The Company is fully reimbursed for its transmission revenue requirements on a monthly basis by NEP through NEP's Tariff No. 1. Effective November 18, 2008, the FERC granted (1) an incentive ROE of 12.89% (125 basis points above the approved base ROE of 11.64%), (2) 100% construction work in progress ("CWIP") in rate base, and (3) recovery of plant abandoned for reasons beyond the companies' control. As discussed in the preceding section, effective October 16, 2014, the FERC issued a series of orders establishing a maximum ROE of 11.74% that effectively caps the NEEWS incentive ROE at that level. The NEEWS upgrades were placed in service in December 2015.

Suspension of Service Terminations and Certain Collections Activities

At an open meeting on March 16, 2020, the RIPUC issued an order prohibiting all electric, natural gas, water, and sewer utilities from engaging in certain collections activities, including termination of residential and non-residential service for nonpayment (the "Order"). This moratorium expired on July 18, 2020 for commercial and industrial customers, on September 30 for residential customers, and on November 1, 2020 for customers eligible for the low-income rate. On July 25, 2021, the RIPUC's extension of the moratorium on service disconnections for National Grid's protected status customers, including those on National Grid's low-income rate, expired. Per the RIPUC's June 25, 2021 order extending the moratorium to July 25, 2021, there will be no further extensions, unless there is substantial evidence of a major resurgence of the COVID-19 Pandemic. To date, the RIPUC has not ordered any additional extensions of the moratorium so the moratorium is no longer in effect. The RIPUC's order directing the Company to temporarily suspend late fees, interest charges, credit card fees, debit card fees and ACH fees remains in effect, and the Company continues to track these costs for later review by the RIPUC. The RIPUC will review these costs in the Company's cost recovery filing in a separate docket (RIPUC Docket No. 5154). The Company continues to offer the 18-24-36-month payment plans per the RIPUC's order.

On May 15, 2020, pursuant to the RIPUC's directive, the Company filed a plan with the RIPUC and the Division that details the Company's plans for recommencing collection activities when the RIPUC lifts the moratorium on utility terminations (the "Plan"). The Plan consists of a four-phase approach, including initial efforts primarily focused on "bill health" messaging and assuring that customers are aware of the programs and services available to assist them with managing and paying their bills. The Company continues to progress through the phases of the Plan. The Company continues to submit arrearage data to the RIPUC and the Division on a weekly and monthly basis, respectively. On September 2, 2021, the Company filed its responses to the RIPUC's data requests regarding waived fees.

Advanced Metering Functionality and Grid Modernization

On January 21, 2021 the Company filed its Updated Advance Metering Functionality ("AMF") Business Case and Grid Modernization Plan ("GMP") with the RIPUC in accordance with the rate case settlement. The Updated AMF Business Case –

a foundational component of the GMP – seeks approval to deploy smart meters throughout the service territory. The Updated AMF Business Case includes approximately $224 million (20-year net present value)/$344 million (20-year nominal) of investment in smart meters and the associated communications infrastructure, as well as customer education and engagement based on a joint deployment scenario with New York. The GMP consists of a five-year implementation plan and ten-year roadmap that serve as a guide for addressing anticipated distribution system needs. Although the Company is not seeking cost recovery for any specific GMP investment at this time, the Company is seeking approval of the GMP business case and benefit-cost analysis, which will provide regulatory clarity when seeking to implement such projects and pursue cost recovery as part of the Infrastructure, Safety and Reliability Plan or a future rate case. Pursuant to written order issued on July 14, 2021, the RIPUC stayed the AMF and GMP proceedings pending further consideration following the issuance of a final Order by the Division on the PPL Transaction. The RIPUC did not rule on whether or not to consolidate the matters.

COVID-19 Deferral Filing

On April 30, 2021, the Company filed a petition for approval to recognize regulatory assets related to COVID-19 Impacts (RIPUC Docket No. 5154). In its Petition, the Company seeks the PUC's authorization to create regulatory assets and consideration of future cost recovery for the following COVID-19 Costs: (1) the increased cost of customer accounts receivable that the Company will be unable to collect as a result of the COVID-19 pandemic, and the executive orders and PUC orders restricting the Company's collection activities as a result of the pandemic, which will result in increased net charge-offs; (2) lost revenue from unassessed late payment charges; and (3) charges to the Company for other fees that the Company has waived pursuant to the RIPUC's orders in R.I.P.U.C. Docket No. 5022. We will continue to monitor the proceeding, pending any updates or new directive issued by the PUC.

Block Island Transmission System Surcharge Issues

The RIPUC has issued discovery to the Company regarding the Block Island Transmission System ("BITS") surcharge calculation during its 2021 Annual Retail Rates proceeding. During the Open Meeting in that docket, the Chairman questioned the Company's BITS arrangement. In addition, the Division has expressed ongoing concerns with the incremental costs associated with the reburial project related to the BITS cable and has retained FERC counsel. The Company is in discussions with the Division on potential options regarding these matters; however, we cannot predict the outcome of these discussions.

PPL Transaction

Pursuant to a Share Purchase Agreement dated March 17, 2021, by and among PPL Energy Holdings, LLC, PPL Corporation ("PPL"), and National Grid USA (the "Transaction"), National Grid USA has agreed to sell 100 percent of the outstanding shares of common stock in Narragansett to PPL Rhode Island Holdings, LLC ("PPL Rhode Island"), a wholly owned indirect subsidiary of PPL. On May 4, 2021, PPL, PPL Rhode Island, National Grid USA, and Narragansett filed a joint petition with the Division seeking the Division's consent and approval of the Transaction, which is currently pending in Docket No. D-21-09.

6. PROPERTY, PLANT AND EQUIPMENT

The following table summarizes property, plant and equipment, at cost and operating leases along with accumulated depreciation and amortization:

	March 31,	
	2021	2020
	(in thousands of dollars)	
Plant and machinery	**$ 4,478,788**	$ 4,133,095
Land and buildings	**135,500**	129,368
Assets in constructions	**208,699**	228,897
Software and other intangibles	**25,988**	25,988
Assets held for future use	**15,028**	15,028
Operating leases	**34,271**	28,624

Total property, plant and equipment	**4,898,274**	4,561,000
Accumulated depreciation and amortization	**(1,150,582)**	(1,083,552)
Operating lease accumulated depreciation	**(13,401)**	(6,691)
Property, plant and equipment, net	**$ 3,734,291**	$ 3,470,757

7. DERIVATIVE INSTRUMENTS

The Company utilizes derivative instruments to manage commodity price risk associated with its natural gas purchases. The Company's commodity risk management strategy is to reduce fluctuations in firm gas sales prices to its customers.

The Company's financial exposures are monitored and managed as an integral part of the Company's overall financial risk management policy. The Company engages in risk management activities only in commodities and financial markets where it has an exposure, and only in terms and volumes consistent with its core business.

The volume of outstanding gas derivative instruments as of March 31, 2021 and March 31, 2020 was 38.5 million dekatherms and 40.6 million dekatherms, respectively.

Derivative Financial Instruments

The following tables reflect the gross and net amounts of the Company's derivative assets and liabilities as of March 31, 2021 and 2020:

March 31, 2021
(in thousands of dollars)

	Gross amounts of recognized assets (liabilities)	Gross amounts offset in the Balance Sheets	Net amounts of assets (liabilities) presented in the Balance Sheets	Gross amounts not offset in the Balance Sheets	Net Amount
ASSETS:	*A*	*B*	*C=A+B*	*D*	*E=C-D*
Other current assets					
Gas contracts (rate recoverable)	$ 4,953	$ -	$ 4,953	$ 513	$4,440
Gas contracts (not subject to rate recovery)	57	-	57	55	2
Other non-current assets					
Gas contracts (rate recoverable)	630	-	630	124	506
Total	$ 5,640	$ -	$ 5,640	$ 692	$ 4,948
LIABILITIES:					
Current liabilities					
Gas contracts (rate recoverable)	$ 5,982	$ -	$ 5,982	$ 504	$ 5,478
Gas contracts (not subject to rate recovery)	102	-	102	55	47
Other non-current liabilities					
Gas contracts (rate recoverable)	5,823	-	5,823	124	5,699
Total	11,907	-	11,907	683	11,224
Net assets/(liabilities)	$ (6,267)	$ -	$ (6,267)	$ 9	$ (6,276)

March 31, 2020
(in thousands of dollars)

ASSETS:	Gross amounts of recognized assets (liabilities) *A*	Gross amounts offset in the Balance Sheets *B*	Net amounts of assets (liabilities) presented in the Balance Sheets *C=A+B*	Gross amounts not offset in the Balance Sheets *D*	Net Amount *E=C-D*
Other current assets					
Gas contracts (rate recoverable)	$ 90	$ -	$ 90	$ 90	$ -
Gas contracts (not subject to rate recovery)	64	-	64	54	10
Other non-current assets					
Gas contracts (rate recoverable)	283	-	283	77	206
Total	437	-	437	221	216
LIABILITIES:					
Current liabilities					
Gas contracts (rate recoverable)	11,658	-	11,658	135	11,523
Gas contracts (not subject to rate recovery)	110	-	110	54	56
Other non-current liabilities					
Gas contracts (rate recoverable)	2,871	-	2,871	77	2,794
Total	14,639	-	14,639	266	14,373
Net liabilities	$ (14,202)	$ -	$ (14,202)	$ (45)	$ (14,157)

The changes in fair value of the Company's rate recoverable contracts are offset by changes in regulatory assets and liabilities. As a result, the changes in fair value of those contracts had no impact in the accompanying statements of income.

Credit and Collateral

The Company is exposed to credit risk related to transactions entered into for commodity price risk management. Credit risk represents the risk of loss due to counterparty non-performance. Credit risk is managed by assessing each counterparty's credit profile and negotiating appropriate levels of collateral and credit support.

The Company enters into enabling agreements that allow for payment netting with its counterparties, which reduces its exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty.

The credit policy for commodity transactions is managed and monitored by the Finance Committee to National Grid plc's Board of Directors ("Finance Committee"), which is responsible for approving risk management policies and objectives for risk assessment, control and valuation, and the monitoring and reporting of risk exposures. NGUSA's Energy Procurement Risk Management Committee ("EPRMC") is responsible for approving transaction strategies, annual supply plans, and counterparty credit approval, as well as all valuation and control procedures. The EPRMC is chaired by the Vice President of U.S. Treasury and reports to both the NGUSA Board of Directors and the Finance Committee.

The EPRMC monitors counterparty credit exposure and appropriate measures are taken to bring such exposures below the limits, including, without limitation, netting agreements, and limitations on the type and tenor of trades. In instances where a counterparty's credit quality has declined, or credit exposure exceeds certain levels, the Company may limit its credit exposure by restricting new transactions with the counterparty, requiring additional collateral or credit support, and negotiating the early termination of certain agreements. Similarly, the Company may be required to post collateral to its counterparties.

The Company's credit exposure for all commodity derivative instruments and applicable payables and receivables, net of collateral, and instruments that are subject to master netting agreements was a net liability of $6.3 million and $14.2 million as of March 31, 2021 and March 31, 2020, respectively.

The aggregate fair value of the Company's commodity derivative instruments with credit-risk-related contingent features that were in a liability position as of March 31, 2021 and March 31, 2020 was $0.1 million and $6.6 million, respectively. The Company had no collateral posted for these instruments at March 31, 2020 and March 31, 2019. If the Company's credit rating were to be downgraded by one or two levels, it would not be required to post any additional collateral. If the Company's credit rating were to be downgraded by three levels, it would have been required to post $0.2 million and $7.1 million of additional collateral to its counterparties at March 31, 2021 and March 31, 2020, respectively.

8. FAIR VALUE MEASUREMENTS

The following tables present assets and liabilities measured and recorded at fair value on the balance sheet on a recurring basis and their level within the fair value hierarchy as of March 31, 2021 and 2020:

	March 31, 2021			
	Level 1	**Level 2**	**Level 3**	**Total**
		(in thousands of dollars)		
Assets:				
Derivative instruments				
Gas contracts	$ -	$ 5,640	$ -	$ 5,640
Securities	3,527	4,431	-	7,958
Total	3,527	10,071	-	13,598
Liabilities:				
Derivative instruments				
Gas contracts	-	9,379	2,527	11,906
Total	-	9,379	2,527	11,906
Net liabilities	$ 3,527	$ 692	$ (2,527)	$ 1,692

	March 31, 2020			
	Level 1	**Level 2**	**Level 3**	**Total**
		(in thousands of dollars)		
Assets:				
Derivative instruments				
Gas contracts	$ -	$ 437	$ -	$ 437
Securities	2,674	3,729	-	6,403
Total	2,674	4,166	-	6,840
Liabilities:				
Derivative instruments				
Gas contracts	-	9,097	5,542	14,639
Total	-	9,097	5,542	14,639
Net assets (liabilities)	$ 2,674	$ (4,931)	$ (5,542)	$ (7,799)

Derivative instruments*:* The Company's Level 2 fair value derivative instruments consist of over-the-counter ("OTC") gas swaps contracts with pricing inputs obtained from the New York Mercantile Exchange ("NYMEX") and the Intercontinental

Exchange ("ICE"), except in cases where the ICE publishes seasonal averages or where there were no transactions within the last seven days. The Company may utilize discounting based on quoted interest rate curves, including consideration of non-performance risk, and may include a liquidity reserve calculated based on bid/ask spread for the Company's Level 2 derivative instruments. Substantially all of these price curves are observable in the marketplace throughout at least 95% of the remaining contractual quantity, or they could be constructed from market observable curves with correlation coefficients of 95% or higher.

The Company's Level 3 fair value derivative instruments consist of gas option and purchase and capacity transactions, which are valued based on internally developed models. Industry-standard valuation techniques, such as the Black-Scholes pricing model, Monte Carlo simulation, and Financial Engineering Associates libraries are used for valuing such instruments. For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivative instruments valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility, and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. The Company considers non-performance risk and liquidity risk in the valuation of derivative instruments categorized in Level 2 and Level 3.

The significant unobservable inputs used in the fair value measurement of the Company's gas derivative instruments are implied volatility, gas forward curves. A relative change in commodity price at various locations underlying the open positions can result in significantly different fair value estimates.

Securities: Securities are included in other non-current assets on the balance sheet and primarily include equity and debt investments based on quoted market prices (Level 1) and municipal and corporate bonds based on quoted prices of similar traded assets in open markets (Level 2).

9. EMPLOYEE BENEFITS

The Company participates with other NGUSA subsidiaries in qualified and non-qualified non-contributory defined benefit plans (the "Pension Plans") and PBOP plans (together with the Pension Plan (the "Plans"), covering substantially all employees.

Plan assets are maintained for all of NGUSA and its subsidiaries in commingled trusts. In respect of cost determination, plan assets are allocated to the Company based on its proportionate share of the projected benefit obligations. The Plans' costs are first directly charged to the Company based on the Company's employees that participate in the Plans. Costs associated with affiliated service companies' employees are then allocated as part of the labor burden for work performed on the Company's behalf. The Company applies deferral accounting for pension and PBOP expenses associated with its regulated gas and electric operations. Any differences between actual costs and amounts used to establish rates are deferred and collected from, or refunded to, customers in subsequent periods. Pension and PBOP service costs are included within operations and maintenance expense, and non-service costs are included within other income, net in the accompanying statements of income. Portions of the net periodic benefit costs disclosed below have been capitalized as a component of property, plant, and equipment.

Pension Plans

The Qualified Pension Plans are defined benefit plans which provide most union employees, as well as non-union employees hired before January 1, 2011, with a retirement benefit. Supplemental non-qualified, non-contributory executive retirement programs provide additional defined pension benefits for certain executives. During the years ended March 31, 2021, 2020, and 2019, the Company made contributions of approximately $4.0 million, $4.3 million, and $12.0 million, respectively, to the Qualified Pension Plans. The Company expects to contribute approximately $7.3 million to the Qualified Pension Plans during the year ending March 31, 2022.
Benefit payments to Pension Plan participants for the years ended March 31, 2021, 2020, and 2019 were approximately $28.7 million, $28.4 million, and $27.6 million, respectively.

PBOP Plans

The PBOP Plans provide health care and life insurance coverage to eligible retired employees. Eligibility is based on age and length of service requirements and, in most cases, retirees must contribute to the cost of their coverage. For each of the years ended March 31, 2021, 2020, and 2019, the Company made zero contributions to the PBOP Plans. The Company does not expect to contribute to the PBOP Plans during the year ending March 31, 2022.

Benefit payments to PBOP plan participants for the years ended March 31, 2021, 2020, and 2019 were approximately $11.2 million, $9.1 million, and $9.8 million, respectively.

Net Periodic Benefit Costs

The Company's total pension cost for the years ended March 31, 2021, 2020, and 2019 were $11.4 million, $7.0 million, and $9.8 million, respectively.

The Company's total PBOP cost for the years ended March 31, 2021, 2020, and 2019 were $0.1 million, $1.0 million, and $2.8 million, respectively.

Amounts Recognized in Regulatory Assets and Accumulated Other Comprehensive Income

The following tables summarize the Company's changes in actuarial gains/losses and prior service costs recognized in regulatory assets and accumulated other comprehensive income ("AOCI") as of March 31, 2021, 2020, and 2019:

	Pension Plans		
	Years Ended March 31,		
	2021	2020	2019
		(in thousands of dollars)	
Net actuarial (gain) loss	**$ (46,483)**	$ 48,706	$ 7,362
Amortization of net actuarial loss	**(11,892)**	(9,222)	(9,659)
Amortization of prior service cost, net	**-**	(15)	(20)
Total	**$ (58,375)**	$ 39,469	$ (2,317)
Included in regulatory assets	**$ (58,357)**	$ 39,309	$ (3,182)
Included in AOCI	**(18)**	160	865
Total	**$ (58,375)**	$ 39,469	$ (2,317)

	PBOP Plans		
	Years Ended March 31,		
	2021	2020	2019
		(in thousands of dollars)	
Net actuarial (gain) loss	**$ (38,482)**	$ 6,752	$ (7,013)
Amortization of net actuarial loss	**(243)**	(442)	(1,275)
Amortization of prior service benefit, net	**20**	20	20
Total	**$ (38,705)**	$ 6,330	$ (8,268)
Included in regulatory assets	**$ (38,705)**	$ 6,330	$ (8,268)
Total	**$ (38,705)**	$ 6,330	$ (8,268)

Amounts Recognized in AOCI and Regulatory Assets – not yet recognized as components of net actuarial loss

The following tables summarize the Company's amounts in regulatory assets and accumulated other comprehensive income on the balance sheet that have not yet been recognized as components of net actuarial loss as of March 31, 2021, 2020, and 2019

	Pension Plans		
	March 31,		
	2021	2020	2019
		(in thousands of dollars)	
Net actuarial loss	**$ 134,413**	$ 192,788	$ 153,304
Prior service cost	**2**	2	17
Total	**$ 134,415**	$ 192,790	$ 153,321
Included in regulatory assets	**$ 133,272**	$ 191,629	$ 152,321
Included in AOCI	**1,143**	1,161	1,000
Total	**$ 134,415**	$ 192,790	$ 153,321

	PBOP Plans		
	March 31,		
	2021	2020	2019
		(in thousands of dollars)	
Net actuarial (gain) loss	**$ (12,905)**	$ 25,820	$ 19,510
Prior service cost (benefit)	**15**	(5)	(25)
Total	**$ (12,890)**	$ 25,815	$ 19,485
Included in regulatory assets	**$ (12,890)**	$ 25,815	$ 19,485
Total	**$ (12,890)**	$ 25,815	$ 19,485

Reconciliation of Funded Status to Amount Recognized

	Pension Plans		PBOP Plans	
	March 31,		March 31,	
	2021	2020	**2021**	2020
	(in thousands of dollars)			
Projected benefit obligation	**$ (636,782)**	$ (606,064)	**$ (205,963)**	$ (200,662)
Fair value of plan assets	**625,259**	543,434	**184,778**	140,828
Total	**$ (11,523)**	$ (62,630)	**$ (21,185)**	$ (59,834)
Current liabilities	**$ (195)**	$ (196)	**$ (93)**	$ (92)
Other non-current liabilities	**(11,328)**	(62,434)	**(21,092)**	(59,742)
Total	**$ (11,523)**	$ (62,630)	**$ (21,185)**	$ (59,834)

For the year end March 31, 2021, the net actuarial gains for pension and PBOP was largely the result of asset performance and lower contract pricing negotiated on certain prescription benefit costs within the PBOP Plans, partially offset by losses generated from the discount rate decrease. For the year end March 31, 2020, the net actuarial loss for pension and PBOP was primarily driven by the discount rate decrease and asset performance below expectations. This loss was partially offset by a gain related to a change in the mortality assumption and a PBOP assumption change for post-65 participation rates. For the year end March 31, 2019, the net actuarial loss for pension was primarily generated by the discount rate decrease. Whereas for the PBOP plans, the net gain was driven by assumptions changes related to pre-65 participation rates, offset by the discount rate decrease.

Expected Benefit Payments

Based on current assumptions, the Company expects to make the following benefit payments subsequent to March 31, 2021:

(in thousands of dollars) Years Ended March 31,	Pension Plans	PBOP Plans
2022	$ 33,507	$ 9,347
2023	34,762	9,554
2024	36,126	9,683
2025	37,458	10,035
2026	38,834	10,302
2027-2031	209,297	53,953
Total	$ 389,984	$ 102,874

Assumptions Used for Employee Benefits Accounting

	Pension Plans		
	As of and Years Ended March 31,		
	2021	2020	2019
Benefit Obligations:			
Discount rate	**3.25%**	3.65%	4.10%
Rate of compensation increase (nonunion)	**4.10%**	3.50%	3.50%
Rate of compensation increase (union)	**4.05%**	3.50%	3.50%
Weighted average cash balance interest crediting rate	**2.75%**	2.75%	3.25%
Net Periodic Benefit Costs:			
Discount rate	**3.65%**	4.10%	4.10%
Rate of compensation increase	**3.50%**	3.50%	3.50%
Expected return on plan assets	**6.00%**	6.50%	6.25%
Weighted average cash balance interest crediting rate	**2.75%**	3.25%	3.00%

	PBOP Plans		
	As of and Years Ended March 31,		
	2021	2020	2019
Benefit Obligations:			
Discount rate	**3.25%**	3.65%	4.10%
Net Periodic Benefit Costs:			
Discount rate	**3.65%**	4.10%	4.10%
Expected return on plan assets	**6.50%-7.00%**	6.50%-7.25%	6.25%-6.75%

The Company selects its discount rate assumption based upon rates of return on highly rated corporate bond yields in the marketplace as of each measurement date. Specifically, the Company uses the Aon AA Only Bond Universe Curve along with the expected future cash flows from the Company retirement plans to determine the weighted average discount rate assumption.

The expected rate of return for various passive asset classes is based both on analysis of historical rates of return and forward looking analysis of risk premiums and yields. Current market conditions, such as inflation and interest rates, are evaluated in connection with the setting of the long-term assumptions. A small premium is added for active management of both equity and fixed income securities. The rates of return for each asset class are then weighted in accordance with the actual asset allocation, resulting in a long-term return on asset rate for each plan.

Assumed Health Cost Trend Rate

	March 31, 2021	March 31, 2020
Health care cost trend rate assumed for next year		
Pre 65	**6.80%**	7.00%
Post 65	**5.40%**	5.50%
Prescription	**7.70%**	8.00%
Rate to which the cost trend is assumed to decline (ultimate)	**4.50%**	4.50%
Year that rate reaches ultimate trend		
Pre 65	**2031+**	2031+
Post 65	**2031+**	2031+
Prescription	**2031+**	2031+

Plan Assets

The Pension Plan is a trusted non-contributory defined benefit plan covering all eligible represented employees of the Company and eligible non-represented employees of the participating National Grid companies. The PBOP Plans are both a contributory and non-contributory, trusteed, employee life insurance and medical benefit plan sponsored by the Company. Life insurance and medical benefits are provided for eligible retirees, dependents, and surviving spouses of the Company.

The Company manages the benefit plan investments for the exclusive purpose of providing retirement benefits to participants and beneficiaries and paying plan expenses. The benefit plans' named fiduciary is The Retirement Plans Committee ("RPC"). The RPC seeks to minimize the long-term cost of operating the Plans, with a reasonable level of risk. The investment objectives of the plans are to maintain a level and form of assets adequate to meet benefit obligations to participants, to achieve the expected long-term total return on the plans' assets within a prudent level of risk and maintain a level of volatility that is not expected to have a material impact on the Company's expected contribution and expense or the Company's ability to meet plan obligations.

The RPC has established and reviews at least annually the Investment Policy Statement ("IPS") which sets forth the guidelines for how plan assets are to be invested. The IPS contains a strategic asset allocation for each plan which is intended to meet the objectives of the plans by diversifying its funds across asset classes, investment styles and fund managers. An asset/liability study typically is conducted periodically to determine whether the current strategic asset allocation continues to represent the appropriate balance of expected risk and reward for the plan to meet expected liabilities. Each study considers the investment risk of the asset allocation and determines the optimal mix of assets for the plan. The target asset allocation for 2021 reflects the results of such a pension study conducted in 2019. The Union PBOP Plan asset liability study was conducted in 2021. As a result of that study the RPC approved changes to the Union PBOP asset allocation effective in fiscal year 2022. The Non-Union PBOP Plan asset liability study is expected to be run within the next 12-18 months.

Individual fund managers operate under written guidelines provided by the RPC, which cover such areas as investment objectives, performance measurement, permissible investments, investment restrictions, trading and execution, and communication and reporting requirements. National Grid management in conjunction with a third party investment advisor, regularly monitors, and reviews asset class performance, total fund performance, and compliance with asset allocation guidelines. This information is reported to the RPC at quarterly meetings. The RPC changes fund managers and rebalances the portfolio as appropriate.

Equity investments are broadly diversified across U.S. and non-U.S. stocks, as well as across growth, value, and small and large capitalization stocks. Likewise, the fixed income portfolio is broadly diversified across market segments and is mainly invested in investment grade securities. Where investments are made in non-investment grade assets the higher volatility is carefully judged and balanced against the expected higher returns. While the majority of plan assets are invested in equities and fixed income other asset classes are utilized to further diversify the investments. These asset classes include private equity, real estate, and diversified alternatives. The objective of these other investments are enhancing long-term returns while improving portfolio diversification. For the PBOP Plans, since the earnings on a portion of the assets are taxable, those investments are managed to maximize after tax returns consistent with the broad asset class parameters established by the asset liability study. Investment risk and return are reviewed by the plan investment advisors, National Grid management and the RPC on a regular basis. The assets of the plans have no significant concentration of risk in one country (other than the United States), industry or entity.

The target asset allocations for the benefit plans as of March 31, 2021 and 2020 are as follows:

	Pension Plans		**Union PBOP Plans**		**Non-Union PBOP Plans**	
	March 31,		**March 31,**		**March 31,**	
	2021	2020	**2021**	2020	**2021**	2020
Equity	**37%**	37%	**63%**	63%	**70%**	70%
Diversified alternatives	**10%**	10%	**17%**	17%	**0%**	0%
Fixed income securities	**40%**	40%	**20%**	20%	**30%**	30%
Private equity	**5%**	5%	**0%**	0%	**0%**	0%
Real estate	**5%**	5%	**0%**	0%	**0%**	0%
Infrastructure	**3%**	3%	**0%**	0%	**0%**	0%
	100%	100%	**100%**	100%	**100%**	100%

Fair Value Measurements

The following tables provide the fair value measurements amounts for the pension and PBOP assets at the Plan level:

	March 31, 2021				
	Level 1	**Level 2**	**Level 3**	**Not categorized**	**Total**
			(in thousands of dollars)		
Pension Assets:					
Investments					
Equity	$ 244,018	$ -	$ -	$ 891,362	$ 1,135,380
Diversified alternatives	70,409	-	-	203,187	273,596
Corporate bonds	-	514,588	-	168,106	682,694
Government securities	480	294,487	-	238,270	533,237
Private equity	-	-	-	168,914	168,914
Real estate	-	-	-	110,603	110,603
Infrastructure	-	-	-	50,489	50,489
Total assets	**$ 314,907**	**$ 809,075**	**$ -**	**$ 1,830,931**	**$ 2,954,913**
Pending transactions					**(148,083)**
Total net assets					**$ 2,806,830**
PBOP Assets:					
Investments					
Equity	$ 196,570	$ -	$ -	$ 335,943	$ 532,513
Diversified alternatives	45,255	-	-	41,632	86,887
Corporate bonds	-	3,792	-	-	3,792
Government securities	14,864	157,025	-	1,032	172,921
Insurance contracts	-	-	-	43,934	43,934
Total assets	**$ 256,689**	**$ 160,817**	**$ -**	**$ 422,541**	**$ 840,047**
Pending transactions					**1,103**
Total net assets					**$ 841,150**

	March 31, 2020				
	Level 1	Level 2	Level 3	Not categorized	Total
	(in thousands of dollars)				
Pension Assets:					
Investments					
Equity	$ 173,535	$ -	$ -	$ 630,567	$ 804,102
Diversified alternatives	57,730	-	-	173,255	230,985
Corporate bonds	-	412,698	-	142,101	554,799
Government securities	(4,072)	300,759	-	267,338	564,025
Private equity	-	-	-	131,200	131,200
Real estate	-	-	-	115,522	115,522
Infrastructure	-	-	-	48,687	48,687
Insurance contracts	-	-	-	3,507	3,507
Total assets	**$ 227,193**	**$ 713,457**	**$ -**	**$ 1,512,177**	**$ 2,452,827**
Pending transactions					**(111,173)**
Total net assets					**$ 2,341,654**
PBOP Assets:					
Investments					
Equity	$ 140,528	$ -	$ -	$ 224,383	$ 364,911
Diversified alternatives	33,367	-	-	32,954	66,321
Corporate bonds	-	2,895	-	-	2,895
Government securities	13,584	147,495	-	1,034	162,113
Insurance contracts	-	-	-	31,473	31,473
Total assets	**$ 187,479**	**$ 150,390**	**$ -**	**$ 289,844**	**$ 627,713**
Pending transactions					**1,362**
Total net assets					**$ 629,075**

The methods used to fair value pension and PBOP assets are described below:

Equity: Equity includes both actively- and passively-managed assets with investments in domestic equity index funds as well as international equities.

Diversified alternatives: Diversified Alternatives consist of holdings of global tactical assets allocation funds that seek to invest opportunistically in a range of asset classes and sectors globally.

Corporate bonds: Corporate Bonds consist of debt issued by various corporations and corporate money market funds. Corporate Bonds also includes small investments in preferred securities as these are used in the fixed income portfolios as yield producing investments. In addition, certain fixed income derivatives are included in this category such as credit default swaps to assist in managing credit risk.

Government securities: Government Securities includes US agency and treasury securities, as well as state and local municipal bonds. The plans also include a small amount of Non-US government debt which is also captured here. US Government money market funds are also included. In addition, interest rate futures and swaps are held as a tool to manage interest rate risk.

Private equity: Private equity consists of limited partnerships investments where all the underlying investments are privately held. This consists of primarily buy-out investments with smaller allocations to venture capital.

Real estate: Real estate consists of limited partnership investments primarily in US core open end real estate funds as well as some core plus closed end real estate funds.

Infrastructure: Infrastructure consists of limited partnerships investments that seek to invest in physical assets that are considered essential for a society to facilitate the orderly operation of its economy. Investments in infrastructure typically include transportation assets (such as airports and toll roads) and utility type assets. Investments in infrastructure funds are utilized as a diversifier to other asset classes within the pension portfolio. Infrastructure investments are also typically income producing assets.

Insurance contracts: Insurance contracts consists of Trust Owned Life Insurance.

Pending transactions: These are short term cash transactions that are expected to settle within a few days of the measurement date.

Defined Contribution Plan

NGUSA has defined contribution retirement plans that cover substantially all employees. For each of the years ended March 31, 2021, 2020, and 2019, the Company recognized an expense in the accompanying statement of income of $3.1 million for matching contributions.

10. CAPITALIZATION

The aggregate maturities of long-term debt for the years subsequent to March 31, 2021 are as follows:

(in thousands of dollars) **March 31,**	**Maturities of Long-Term Debt**
2022	$ 1,375
2023	13,875
2024	750
2025	750
2026	750
Thereafter	1,500,000
Total	$ 1,517,500

The Company's debt agreements and banking facilities contain covenants, including those relating to the periodic and timely provision of financial information by the issuing entity and financial covenants such as restrictions on the level of indebtedness. Failure to comply with these covenants, or to obtain waivers of those requirements, could in some cases trigger a right, at the lender's discretion, to require repayment of some of the Company's debt and may restrict the Company's ability to draw upon its facilities or access the capital markets. As of March 31, 2021 and 2020, the Company was in compliance with all such covenants.

Debt Authorizations

The Company had regulatory approval from the FERC to issue up to $400 million of short-term debt. The authorization was renewed with an effective date of January 11, 2021 and expires on October 14, 2022. The Company had no external short-term debt as of March 31, 2021 and 2020. Refer to Note 15, "Related Party Transactions" under "Intercompany Money Pool" for short-term debt outstanding with associated companies.

A new financing petition was filed with the RIPUC and approved on January 19, 2020 authorizing the issuance of up to $900 million of new long term debt through March 31, 2023. In April 2020, the Company issued $600 million of unsecured long-term debt at 3.395% with a maturity date of April 9, 2030, resulting in $300 million of remaining authorization.

First Mortgage Bonds

As of March 31, 2021, the Company had $17.5 million of FMB outstanding. Substantially all of the assets used in the gas business of the Company are subject to the lien of the mortgage indentures under which these FMB have been issued. The FMB have annual sinking fund requirements totaling approximately $1.4 million.

The Company has a maximum 70% of debt-to-capitalization covenant. Furthermore, if at any time the Company's debt exceeds 60% of the total capitalization, each holder of bonds then outstanding, shall receive effective as of the first date of such occurrence, a one time, and permanent, 0.20% increase in the interest rate paid by the Company on its bonds. As of March 31, 2021, and 2020, the Company was in compliance with this covenant.

Dividend Restrictions

Pursuant to the preferred stock arrangement, as long as any preferred stock is outstanding, certain restrictions on payment of common stock dividends would come into effect if the common stock equity was, or by reason of payment of such dividends became, less than 25% of total capitalization. The Company was in compliance with this covenant and accordingly, the Company was not restricted as to the payment of common stock dividends under the foregoing provisions as of March 31, 2021 or 2020.

Cumulative Preferred Stock

The Company has certain issues of non-participating cumulative preferred stock outstanding where it can be redeemed at the option of the Company. There are no mandatory redemption provisions on the Company's cumulative preferred stock. A summary of cumulative preferred stock is as follows:

	Shares Outstanding		Amount		
	March 31,		March 31,		Call
Series	**2021**	2020	**2021**	2020	Price
	(in thousands of dollars, except per share and number of shares data)				
$50 par value -					
4.50% Series	**49,089**	49,089	**$ 2,454**	$ 2,454	$ 55.000

The Company did not redeem any preferred stock during the years ended March 31, 2021, 2020, or 2019. The annual dividend requirement for cumulative preferred stock was $0.1 million for the years ended March 31, 2021, 2020 and 2019.

11. INCOME TAXES

Components of Income Tax Expense

	Years Ended March 31,		
	2021	2020	2019
	(in thousands of dollars)		
Current federal income tax expense (benefit)	**$ 19,169**	$ 23,920	$ (12,398)
Deferred federal tax expense	**10,657**	2,976	36,415
Amortized investment tax credits [(1)]	**-**	(1)	(16)
Total deferred tax expense	**10,657**	2,975	36,399
Total income tax expense	**$ 29,826**	$ 26,895	$ 24,001

(1) Investment tax credits ("ITC") are accounted for using the deferral and gross up method of accounting and amortized over the depreciable life of the property giving rise to the credits.

Statutory Rate Reconciliation

The Company's effective tax rates for the years ended March 31, 2021, 2020 and 2019 are 18.1%, 18.0% and 17.9%, respectively. The following table presents a reconciliation of income tax expense (benefit) at the federal statutory tax rate of 21% to the actual tax expense:

	Years Ended March 31,		
	2021	2020	2019
	(in thousands of dollars)		
Computed tax	**$ 34,608**	$ 31,353	$ 28,231
Change in computed taxes resulting from:			
Temporary differences flowed through	**(4,687)**	(4,655)	(4,293)
Other items, net	**(95)**	197	63
Total	**(4,782)**	(4,458)	(4,230)
Total income tax expense	**$ 29,826**	$ 26,895	$ 24,001

The Company is included in the NGNA and subsidiaries consolidated federal income tax return. The Company has joint and several liability for any potential assessments against the consolidated group.

Deferred Tax Components

	March 31,	
	2021	**2020**
	(in thousands of dollars)	
Deferred tax assets:		
Allowance for doubtful accounts	$ 13,312	$ 9,091
Postretirement benefits and other employee benefits	10,821	29,126
Regulatory liabilities	91,251	89,216
Environmental remediation costs	23,485	25,096
Net operating losses	48,321	56,451
Other items – net	17,557	17,206
Total deferred tax assets	**204,747**	**226,186**
Deferred tax liabilities:		
Property related differences	438,025	420,471
Regulatory assets	110,015	128,530
Amortization of intangibles	47,872	44,119
Other items	1,057	384
Total deferred tax liabilities	**596,969**	**593,504**
Deferred income tax liabilities, net	**$ 392,222**	**$ 367,318**

Net Operating Losses

The amounts and expiration dates of the Company's net operating losses carryforwards as of March 31, 2021 are as follows:

Expiration of Net Operating Losses	Gross Carryforward Amount	Expiration Period
	(in thousands of dollars)	
Federal	**$ 365,964**	**2033 – 2038**

As a result of the accounting for uncertain tax positions, the amount of deferred tax assets reflected in the financial statements is less than the amount of the tax effect of the federal and state net operating losses carryforward reflected on the income tax returns.

Federal Income Tax Audit

During the year ended March 31, 2021, the Company reached a settlement with the IRS for the tax years ended March 31, 2013, March 31, 2014 and March 31, 2015. As a result of the settlement, the Company received a refund for tax and interest of $4.7 million.

During the year ended March 31, 2021, the IRS informed the Company that it does not intend to audit the Company's income tax returns for the periods ended March 31, 2016 and 2017 and commenced its examination of the next audit cycle which includes periods ended March 31, 2018 and 2019. While the income tax returns for fiscal years 2016 and 2017 are not currently being audited by the IRS, the statute of limitations for these tax periods does not expire until December 31, 2021. Therefore, the income tax returns for the years ended March 31, 2016 through March 31, 2021 remain subject to examination by the IRS.

The following table indicates the earliest tax year subject to examination for each major jurisdiction:

Jurisdiction	Tax Year
Federal	March 31, 2016

The Company is not subject to state income tax due to the State of Rhode Island's exclusion of public utilities from income tax.

Uncertain Tax Positions

The Company recognizes interest related to unrecognized tax benefits in other interest, including affiliate interest and related penalties, if applicable, in other income, net, in the accompanying statements of income. As of both March 31, 2021 and 2020, the Company has accrued for interest related to unrecognized tax benefits of $0.3 million. During the years ended March 31, 2021, 2020 and 2019, the Company recorded interest expense of zero, zero, and $0.3 million, respectively. No tax penalties were recognized during the years ended March 31, 2021, 2020 or 2019.

It is reasonably possible that other events will occur during the next twelve months that would cause the total amount of unrecognized tax benefits to increase or decrease. However, the Company does not believe any such increases or decreases would be material to its results of operations, financial position, or cash flows.

12. ENVIRONMENTAL MATTERS

The normal ongoing operations and historic activities of the Company are subject to various federal, state, and local environmental laws and regulations. Under federal and state Superfund laws, potential liability for the historic contamination of property may be imposed on responsible parties jointly and severally, without regard to fault, even if the activities were lawful when they occurred.

The United States Environmental Protection Agency ("EPA"), the Massachusetts Department of Environmental Protection ("DEP"), and the Rhode Island Department of Environmental Management ("DEM") have alleged that the Company is a potentially responsible party under state or federal law for the remediation of a number of sites at which hazardous waste is alleged to have been disposed. The Company's most significant liabilities relate to former Manufactured Gas Plant ("MGP") facilities formerly owned by the Blackstone Valley Gas and Electric Company and the Rhode Island gas distribution assets of New England Gas. The Company is currently investigating and remediating, as necessary, those MGP sites and certain other properties under agreements with the EPA, DEM and DEP. Expenditures incurred for the years ended March 31, 2021, 2020, and 2019 were $7.3 million, $1.9 million, and $1.8 million, respectively.

The Company estimated the remaining costs of environmental remediation activities were $111.8 million and $119.8 million as of March 31, 2021 and 2020, respectively. These costs are expected to be incurred over approximately 37 years, and these undiscounted amounts have been recorded as estimated liabilities on the balance sheet. However, remediation costs for each site may be materially higher than estimated, depending on changing technologies and regulatory standards, selected end use for each site, and actual environmental conditions encountered. The Company has recovered amounts from certain insurers and potentially responsible parties, and, where appropriate, the Company may seek additional recovery from other insurers and from other potentially responsible parties, but it is uncertain whether, and to what extent, such efforts will be successful.

The RIPUC has approved a settlement agreement that provides for rate recovery of remediation costs of former MGP sites and certain other hazardous waste sites located in Rhode Island. Under that agreement, qualified costs related to these sites are paid out of a special fund established as a regulatory liability on the balance sheet. Rate-recoverable contributions of approximately $3.1 million are added annually to the fund, along with interest and any recoveries from insurance carriers and other third-parties. Accordingly, as of March 31, 2021 and 2020, the Company has recorded environmental regulatory assets of $110.0 million and $119.0 million, respectively, and environmental regulatory liabilities of $16.2 million and $18.8 million, respectively (See Note 4, "Regulatory Assets and Liabilities" for additional details).

The Company believes that its ongoing operations, and its approach to addressing conditions at historic sites, are in substantial compliance with all applicable environmental laws. Where the Company has regulatory recovery, it believes that the obligations imposed on it because of the environmental laws will not have a material impact on its results of operations or financial position.

13. COMMITMENTS AND CONTINGENCIES

Purchase Commitments

The Company has several long-term contracts for the purchase of electric power. Substantially all of these contracts require power to be delivered before the Company is obligated to make payment. Additionally, the Company has entered into various contracts for gas delivery, storage, and supply services. Certain of these contracts require payment of annual demand charges, which are recoverable from customers. The Company is liable for these payments regardless of the level of service required from third-parties.

The Company's commitments under these long-term contracts for the years subsequent to March 31, 2021 are summarized in the table below:

(in thousands of dollars) March 31,	Energy Purchases
2022	$ 266,493
2023	104,693
2024	50,583
2025	47,598
2026	39,870
Thereafter	349,765
Total	$ 859,002

Long-term Contracts for Renewable Energy

Deepwater Agreement

The 2009 Rhode Island law required the Company to solicit proposals for a small scale renewable energy generation project of up to eight wind turbines with an aggregate nameplate capacity of up to 30 MW to benefit the Town of New Shoreham. The renewable energy generation project also included a transmission cable to be constructed between Block Island and the mainland of Rhode Island. On June 30, 2010, the Company entered into a 20-year Amended Power Purchase Agreement ("PPA") with Deepwater Wind Block Island LLC ("Deepwater"), which was approved by the RIPUC in August 2010. The wind turbines reached commercial operation on December 12, 2016 and the PPA is being accounted for as a capital lease. The Company also negotiated a Transmission Facilities Purchase Agreement ("Facilities Purchase Agreement," or "FPA") with Deepwater to purchase the permits, engineering, real estate, and other site development work for construction of the undersea transmission cable (collectively, the "Transmission Facilities"). On April 2, 2014, the Division issued its Consent Decision for the Company to execute the FPA with Deepwater. In July 2014, four agreements were filed with the FERC, in part, for approval to recover the costs associated with the transmission cable and related facilities (the "Project") that will be allocated to the Company and Block Island Power Company through transmission rates. On September 2, 2014, the FERC accepted all four agreements thus approving cost recovery for the Project, with no conditions, that will apply to the Company's costs, as well as those of NEP. The agreements went into effect on September 30, 2014. On January 30, 2015, the Company closed on its purchase of the Transmission Facilities from Deepwater. The Company placed the Transmission Facilities into service on October 31, 2016.

Three-State Procurement

On April 9, 2018, the RIPUC approved eight long-term (20-year) contracts for the purchase of the electricity and renewable energy credits from eight separate generating facilities pursuant to the Rhode Island Long-Term Contracting Standard. The Company will purchase the actual output generated by the individual facilities, which in aggregate represents approximately 39 MWs of nameplate capacity. Because the contracts were approved pursuant to the Rhode Island Long-Term Contracting Standard, the Company may collect 2.75% remuneration on the annual payments made under the contracts. The contracts resulted from a three-state solicitation for renewable energy generation proposals.

Offshore Wind Energy Procurement

On December 6, 2018, the Narragansett Electric Company entered into a 20-year PPA with DWW Rev I, LLC ("Revolution Wind"), for the purchase of the electricity and renewable energy credits generated by the offshore windfarm proposed by Revolution Wind, that will have a capacity of up to 408 MW. The anticipated commercial operations date for the windfarm is in January 2024. On May 28, 2019, at an open meeting, the RIPUC approved the contract without remuneration. The written order approving the agreement and that Company will be able to recover the cost incurred under the agreement was issued by the RIPUC on June 7, 2019.

Annual Solicitations

The 2009 Rhode Island law (Long Term Contracting Standard ("LTCS")) also requires that, beginning on July 1, 2010, the Company conduct four annual solicitations for proposals from renewable energy developers and, provided commercially reasonable proposals have been received, enter into long-term contracts for the purchase of capacity, energy, and attributes from newly developed renewable energy resources. The Company's four solicitations have resulted in four PPAs that have been approved by the RIPUC:

- First Solicitation: On July 28, 2011, the RIPUC approved a 15-year PPA with Orbit Energy Rhode Island, LLC for a 3.2 MW anaerobic digester biogas project located in Johnston, Rhode Island. The facility reached commercial operation on August 24, 2017.
- Second Solicitation: On May 11, 2012, the RIPUC approved a 15-year PPA with Black Bear Development Holdings, LLC for a 3.9 MW run-of-river hydroelectric plant located in Orono, Maine. The facility reached commercial operation on November 22, 2013.
- Third Solicitation: On October 25, 2013, the RIPUC approved a 15-year PPA with Champlain Wind, LLC for a 48 MW land-based wind project located in Carroll Plantation and Kossuth Township, Maine. The PPA was terminated on January 23, 2017 because one of the required permits for the project was rejected. The impact of this termination is that the Company then needed to backfill the MW capacity from that project to meet the 90 MW minimum long-term capacity requirements under the state statute, that it fulfilled in the fifth solicitation.
- Fourth Solicitation: On October 29, 2015, the RIPUC approved a 15-year PPA with Copenhagen Wind Farm, LLC for an 80 MW land-based wind project located in Denmark, New York. The facility reached commercial operation on December 27, 2018.

In 2014 the LTCS was amended to allow for additional solicitations until the 90 MW contracting capacity requirement was met.

- Fifth Solicitation: On May 11, 2020, the RIPUC approved a 20 year PPA with Gravel Pit Solar II, LLC for a 49.5 MW land based bifacial solar project located in East Windsor, CT. The anticipated commercial operation date is March 31, 2023.

As approved by the RIPUC, the Company is allowed to pass through commodity-related / purchased power costs to customers and collect remuneration equal to 2.75%.

Aquidneck Island

On January 21, 2019, we suffered a significant loss of gas supply to the distribution system that serves our customers on Aquidneck Island in Rhode Island. As a result, we made the decision to interrupt the gas service to the Aquidneck Island system to protect the safety of our customers and the public. Overall, approximately 7,500 customers lost their gas service. On October 30, 2019, the RI Division issued their Summary Investigation Report regarding the gas service interruption. In the report, the Division identified the causes of the outages, which included multiple factors, some of which were outside the control of the Company. The Division's Report also recommended several gas system improvements, many of which we have addressed already. On December 13, 2019, we filed our response to the Division's Report and continue to meet with the Division on a quarterly basis regarding winter reliability issues for Aquidneck Island and Rhode Island. On September 23, 2020, we published a long-term capacity study for energy solutions for Aquidneck Island for stakeholder feedback. We are gathering stakeholder feedback on a hybrid model approach that will offset gas demand growth with advanced non-infrastructure solutions while addressing existing gas capacity and vulnerability challenges with an alternate LNG solution. On May 18, 2021, we attended an informational session at the Rhode Island Public Utilities Commission to update the Commission on the Company's long-term capacity solutions for Aquidneck Island.

In November 2019, the Company was first served with an amended class action complaint on behalf of business owners on Aquidneck and a separate class action on behalf of individuals in the affected areas. Further amendments to the complaints have subsequently been filed. The Company is actively defending against these class action complaints. Additionally, six subrogation actions allegedly related to event have been filed against the Company to date.

Legal Matters

The Company is subject to various legal proceedings arising out of the ordinary course of its business. The Company does not consider any of such proceedings to be material, individually or in the aggregate, to its business or likely to result in a material adverse effect on its results of operations, financial position, or cash flows.

New York Public Service Commission Investigation

On June 17, 2021, five former NGUSA employees in the downstate New York facilities department were arrested on federal charges alleging fraud and bribery. It is NGUSA's understanding that the investigation by the US Attorney's Office and FBI remains ongoing; NGUSA is a victim of the alleged crimes and will continue to comply with the government's investigation. The New York Public Service Commission, the Massachusetts Department of Public Utilities, and the Rhode Island Public Utilities Commission have each issued requests for information related to the alleged criminal conduct. At this time, it is not possible to predict the outcome of the regulatory review or determine the amount, if any, of any potential liabilities that may be incurred by the Company related to this matter. However, the Company does not expect this matter will have a material adverse effect on its results of operations, financial position or cash flows.

Energy Efficiency Programs Investigation

NGUSA is performing an internal investigation regarding conduct associated with the Company's energy efficiency programs. At this time, it is not possible to predict the outcome of the investigation or determine the amount, if any, of any liabilities that may be incurred in connection with it by the Company. However, the Company does not expect this matter will have a material adverse effect on its results of operations, financial position or cash flows.

14. LEASES

The Company has no finance leases as of March 31, 2021 or 2020. The Company has various operating leases, primarily related to a transmission line, buildings, land, and fleet vehicles used to support the electric and gas operations, with lease terms ranging between 4 and 50 years. The expense related to operating leases was $8.0 million and $7.9 million for the years ended March 31, 2021 and 2020, respectively.

Certain building leases provide the Company with an option to extend the lease term. The Company has included the periods covered by the extension options in its determination of the lease term when management believes it is reasonably certain the Company will exercise its option.

In measuring lease liabilities, the Company excludes variable lease payments, other than those that depend on an index or a rate, or are in substance fixed payments, and includes lease payments made at or before the commencement date. The variable lease payments were not material for the year ended March 31, 2021.

Lease liabilities are recognized based on the present value of the lease payments over the lease term at the commencement date. For any leases that do not provide an implicit rate, the Company uses an estimate of its collateralized incremental borrowing rate based on the information available at the commencement date to determine the present value of future payments. Operating lease ROU assets are included in property, plant and equipment, net, and operating lease liabilities are included in other current liabilities and other noncurrent liabilities on the balance sheet.

As of March 31, 2021, the Company does not have material rights or obligations under operating leases that have not yet commenced.

The following table presents the components of cash flows arising from lease transactions and other operating lease-related information:

	Year ended March 31, 2021	Year ended March 31, 2020
(in thousands of dollars)		
Cash paid for amounts included in lease liabilities		
Operating cash flows from operating leases	**$ 8,006**	$ 7,889
ROU assets obtained in exchange for new operating lease liabilities	**$ 6,108**	$ 2,644
Weighted-average remaining lease term – operating leases	**5**	4
Weighted-average discount rate – operating leases	**2.53%**	2.65%

The following contains the Company's maturity analysis of its operating lease liabilities as of March 31, 2021, showing the undiscounted cash flows on an annual basis reconciled to the undiscounted cash flows of the operating lease liabilities recognized in the comparative balance sheet:

Year Ending March 31,	**Operating Leases** *(in thousands of dollars)*
2022	**$ 6,662**
2023	**5,436**
2024	**3,945**
2025	**2,127**
2026	**1,446**
Thereafter	**2,457**
Total future minimum lease payments	**$ 22,073**
Less: imputed interest	**(1,203)**
Total	**$ 20,870**
Reported as of March 31, 2021:	
Current lease liability	**$ 6,210**
Non-current lease liability	**14,660**
Total	**$ 20,870**

There are certain leases in which the Company is the lessor. Revenue under such leases was immaterial for the years ended March 31, 2021 and 2020.

15. RELATED PARTY TRANSACTIONS

Accounts Receivable from and Accounts Payable to Affiliates

NGUSA and its affiliates provide various services to the Company, including executive and administrative, customer services, financial (including accounting, auditing, risk management, tax, and treasury/finance), human resources, information technology, legal, and strategic planning, that are charged between the companies and charged to each company.

The Company records short-term receivables from, and payables to, certain of its affiliates in the ordinary course of business. The amounts receivable from, and payable to, its affiliates do not bear interest and are settled through the intercompany money pool. A summary of outstanding accounts receivable from affiliates and accounts payable to affiliates is as follows:

	Accounts Receivable from Affiliates		**Accounts Payable to Affiliates**	
	March 31,		**March 31,**	
	2021	2020	**2021**	2020
	(in thousands of dollars)			
New England Power Company	**$ 13,803**	$ 12,872	**$ 27,764**	$ 25,937
NGUSA Service Company	**3,498**	4,571	**29,423**	24,754
Other	**85**	2,231	**3,200**	3,740
Total	**$ 17,386**	$ 19,674	**$ 60,387**	$ 54,431

As discussed in Note 5 "Rate Matters," NEP operates the pooled transmission facilities of MECO, the Company, and NEP as a single integrated system ("NEPOOL") under NEP's Tariff No. 1. These transmission services are regulated by both ISO-NE and by the FERC. NEP charges ISO-NE for these transmission services. As NEP is the sole operator of NEPOOL assets, ISO-NE revenues are remitted from NEP to the Company representing the substantial portion of the affiliated accounts receivable due from NEP.

In turn, ISO-NE charges the Company for regional network services ("RNS") with some of those charges being associated with the Company-owned transmission assets in the NEPOOL. As of March 31, 2021 and March 31, 2020, $18.6 million and $17.2 million of the unpaid charges from ISO-NE to the Company have been presented as an affiliated payable to NEP related to these Company-owned transmission assets, respectively. Additionally, NEP also charges the Company local network service ("LNS") rates. Amounts paid to NEP for LNS for the years ended March 31, 2021, 2020 and 2019 were $52.7 million, $57.4 million, and $46.5 million, respectively. These amounts are presented within operations and maintenance expense within the accompanying statements of income.

Advances from Affiliates

Since December 2008, the Company had FERC and board authorization to borrow up to $250 million as deemed necessary for working capital needs. The advance is non-interest bearing. As of March 31, 2021 and 2020, the Company had no outstanding advances from affiliates.

Intercompany Money Pool

The settlement of the Company's various transactions with NGUSA and certain affiliates generally occurs via the intercompany money pool in which it participates. The Company is a participant in the Regulated Money Pool and can both borrow and invest funds. Borrowings from the Regulated Money Pool bear interest in accordance with the terms of the Regulated Money Pool Agreement. As the Company fully participates in the Regulated Money Pool rather than settling intercompany charges with cash, all changes in the intercompany money pool balance are reflected as investing or financing activities in the accompanying statements of cash flows. For the purpose of presentation in the statements of cash flows, it is assumed all amounts settled through the intercompany money pool are constructive cash receipts and payments, and therefore are presented as such.

The Regulated Money Pool is funded by operating funds from participants. NGUSA has the ability to borrow up to $3.0 billion from National Grid plc for working capital needs including funding of the Regulated Money Pool, if necessary. The Company had short-term intercompany money pool investments of $158.6 million and borrowings of $351.4 million as of March 31, 2021 and 2020, respectively. The average interest rates for the intercompany money pool were 0.7%, 2.4%, and 2.4% for the years ended March 31, 2021, 2020, and 2019, respectively.

Service Company Charges

The affiliated service companies of NGUSA provide certain services to the Company at cost without a markup. The service company costs are generally allocated to associated companies through a tiered approach. First and foremost, costs are directly charged to the benefited company whenever practicable. Secondly, in cases where direct charging cannot be readily determined, costs are allocated using cost/causation principles linked to the relationship of that type of service, such as number of employees, number of customers/meters, capital expenditures, value of property owned, and total transmission and distribution expenditures. Lastly, all other costs are allocated based on a general allocator determined using a 3-point formula based on net margin, net property, plant and equipment, and operations and maintenance expense.

Charges from the service companies of NGUSA to the Company are mostly related to traditional administrative support functions, of which for the years ended March 31, 2021, 2020, and 2019 were $270.6 million, $250.8 million, and $229.7 million, respectively.

Division 2-36

Request:

Referring to paragraph 38 of the Petition, please:

a. provide any available estimate of the acquisition premium that will be booked, but not recovered through rates, as a result of the Transaction;

b. State whether the Applicants will seek to include the effect of the acquisition premium or transaction costs in the capital structure used for ratemaking purposes; and

c. provide any available estimate of the transaction costs related to the Transaction. The response should itemize and quantify all such Transaction costs, regardless of whether PPL will seek to recover such costs in Rhode Island retail rates.

Response:

a. PPL's current estimate of the acquisition premium is $1.0 billion. Narragansett currently has goodwill on its books of $725 million. The acquisition premium anticipated to be recorded by PPL will not be pushed down to Narragansett's balance sheet and will be retained on PPL's corporate balance sheet.

b. PPL and PPL RI will not seek to include the effect of the acquisition premium or transaction costs in the capital structure used for ratemaking purposes. See PPL and PPL RI's response to data request Division 2-3. The purchase accounting journal entries, including the creation of additional goodwill/acquisition premium, will be recorded at PPL RI and will not be pushed down to Narragansett, resulting in no changes to Narragansett's books and therefore, will not be included in the capital structure used for ratemaking purposes. In addition, see PPL and PPL RI's response to data request Division 1-33. PPL will not seek recovery of transaction costs and such costs will not be included in the capital structure used for ratemaking purposes.

c. See PPL and PPL RI's response to data request Division 1-32. At this time PPL and PPL RI do not have an estimate of what the total Transaction costs will be as they continue to assess system needs. PPL and National Grid continue to work together to ascertain that estimate.

Prepared by or under the supervision of: Stephen K. Breininger

Division 6-3

Request:

Please explain the extent to which PPL has evaluated the need for ring-fencing to protect PPL Rhode Island/Narragansett post-Transaction, and provide any documents related to the consideration of ring-fencing measures related to the Transaction.

Response:

PPL has evaluated the need for ring-fencing to protect PPL Rhode Island/Narragansett post-Transaction that included the following considerations. First, PPL is a financially strong company with a market capitalization of approximately $22 billion as of June 30, 2021. Second, PPL's earnings are almost entirely derived from its regulated utility operations. Third, PPL has strong investment grade credit ratings that should benefit Narragansett; PPL expects Narragansett's overall credit rating profile will be stronger under PPL's ownership based on PPL and National Grid USA's respective current and expected credit ratings. Please see Attachments PPL-DIV 1-11-1 through PPL-DIV 1-11-16 and Attachments NG-DIV 1-11-1 through NG-DIV 1-11-5.

Based on these considerations, PPL has identified certain financial protections to ensure the financial stability of Narragansett and the reliability of its service in the event PPL or any of its affiliates face financial or other difficulties in the future. First, PPL plans to have Narragansett continue to issue its own long-term debt to finance its operations. Second, Narragansett has no plans to guarantee the credit of any PPL affiliates and will not do so at any point in the future without first obtaining regulatory approval. Third, neither PPL nor any of its affiliates plan to borrow or issue any security or incur any debt that pledges any assets of Narragansett, and they will not do so at any point in the future without first obtaining regulatory approval. These measures are consistent with measures currently in place for PPL's existing regulated utilities. In addition, PPL's financial strength and these protective measures insulate Narragansett against financial risk at least as much as the existing ownership and financial structure under National Grid. PPL, therefore, believes that the above-mentioned conditions provide sufficient ring-fencing to protect the financial health of Narragansett.

Division 8-6

Request:

Please provide a five-year history of credit ratings for PPL and each of PPL's U.S. utility subsidiaries. This history should identify for each entity: the issuer or corporate ratings, unsecured debt ratings, secured debt ratings and short-term debt ratings during the specified five-year period.

Response:

PPL and PPL RI refer to Attachment PPL-DIV 8-6-1 that includes the five-year history of credit ratings for PPL and each of PPL's U.S. utility subsidiaries.

5 Year Historical Ratings

Moody's 5 Year Historical Summary

Issuer	6/30/2021	12/31/2020	12/31/2019	12/31/2018	12/31/2017	12/31/2016
PPL Corporation						
Issuer Rating	Baa2	Baa2	Baa2	Baa2	Baa2	Baa2
Outlook	**Positive**	**Stable**	**Stable**	**Stable**	**Stable**	**Stable**
PPL Capital Funding						
Senior Unsecured	Baa2	Baa2	Baa2	Baa2	Baa2	Baa2
Junior Subordinated Notes	Baa3	Baa3	Baa3	Baa3	Baa3	Baa3
Short-term/Commercial Paper	P-2	P-2	P-2	P-2	P-2	P-2
Outlook	**Positive**	**Stable**	**Stable**	**Stable**	**Stable**	**Stable**
PPL Electric Utilities						
Issuer Rating	A3	A3	A3	A3	A3	A3
Senior Secured/First Mortgage Bonds	A1	A1	A1	A1	A1	A1
Tax Exempt Bonds(1)	A1/A3	A1/A3	A1/A3	A1/A3	A1/A3	A1/A3
Short-term/Commercial Paper	P-2	P-2	P-2	P-2	P-2	P-2
Outlook	**Stable**	**Stable**	**Stable**	**Stable**	**Stable**	**Stable**
LG&E and KU Energy LLC						
Issuer Rating	Baa1	Baa1	Baa1	Baa1	Baa1	Baa1
Senior Unsecured	Baa1	Baa1	Baa1	Baa1	Baa1	Baa1
Outlook	**Stable**	**Stable**	**Stable**	**Stable**	**Stable**	**Stable**
LG&E						
Issuer Rating	A3	A3	A3	A3	A3	A3
Senior Secured/First Mortgage Bonds	A1	A1	A1	A1	A1	A1
Tax Exempt Bonds(1)	A1/P-2	A1/P-2	A1/P-2	A1/P-2	A1/P-2	A1/P-2
Short-term/Commercial Paper	P-2	P-2	P-2	P-2	P-2	P-2
Outlook	**Stable**	**Stable**	**Stable**	**Stable**	**Stable**	**Stable**
Kentucky Utilities						
Issuer Rating	A3	A3	A3	A3	A3	A3
Senior Secured/First Mortgage Bonds	A1	A1	A1	A1	A1	A1
Tax Exempt Bonds(1)	A1/P-2	A1/P-2	A1/P-2	A1/P-2	A1/P-2	A1/P-2
Short-term/Commercial Paper	P-2	P-2	P-2	P-2	P-2	P-2
Outlook	**Stable**	**Stable**	**Stable**	**Stable**	**Stable**	**Stable**

(1) *Ratings may differ for each issuance due to differences on credit backing (Letter of Credit/Insured), if applicable.*

S&P's 5 Year Historical Summary

Issuer	6/30/2021	12/30/2020	12/30/2019	12/30/2018	12/30/2017	12/30/2016
PPL Corporation						
Issuer Rating	A-	A-	A-	A-	A-	A-
Short-term Issuer Rating	A-2	A-2	A-2	A-2	A-2	A-2
Outlook	**Stable**	**Stable**	**Stable**	**Stable**	**Stable**	**Stable**
PPL Capital Funding						
Issuer Rating	A-	A-	A-	A-	A-	A-
Senior Unsecured	BBB+	BBB+	BBB+	BBB+	BBB+	BBB+
Junior Subordinated Notes	BBB	BBB	BBB	BBB	BBB	BBB
Short-term/Commercial Paper	A-2	A-2	A-2	A-2	A-2	A-2
Outlook	**Stable**	**Stable**	**Stable**	**Stable**	**Stable**	**Stable**
PPL Electric Utilities						
Issuer Rating	A-	A-	A-	A-	A-	A-
Senior Secured/First Mortgage Bonds	A	A	A	A	A	A
Tax Exempt Bonds[(1)]	A	A	A	A	A	A
Short-term/Commercial Paper	A-2	A-2	A-2	A-2	A-2	A-2
Outlook	**Positive**	**Stable**	**Stable**	**Stable**	**Stable**	**Stable**
LG&E and KU Energy LLC						
Issuer Rating	A-	A-	A-	A-	A-	A-
Senior Unsecured	BBB+	BBB+	BBB+	BBB+	BBB+	BBB+
Outlook	**Stable**	**Stable**	**Stable**	**Stable**	**Stable**	**Stable**
LG&E						
Issuer Rating	A-	A-	A-	A-	A-	A-
Senior Secured/First Mortgage Bonds	A	A	A	A	A	A
Tax Exempt Bonds[(1)]	A/A-2	A/A-2	A/A-2	A/A-2	A/A-2	A/A-2
Short-term/Commercial Paper	A-2	A-2	A-2	A-2	A-2	A-2
Outlook	**Stable**	**Stable**	**Stable**	**Stable**	**Stable**	**Stable**
Kentucky Utilities						
Issuer Rating	A-	A-	A-	A-	A-	A-
Senior Secured/First Mortgage Bonds	A	A	A	A	A	A
Tax Exempt Bonds[(1)]	A/A-2	A/A-2	A/A-2	A/A-2	A/A-2	A/A-2
Short-term/Commercial Paper	A-2	A-2	A-2	A-2	A-2	A-2
Outlook	**Stable**	**Stable**	**Stable**	**Stable**	**Stable**	**Stable**

[(1)] Ratings may differ for each issuance due to differences on credit backing (Letter of Credit/Insured), if applicable.

Division 8-7

Request:

Please provide a comprehensive listing and description of all "ring fencing" measures to be implemented and maintained for Narragansett to protect Narragansett from affiliate risk and potential affiliate abuse post-closing on this Transaction. This should include both structural measures (e.g., maintaining Narragansett as a distinct corporate subsidiary with its own board of directors) and behavioral measures (e.g., a prohibition on Narragansett guaranteeing debt of an affiliate). For each measure identified, please state whether this is a commitment associated with the approval of this Transaction.

Response:

PPL expects to maintain Narragansett as a distinct corporate subsidiary with its own Board of Directors, which is consistent with PPL's other U.S. utility subsidiaries. PPL has previously outlined other behavioral measures as part of its response to data request Division 6-3 and incorporates that response by reference. The measure described in this response and the measures described in the response to data request Division 6-3 are PPL's plans and expectations for its operation of Narragansett post-closing; they are not currently specific commitments being made to obtain approval of this Transaction.

Prepared by or under the supervision of: Tadd Henninger

Division 8-8

Request:

The Advocacy Section understands that all of Narragansett's outstanding long-term debt is in the form of unsecured notes (other than the legacy Providence Gas first mortgage bonds). All else equal, for a given utility company and debt tenor, secured debt generally carries a lower cost rate than unsecured debt. Please state whether Narragansett will be issuing secured or unsecured debt following the close of the Transaction. If PPL is unwilling to issue secured debt in order to minimize costs for Narragansett debt in the future, please explain why.

Response:

After the transaction closes, PPL will evaluate Narragansett's current financing structure that is primarily senior unsecured long-term debt to determine if that is the most cost-effective structure and efficient form of financing prospectively. Narragansett may issue additional unsecured debt if appropriate under the circumstances. Currently, PPL's U.S. utility subsidiaries are SEC Registrants that access the public capital markets to issue senior secured debt through a First Mortgage Bond indenture. PPL plans to evaluate the cost benefits and constraints associated with making Narragansett an SEC registrant, which would also provide Narragansett the ability to issue senior secured, First Mortgage bonds in the public market versus senior unsecured debt via private placement.

Prepared by or under the supervision of: Tadd Henninger

Division 8-10

Request:

Please describe the role (if any) of PPL Capital Funding, Inc. will have, whether directly or indirectly, in providing financing for Narragansett following the close of the Transaction.

Response:

PPL Capital Funding is the financing entity of PPL Corporation that issues senior unsecured debt for the purpose of providing financing support to PPL's subsidiaries. PPL Capital Funding will likely provide Narragansett financial support indirectly through affiliate loans or capital contributions to balance and maintain Narragansett's capital structure following the close of the Transaction.

Prepared by or under the supervision of: Tadd Henninger

Division 8-11

Request:

In past base rate cases in recent years, Narragansett has removed "goodwill" on its balance sheet from the equity balance used to calculate its ratemaking capital structure. Please state whether PPL commits to continuing this practice for the ratemaking capital structure in the future. If PPL does not commit to continuing this practice, please explain why.

Response:

PPL plans to continue to exclude "goodwill" from the equity balance used to calculate its ratemaking capital structure. PPL will continue to exclude goodwill from this calculation so long as this treatment of goodwill remains consistent with the prevailing regulatory best practices with respect to ratemaking capital structure.

Prepared by or under the supervision of: Stephen Breininger and Tadd Henninger

---

Division 8-12

Request:

Please state whether PPL and its U.S. utility subsidiaries operate a utility money pool. If the answer is yes, state whether Narragansett will participate in that money pool following the close of the Transaction. If there is no such money pool at present, please state whether PPL anticipates implementing such an arrangement in the future, and provide detail regarding any such plans.

Response:

PPL does not operate a corporate money pool that includes all its U.S. utility subsidiaries. However, LG&E and KU participate in a money pool arrangement with their parent company, LKE. This money pool arrangement in Kentucky provides the ability to utilize cash amongst these operating subsidiaries that are jointly managed for purposes of rate case proceedings and ongoing financing needs with the Kentucky Public Service Commission. PPL currently has no plans to implement a utility money pool following the close of the Transaction, nor does PPL intend to have Narragansett participate in the LKE money pool arrangement. PPL will continue to evaluate and consider whether a money pool would be beneficial prospectively. This evaluation would include the cost benefits associated with that arrangement for Narragansett and PPL's other U.S. utility subsidiaries, including any required regulatory approvals in all of PPL's regulatory jurisdictions.

Prepared by or under the supervision of: Tadd Henninger

Division 8-14

Request:

Please state whether PPL commits to maintaining a minimum common equity ratio (i.e., excluding any goodwill on its balance sheet) for Narragansett following the close of the Transaction. If yes, please identify that minimum percentage.

Response:

PPL is not committing to maintaining a minimum common equity ratio for Narragansett following the close of the Transaction, but, consistent with PPL's practice in its other jurisdictions, PPL will manage Narragansett's common equity ratio to remain substantially consistent with the approved common equity ratio from Narragansett's most recent rate case, Rhode Island Public Utilities Commission Docket No. 4770, which is currently approximately 51%.

Prepared by or under the supervision of: Tadd Henninger