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March 8, 2019

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Review of Proposed Power Purchase Agreements Pursuant to R.I. Gen. Laws § 39-31 Docket No. 4929

Dear Ms. Massaro:

Enclosed for filing with the Rhode Island Public Utilities Commission (PUC) are the responses of National Grid[1] to the Division's First Set of Data Requests.

Please contact me at 617-951-1400 if you have any questions regarding this filing.

Very truly yours,

John K. Habib

John K. Habib, Esq.
R.I. Bar # 7431

cc: Docket No. 4929 Service List

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

Docket No. 4929 – National Grid's Review of PPA w/ WWD Rev I, LLC

Service List updated 2/22/2019

Name/Address	E-mail Distribution	Phone
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DWW Rev I, LLC Joseph A. Keough Jr., Esquire Keough + Sweeney, Ltd. 41 Mendon Avenue Pawtucket, Rhode Island 02861	jkeoughjr@keoughsweeney.com;	401-724-3600
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The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4929
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	Attachment	CONFIDENTIAL ATTACHMENT
COMMISSION SET 1							
COMMISSION SET 1	PUC 1-1	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Pricing		
COMMISSION SET 1	PUC 1-2	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Pricing		
COMMISSION SET 1	PUC 1-3	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Transmission		
COMMISSION SET 1	PUC 1-4	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Transmission		
COMMISSION SET 1	PUC 1-5	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Transmission		
COMMISSION SET 1	PUC 1-6	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Transmission		
COMMISSION SET 1	PUC 1-7	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Transmission		
COMMISSION SET 1	PUC 1-8	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Pricing		
COMMISSION SET 1	PUC 1-9	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Transmission		
COMMISSION SET 1	PUC 1-10	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Cost Recovery		
COMMISSION SET 1	PUC 1-11	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Transmission		
COMMISSION SET 1	PUC 1-12	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Cost Recovery		
COMMISSION SET 1	PUC 1-13	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Transmission		
COMMISSION SET 1	PUC 1-14	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Transmission		
COMMISSION SET 1	PUC 1-15	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Pricing		
COMMISSION SET 1	PUC 1-16	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	Transmission		
COMMISSION SET 1	PUC 1-17	2/25/2019	3/7/2019	Timothy J. Brennan and Corinne M. DiDomenico	PPA Terms		

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4929
Discovery Log

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	TOPIC	Attachment	CONFIDENTIAL ATTACHMENT
DIVISION SET 1							
DIVISION SET 1	DIV 1-1	2/25/2019	3/8/2019	Timothy J. Brennan and Corinne M. DiDomenico	Remuneration	Att. DIV 1-1	
DIVISION SET 1	DIV 1-2	2/25/2019	3/8/2019	Timothy J. Brennan and Corinne M. DiDomenico	Remuneration	Att. DIV 1-2	
DIVISION SET 1	DIV 1-3	2/25/2019	3/8/2019	Timothy J. Brennan and Corinne M. DiDomenico	Remuneration		
DIVISION SET 1	DIV 1-4	2/26/2019	3/8/2019	Timothy J. Brennan, Corinne M. DiDomenico & Robert B. Hevert	Remuneration		
DIVISION SET 1	DIV 1-5	2/26/2019	3/8/2019	Timothy J. Brennan, Corinne M. DiDomenico & Robert B. Hevert	Remuneration		
DIVISION SET 1	DIV 1-6	2/26/2019	3/8/2019	Timothy J. Brennan, Corinne M. DiDomenico & Robert B. Hevert	Remuneration		
DIVISION SET 1	DIV 1-7	2/26/2019	3/8/2019	Timothy J. Brennan, Corinne M. DiDomenico & Robert B. Hevert	Remuneration		
DIVISION SET 1	DIV 1-8	2/26/2019	3/8/2019	Robert B. Hevert	Remuneration		
DIVISION SET 1	DIV 1-9	2/26/2019	3/8/2019	Robert B. Hevert	Remuneration		
DIVISION SET 1	DIV 1-10	2/26/2019	3/8/2019	Robert B. Hevert	Remuneration		
DIVISION SET 1	DIV 1-11	2/26/2019	3/8/2019	Robert B. Hevert	Remuneration		
DIVISION SET 1	DIV 1-12	2/26/2019	3/8/2019	Robert B. Hevert	Remuneration	Att. DIV 1-12-1, DIV 1-12-2, DIV 1-12-3, DIV 1-12-4, DIV 1-12-5, DIV 1-12-6, DIV 1-12-7, DIV 1-12-8, DIV 1-12-9, DIV 1-12-10, DIV 1-12-11, DIV 1-12-12, DIV 1-12-13, DIV 1-12-14, DIV 1-12-15, DIV 1-12-16, DIV 1-12-17, DIV 1-12-18, & DIV 1-12-19	
DIVISION SET 1	DIV 1-13	2/26/2019	3/8/2019	Timothy J. Brennan, Corinne M. DiDomenico & Robert B. Hevert	Remuneration		
DIVISION SET 1	DIV 1-14	2/26/2019	3/8/2019	Robert B. Hevert	Remuneration		
DIVISION SET 1	DIV 1-15	2/26/2019	3/8/2019	Timothy J. Brennan, Corinne M. DiDomenico & Robert B. Hevert	Remuneration		

DIV 1-1

Request:

Please provide copies of all Narragansett Electric Company ("NEC" or "the Company") credit rating reports issued since January 1, 2018 to the present.

Response:

Please see Attachment 1 for the credit ratings report by Moody's from January 1, 2018 to present. There were no reports by S&P during the period and the Company is not rated by Fitch.

Prepared by or under the supervision of: Timothy J. Brennan and Corinne M. DiDomenico

INFRASTRUCTURE AND PROJECT FINANCE

MOODY'S INVESTORS SERVICE

CREDIT OPINION
14 May 2018

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.

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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

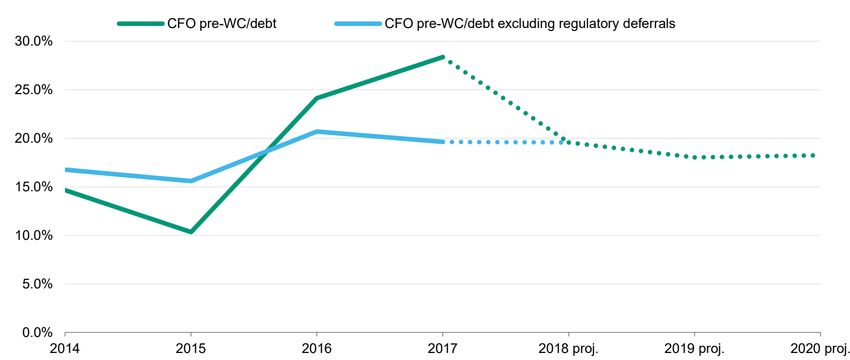
Summary

The credit quality of Narragansett Electric Company (NEC) is supported by the diversification of its revenues between distribution and transmission, stable and predictable cash flows, and the generally supportive regulatory environment in Rhode Island, where a wide variety of de-risking provisions for utilities have been included in recent rate cases. Credit quality is constrained by additional debt at the parent holding companies, including National Grid North America Inc (NGNA, Baa1 stable) and National Grid Plc (NG plc, Baa1 stable).

The achieved returns on equity in NEC's distribution businesses have generally been at or above the allowed ROE of 9.5% under the previous rate plan, although electricity distribution fell to 6.2% in the year to March 2017. Electricity transmission has demonstrated stable returns consistently above the 10.57% allowance, although ongoing challenges to FERC's rate-setting process creates some uncertainty about future returns. Excluding regulatory deferrals, CFO pre-WC to Debt has been stable in the mid to high teens, in percentage terms.

The company has recently filed new rate cases for its distribution businesses, with the new rates expected to be effective in September 2018. We had expected this to support a modest strengthening in NEC's key credit metrics. However, following US tax reforms, announced in December 2017, we now expect metrics to remain around current levels.

Exhibit 1
New rate case expected to support CFO-pre WC to Debt in the high teens



Source: Moody's

Credit strengths

» Supportive regulatory environment for low business risk electricity and gas distribution in Rhode Island

» Stable and predictable FERC regulatory framework and low transmission business risk underpins transmission cash flows

Credit challenges

» Limited regulatory ring-fencing protections from additional debt at various holding companies

Rating outlook

NEC is expected to remain comfortably positioned for the assigned rating, with CFO pre-WC/debt in the mid- to high-teens in percentage terms, excluding regulatory deferrals.

Factors that could lead to an upgrade

» CFO pre-working capital to gross debt consistently above the low 20s, in percentage terms

» Increase of FERC and/or RIPUC's supportiveness towards utilities versus its current approach

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

Factors that could lead to a downgrade

» Decrease of FERC and/or RIPUC's overall supportiveness

» CFO pre-WC / debt persistently below the mid teens, in percentage terms

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

Key indicators

Exhibit 2

Key indicators[1]

Narragansett Electric Company

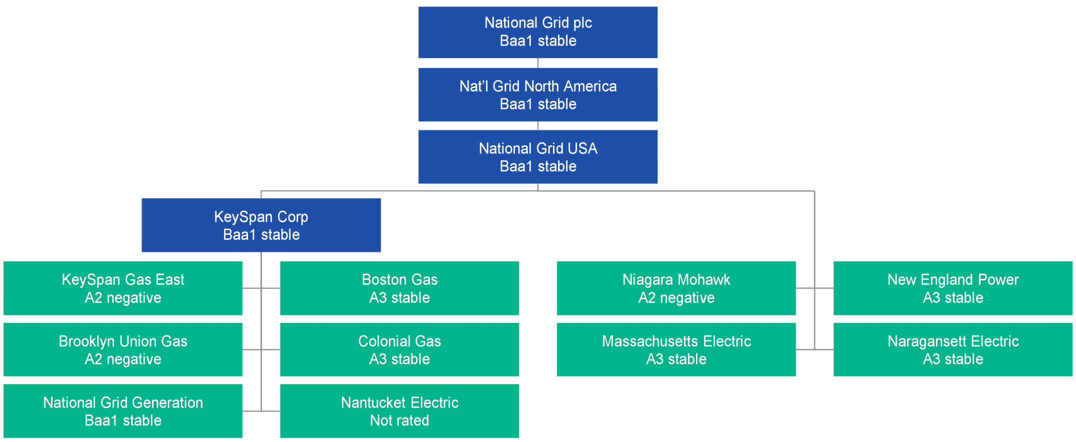
	FY14	FY15	FY16	FY17	FY18 proj.	FY19 proj.	FY20 proj.
CFO pre-WC + Interest / Interest	4.6x	3.4x	6.7x	7.1x	5.9x	5.8x	6.1x
CFO pre-WC / Debt	14.7%	10.3%	24.1%	28.4%	19.6%	18.0%	18.2%
CFO pre-WC – Dividends / Debt	14.7%	10.3%	24.1%	28.4%	19.6%	10.5%	11.4%
Debt / Capitalization	36.7%	35.7%	32.9%	31.5%	31.4%	36.2%	38.3%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics™

Corporate profile

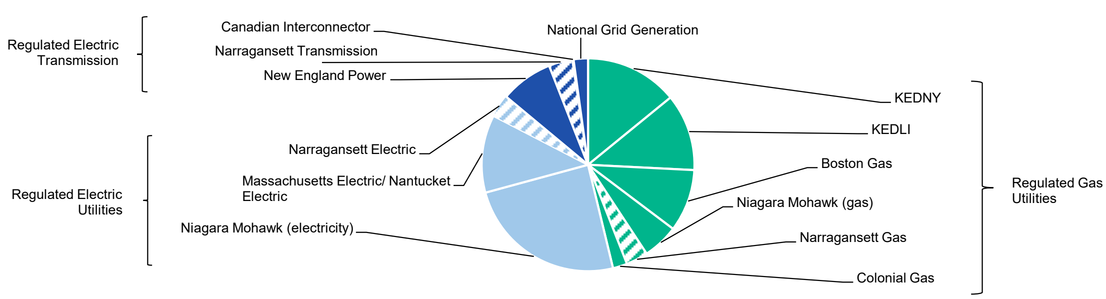
NEC is a retail distribution company providing electric service to approximately 500,000 customers and gas service to approximately 270,000 customers in Rhode Island. It also owns electricity transmission assets in Rhode Island operated by sister company New England Power (NEP, A3 stable). As of March 2017, NEC has a rate base of $2.0 billion, comprised of $697 million of electricity transmission (regulated by the FERC) and $665 million and $640 million of electric and gas distribution respectively (regulated by the RIPUC). NEC is fully owned by National Grid USA (NG USA, Baa1 stable), a holding company which is ultimately owned by National Grid plc (National Grid, Baa1 stable).

Exhibit 3
National Grid North America simplified group structure



Source: Moody's

Exhibit 4
Narragansett represents 10% of National Grid's US rate base
Rate base at 31 March 2017



Narragansett regulated entities dashed
Source: National Grid

Detailed credit considerations

Distribution businesses generating consistent performance; new rate case expected this year

The current rate plans for NEC's electricity and gas business were approved by the RIPUC in December 2012 and have been effective from February 2013. Approved returns on equity (ROEs) are 9.5%, which was slightly below the average equity returns accorded to energy utilities nationwide during the 12 months leading up to the decision. NEC is subject to an earnings sharing mechanism, under which NEC is required to share equally with ratepayers incremental earnings between a 9.5% and a 10.5% ROE, and 75% of incremental earnings above a 10.5% ROE.

The rate plan provides for 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.

Exhibit 5
Narragansett Distribution Service Areas
Rhode Island

Source: National Grid

Exhibit 6
Rate Cases Summary

Regulated Business	Narragansett Electric	Narragansett Gas	Narragansett Transmission
Regulator	Rhode Island Public Utilities Commission		Federal Energy Regulatory Commission
Primary term of rate case	2013		-
Allowed return on equity	9.50%		10.57%
Achieved return on equity (2016/17)	6.20%	9.40%	11.40%
Rate Base at March 2017	$665m	$640m	$697m

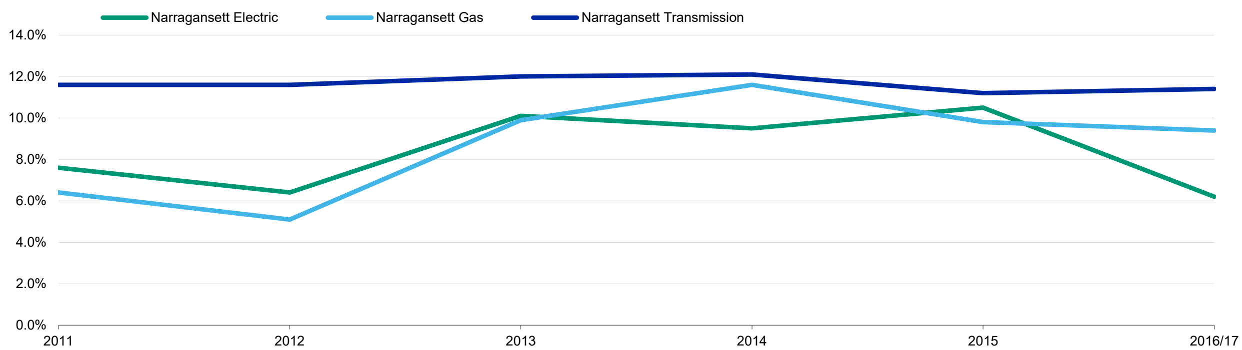
Source: National Grid

Despite the introduction of a number of de-risking provisions, including full revenue decoupling and capital trackers, we view the regulatory environment in Rhode Island as tougher than in some other states due to the RIPUC's history of allowing lower returns than other regulators, and its use of backward-looking test years. Utilities operating under backward-looking test years are generally expected to have more difficulties in recovering their opex, resulting in a need to file more frequently for a new rate case, a source of regulatory risk, although the RIPUC incorporates some adjustments for forecast capital investment, volumes and operating costs.

In 2016/17, NEC's achieved ROEs for the electric and gas businesses were 6.2% and 9.4%, respectively, below the allowed level of 9.5%.

NEC filed for a new rate case in November 2017, which included a proposal for a $71.6m uplift in allowed revenue. The new rate plan would be effective from September 2018. The filing proposes a return on equity of 10.1% and a cost of debt allowance of 4.69% and 5.18% for NEC's Electric and Gas segments respectively, subject to an assumed capitalization rate of 51%. The RIPUC provided its initial response to NEC's request in April 2018 with a final Commission decision expected in August 2018.

Exhibit 7
Dip in electricity distribution ROE to 6.2% in 2016/17; new rate plan expected to support credit metrics from FY19



Source: National Grid

Transmission benefits from stable and predictable FERC regulatory framework

New England Power (NEP), another National Grid subsidiary, operates the transmission facilities of its New England associate as a single integrated system and reimburses Narragansett Electric Transmission for the cost of its transmission facilities in Rhode Island, including a return on those facilities. The amount reimbursed to Narragansett Electric Transmission for the year ended 31 March 2017 was $143 million.

Transmission business has no exposure to the end consumer, and therefore no commodity price risk. The credit supportive regulatory environment and formula-based rate making process provided by the FERC also support credit quality. Provisions include a forward-looking rate setting mechanism, designed to reimburse the company for all prudently-incurred operating and maintenance expenditure, 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 Narragansett Electric Transmission 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 transmission owners to earn ROEs that tend to be above those allowed by state regulators. In line with NEP and other transmission owners in New England, Narragansett Electric 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 Electric Transmission benefits from additional incentive mechanisms which could increase the allowed ROE up to 11.74%. However, the base return could be increased following a decision by the court of appeals (see highlight box).

Section 206 dispute creates uncertainty over future allowed returns

Allowed returns for transmission operators in the ISO-NE 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. Although FERC determined, based on a discounted cash flow analysis, that the plausible range of returns, known as the "zone of reasonableness," was 7.03-11.74% (down from 7.3-13.1% in a previous 2006 decision), the commission declared that the existing 11.14% return was "unjust and unreasonable." 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[1], which found that 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 remanded to FERC for reconsideration.

There are currently several outstanding ROE challenges, the most recent brought by Eastern Massachusetts Consumer-Owned Systems, which has called for the ROE to be cut to 8.93%.

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 to be more stable and predictable than for state-regulated utility businesses. The transmission business continued to perform strongly with achieved ROE of 11.4% in 2017, slightly above the allowed level, as has been the case for the last eight years.

Tax reforms will negatively affect utility cash flows

The 2017 tax reform legislation will have an overall negative credit impact on regulated operating companies and their holding companies (see Regulated Utilities - US: Tax reform is credit negative for sector, but impact varies by company, 24 January 2018). Moody's estimates that the recent changes in tax laws will dilute most utilities' CFO pre-WC/debt by approximately 150-250 basis points, depending to some degree on the size of the company's capital expenditure program.

Although the regulated utility sector is carved out in terms of the treatment of interest deductibility and expensing of capital expenditures, from an earnings perspective the effect on regulated entities is neutral because savings on the lower tax expense are passed on to their customers, as required by regulation. However, from a cash flow perspective the legislation is credit negative, because regulated utilities typically pay much less tax in cash.

It is not yet clear how, and how quickly, various regulators, including FERC and RIPUC, will adjust allowed revenues to reflect the change. However, in March 2018, FERC initiated an inquiry into the impact of US tax reforms on public utilities with a view to ensuring that the benefits of tax reform are being accurately reflected in customer rates. In the January 2018 rate order for Niagara Mohawk Power Corporation (NiMo, A2 stable), an NGNA subsidiary, the NYPSC noted that the benefits of tax reform should accrue to customers.

Stable credit metrics, but high parent debt and weak financial ring-fencing provisions constrain the ratings

NEC's headline credit metrics have strengthened since 2015, with CFO to gross debt at 28.4% in 2017 compared to 10.6% in 2015. However, the improvement was driven partially by swings in regulatory assets and liabilities; excluding these cash flows, NEC's CFO pre-WC/debt has been consistently in the mid to high teens in percentage terms. Assuming that NEC's rate plan will require it to pass through substantially all of the reduction in tax expense through lower bills, we expect NEC's ratio of CFO pre-WC to Debt to remain in the high teens.

However, NEC's credit quality is constrained by the presence of additional debt at the company's parent holdings companies, NG USA, National Grid North America Inc (NGNA, Baa1 stable) and National Grid. This risk is exacerbated by weaker regulatory ring-fencing provisions applicable to NEC compared with some other state-regulated utilities within the National Grid group, particularly those in New York. Under FERC licence conditions, NEC must maintain a debt to total capitalisation ratio of less than 70%, which gives the company a significant degree of headroom compared with its existing level of leverage, around 56%.

Liquidity analysis

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

National Grid manages its financing and liquidity on a fully group basis with a central Finance Committee setting the rules by which individual entities can raise capital. For the US subsidiaries, including NEC, 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, while the unregulated holding companies – NG USA, NGNA and KeySpan Corporation (Keyspan, Baa1 stable) – may only act as lenders. The interest rate for borrowing under the money pool is determined by reference to the cost of meeting its funding needs, typically a mix of 30-day A2 commercial paper and any other long- and short-term funding sources issued at its parent, NGNA.

To support the regulated money pool, the parent holding companies have in place bilateral facilities of £2.4 billion maturing between 2019 and 2022 and for which National Grid, NG USA and NGNA are named borrowers. The facilities were undrawn as of March 2017. In addition, NGUSA and Keyspan can borrow $3 billion under a working capital facility with National Grid plc. NG USA also has two commercial paper programs totaling $4 billion denominated equally in US dollars and Euros. As of March 2017, there was $759 million outstanding on the US commercial paper program and €210 million outstanding on the Euro commercial paper program. Viewed in this wider context, NEC's liquidity position appears much stronger.

Rating methodology and scorecard factors

NEC is rated in accordance with the methodology Regulated Electric and Gas Utilities published in June 2017. The outcome of the methodology grid for NEC is A2 based on historical and A3 based on projected metrics.

Exhibit 8
Rating factors
Narragansett Electric Company

Regulated Electric and Gas Utilities Industry Grid [1][2]	Current FY 3/31/2017		Moody's 12-18 Month Forward View As of 4/27/2018 [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	5x - 6x	A
b) CFO pre-WC / Debt (3 Year Avg)	20.7%	A	17% - 19%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	20.7%	A	10% - 12%	Baa
d) Debt / Capitalization (3 Year Avg)	33.3%	Aa	36% - 38%	Aa
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A2		A3
HoldCo Structural Subordination Notching		0		0
a) Indicated Rating 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 03/31/2017
[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 Table

	Narragansett Electric Company			Delmarva Power & Light Company			Potomac Electric Power Company			Jersey Central Power & Light Company		
	A3			Baa1			Baa1			Baa2		
USD Millions	FY15	FY16	FY17	FY15	FY16	FY17	FY15	FY16	FY17	FY15	FY16	FY17
Revenue	1,500.0	1,306.2	1,263.4	1,302.0	1,277.0	1,300.0	2,129.0	2,186.0	2,158.0	1,853.0	1,833.0	1,827.0
CFO Pre - W/C	125.4	275.0	317.3	325.4	288.7	328.6	494.0	501.9	430.6	379.5	422.2	478.4
Interest Expense	52.5	48.6	51.9	56.5	55.1	58.1	130.1	142.2	137.4	153.1	145.2	117.8
Gross Debt	1,214.1	1,139.5	1,118.8	1,579.8	1,467.4	1,631.1	2,623.4	2,539.8	2,680.6	2,756.0	2,481.0	2,121.0
Net Debt	1,194.8	1,125.1	1,111.0	1,574.8	1,421.4	1,629.1	2,618.4	2,530.8	2,675.6	2,756.0	2,481.0	2,121.0
Book capitalization	3,398.0	3,459.8	3,556.0	3,753.8	3,841.4	3,557.1	6,552.4	6,707.8	6,234.6	6,279.0	6,382.0	5,867.0
(CFO Pre-W/C + Interest) / Interest	3.4x	6.7x	7.1x	6.8x	6.2x	6.7x	4.8x	4.5x	4.1x	3.5x	3.9x	5.1x
(CFO Pre-W/C) / Debt	10.3%	24.1%	28.4%	20.6%	19.7%	20.1%	18.8%	19.8%	16.1%	13.8%	17.0%	22.6%
(CFO Pre - W/C - Dividends) / Debt	10.3%	24.1%	28.4%	14.8%	16.0%	13.3%	13.3%	14.4%	11.1%	13.8%	17.0%	22.6%
Debt / Book Capitalization	35.7%	32.9%	31.5%	42.1%	38.2%	45.9%	40.0%	37.9%	43.0%	43.9%	38.9%	36.2%

Source: Moody's Financial Metrics™. All figures are calculated using Moody's estimates and standard adjustments.

Exhibit 10
Debt Adjustment Breakdown

(in US Millions)	FYE Mar-12	FYE Mar-13	FYE Mar-14	FYE Mar-15	FYE Mar-16	FYE Mar-17
As Reported Debt	**798.2**	**906.6**	**848.6**	**1,084.7**	**1,039.7**	**969.0**
Pensions	91.1	138.8	123.0	128.2	94.2	144.4
Hybrid Securities	1.2	1.2	1.2	1.2	1.2	1.2
Non-Standard Adjustments	0.0	0.0	253.0	0.0	4.4	4.1
Moody's-Adjusted Debt	**890.6**	**1,046.7**	**1,225.8**	**1,214.1**	**1,139.5**	**1,118.8**

Source: Moody's Financial Metrics™. All figures are calculated using Moody's estimates and standard adjustments.

Ratings

Exhibit 11

Category	Moody's Rating
NARRAGANSETT ELECTRIC COMPANY	
Outlook	Stable
Issuer Rating	A3
Senior Secured MTN	(P)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 USA	
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured MTN	(P)Baa1
Commercial Paper	P-2

Source: Moody's Investors Service

Endnotes

1 United States Court of Appeals for the District of Columbia, On Petitions for Review of Orders of the Federal Energy Regulatory Commission, 14 April 2017

REPORT NUMBER 1105131

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

DIV 1-2

Request:

Please provide a copy of the most recent presentation by NEC management (or National Grid management on NEC's behalf) to the credit rating agencies.

Response:

See Attachment 2 for the presentation provided to the credit rating agencies.

Prepared by or under the supervision of: Timothy J. Brennan and Corinne M. DiDomenico

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Half Year Results
2018/19

8 November 2018

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Cautionary statement

This presentation contains certain statements that are neither reported financial results nor other historical information. These statements are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These statements include information with respect to National Grid's (the Company) financial condition, its results of operations and businesses, strategy, plans and objectives. Words such as 'aims', 'anticipates', 'expects', 'should', 'intends', 'plans', 'believes', 'outlook', 'seeks', 'estimates', 'targets', 'may', 'will', 'continue', 'project' and similar expressions, as well as statements in the future tense, identify forward-looking statements. These forward-looking statements are not guarantees of National Grid's future performance and are subject to assumptions, risks and uncertainties that could cause actual future results to differ materially from those expressed in or implied by such forward-looking statements. Many of these assumptions, risks and uncertainties relate to factors that are beyond National Grid's ability to control, predict or estimate precisely, such as changes in laws or regulations, including any arising as a result of the United Kingdom's exit from the European Union, announcements from and decisions by governmental bodies or regulators, including those relating to the role of the UK electricity system operator; the timing of construction and delivery by third parties of new generation projects requiring connection; breaches of, or changes in, environmental, climate change and health and safety laws or regulations, including breaches or other incidents arising from the potentially harmful nature of its activities; network failure or interruption, the inability to carry out critical non network operations and damage to infrastructure, due to adverse weather conditions including the impact of major storms as well as the results of climate change, due to counterparties being unable to deliver physical commodities, or due to the failure of or unauthorised access to or deliberate breaches of National Grid's IT systems and supporting technology; performance against regulatory targets and standards and against National Grid's peers with the aim of delivering stakeholder expectations regarding costs and efficiency savings, including those related to investment programmes and internal transformation, cost efficiency and remediation plans; and customers and counterparties (including financial institutions) failing to perform their obligations to the Company. Other factors that could cause actual results to differ materially from those described in this announcement include fluctuations in exchange rates, interest rates and commodity price indices; restrictions and conditions (including filing requirements) in National Grid's borrowing and debt arrangements, funding costs and access to financing; regulatory requirements for the Company to maintain financial resources in certain parts of its business and restrictions on some subsidiaries' transactions such as paying dividends, lending or levying charges; inflation or deflation; the delayed timing of recoveries and payments in National Grid's regulated businesses and whether aspects of its activities are contestable; the funding requirements and performance of National Grid's pension schemes and other post-retirement benefit schemes; the failure to attract, train or retain employees with the necessary competencies, including leadership skills, and any significant disputes arising with National Grid's employees or the breach of laws or regulations by its employees; the failure to respond to market developments, including competition for onshore transmission, the threats and opportunities presented by emerging technology, development activities relating to changes in the energy mix and the integration of distributed energy resources; and the need to grow the Company's business to deliver its strategy, as well as incorrect or unforeseen assumptions or conclusions (including unanticipated costs and liabilities) relating to business development activity, including assumptions in connection with the Company's sale of the remaining Cadent stake. For further details regarding these and other assumptions, risks and uncertainties that may impact National Grid, please read the Strategic Report section and the 'Risk factors' on pages 193 to 196 of National Grid's most recent Annual Report and Accounts. In addition, new factors emerge from time to time and National Grid cannot assess the potential impact of any such factor on its activities or the extent to which any factor, or combination of factors, may cause actual future results to differ materially from those contained in any forward-looking statement. Except as may be required by law or regulation, the Company undertakes no obligation to update any of its forward-looking statements, which speak only as of the date of this presentation.

Agenda

Highlights
John Pettigrew

Financial review
Andy Agg

Priorities and outlook
John Pettigrew

nationalgrid

Highlights

John Pettigrew
Chief Executive

nationalgrid

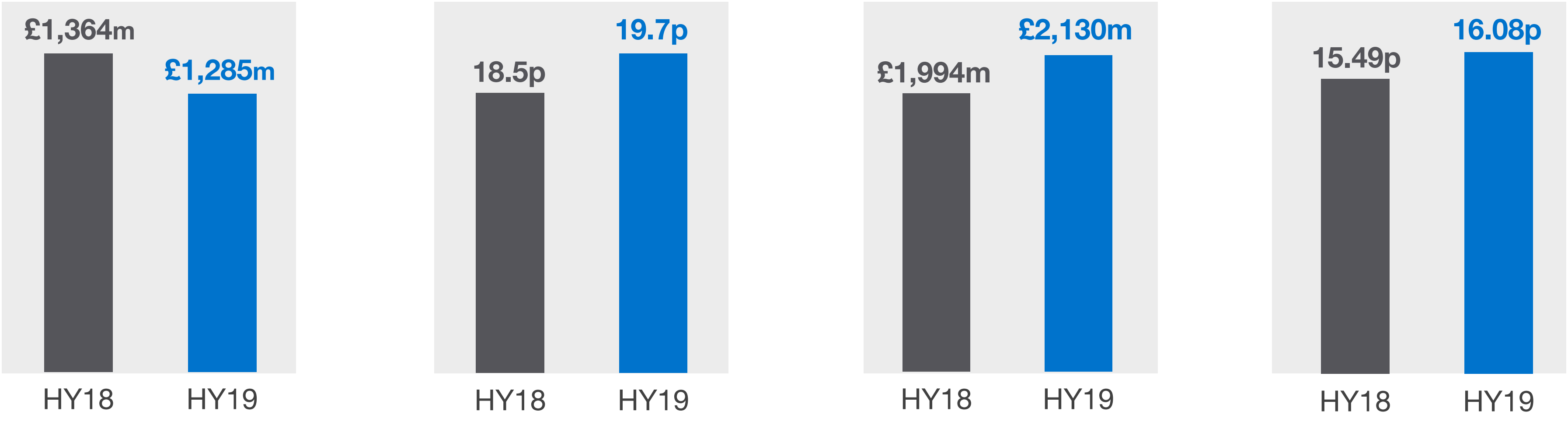
Solid financial performance

Underlying operating profit
down 6%

Underlying earnings per share
up 6%

Capital investment
up 7%

Dividend growth in line with policy
up 3.8%



Underlying results from continuing operations, excluding exceptional items, remeasurements, timing and major storms

Operating profit and capital investment calculated at constant currency

Capital investment includes investment in JVs (excluding equity contributions to St William property JV)

Safety and reliability performance

- Continued strong safety performance
  - employee IFR of under 0.1*
- Strong reliability across our networks in H1
- Good response to US storms in April and May
- Well prepared for the winter

* Employee IFR is the number of injuries per 100,000 hours worked in a 12 month period for employees

Strong strategic progress

- Decision to exercise the options on our remaining 39% stake in Cadent
- Completed full refresh of rates for US distribution companies
- Started significant cost efficiency programme in the UK
- Taken final investment decision on Viking interconnector to Denmark

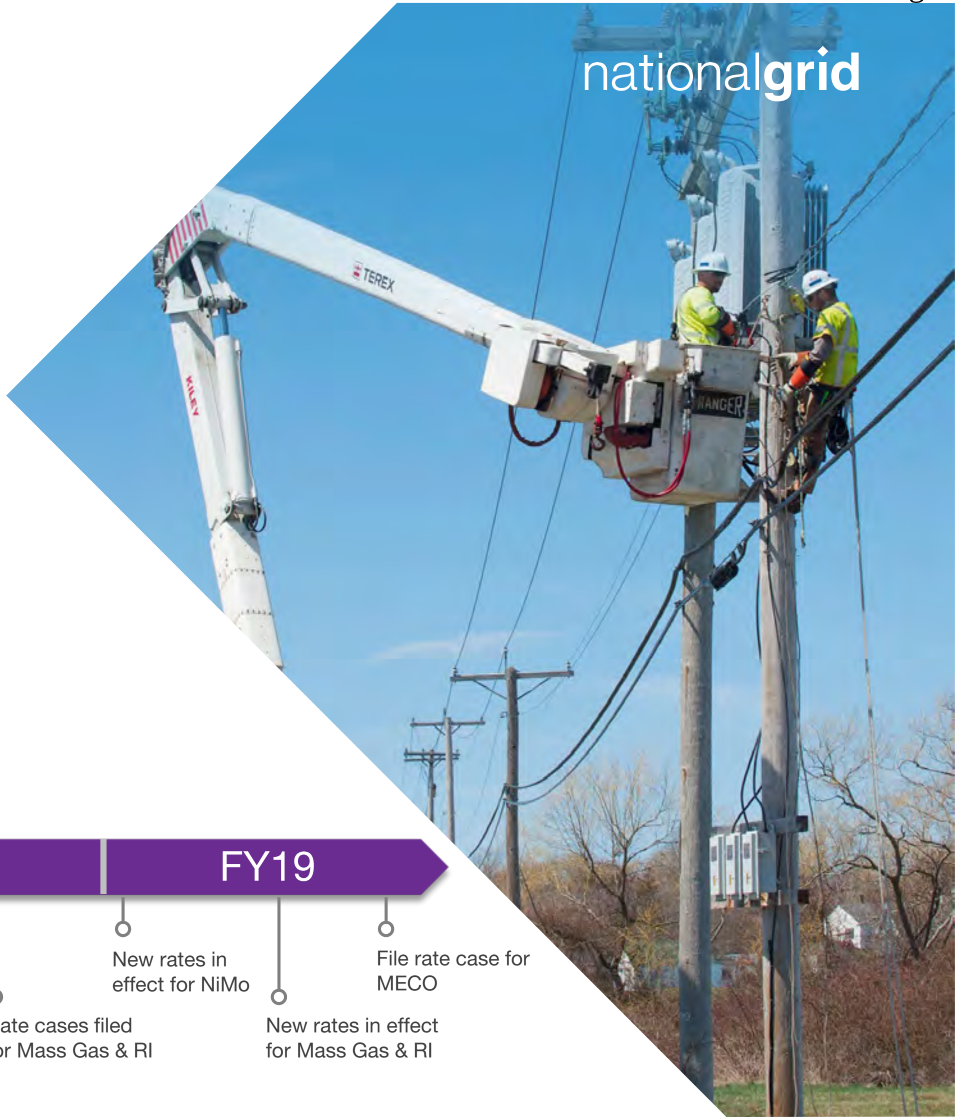
Cadent – sale of remaining share

- Sale completion in June 2019
- Will complete exit of UK gas distribution
- Created significant value for shareholders
  - £4bn returned to shareholders last year
- Cash proceeds of £2bn to be reinvested in the business

Delivering strong US organic growth

- $1.5bn capital invested in H1
- Mix of multiple small and large projects drive rate base growth
- e.g. South Street substation, Providence RI, $80m project
  - to build a new substation and secure reliability for downtown Providence
  - increases reliability and supports economic development

Good regulatory progress in the US



- All distribution businesses now under refreshed rate plans
  - RI and Mass. Gas agreed most recently
  - full refresh provides solid foundation to deliver capex and strong returns
- Clarity on tax reform impact

Progress on regulatory filings

FY16	FY17	FY18	FY19
Rate cases filed for MECO, KEDNY & KEDLI	New rates in effect for MECO; New rates in effect for KEDNY & KEDLI	Rate cases filed for NiMo; Rate cases filed for Mass Gas & RI	New rates in effect for NiMo; New rates in effect for Mass Gas & RI; File rate case for MECO

New rates agreed in Rhode Island and Massachusetts Gas

Rhode Island
Gas and Electric rates

Summary of outcome

- 3 year rate plan from September 2018
- RoE of 9.3%
- $240m annual capex allowance
- Upside only incentives of 7-20 bps

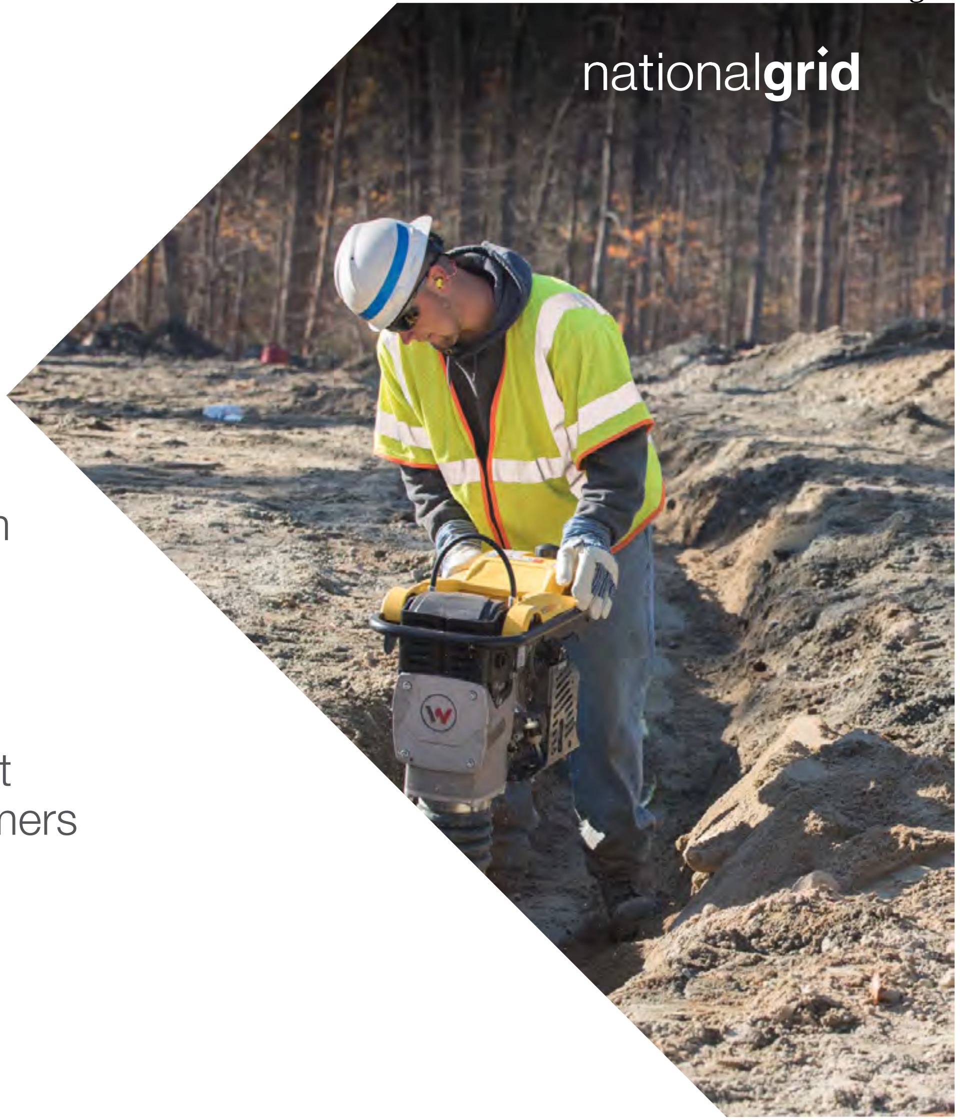
Massachusetts
Gas rates

Summary of outcome

- RoE of 9.5%
- $413m annual capex allowance
- New rates effective from October 2018

Massachusetts Gas union negotiation update

- Ongoing negotiations with two unions
  - 16 other unions accepted deals on similar terms
- Contingency workforce plan implemented from end of June
- Incremental costs of £97m incurred to 30 September
- Negotiations ongoing to achieve fair settlement that minimises future cost increases for customers



Good UK performance continues

- Strong operational performance
- Consistent levels of investment
- Delivery of forecast ET Network Output Measures for FY19 well ahead of schedule
  - forecast to outperform over RIIO-T1
- Feeder 9 project progressing well
  - 1.7km tunnelling complete
  - on track for completion in Autumn 2020

Creating a more agile UK organisation

- Comprehensive review of UK cost base to ensure we are:
  - well positioned for the future
  - a more agile organisation
  - even more responsive to customers
- Expect to deliver at least £100m of opex savings from FY21

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UK regulatory update

- RIIO-T1 reopeners
  - allowances agreed for enhanced physical and cyber security spend
  - funding disallowed for compressor works
    - reviewing our approach to meeting emissions standards
  - asset health spend for Feeder 9 gas pipeline to continue project
- Approval for Visual Impact Provision for undergrounding transmission lines in Dorset

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Progress on NG Ventures and Property

North Sea Link
260km subsea cable laid so far

- 1.4GW, 720km link to Norway
- Expected to be operational in FY22

IFA 2
Cable duct drilling complete on UK end

- 1GW, 240km link to France
- Expected to be operational in FY21

Nemo Link
Energisation & station testing underway

- 1GW, 140km link to Belgium
- Commissioning before the end of March 2019

Fulham, London
Preliminary planning approval granted

- 17 acre site in central London
- 1,800 residential units, 35% affordable homes

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Financial Performance

Andy Agg
Interim CFO

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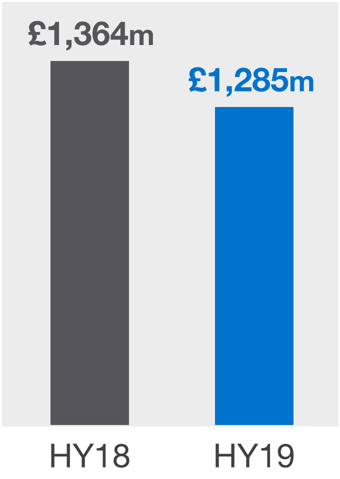
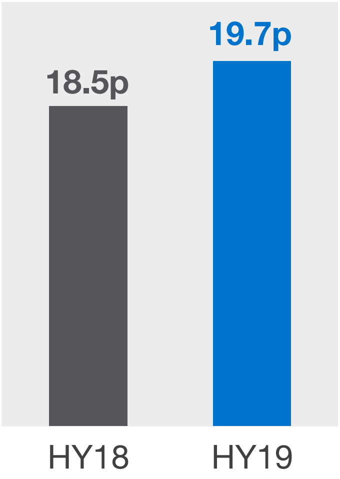
Solid financial performance

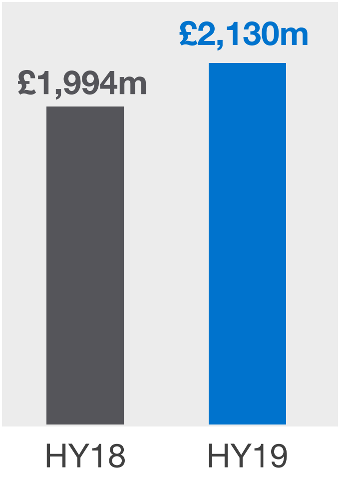
Underlying operating profit
down 6%



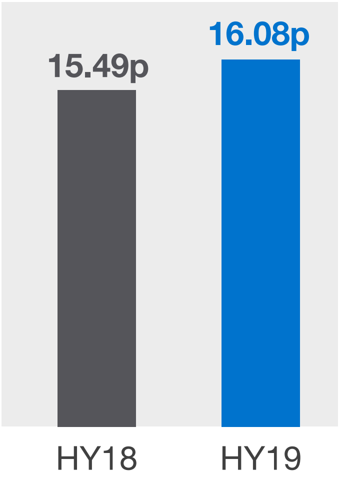
Underlying earnings per share
up 6%



Capital investment
up 7%



Dividend growth in line with policy
up 3.8%



Underlying results from continuing operations, excluding exceptional items, remeasurements, timing and major storms

Operating profit and capital investment calculated at constant currency

Capital investment includes investment in JVs (excluding equity contributions to St William property JV)

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UK Electricity Transmission

OUTLOOK	Totex incentive ▲	Other incentives ◀▶	Additional allowances ◀▶	▲ RoE
FY18	180bps	40bps	70bps	13.1%

UNDERLYING OPERATING PROFIT

£556m +3%

HY18 **£540m**

CAPITAL INVESTMENT

£462m

HY18 **£515m**

- Capital investment lower due to completion of non-load investments
  - FY20 will include cable undergrounding in Dorset and higher NOM's delivery
- Totex incentive expected to benefit from higher allowances in the re-opener filings

Underlying results, excluding timing, exceptional items, remeasurements and major storms

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UK Gas Transmission

OUTLOOK	Totex incentive ▼	Other incentives ▼	Additional allowances ◀▶	▼ RoE
FY18	(80)bps	120bps	(40)bps	10.0%

UNDERLYING OPERATING PROFIT

£91m -37%

HY18 **£144m**

CAPITAL INVESTMENT

£153m

HY18 **£157m**

- H1 operating profit decrease due to expected return of Avonmouth revenues received in prior years
- Totex incentive expected to reduce due to lower allowances in the re-opener filings
  - FY20 MOD expected to be approx. -£80m

Underlying results, excluding timing, exceptional items, remeasurements and major storms

UK cost efficiency programme

- Creating a leaner, more agile organisation
- £127m exceptional charge recognised in H1 of FY19
- Will generate opex savings of ~£50m in FY20 and ~£100m per annum from FY21 onwards
  - net cash positive from FY20 onwards
- Continue to expect 200-300bps of out-performance over the remainder of RIIO-T1

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US Regulated

OUTLOOK Targeting ROE in line with prior year ◀▶ **RoE**

UNDERLYING OPERATING PROFIT	CAPITAL INVESTMENT
£431m -17%	**$1.5bn**
HY18 **£522m**	HY18 **$1.4bn**

- Underlying operating profit reflects
  - benefit of new rate case outcomes
  - £56m higher storm costs and impact of US tax reform
- US profitability more weighted to H2 this year
- Massachusetts work contingency plan costs classified as an exceptional item
  - lower capex in Massachusetts Gas

Operating profit and capital investment calculated at constant currency
Underlying results, excluding timing, exceptional items, remeasurements and major storms

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Update on US tax reform impact

- Tax reform is economically neutral for utilities
  - lower cashflows in the near term
- Clarity on bill reductions for all operating companies
- $2.2bn deferred tax credit to be returned over up to 50 years
- Higher rate base growth

Overall impact on income statement	
FY19	• Impact on operating profit of $210m • More than offset by the lower tax charge • Small benefit to earnings
FY20	• Additional impact to operating profit of around $110m • Offset by the lower tax rate • No significant in year impact on earnings

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NG Ventures

OPERATING PROFIT	£78m Metering	£37m Grain LNG	£34m IFA	£(18)m Other	**£131m**
HY18	£83m	£37m	£34m	£(22)m	HY18 £132m

POST TAX SHARE of JVs	£13m BritNed	£8m Millennium	£10m Other	**£31m**
HY18	£18m	£6m	£nil	HY18 £24m

TOTAL INVESTMENT **£212m**
HY18 £180m

- Interconnector projects driving higher investment in NGV

Operating profit, share of joint venture profit after tax and investment calculated at constant currency
Underlying results, excluding timing, exceptional items, remeasurements and major storms

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Other activities

OPERATING PROFIT	£38m Property	£38m Corporate centre and other	**£76m**
HY18	**£53m**	**£(27)m**	HY18 **£26m**

POST TAX SHARE of JVs	£(6)m St. William	**£(6)m**
HY18	**£(4)m**	HY18 **£(4)m**

TOTAL INVESTMENT[1] **£126m**
HY18 **£53m**

- Fulham transaction expected in H2, subject to finalisation of site works and planning consents
- Legal settlements of £94m

1 Excludes investment in St. William joint venture
Operating profit, share of joint venture profit after tax and investment calculated at constant currency
Underlying results, excluding timing, exceptional items, remeasurements and major storms

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Interest, tax and earnings

FINANCE COSTS

£494m

9% lower than HY18

- One-off benefits offset higher net debt
- Effective interest rate of 4.4%

UNDERLYING EFFECTIVE TAX RATE[1]

19.3%

at £(153)m

- Tax rate 360bps lower than HY18
- Tax charge £36m lower than HY18

UNDERLYING EARNINGS

£662m

HY18 £656m

- 3,367m weighted average shares
- 19.7p/share

1 Excluding joint ventures and associates

Underlying results, excluding timing, exceptional items, remeasurements and major storms

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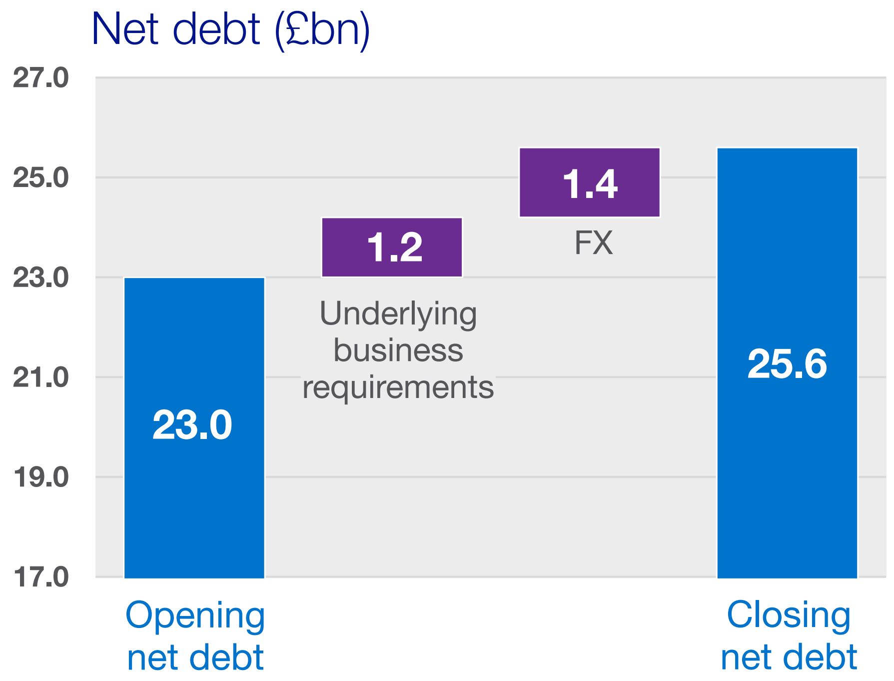
Cash flow and net debt

£m Period ended 30 September 2018	
Operating profit	1,202
Depreciation & amortisation	791
Pensions	(128)
Working capital & other	76
Net operating cash flow	**1,941**
Net debt	**(25,631)**



Underlying results, excluding timing, exceptional items, remeasurements and major storms

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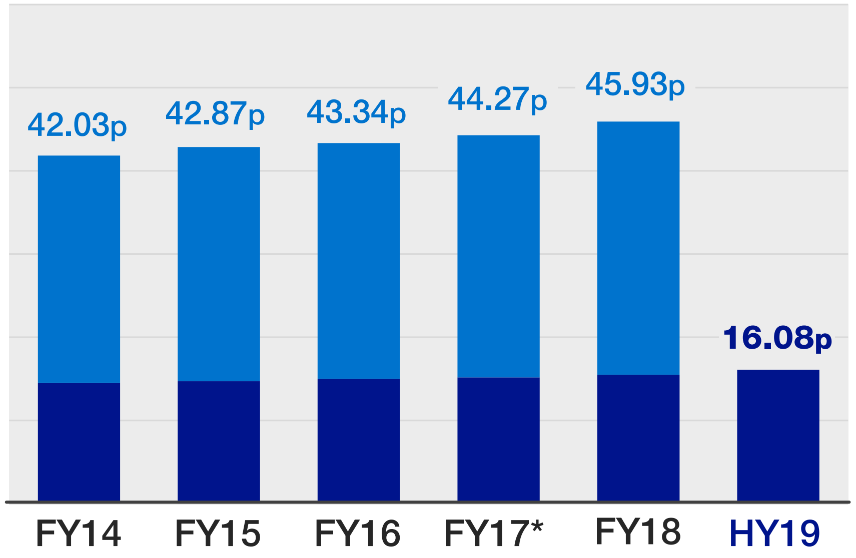
Dividend and scrip

- 16.08p, 35% of prior year full-year dividend
- Scrip option to be offered
- Policy to aim to grow dividend at least in line with UK RPI inflation

Dividend per share



* Excludes special dividend of 84.375p

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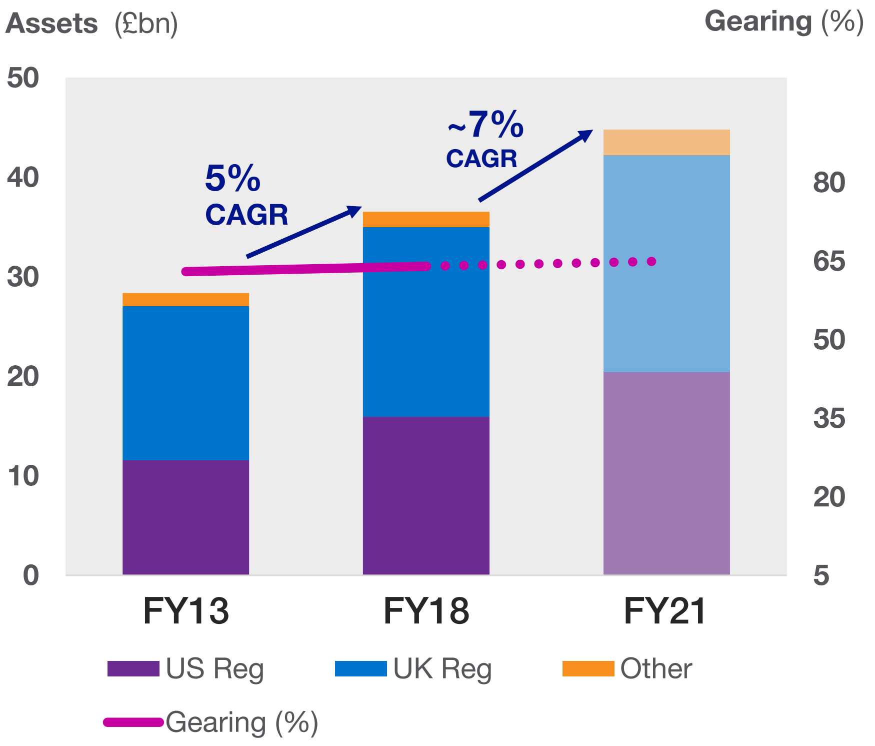
Efficiently funding growth

- Current strong organic growth being funded through
  - mix of debt at attractive rates
  - internally generated cash flows
  - scrip utilisation
  - Cadent proceeds in June 2019
- Forecast to maintain gearing at around 65% over the medium-term
  - higher gearing at 31 March 2019, ahead of Cadent proceeds
  - consistent with a strong credit rating
- Benefit of additional EBITDA from 2022 onwards



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Update to FY18/19 technical guidance

2017/18 underlying EPS excluding discontinued operations of 56.2p

- Key updates compared to year end technical guidance:
  - higher than anticipated storm costs in the first half, no impact on US RoE
  - legal settlements of £94m in Other activities segment to benefit full year
  - interest charge for the second half to be higher, as benefits in the first half are not repeated
- Performance remains on track

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Priorities & Outlook

John Pettigrew
Chief Executive

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Long-term drivers of success

Customer first

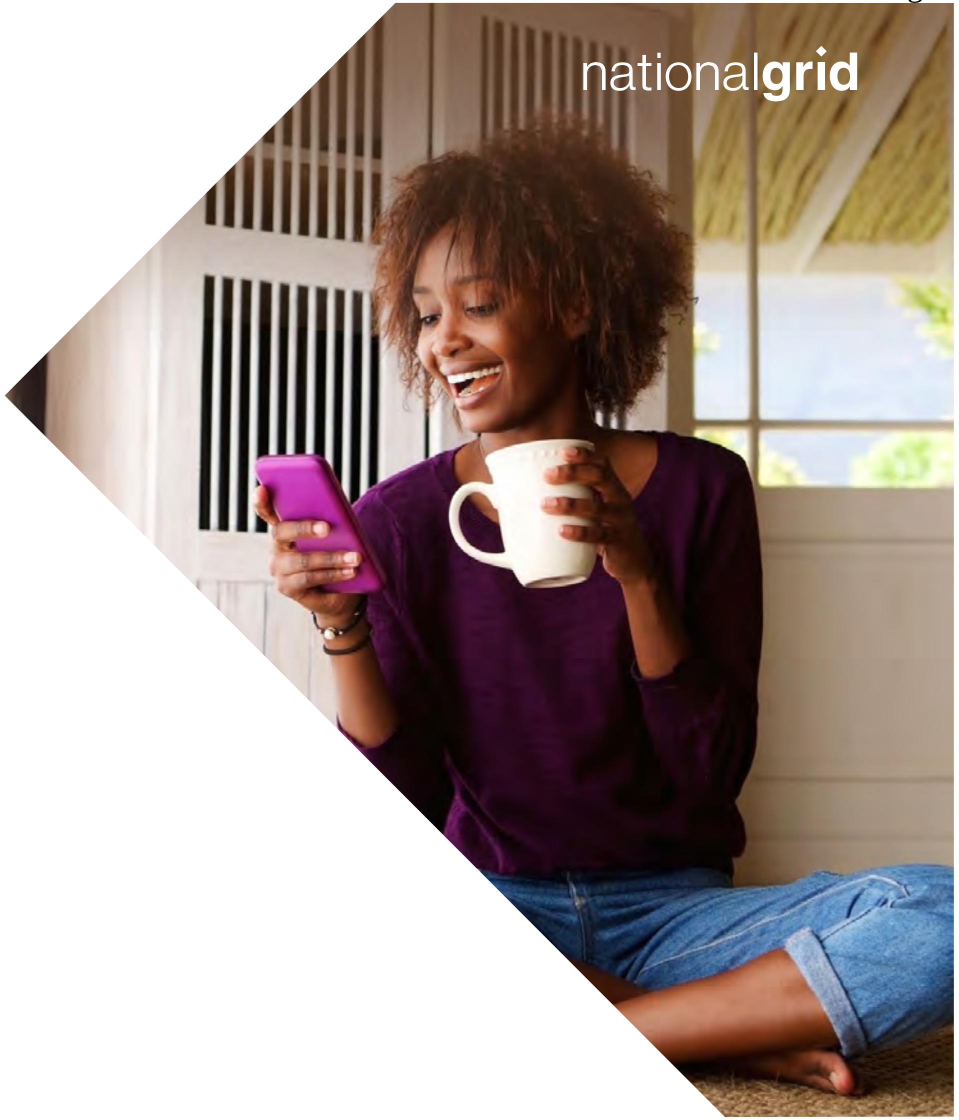
Performance optimisation

Growth

Evolve for the future

Customer first

- Energy transition and technological advancements enable more cost-effective customer service
- Performance optimisation central to meeting changing customer needs
- Stable and predictable regulatory frameworks are key



Performance optimisation

Regulatory frameworks that enable performance optimisation - UK

- Regulatory frameworks major area of focus
- RIIO-2 Framework decision in July
  - key RIIO principles reaffirmed
  - will work towards a fair return, reflecting level of risk borne by transmission
- Sector specific consultations in December
  - stakeholder led process

RIIO-T2 timeline

2017 | 2018 | 2019 | 2020 | 2021

Programme launch: Open letter

Framework consultation

Framework decision

Sector specific methodology consultation

Sector specific methodology decision

Formal business plan submission

Draft determination

Final determination

Statutory licence consultation

RIIO-T2 starts

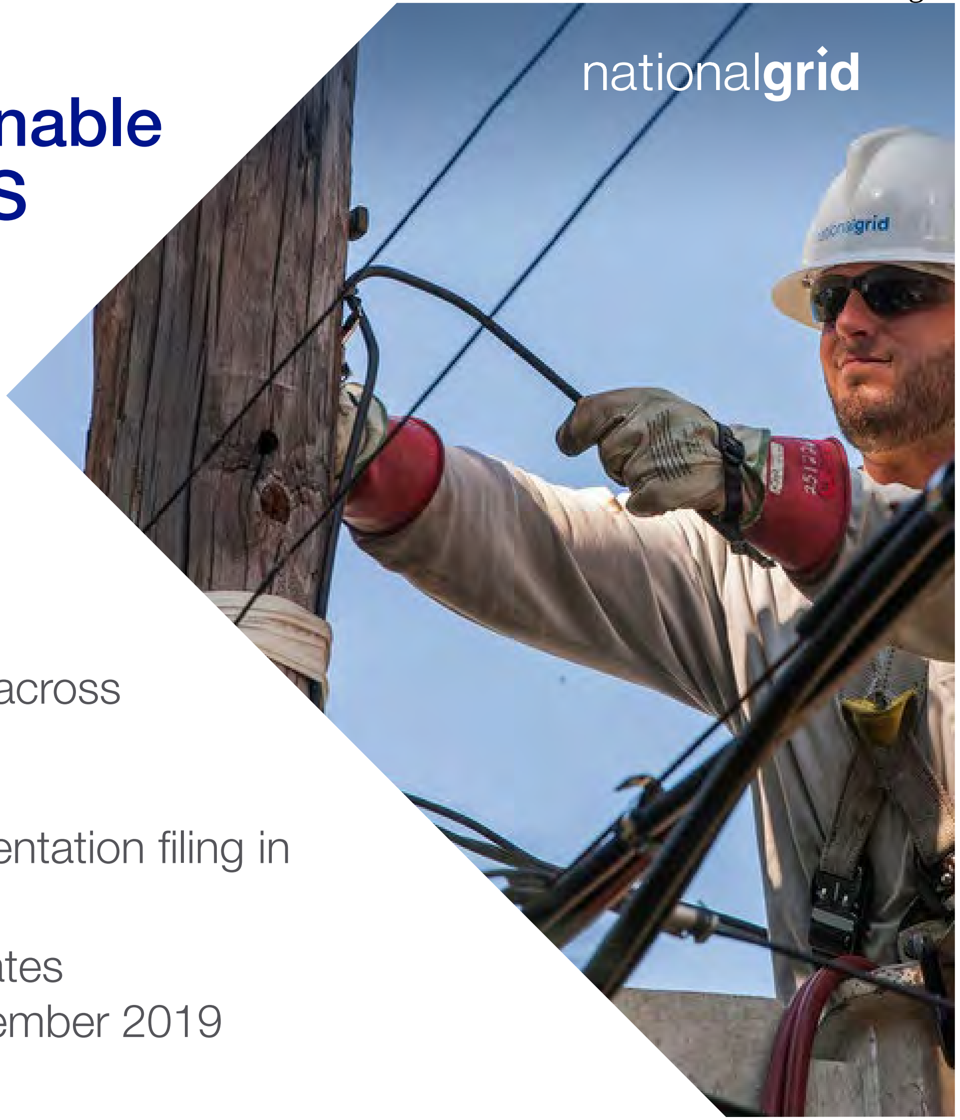
Performance optimisation

Regulatory frameworks that enable performance optimisation - UK

- SPV consultation on onshore competition underway
- Will work with Ofgem to develop a framework that delivers value for both customers and shareholders
- Complex model that doesn't present a clear customer benefit case
- Long-term track record of efficient delivery puts us in a strong position to win in a competitive environment
  - competitively tender around 90% of our costs

Performance optimisation

Regulatory frameworks that enable performance optimisation - US



- Trend of higher investment to continue across all jurisdictions
- Rate filing for new rates for Massachusetts Electric in November
  - will propose five year, forward-looking incentive based framework
- Changing customer needs driving investment across all jurisdictions
  - electric vehicle filings made
  - advanced metering infrastructure implementation filing in New York
- Reviewing next steps on KEDNY and KEDLI rates
  - current three-year plan concludes in December 2019

Growth

Interconnectors provide attractive long term cash flows

- Final investment decision taken on Viking interconnector
  - £850m investment
  - 760km, 1.4GW JV with the Danish transmission owner
  - go live in 2023
- All four new interconnectors provide
  - combined investment of £2.1bn
  - expected annual EBITDA contribution of £250m when fully operational in mid 2020s

Growth

Efficient delivery of growth

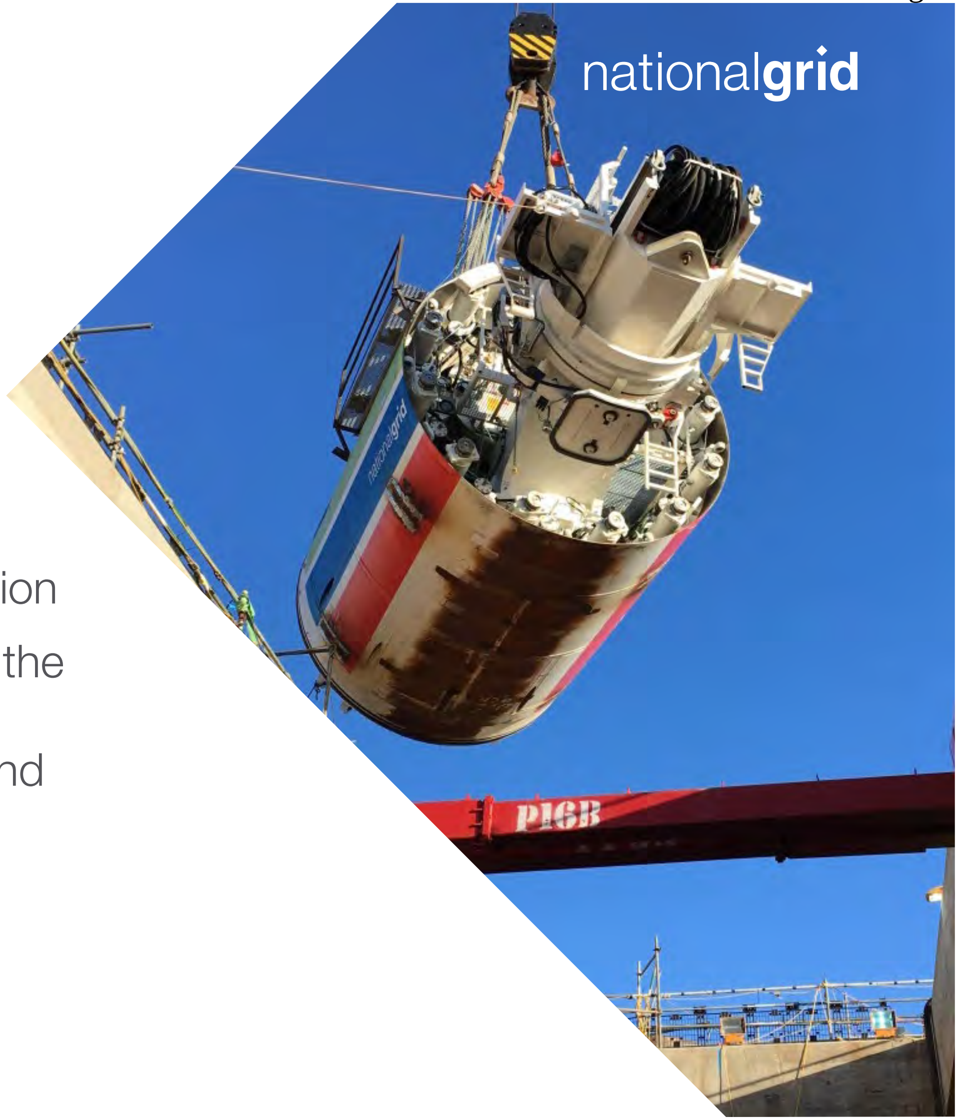
- Wide range of future growth drivers
  - asset health for safety and reliability in our core networks
  - new opportunities to meet changing customer needs
- Significant capex visibility to 2021
- Driving asset growth of at least 7% for the next two years
- Portfolio of businesses with high quality future growth prospects

Evolving for the future

- Small but growing portfolio of US renewables
  - almost 30MW solar and storage in operation and more under construction
- Wind and solar opportunities that match our capabilities and risk/reward profile
- Offshore wind agreements with Deepwater Wind
  - advising on subsea cable construction
  - options to purchase subsea links when commissioned

Summary

- Delivered solid financial performance and strong strategic progress
- Influencing the evolution of regulatory frameworks in UK and US
- Significant activity to be a more agile organisation
- Disciplined delivery on growth opportunities in the medium term
  - to create long term value for customers and shareholders



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John Pettigrew
Chief Executive

Andy Agg
Interim CFO

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Appendices

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Appendix 1

Pensions & other post-retirement benefit obligations (IAS 19 data)

	UK		US		
At 30 September 2018 (£m)	ESPS	NGUK PS	Pensions	OPEBs[1]	Total
Market value of assets	3,070	11,970	6,552	2,715	**24,307**
Present value of liabilities	(2,905)	(10,721)	(6,925)	(3,426)	**(23,977)**
Net asset / (liability)	165	1,249	(373)	(711)	**330**
Taxation	(28)	(212)	106	193	**59**
Asset / (liability) net of taxation	**137**	**1,037**	**(267)**	**(518)**	**389**
Discount rates	2.9%	2.9%	4.3%	4.3%	

	UK		US		
At 31 March 2018 (£m)	ESPS	NGUK PS	Pensions	OPEBs[1]	Total
Market value of assets	3,052	12,278	6,030	2,498	**23,858**
Present value of liabilities	(3,025)	(11,201)	(6,582)	(3,313)	**(24,121)**
Net asset / (liability)	27	1,077	(552)	(815)	**(263)**
Taxation	(5)	(183)	158	233	**203**
Asset / (liability) net of taxation	**22**	**894**	**(394)**	**(582)**	**(60)**
Discount rates	2.6%	2.6%	4.0%	4.0%	

1 OPEBs = other post employment benefits

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Appendix 2
Timing impacts

£m	UK Electricity Transmission	UK Gas Transmission	US Regulated[1]	Total
1 April 2018 opening balance	(44)	93	246	**295**
Restatement of opening balance	(6)	9	(6)	**(3)**
(Under) / over recovery	(25)	(12)	(46)	**(83)**
30 Sept 2018 closing balance to (recover) / return	**(75)**	**90**	**194**	**209**
1 April 2017 adjusted opening balance	(39)	110	332	**403**
(Under) / over recovery	2	(18)	(92)	**(108)**
30 Sept 2017 closing balance to (recover) / return	(37)	92	240	**295**
Year on year timing variance	(27)	6	46	**25**

1. Constant currency, presented using the average exchange rate for the 6 months to 30 September 2018 ($1.31 to £1.00)
Closing timing balances at actual closing exchange rates for September 2018 and September 2017 were £211m and £290m respectively

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Appendix 3
Weighted average number of shares

For period ended 30 September	**2018**	2017
Number of shares (millions):		
Current period opening shares	**3,355**	
Scrip dividend shares (weighted issue)	**10**	
Other share movements (weighted from issuance/repurchase)	**2**	
Weighted average number of shares	**3,367**	3,539
Underlying earnings (£m) - continuing operations	**662**	656
Underlying EPS (re-presented) - continuing operations	**19.7p**	18.5p

Underlying earnings represent statutory results excluding exceptional items, remeasurements, timing and major storms

nationalgrid

Appendix 4

Prior year income statement from continuing operations adjusted to exclude 39% of Cadent

	6 months to September 2017			12 months to March 2018		
	As reported	Cadent	Continuing	As reported	Cadent	Continuing
Underlying operating profit	1,368	-	1,368	3,495	-	3,495
Net financing costs	(527)	(15)	(542)	(974)	(27)	(1,001)
Post tax share of JVs & associates (Cadent)	55	(55)	-	123	(123)	-
Post tax share of JVs & associates (Other)	20	-	20	44	-	44
Underlying profit before tax	916	(70)	846	2,688	(150)	2,538
Tax	(192)	3	(189)	(598)	5	(593)
Non-controlling interest	(1)	-	(1)	(1)	-	(1)
Underlying profit after tax for the period	723	(67)	656	2,089	(145)	1,944
Weighted average number of shares (million)	3,539	3,539	3,539	3,461	3,461	3,461
Underlying earnings per share (pence)	20.4	(1.9)	18.5	60.4	(4.2)	56.2
Underlying profit after tax for the period	723	(67)	656	2,089	(145)	1,944
Timing	(109)	-	(109)	104	-	104
Major storms	-	-	-	(142)	-	(142)
Taxation on timing and major storms	40	-	40	9	-	9
Headline profit after tax for the period	654	(67)	587	2,060	(145)	1,915
Headline earnings per share (pence)	18.5	(1.9)	16.6	59.5	(4.2)	55.3

DIV 1-3

Request:

Please provide copies of all communications (inclusive of all correspondence, emails, memoranda, meeting notes) between NEC (or National Grid) and credit rating agencies pertaining to the Revolution Wind Purchase Power Agreement ("the PPA").

Response:

It is not typical for National Grid to raise issues with the credit-rating agencies in relation to future circumstances, not yet shown or included in the financial portfolio under review. Accordingly, National Grid has not yet had any cause to communicate with the credit-rating agencies pertaining to the proposed PPA.

Prepared by or under the supervision of: Timothy J. Brennan and Corinne M. DiDomenico

DIV 1-4

Request:

Please provide all analyses conducted by or for NEC concerning the expected or potential impact of the PPA on NEC's credit quality, credit metrics, cost of capital or liquidity requirements.

Response:

Please see Mr. Hevert's Direct Testimony at pages 18 through 28. There, Mr. Hevert discusses the qualitative and quantitative business and financial risks that the credit rating agencies consider when evaluating the effect of large-scale, long-term, fixed financial obligations, such as the PPA, on a company's credit quality. As his testimony explains, many of the assessments made by rating agencies are qualitative in nature, and do not lend themselves to a strictly quantitative analysis. Beyond the assessments included in his Direct Testimony, Mr. Hevert is not aware of specific, quantitative analysis of potential credit rating effects on NEC's cost of capital or credit profile. NEC has not performed any supplemental analyses.

Prepared by or under the supervision of: Timothy J. Brennan, Corinne M. DiDomenico, and Robert B. Hevert

DIV 1-5

Request:

NEC in this proceeding is requesting remuneration of 2.75 percent of PPA total contract expenditures by NEC. Please explain how the figure of 2.75 percent was calculated or developed and why this is the appropriate figure. Please provide with this response all supporting calculations, data inputs, assumptions and other documentation. If no specific calculations were performed in developing the 2.75 percent request, please so state but indicate the basis for requesting this amount.

Response:

NEC is voluntarily entering into this contract with DWW in recognition and support of Rhode Island's long-term clean energy goals. The 2.75 percent remuneration rate requested by NEC in this proceeding is consistent with the level of remuneration and incentives included in the Long-Term Contracting Standard for Renewable Energy (LTCS). Because the 400 MW Revolution Wind Project (Project) represents a large-scale renewable energy generation resource and is consistent with the type of generation facilities that would qualify for remuneration and incentives under the LTCS, the 2.75 percent Remuneration Rate is considered to be an appropriate level of remuneration and incentive in this proceeding. It is the same remuneration rate that National Grid's subsidiaries Massachusetts Electric Company and Nantucket Electric Company and other distribution companies are requesting in Massachusetts under Section 83C and Section 83D of An Act Relative to Green Communities.

Aside from the 2.75 percent expressly recognized by the LTCS, there is no remuneration rate that is reasonably derived through an analytical approach. As discussed on page 13 of Mr. Hevert's direct testimony, the effects of long-term renewable contract solicitations under the LTCS and the Rhode Island Affordable Clean Energy Security Act (ACES Act) on the Company's financial profile are not readily quantifiable because "the cumulative effect on the Company's financial profile depends on a range of variables, including prevailing market conditions, Company specific financial and business circumstances, and changes to state and federal laws and regulations." Importantly, certain of the factors consequential to debt and equity holders are assessed qualitatively and not readily reflected through quantitative analysis.

Moreover, there is no accepted or recognized method for calculating the impact of long-term renewable contracts on a company's balance sheet where the obligations do not constitute a debt obligation, which is the case here. Debt obligations typically arise when companies borrow capital in the form of loans, bonds, leases or other debt instruments owed by a corporation. That capital is invested in assets in which the borrowing entity has an economic interest, and on which it would earn a return. Here, there is no borrowing associated with the long-term Power

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Purchase Agreement (PPA) executed for the Project, nor will the Company earn a return on the Project, or on its payments under the PPA.

Nor is there any single quantitative analysis that would isolate the effect of the fixed obligations associated with the Project executed under the ACES Act. Numerous, speculative assumptions would need to be made, which may or may not be possible to validate. In fact, maintaining the strength of the balance sheet, and ensuring the ability to finance utility assets and to fund day-to-day operations is a fully dynamic exercise, dependent upon numerous inputs that vary on a daily, weekly, monthly, and yearly basis and that are inherently intertwined with the Company's overall operations. The Company employs a trained and experienced staff charged with assuring the integrity of the balance sheet and maintaining the best possible credit rating achievable on the basis of that balance sheet. The Company works daily to manage the factors affecting credit ratings and there is no discrete threshold at which financial obligations become a burden to the balance sheet. In that regard, there are numerous shifting considerations that interact to create balance sheet value including the availability and cost of different forms of financing at a particular time, existing and expected capital market conditions (including the availability of capital, the terms at which capital may be acquired, and the ability to subsequently "roll over" maturing financings), the level of existing and proposed debt relative to rating agency criteria, cash flow contingencies, planned and existing capital spending plans, and lead times associated with changing from short-term to long-term financing.

Nonetheless, the PPA represents a long-term, fixed obligation that must be satisfied regardless of the Company's cash flows, or its ability to access the capital markets. Moreover, as the residual claimants on cash flows, the equity investors that have provided the capital supporting the Company's credit profile would fall behind the PPA, as they generally fall behind other creditors. That is the case even though (as noted earlier) the Company is not investing in, and will not receive a return on the Project, or the PPA payments that enable the project.

Although Mr. Hevert's analysis determined a remuneration rate of up to 13.59 percent would produce net benefits for customers relative to the cost of the Project using a merchant financing method, the Company did not base its request on a specific calculation for the reasons discussed above. As discussed on page 3 of Mr. Hevert's direct testimony, the proposed 2.75 percent Remuneration Rate partially addresses the likely adverse effects on NEC's ongoing financial flexibility and credit profile brought about by the large, long-term, fixed financial obligation of entering into the PPA contract, and provides a high likelihood of creating significant customer benefits after consideration of the annual remuneration payments.

In summary, the 2.75 percent remuneration rate is appropriate for several reasons:

- The PPA to which the Company would become party is a substantial, long-term financial commitment, without which the public policy goals contemplated by the LTCS and the

ACES Act likely would not be attainable. It is unlikely that an offshore wind energy project of the size and scope contemplated in this proceeding could be developed in the absence of wholesale energy and capacity market mechanisms that enable renewable generation without the security of the contract revenues available by virtue of the PPA, and the Company's obligation thereunder. The need for stable financing for capital-intensive, offshore wind projects is particularly evident when we consider that only one offshore wind project has been completed in the United States to date, which has a much smaller capacity than the Project and was not selected through a competitive solicitation.

- It is the strength of NEC's balance sheet, as a creditworthy counterparty, that will enable the realization of the public policy goals envisioned in the LTCS and ACES Act. That financial strength and flexibility has been achieved over many decades of prudent investment and careful management and enables the Company to invest in assets that are dedicated to the public use, that is, to utility operations. The Company cannot add to its financial obligations in an unlimited manner without hindering its financial strength and flexibility, and limiting its opportunity to cost-effectively finance other investments.

- The Company will sell or use the products received under the contract, valued at prevailing market prices, and will pass through any net costs (or proceeds) to customers through rates. See ACES Act § 39-31-7(a)(5). Consequently, absent remuneration, the Company would be extending its balance sheet and transferring valuable economic benefits to the developers and consequently customers to support clean energy generation without compensation for the use of that capital.

- Notwithstanding the strength of the Company's balance sheet, it is not an unlimited resource that may be continually called upon at no economic cost. A utility company cannot continually rely on the strength of its balance sheet while taking on multiple financial obligations that provide no corresponding economic remuneration without diminishing its financial wherewithal and ability to access capital.

- If, at some point, the Company cannot acquire and deploy capital as it otherwise would have, there is an opportunity cost to investors. The 2.75 percent Remuneration Rate, which is compensation for taking on the financial obligation reflected in the PPA, may partially mitigate that opportunity cost, but not offset that opportunity cost.

- The proposed Remuneration Rate falls considerably below the net benefits likely to be created by the Company's financial profile and balance sheet. Putting aside the ACES Act's public policy objectives, the net benefits to ratepayers from relying on the Company's balance sheet are significant.

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- A remuneration amount equal to 2.75 percent of the annual payments under the long-term contract is reasonable and consistent with the LTCS.

For all of these reasons, remuneration equal to 2.75 percent of the annual payments under the PPA is the appropriate amount to compensate the company for accepting the long-term financial obligation of the 400 MW Revolution Wind PPA, and supporting the public policy goals contemplated the ACES Act. The need for such compensation "over and above the base rate revenue requirement established in [a utility's] cost of service for distribution ratemaking" is recognized by the LTCS § 39-26.1-4, and the ACES Act § 39-31-7(a)(7) allows the Commission to "[a]pprove any other proposed regulatory or ratemaking changes that reasonably advance the goals set forth herein."

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DIV 1-6

Request:

Is it NEC's or witness Hevert's position that the PPA will cause NEC to incur greater cash working capital requirements compared with no PPA? If so, please provide an estimate of the increased working capital requirement.

Response:

Based on the magnitude of the contractual payments required under the PPA, and the timing difference between payment for energy under the PPA and the collection of receivables from customers for the sale of energy from the Project, both NEC and Mr. Hevert believe that the PPA will cause NEC to incur greater cash working capital requirements on a par with other sizable investments such as capital investment programs. At this time, an estimate of the increased working capital requirement has not been prepared by NEC. As Mr. Hevert explains at pages 18 through 21 of his Direct Testimony, however, increased working capital requirements are only one of several factors that should be considered in assessing the proposed remuneration rate. Other factors include an increase in business and financial risks associated with long-term fixed financial obligations, such as increased earnings and cash flow variability created by increased operating leverage, that would be considered in the credit rating process. In Section V of his Direct Testimony at page 29 through 44, Mr. Hevert discusses the net economic benefits to customers after giving effect to the 2.75 percent remuneration rate, which is another important consideration in assessing the proposed remuneration rate.

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DIV 1-7

Request:

If the PPA does result in NEC incurring a greater cash working capital requirement, would the Company request the inclusion of the increased working capital in retail utility rate base as part of rate cases? Or would the 2.75 percent Remuneration Rate eliminate the need to include that increased cash working capital in the retail rate base. Please explain.

Response:

Yes, NEC expects that any increase in the cash working capital requirement would be reflected in its retail utility rate base and its utility cost of service to be submitted in future rate cases before the Commission. Please note that any increase in utility rate base attributable to an increase in cash working capital would recover the additional costs associated with the PPA, and it would not provide NEC with compensation for taking on the financial obligation of the PPA. The need for such compensation "over and above the base rate revenue requirement established in [a utility's] cost of service for distribution ratemaking" is recognized by the Long Term Contracting Standard for Renewable Energy § 39-26.1-4, and the Affordable Clean Energy Security Act § 39-31-7.(a)(7) allows the Commission to "[a]pprove any other proposed regulatory or ratemaking changes that reasonably advance the goals set forth herein."

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DIV 1-8

Request:

Assuming the Company's requested cost recovery mechanism for the PPA is approved, will the PPA have the net effect of increasing the Company's business risk and therefore its cost of equity? If so, please provide an estimate of the increased cost of equity.

Response:

As discussed on pages 13 and 14 of Mr. Hevert's Direct Testimony, the PPA represents a very sizeable, likely disclosable contractual commitment. The cumulative effect of that commitment on the Company's financial profile will depend upon a range of variables, including Company-specific financial and business circumstances such as the increased earnings and cash flow variability created by increased operating leverage. Moreover, equity investors' claims on cash flows generally fall behind the claims of creditors. To the extent that investors perceive even marginally more risk associated with the PPA, their required return would increase. Although Mr. Hevert has not estimated that effect, the relationship between increased risk and increased returns is well-accepted.

As explained at pages 6 and 7 of the Direct Testimony, the Affordable Clean Energy Security Act § 39-31-7.(a)(7) specifically allows the Commission to "[a]pprove any other proposed regulatory or ratemaking changes that reasonably advance the goals set forth herein." Also, the Long Term Contracting Standard for Renewable Energy § 39-26.1-4, entitles a utility to "financial remuneration and incentives for long-term contracts supporting newly developed renewable energy resources" equal to 2.75 percent for accepting the financial obligations created by the long-term contracts. The remuneration rate would help mitigate investors' concerns associated with increased risk, including investors' perceptions of regulatory risk.

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DIV 1-9

Request:

Will the PPA have the effect of changing the Company's target capital structure ratios (e.g., a higher equity ratio) as compared with no PPA? If so, please provide an estimate of the net change due to the presence of the PPA, including any support for this estimate.

Response:

Although it is possible, any potential change in the Company's target capital structure ratios associated with entering into the PPA would depend on whether a change in target capital structure ratios is appropriate to maintain the Company's current financial profile and credit ratings. To Mr. Hevert's knowledge, no specific change in the Company's target capital structure ratios has been determined at this time.

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DIV 1-10

Request:

If the PPA induces NEC to increase its equity ratio as a result of the PPA, would this increased equity ratio be reflected in the utility cost of service submitted in RIPUC rate cases, or would the Company consider this added cost to be covered by the Remuneration Rate.

Response:

As stated in the response to Data Request DIV 1-9, a PPA-related increase in the equity ratio would result from a decision by rating agencies to impute debt associated with the PPA. If that occurs, NEC may require an offsetting amount of increased equity in its capital structure to preserve its credit metrics. The extent of such an increase would depend on the amount, if any, of debt imputed by rating agencies. In NEC's view, the best outcome would be that no debt is imputed in connection with the PPA. That said, if NEC determines that an increase in its target equity ratio is necessary, then NEC expects the increased equity ratio would be reflected in the utility cost of service to be submitted in future rate cases before the Commission.

Please note that any increase in the equity ratio simply would recover the additional costs associated with the PPA. As discussed in the responses to Data Requests DIV 1-7 and 1-8, the purpose of the requested remuneration is to provide the Company with compensation for taking on the financial obligation of the long-term contract.

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DIV 1-11

Request:

Please provide a listing and description of other instances in which a utility regulatory commission has provided the regulated utility with purchase power remuneration payments (i.e., payments to the utility from customers in excess of the contract costs incurred by the utility) in jurisdictions other than Rhode Island. In each case, please state the jurisdiction, the utility, year approved and docket number. Also, please state whether this was mandated by legislation or at the discretion of the regulator.

Response:

To date, every procurement for long-term power purchase agreements under the Massachusetts Green Communities Act (GCA) has provided for remuneration to compensate the electric distribution companies for accepting the financial obligation of the long-term contract.

Section 83 of the GCA provided remuneration of 4 percent of annual contract payments. Chapter 169 of the Acts of 2008, An Act Relative to Green Communities, Section 83. The Massachusetts Department of Public Utilities provided the distribution companies with remuneration of 4 percent as mandated by the GCA. See Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, D.P.U. 10-54 Final Order at 315-317 (November 22, 2010); NSTAR Electric Company, D.P.U. 11-05/06/07 Final Order at 49 (August 19, 2011); Western Massachusetts Electric Company, D.P.U. 11-12 Final Order at 38 (October 7, 2011); NSTAR Electric Company, D.P.U. 12-30 Final Order at 182 (November 26. 2012); NSTAR Electric Company, D.P.U. 12-98 Final Order at 29-30 (May 3, 2013).

Subsequently, Section 83A was added to the Green Communities Act by Chapter 209 of the Acts of 2012, An Act Relative to Competitively Priced Electricity in the Commonwealth, Sections 35 and 37. Section 83A provided remuneration of 2.75 percent, mandated by statute. Remuneration of 2.75 percent was approved by the Department of Public Utilities. See Fitchburg Gas and Electric Company et al., D.P.U. 13-146/147/148/149 Final Order at 63 (February 26, 2014) and Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid et al., D.P.U. 17-117/118/119 Final Order at 62-63 (June 15, 2018).

Most recently, Chapter 188 of the Acts of 2016, An Act to Promote Energy Diversity added Section 83C and Section 83D to the Green Communities Act. Section 83C and Section 83D each provide for an annual remuneration for the contracting distribution company up to 2.75 percent of the annual payments under the contract to compensate the company for accepting the financial obligation of the long-term contract. The provision for remuneration must be acted upon by the Department of Public Utilities at the time of contract approval. The Section 83C and Section 83D

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long-term contracts, and the issue of remuneration, are currently pending before the Massachusetts Department of Public Utilities. See NSTAR Electric Company d/b/a Eversource Energy et al., D.P.U. 18-76/18-77/18-78 and NSTAR Electric Company d/b/a Eversource Energy et al., D.P.U. 18-64/18-65/18-66.

In the Commonwealth of Virginia, where the electricity market is regulated[1], there is legislation providing "enhanced" returns for certain types of generating assets and investments. The legislation makes clear the objectives are policy-oriented, and include social benefits beyond adding in-state generating capacity:

> To ensure the generation and delivery of a reliable and adequate supply of electricity, to meet the utility's projected native load obligations and to promote economic development, a utility may at any time, after the expiration or termination of capped rates, petition the Commission for approval of a rate adjustment clause for recovery on a timely and current basis…[2]

The Virginia legislation specifies the enhanced returns available to projects of varying types, including renewable energy, during certain portions of their service lives. Those returns vary from 100 to 200 basis points, depending on the nature of the asset and the timing of its construction and commercial operation.[3] The legislation aims to support and encourage equity investments designed to meet both generating resource and economic development objectives, both of which Virginia presumably considered important policy objectives.

[1] The Virginia Electric Utility Regulation Act ended Virginia's planned transition to retail competition for electric supply service to most classes of customers. See Act of Apr. 4, 2007, ch. 888, 2007 Va. Acts 2402 (codified as amended at VA. CODE ANN. §§ 56-576 to -594 (Repl. Vol. 2012 & Cum. Supp. 2014)); Act of Apr. 4, 2007, ch. 933, 2007 Va. Acts 2614 (codified as amended at VA. CODE ANN. §§ 56-576 to -594 (Repl. Vol. 2012 & Cum. Supp. 2014)).

[2] Code of Virginia Title 56. Public Service Companies Chapter 23. Virginia Electric Utility Regulation Act, §56-585.1.A.6.

[3] Id.

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DIV 1-12

Request:

Please provide copies of all documents (including relied upon credit rating reports) referenced in witness Hevert's testimony.

Response:

The 19 documents referenced in Mr. Hevert's testimony are being provided as attachments to this Discovery Request. Also included here is an index.

Prepared by or under the supervision of: Robert B. Hevert

Footnote	Document Name	Attachment Reference
1	Docket No. 4434, PUC Order 21593	DIV 1-12-1
2	Moody's, Changes Outlook on 25 US Reg Utilties, Jan 19, 2018 Report	DIV 1-12-2
3,4,6,7	NECO Annual Report 2017-2018	DIV 1-12-3
10,20	Moody's, Regulated Electric and Gas Utilities, June 23, 2017	DIV 1-12-4
11	S&P, U.S. Utilities Ratings Analysis Now Portrayed In The S&P Corporate Ratings Matrix, Nov. 30, 2007, at 2-3	DIV 1-12-5
12	S&P Criteria Methodology - Business Risk Financial Risk Matrix Expanded, May 27, 2009	DIV 1-12-6
13	S&P Methodology Business Risk Financial Risk Matrix Expanded, September 18, 2012	DIV 1-12-7
14,15	S&P, Key Credit Factors For The Regulated Utilities Industry, November 19, 2013	DIV 1-12-8
16	S&P Corporate Methodology Nov. 19, 2013	DIV 1-12-9
17	S&P, How Regulatory Advantage Scores Can Affect Ratings on Regulated Utilities, April 23, 2015	DIV 1-12-10
18	S&P, Assessing U.S. IOU Regulatory Environments, 10AUG2016	DIV 1-12-11
22	Weston, Brigham Managerial Finance p. 371-373	DIV 1-12-12
23	CFA Institute measures-leverage	DIV 1-12-13
28a	Mandelker & Rhee, Impact of the Degrees of Operating and Financial Leverage on Systematic Risk of Common Stock	DIV 1-12-14
28b	Mensah, Adjusted Accounting Beta Operating Leverage and Financial Leverage as Determinants of Market Beta: A Synthesis and Empirical Evaluation, Review of Quantitative Finance and Accounting, 2, (1992), at 199.	DIV 1-12-15
31a	Simple Levelized Cost of Energy (LCOE) Calculator Documentation _ Energy Analysis _ NREL	DIV 1-12-16
31b	Nrel_wind_energy_report_0817	DIV 1-12-17
32,36	lazards-levelized-cost-of-energy-version-12.0, Nov 2018	DIV 1-12-18
41,45	Blue Chip Financial Forecast 12.01.2018	DIV 1-12-19

Order 21593 - United Water: Rate Filing

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: UNITED WATER RHODE ISLAND
GENERAL RATE FILING

DOCKET NO. 4434

REPORT AND ORDER

I. Background

On August 13, 2013, United Water Rhode Island, Inc. (United Water RI or Company) submitted an application with the Rhode Island Public Utilities Commission (PUC or Commission) pursuant to R.I. Gen. Laws §39-3-11 for authority to increase its rates and charges for water service rendered within its service area. United Water RI is a wholly-owned subsidiary of United Waterworks, Inc. (sometimes UWW) which in turn is a wholly owned subsidiary of United Water Resources (sometimes UWR). UWR is owned by Suez Environment. The Company requested an overall increase in annual revenues of $1,563,153, or 42.59%, to be effective September 13, 2013 for a total cost of service of $5,233,419. At an open meeting on August 29, 2013, the Commission suspended the effective date of United Water RI's requested rate increase in order to conduct a full investigation and to hold public hearings. On August 23, 2013 and September 2, 2013, the Towns of Narragansett and South Kingstown, respectively, municipalities within the Company's service area, moved to intervene. On September 9, 2013, the Union Fire District of South Kingstown, a Chartered Fire District that rents hydrants for public streets within South Kingstown from United Water RI, also moved to intervene in the proceedings.[1]

Just two years prior on June 3, 2011, United Water RI had filed a general rate case requesting an overall increase in annual revenues of $1,218,702, or 43%, for a total cost of service of $4,077,004. After conducting a full investigation, the Commission in that case authorized United Water RI to collect additional revenues of $941,834 for a total cost of service of $3,817,598 for usage on and after January 12, 2012.[2]

In support of this filing, United Water RI submitted pre-filed testimony[3] addressing United Water RI's revenue requirement for the twelve-month period ending December 31, 2014 as the proposed rate year and using the twelve-month period ending December 31, 2012 as the test year.

II. United Water Rhode Island: Direct Testimony

In support of its request for increased revenues, United Water RI submitted the pre-filed direct testimony of Stanley J. Knox, General Manager of United Water RI; Gary S. Prettyman, Senior Director Regulatory Business for United Water Management and Services, Inc. (UWMS);[4] Obioma N. Ugboaja, Rate Analyst with UWMS; Elda Gil, Regulatory Specialist with UWMS; Timothy J. Michaelson, Director of Regulatory Business for UWMS; Paula L. McEvoy, Director of Engineering for the New York Division of United Water; and Pauline M. Ahern, CRRA, a Principal with AUS Consultants.

Mr. Knox provided testimony on the Company's history, its cost-cutting control measures, current initiatives and improvements, affiliate relationships, and why the rate increase is necessary. In describing United Water RI, Mr. Knox noted that it employs 10 full time employees to serve the 7,399 metered residential customers, 717 commercial customers, 10 industrial customer, 88 municipal customers, 2 wholesale customers, and 185 private fire customers as well as to provide private and public fire service in South Kingstown and Narragansett.[5]

Mr. Knox described the Company's water treatment process, noting that it is currently in compliance with all state and federal regulations. He identified the major additions made to plant in-service since the Company's last rate case, including the replacement of pipe, mains, and a tank. He expressed that the Company is committed to water conservation and education and obtains grants to research various drinking water-related issues.[6]

Gary S. Prettyman sponsored testimony setting forth the overall revenue requirement, revenue conversion factor, and federal income taxes. He related that operating expenses, rate base, capitalization, and the current rate of return evidence a need for $1,563,153 of additional revenues resulting from increases in operating expenses and the addition of improvements to the Company's existing facilities. He identified the test year as the year ending December 31, 2012 and the rate year as the year ending December 31, 2014. After explaining the exhibits attached to his testimony, Mr. Prettyman concluded his testimony by representing that United Water RI needs to recover the amounts included in operating expenses and rate base in order to allow it to earn a fair rate of return while providing safe, adequate, and proper service to its customer.[7]

Obioma N. Ugboaja's testimony provided normalized operating revenues and presented the proposed tariffs for the rate year. He noted that with the exception of the public and private fire classes, United Water RI used a simple trend analysis to project customer growth, with a five-year historical period as its data sample. For the fire classes, Mr. Ugboaja used the number of hydrants in the test year as the projected number of hydrants for the rate year. He related that customer growth projections showed a modest growth in the residential, 1.5%, and commercial, 0.6%, classes and no growth in the industrial, public authority, or resale customer bases. He described how he projected water usage for all classes and explained that the Company used a four-year average for all customers except for residential customers to balance unusually high consumption for these classes in 2008. Because residential customers account for approximately 90% of the Company's customer base, a more detailed approach and longer time period --seven years-- was used to project consumption for the residential class. The seven-year period recognizes that actual billed consumption has historically trended downwards even with a modest increase in residential customer growth.[8]

Mr. Ugboaja asserted that the modest increase in customer growth is tempered by the lower consumption volumes. Additionally, since no construction of new developments was planned for the rate year, Mr. Ugboaja explained, the number of fire service lines (192) and the public fire hydrants (658) included under the Company's fire protection services for the test year would be the same for the rate year. Finally, he noted that since a complete cost-of-service study was performed two years ago and the structure of United Water RI's customer base has not changed, it was not reasonable to conduct another one, particularly given the cost.[9]

Elda Gil provided support for operation and maintenance expenses and taxes other than income taxes, and developed adjustments reflecting known and measurable changes. She also made normalizing calculations to develop costs that United Water RI will incur as it continues operations. She made adjustments to wages and salaries to reflect pay increases that became effective prior to the filing and normalized fringe benefits costs. She calculated power expense to reflect projected power costs. She adjusted chemical expense by averaging usage over the past three years and, based on projected prices, determined the cost.[10]

Ms. Gil noted that pension and post-employment benefits other than pension amounts for the rate year were determined by the Company's actuary and pointed out that those benefits are no longer provided for new hires. She projected a 12% increase in health and medical expense based on the actual increase from 2012 to 2013. She amortized tank painting expense over a 10-year period and made inflationary adjustments to transportation and vehicle expenses that included lease, fuel, maintenance and repair, insurance, and other miscellaneous costs. The Company's insurance costs, customer information, and billing were also adjusted to account for inflation.[11]

To determine rate case expense, Ms. Gil added the total estimated cost of the current rate case expense to the unamortized amount from the previous rate case and amortized that total expense over two years. Rent expense was reduced due to the satisfaction of a loan for a transmission line that is now included in utility plant. Ms. Gil determined the expense amount for outside services, which includes professional and technical services, by evaluating the need for professional and technical support that will arise during the rate year. The PUC Assessment Fee was calculated based on the statutory requirement. Other Operation and Maintenance expenses were adjusted to reflect the removal of non-recoverable items, such as the lobbying expense portion of the National Association of Water Companies dues. Ms. Gil developed three inflationary rates to forecast certain expenses from the test year to the rate year. Property taxes were adjusted using a four year average percentage change. Payroll tax expense was calculated using the current statutory rates. Finally, she applied a 1.25% gross receipts tax to the rate year operating revenues.[12]

Timothy Michaelson, Director of Regulatory Business, provided the Company's rate base and depreciation expense. He related that actual rate base for the test year as of December 31, 2012 averaged $10,767,870 and that the projected rate base for the rate year averaged $15,859,818.[13]

Paula McEvoy provided testimony regarding the capital needs of the Company. Ms. McEvoy is responsible for the development and implementation of the Company's capital plan. She described the significant projects in which United Water RI has engaged, including storage tank construction, infrastructure improvements, and operations improvements. She also identified other capital projects required to maintain asset conditions to meet customer service standards and regulatory requirements.[14]

Pauline M. Ahern, a principal with AUS Consultants, provided testimony regarding the rate of return, the cost of equity, the cost long-term debt, and the capital structure. She recommended a rate of return of 8.75% based on the consolidated capital structure of UWW on March 31, 2013 which consists of 46.55% long-term debt and 53.45% common equity at a long term debt cost of 6.05% and her recommended cost of equity of 11.10%. Ms. Ahern used a proxy group to arrive at her recommended cost of equity. Because United Water RI is not publicly traded, a market-based cost of common equity could not be determined directly for the Company. Noting that no proxy group identical to United Water RI could be assembled, she asserted that the proxy group results could be adjusted to reflect the unique financial and/or business risk of the Company. After evaluating three market-based, cost of common equity models, each of which she discussed individually, she arrived at an 11.10 percent cost of common equity. Ms. Ahern noted that her recommended common equity cost was based on a proxy group of nine water companies that was adjusted upward by 55 basis points to account for United Water RI's small size relative to the nine companies in the proxy group.[15]

Prior to beginning her discussion on each of the cost methods she utilized to reach her conclusion, Ms. Ahern asserted that use of multiple models adds reliability when a cost rate is set for a particular company. She also reviewed business risk, explaining that the water industry is much more capital intensive than other utilities, requiring much greater investment to produce revenue. In support of her assertion that United Water RI faces an additional, extraordinary business risk because of its small size, Ms. Ahern explained that smaller companies are less able to cope with significant events that affect sales, revenues, and earnings such as the loss of a large customer or extreme weather conditions. Because of the risk associated with the smallness of a company, she noted, investors demand a greater return to compensate for the lack of liquidity and marketability of their investment.[16]

Ms. Ahern also discussed financial risk, the additional risk created by the introduction of more capital, debt, and preferred stock into the capital structure. She described how she selected the nine companies in her proxy group. Emphasizing that no specific common equity model should be relied on exclusively to emulate investor behavior, she considered three models in determining an appropriate cost of equity: 1) the Discounted Cash Flow model; 2) the Risk Premium Model; and 3) the Capital Asset Pricing Model. For each of these models, Ms. Ahern explained the theory and how she arrived at her results. Her Discounted Cash Flow model results revealed a median result of 8.91% for the nine companies in the proxy group. She relied on two Risk Premium Model methods, the Predictive Risk Premium Model and the Risk Premium Model, using a total market approach which yielded a Risk Premium Model result of 11.46%. Lastly, she applied both the traditional Capital Asset Pricing Model and the Empirical Capital Asset Pricing Model to the proxy companies, resulting in a cost rate of 10.52%, based on the average of the results under both models.[17]

Considering the results of all the models she employed, Ms. Ahern's concluded that a cost of equity of 10.55% was reasonable. She noted that she made an upward adjustment of 00.55% to account for the small size of the Company resulting in an 11.10% cost of equity for an overall rate of return of 8.75%.[18]

III. Division of Public Utilities and Carriers: Direct Testimony

The Division presented the pre-filed testimony of Thomas S. Catlin, a principal with Exeter Associates, Inc., and Matthew I. Kahal, an independent consultant specializing in the areas of energy, utility, and telecommunications.

Mr. Catlin provided testimony evaluating United Water RI's rate year rate base and net operating income at present rates. He determined the overall revenue increase he believes necessary to generate the return on rate base recommended by Mr. Kahal. For determining the revenue requirement, Mr. Catlin accepted United Water RI's test year as the year ending December 31, 2012 and its rate year as the year ending December 31, 2014. He recommended a revenue increase of $1,006,902 as opposed to the $1,563,153 requested by the Company, which he found adequate to generate the 7.72% rate of return recommended by Mr. Kahal.[19]

Mr. Catlin made $1,122,445 in downward adjustments to United Water RI's rate base, specifically to Cash Working Capital [20], Deferred Rate Case Expense[21], and Accumulated Deferred Income Taxes. Mr. Catlin criticized the Company's use of a trending analysis to determine the number of customers, finding it was not supported by the existence of a discernable trend. He proposed using the actual number of customers by rate class for 2013, adjusting them by the change in the number of customers from 2012 to 2013, to determine the number of customers by rate class for 2014. Regarding consumption, he recommended utilizing a four-year average –2010 through 2013-- for the Company's residential and non-residential customers and adjusting the number of units for fire service for the addition of one private fire service and one public hydrant. The adjustments increased the Company's revenues by $80,673.[22]

Mr. Catlin made a slight adjustment to the percentage of wages charged to expense and eliminated the portion of incentive compensation directly associated with meeting financial performance goals. He updated chemical expense to reflect average quantities and to include the revised rate year consumption and actual chemical prices for 2014. United Water RI's cost of power was adjusted to reflect production and non-production related power and to recognize additional costs due to Hurricane Sandy. Mr. Catlin amortized remaining retiree medical costs over two years, resulting in a minor reduction to rate year expense. He also made three adjustments to transportation expense: 1) reflecting updated inflationary factors, 2) eliminating abnormally high costs for vehicle repairs, and 3) reflecting the update to wages capitalized. Additionally, he adjusted the Company's outside service expense to reflect updated inflationary factors and to eliminate $5,000 of the $10,000 requested for hydrant painting. This account was also adjusted to reflect a correction that the Company made to its test year expense, for efficiency testing of seven wells and to normalize well rehabilitation expense.[23]

Mr. Catlin revised the inflation factors the Company had used to reflect an updated projection of inflation. Noting that consistency should be used from case to case, he modified the growth rate used in calculating property expense to the three-year growth rate that United Water RI used in its last rate case. He noted that since the Company had performed a cost-of-service study in its prior rate case, he was accepting the proposed uniform percentage increases in the service and commodity charges for all customers. Mr. Catlin's adjustments resulted in an overall percentage increase of 27.10% necessary to generate required rates.[24]

Mr. Kahal presented testimony addressing the Company's proposed rate of return and cost of common equity. He concurred with the Company's use of

United Waterworks' capital structure which the Commission approved of in the last rate case. He recommended a rate of return of 7.72% that includes a return on equity of 9.25% and a capital structure of 46.9% debt and 53.1% equity. He utilized the same cost of debt, 6.05%, as the Company. After reviewing how Ms. Ahern developed her 11.10% return on equity recommendation, Mr. Kahal explained that he relied primarily on the Discounted Cash Flow model to determine his own recommendation of 9.25%. He voiced no objection to United Water RI's requested increase in the equity ratio from approximately 50% to 53% which he equated to a diminishment in financial risk.[25]

Mr. Kahal noted declining trends in capital costs in recent years and the Federal Reserve Board of Governors (Fed) policy to ensure price stability and promote full employment by keeping interest rates low during this time of high unemployment. He observed that in addition to this Fed policy, a sluggish economy has kept interest rates low, something he expects to continue. He incorporated utility stock market data from the six months ending December 2013 into his Discounted Cash Flow analysis. He asserted that was reasonable for assessing United Water RI's current cost of capital as it reflects recent market and economic trends.[26]

In discussing the capital structure, Mr. Kahal noted that the parent company at times utilizes short-term debt to fund operations, something that United Water RI omitted from its proposed capital structure. He noted it also omitted a negative balance sheet entry, causing the parent's actual common equity balance to be overstated. Mr. Kahal added 0.64% of short-term debt into the Company's capital structure, along with 46.24% of long-term debt, and 53.13% common equity. He accepted the Company's cost of debt of 6.05%, but found that Ms. Ahern's 0.55% size adjustment for risk was not justified.[27]

Mr. Kahal discussed his Discounted Cash Flow analysis in great detail. He used a proxy group that was nearly identical to Ms. Ahern's proxy group, eliminating one company that lacked projections data and which had no material effect on his analysis. He recommended a return on equity of 9.25%, which did not include a risk adjustment for size and was the midpoint of his proxy group's Discounted Cash Flow range, which he discussed in great detail. In addition to his Discounted Cash Flow analysis, Mr. Kahal performed a Capital Asset Pricing Model analysis as a verification check.[28]

IV. Intervenors: Direct Testimony

The Intervenors, the Towns of Narragansett and South Kingstown and the Union Fire District, filed the direct testimony of David Bebyn, CPA, to address United Water RI's request. Mr. Bebyn asserted that United Water RI's current request, coupled with the 32.8% increase approved by the Commission approximately two years ago, is concerning to the intervenors. He relied primarily on Mr. Kahal's testimony regarding rate of return and supported for the recommended 7.72% rate of return presented by Mr. Kahal. Mr. Bebyn agreed with Mr. Catlin's adjustments to Outside Services. Regarding Rate Case Expense, Mr. Bebyn recommended amortizing this expense over three years as opposed to the two years proposed and agreed to by United Water RI and the Division.[29]

Mr. Bebyn accepted Mr. Catlin's calculation of customer counts and water consumption for the rate year. He supported Mr. Catlin's position regarding wages and benefits capitalized, as well as the adjustments he made to O&M expense. He agreed with Mr. Catlin's rational that tank painting amortization should not be included in the calculation for working capital and supported the Division's adjustment to the Company's proposal. Mr. Bebyn agreed with Mr. Catlin's elimination of deferred rate case expense from rate base and his reduction of rate base to reflect the balance of accumulated deferred income taxes in the rate year.[30]

Regarding rate design, Mr. Bebyn objected to United Water RI's proposed across-the-board increase. He asserted that to avoid rate shock to fire and customer service rates, it is necessary to maintain the fire adjustment and customer service adjustment when allocating general water to each customer. He pointed out that when the Cost of Service Study was prepared two years ago, class demand factors were not updated and indeed had not been updated since 1991. He explained that increases to fire service have been extraordinarily large and much higher than any other regulated water utility in the state. Finally, Mr. Bebyn recommended that United prepare a full cost-of-service study updating the calculation for customer demand factors and identifying the individual asset by asset basis for all assets valued over $100,000.[31]

V. United Water Rhode Island: Rebuttal Testimony

United Water RI presented the rebuttal testimony of Mr. Prettyman, Ms. Gil, and Ms. Ahern. Mr. Prettyman responded to Mr. Catlin's and Mr. Bebyn's direct testimony. Regarding Mr. Catlin's testimony concerning customer numbers, Mr. Prettyman noted that while he did not agree with the method used by Mr. Catlin, he would agree with the result, as it was only one customer different than his projection. He asserted that the Company's consumption figures for residential usage should be used because they accurately depict the declining residential use. When discussing consumption for other classes, Mr. Prettyman stressed that 2009 was an abnormal year, so any averaging should take that year into account. He explained that the Company didn't take into account bonus depreciation when calculating deferred income tax. The benefit of that only applies when the Company has positive taxable income, which in 2012 was offset by a greater loss in 2011.[32]

Mr. Prettyman disagreed with Mr. Bebyn's recommendation that rate case expense be amortized over three years. He said it is likely the Company will file another case in two years to fund new tank construction. Mr. Prettyman also addressed Mr. Bebyn's testimony regarding rate design, opining that the adjustment he made to fire rates was neither justified nor explained and that his testimony regarding demand factors was unsubstantiated. He asserted that requiring the Company to prepare another cost-of- service study, when one was completed approximately two years ago, would be unwarranted and an unnecessary expense.[33]

Mr. Prettyman contended that Mr. Bebyn's testimony failed to include a proof of revenues to prove his recommended rates will produce the total level of revenues. He averred that a balancing must take place when implementing cost of service based rates and that the balancing was achieved through the Company's last cost-of-service study.[34]

Ms. Gil's rebuttal testimony similarly reviewed a number of Mr. Catlin's adjustments. Specifically, she noted that United Water RI agreed with Mr. Catlin's adjustments to percentage of wages and benefits charged to expense, fringe benefits transferred out, chemicals, post-retirement benefits, testing wells, well rehabilitation, and inflation. However, she contended that incentive compensation should not be adjusted, because it is necessary to attract and retain competent employees, can reduce costs and improve productivity, allows the Company to award high performance, and aligns the interests of employees, shareholders, and customers.[35]

Regarding power expense, Ms. Gil disagreed with Mr. Catlin's adjustment updating rates for Constellation Energy and National Grid, noting that the Company provided the most recent actual prices paid which were higher than what the Division proposed. Additionally, she stated that Mr. Catlin's adjustment to non-production related power did not add back the component related to distribution. Finally, Ms. Gil related that while the Company agrees to a three year cost averaging of power data, it does not agree with the exclusion of either the 2011 storm costs or the inflation adjustment.[36]

Ms. Gil also addressed Mr. Catlin's three adjustments to transportation expense. She agreed with the adjustments to update the inflation factors and to reflect the new percentage of wages capitalized, but did not agree with the adjustment that eliminated the trailer and truck repairs. She pointed out that the Division accepted a three-year normalization of backhoe repairs and should also accept a three-year normalization of the truck and trailer repair expense. Ms. Gil represented that the Company's purpose in including hydrant painting in its maintenance program is to enhance the appearance and improve the visibility of the Company's faded and weathered hydrants. She contended the Company should be allowed the full $10,000 requested for hydrant painting.[37]

Finally, Ms. Gil disagreed with Mr. Catlin's adjustment to property tax expense. She asserted that using a four year average to project this expense produces a more comparable result than a three-year average, noting that the Company's average was less than the previous year's actual expense and that Mr. Catlin's average was significantly lower than that. She proposed a modified operation and maintenance expense budget of $2,266,440, which accounts for the adjustments made by Mr. Catlin that were agreeable to the Company.[38]

Ms. Ahern asserted that Mr. Kahal's common cost of equity analysis was inadequate because it relied primarily upon the Discounted Cash Flow analysis. She reiterated the point made in her direct testimony that academic literature substantially supports using more than one model. She explained that while a number of regulatory commissions rely upon the Discounted Cash Flow model, many of those commissions also consider other cost equity models. She criticized Mr. Kahal's use of the Capital Asset Pricing Model as a check on his Discounted Cash Flow analysis and alleged that his failure to make a size adjustment ignored the fact that the use of funds and not the source of funds is what gives rise to risk and the appropriate rate of return. Finally, she updated her recommended cost of common equity to 10.55%, noting that she relied exclusively upon forecasted interest rates in her risk premium and Capital Asset Pricing Model analyses.[39]

VI. Settlement Agreement

Prior to the commencement of the hearing, the Company and the Division presented a Settlement Agreement (Agreement). The Agreement provided for an across-the-board increase of 32.83% for all customer classes designed to generate a total cost of service of $4,923,600 or an additional $1,207,267 of operating revenue. The Company and the Division agreed to a capital structure of 46.9% total debt and 53.1% equity with a 9.65% return on equity, and an overall rate of return of 7.94%. The Agreement resolved the issues that the Division and the Company had disagreed on at the time the rebuttal testimony was filed.[40]

Specifically, the Company and the Division agreed to a $46,067 increase in revenues, which recognized both the Company's concern with the downward trend in residential sales and the Division's position regarding non-residential sales. The Division agreed with United Water RI's position regarding that because the increase in the balance of Accumulated Deferred Income Taxes will not be recognized in the near term, it should not be deducted from rate base. United Water RI agreed to eliminate the portion of incentive compensation associated with meeting financial goals. Regarding power expense, the Company and the Division agreed to include storm-related diesel and other power costs incurred during 2011 when calculating the three-year average for this account of power costs. The Company accepted the Division's adjustment to transportation expense which eliminated certain 2012 truck and trailer repairs prior to the three year averaging of this expense. The Agreement also allowed the Company the full amount originally requested for hydrant painting foregoing the Division's initial objection. Additionally, the Company accepted the Division's reduction in property tax to reflect a three year average.[41]

VII. Hearing

The Commission conducted an evidentiary hearing on the terms of the Settlement Agreement and certain other issues that it wanted to further explore. United Water RI presented a panel of Mr. Prettyman, Ms. Gil, Mr. Michaelson, Mr. Knox, and Ms. McEvoy to address the Commission's inquiries. Mr. Prettyman reiterated that the main driver of the increase in rate base was the addition of new facilities that the Company had invested in since its last rate case, specifically a new water storage tank and replacement of mains, hydrants, and other facilities. Increased operations and maintenance expense and a decrease in consumption made up the remainder of the increase. He explained how after negotiation, the Company and the Division were able to arrive at a settlement that they considered fair and reasonable and which avoids expensive litigation.[42]

Mr. Prettyman explained each of the pertinent points of the settlement issues including how the Company willingly adjusted its projections for residential consumption, how it agreed to capitalize a greater portion of salaries and wages, and how it agreed to eliminate its request for an incentive based on financial considerations. He discussed the five components of the Company's power expense, noting that the upward adjustment was the result of the segregation between purchased power and non-operating power. He explained that the Company agreed to lengthen the amortization period for the well maintenance and it was amenable to using a three-year average to project property tax expense. Additionally, he noted the Company agreed to eliminate deferred rate case expense, which had been included in the initial filing prior to the Company learning of the Rhode Island Supreme Court decision prohibiting inclusion of that expense in rate base.[43]

Regarding the Company's capital structure, Mr. Prettyman testified that the Division's recommendation that included short-term debt and provided for a 9.65% return on equity was fair and in the best interest of all parties. He represented that it is the position of United Water RI that the terms of the Agreement are fair and reasonable and that the rates are necessary. He noted that the terms of the Agreement will allow United Water RI to continue to provide high quality water and high quality customer service to its ratepayers.[44]

Lastly, Mr. Prettyman discussed the difference in rates between private fire service and the tariffs for public hydrants. He noted that neither the private fire service nor the public hydrant charge is in the cost of service. He described a private fire service connection, which is based upon the size of the connection to the main and allows customers to connect as many things as they wish, such as hydrants or sprinkler systems, as long as the main will allow the volume needed through the service connection. He testified that the Town or the Union Fire District will not pay a hydrant rental charge for a hydrant that is not on a public street. Mr. Knox offered that United Water RI has no input into what the Town or the Union Fire District chooses to pay for. Mr. Prettyman explained that to keep the fire rate at a reasonable level, a portion of the fire charges are shifted to or cross-subsidized by the general metered service customers.[45]

In response to the Commission's inquiry about the $10,000 United Water RI requested for hydrant painting, Ms. Gil acknowledged that her pre-filed testimony stated that the reason for the requested expense amount was to enhance the appearance and improve the visibility of faded and weathered hydrants. She testified during the hearing that structural integrity was not an issue. However, Mr. Knox contended that the primary reason for painting the hydrants was corrosion. He noted that controlling corrosion helps ensure that hydrants operate properly when needed. He claimed that deferring the painting could risk public safety. Additionally, he related that although painting had previously been done in-house, it was now necessary to hire summer help, specifically college students, because the Company's employees could no longer effectively maintain the schedule.[46]

When questioned about the percentage of the requested increase, Mr. Knox acknowledged concern with customers' ability to pay. But he stated that the increase was justified because the Company needed to earn a return on the capital improvements it had made. Mr. Prettyman supported Mr. Knox's views, noting that over the last two years, the Company had invested almost $7 million in facility improvements. He expressed that the requested increase amounted to less than a penny a gallon. He further asserted that the Company intends to build another replacement tank in the next two years, which will necessitate a new filing.[47]

Mr. Knox also described the Company's short-term incentive program, which affords employees a bonus based on performance in addition to any salary increase that employees may receive. Finally, Mr. Prettyman related that all residential customers are billed quarterly, and that the approximate increase for a residential customer pursuant to the terms of the Agreement would be $20 per quarter.[48]

Mr. Catlin testified on behalf of the Division. He addressed the public hydrant and private fire connection issue. He also explained that because the Company's rates are too low relative to costs, raising them suddenly closer to the cost of service would result in significant increases in the quarterly customer charge for residential customers and for the municipal fire charges. He stated that if the public fire rate were to be moved to cost, the result would be about a 200% increase. He noted that volumetric rates paid by all those customers who take volumetric service subsidize most of the other rates for the Company. Mr. Catlin also expressed concern about the overall amount of percentage increase, but stated that if expenses are legitimate, they have to be accepted. He also explained that while he had originally recommended that the expense for hydrant painting expense be limited to $5,000 he had agreed to the full $10,000 amount as part of the compromise to reach agreement.[49]

Finally, Mr. Bebyn testified that he had participated in the settlement discussions. He provided that the reason that the public hydrant fee and the private fire service are different is because of additional billing charges that are included in the rate which is a fixed charge. He testified that the billing charge included a cost to create the bill, the labor to generate the bill, and the collection of the bill.[50]

The Commission made a number of data requests during the course of the hearing, all of which were responded to by United Water RI prior to the Commission's decision.

VIII. Decision

At its open meeting on May 7, 2014, the Commission deliberated on the evidence presented and the terms of the Settlement Agreement. The Commission thoroughly reviewed, analyzed, and evaluated all the evidence, documentary and oral, presented by the parties and considered the public comment presented. This process began as soon as the initial application was filed in August 2013.

This Commission is statutorily bound to ensure that rates are just and reasonable and that any approved rate increases are otherwise necessary for the utility to obtain reasonable compensation for services rendered to the public. R.I. Gen. Laws §§ 39-3-11 and 39-3-12. Specifically, the Settlement Agreement represents a significant reduction in the additional operating revenue originally requested by United Water RI. The Commission unanimously approved the terms of the Settlement Agreement with two modifications: 1) elimination of $2,500 expended for a holiday party and 2) reduction of the $10,000 requested hydrant painting expense to $5,000. United Water RI presented no evidence that a holiday party is an expense necessary to maintain water quality or to provide safe and reliable service. The Commission finds no justification in requiring ratepayers to assume the cost of such.

Regarding the decision to reduce the hydrant painting request by half, the Commission noted that in Ms. Gil's pre-filed testimony, she identified enhancing the appearance of the hydrants as the Company's reason for seeking the money to fund the expense. It wasn't until the evidentiary hearing that Mr. Knox raised the corrosion issue. At no time did United Water RI articulate why it had fallen behind in their hydrant painting. Furthermore, any sense of urgency on the corrosion issue was belied by the fact that United Water RI presented no evidence that it did anything to address those corrosion concerns from the time that it filed the case in August 2013 until the date of the hearing. In the future, the Company would be better served by presenting evidence of corrosion, such as photos or a detailed description of the existence and the extent of the corrosion. The Commission believes that after months of thorough and probing review, the Settlement Agreement, presented by United Water RI and the Division and agreed to by the Intervenors with the two modifications, set forth above, is supported by the considerable evidence presented and is fair, reasonable, and in the best interest of the utility and its ratepayers.

The Rhode Island Supreme Court has stated that "the proper rate of return 'is a matter of judgment, not an immutable number.'" *Blackstone Valley Electric Company*, Docket No. 1605, Order No. 10695 (issued May 12, 1982) *citing Providence Gas v. Burman*, 376 A.2d 687 (R.I. 1977). A public utility is not entitled to earn a return that may be earned by a highly profitable enterprise; however, the return should be sufficient to permit the utility to maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed while at the same time providing appropriate protection to the relevant public interests, both existing and foreseeable. *Bristol County Water Company*, Docket No. 1502, Order No. 10355 (issued January 15, 1981). The Company's original filing proposed a return on equity of 11.1%. The Division filed testimony supporting a return on equity of 9.25%. Both parties presented extensive testimony in support of their own positions and challenged the positions of the other before agreeing to settle their differences. The Commission believes that the 9.65% return on equity agreed to by the parties in the Settlement Agreement is a fair and reasonable amount and is representative of the proxy group used by the parties.

Because United Water RI is capitalized at 100% equity, its capital structure would not be appropriate for ratemaking purposes. Nor is the capital structure of Suez Environment appropriate, because only a small portion of its operations are water utility operations. When faced with an inappropriate capital structure from which to set rates, the Commission may either rely on the capital structure of the parent, in this case UWW, or a proxy group. *See The Narragansett Electric Company v. Rhode Island Public Utilities Commission*, 35 A.3d 925 (R.I. 2012); *In Re: New England Gas Company's Distribution Adjustment Clause*, Docket No. 3459, Order No. 17524 (issued August 1, 2003); *Public Service Commission of State of New York v. FERC*, 813 F.2d 448 (1987). In the past, this Commission has utilized the actual capital structure at the holding company level when the subsidiary utility's capital structure is either non-existent or otherwise deemed not reasonable for rate setting purposes.

Both Ms. Ahern and Mr. Kahal recommended using the capital structure of the parent UWW, as UWW is the ultimate source of United Water RI's capital base. The Commission finds this to be an appropriate capital structure. United Water RI proposed a capital structure of 53.45% common equity with an actual cost rate of 11.1% and 46.55% long-term debt with an actual cost rate of 6.05%. The Division proposed 53.13% common equity at 9.65%, 46.24% long term debt at 6.05%, and included 0.64% short term debt at a cost rate of 1.00%. The Commission is satisfied that United Water RI's agreement to use the capital structure proposed by the Division resulting in a 7.94% rate of return is fair and reasonable and will be sufficient to permit United Water RI to maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed, while at the same time providing appropriate protection to the relevant existing and foreseeable public interests.

During its open meeting, the Commission expressed concern that this was United Water RI's second request for a significant rate increase in a short period of time. It further questioned the Company's practice of awarding bonuses or incentive payments in addition to salary increases and overtime expenses adding to the overall percentage increase imposed on customers. The Commission observed that such inflated increases are particularly difficult for customers to absorb during these troubled economic times. The Commission understands and appreciates the Company's attempts to maximize the amount of time between rate cases and thereby insulate customers from frequent increases. However, because the Company waited so long, when it finally did file, the requested rate increase was significant. In the future, United Water RI ought to consider alternatives to mitigate large rate increases, such as filing a multi-year rate plan, especially if the Company anticipates the frequency of its filings that have occurred during the past couple of years to continue. Moreover, raising rates cannot fully alleviate losses attributable to continued declining consumption. It is, therefore, incumbent upon the utility to explore alternatives to address declining consumption that will not continue to financially stress its ratepayers.

The Commission applauds the parties for the compromises they made throughout the course of this rate case, especially with regard to United Water RI's agreement to reduce incentive compensation for its top management. This agreement is a clear indication to the Commission that United Water RI understands how the increase requested will impact its customers and is willing to work to minimize that impact. United Water RI is to be commended for its obvious concern for its ratepayers as well as its continued and successful efforts to provide high quality and exceptional service to its customers.

ACCORDINGLY, it is

(21593) ORDERED:

1. United Water Rhode Island, Inc.'s request to collect an additional $ 1,563,153 is denied. United Water Rhode Island, Inc. is authorized to collect an additional $1,200,706 in revenues on usage on and after May 13, 2014.
2. The terms of the Settlement Agreement between United Water Rhode Island, Inc. and the Division of Public Utilities and Carriers, with the modifications made by the Commission to eliminate $5000 of hydrant painting expense and $2500 of miscellaneous expense, are approved.
3. United Water Rhode Island is allowed a rate year rate base of $15,644,693.
4. United Water Rhode Island, Inc. is allowed an overall rate of return of 7.94%.
5. United Water Rhode Island, Inc.'s proposed capital structure is denied. The capital structure approved for ratemaking purposes shall be comprised of 53.13% equity, 46.24% long-term debt, and 0.64% short-term debt.
6. United Water Rhode Island, Inc.'s proposed cost of capital is denied. The cost of common equity shall be 9.65%, the cost of long-term debt shall be 6.05%, and the cost of short-term debt shall be 1.00%.
7. The Parties shall act in accordance with all other findings and instructions contained in this Order.

EFFECTIVE AT WARWICK, RHODE ISLAND ON MAY 13, 2014, PURSUANT TO AN OPEN MEETING DECISION ON MAY 7, 2014. WRITTEN ORDER ISSUED AUGUST , 2014.

PUBLIC UTILITIES COMMISSION

____
Margaret E. Curran, Chairperson

____
Paul J. Roberti, Commissioner

____
Herbert F. DeSimone, Jr., Commissioner

Appendix A - Settlement Agreement

[1] Rule 1.13 of the Commission's Rules of Practice and Procedure provides that "any person claiming a right to intervene of an interest of such nature that intervention is necessary or

appropriate may intervene in any proceeding before the Commission. Such right or interest may be…[a]n interest which may be directly affected and which is not adequately represented by existing parties and as to which movants may be bound by the Commission's action in the proceeding…[or] any other interest of such nature that movant's participation may be in the public interest."

[2] Docket No. 4255, Order No. 20782 ; http://www.ripuc.org/eventsactions/docket/4255page.html.

[3] Prefiled testimony is available at the Commission offices located at 89 Jefferson Boulevard, Warwick, Rhode Island or at www.ripuc.org/eventsactions/4431page.html.

[4] United Water Management Services, Inc. or UWMS is a subsidiary of United Water Resources.

[5] Knox Direct at 1-3 (Aug. 13, 2013); http://www.ripuc.org/eventsactions/docket/4434-UWRI-KNOX.pdf.

[6] *Id.* at 4-18.

[7] Prettyman Direct at 1-5 (Aug. 13, 2013); http://www.ripuc.org/eventsactions/docket/4434-UWRI-PRETTYMAM.pdf.

[8] Ugboaja Direct at 1-6 (Aug. 13, 2013); http://www.ripuc.org/eventsactions/docket/4434-UWRI-UGBOAJA.pdf.

[9] *Id.* at 6-8.

[10] Gil Direct at 2-7 (Aug. 13, 2013); http://www.ripuc.org/eventsactions/docket/4434-UWRI-GIL.pdf.

[11] *Id.* at 8-10.

[12] *Id.* at 10-14.

[13] Michaelson Direct at 1-7 (Aug. 13, 2013); http://www.ripuc.org/eventsactions/docket/4434-UWRI-MICHAELSON.pdf.

[14] McEvoy Direct at 1-8 (Aug. 13, 2013); http://www.ripuc.org/eventsactions/docket/4434-UWRI-MCEVOY.pdf.

[15] Ahern Direct at 1-5 (Aug. 13, 2013); http://www.ripuc.org/eventsactions/docket/4434-UWRI-AHERN.pdf.

[16] *Id.* at 6-15.

[17] *Id.* at 16-38.

[18] *Id.* at 39-43.

[19] Catlin Direct at 1-5 (Feb. 3, 2014); http://www.ripuc.org/eventsactions/docket/4434-DPU-Catlin_2-3-14.pdf .

[20] Because the Company records the balance of the deferred costs of tank painting as a regulatory asset, it should not be included as an O&M expense, the base of which Mr. Catlin adjusted to reflect this elimination. This adjustment was made prior to calculating Cash Working Capital.

[21] In *Providence Gas Company v. Malachowski*, 656 A.2d 949 at 953 (R.I. 1995), the Rhode Island Supreme Court upheld and found sound the PUC's long-standing policy prohibiting deferred rate case expense from being included in rate base and which provides for "ratepayers to pay the actual, prudently incurred rate case expenses over a period of time, while stockholders pay the carrying costs on the unamortized balance. Such a policy is based upon a sharing of costs between ratepayers and stockholders." *In re Block Island Power Co.,* Report and Order No. 13769, Docket No. 1998, at 20 (1991). The Court recognized the PUC's allowance of an exception to this policy in unusual circumstances. However there, as here, no unusual circumstances were established by the utility.

[22] Catlin Direct at 6-13.

[23] *Id.* at 13-23.

[24] *Id.* at 23-26.

[25] Kahal Direct at 1-7 (Feb.3, 2014); http://www.ripuc.org/eventsactions/docket/4434-DPU-Kahal_2-3-14.pdf .

[26] *Id.* at 7-13.

[27] *Id.* at 13-20.

[28] *Id.* at 20-35.

[29] Bebyn Direct at 1-6 (Feb. 7, 2014); http://www.ripuc.org/eventsactions/docket/4434-Intervenors-Bebyn(2-8-13).pdf.

[30] *Id.* at 6-9.

[31] *Id.* at 10-12.

[32] Prettyman Rebuttal at 1-5 (March 3, 2014); http://www.ripuc.org/eventsactions/docket/4434-UWRI-Prettyman(3-3-14).pdf.

[33] *Id.* at 6-10.

[34] *Id.* at 10-12.

[35] Gil Rebuttal at 1-3 (March 3, 2014); http://www.ripuc.org/eventsactions/docket/4434-UWRI-Gil(3-2-14).pdf.

[36] *Id.* at 4-5.

[37] *Id.* at 6-7.

[38] *Id.* at 7-8.

[39] Ahern Rebuttal at 1-20 (March 3, 2014); http://www.ripuc.org/eventsactions/docket/4434-UWRI-Ahern(2-26-14).pdf.

[40] Settlement Agreement, March 28, 2014; http://www.ripuc.org/eventsactions/docket/4434-DPU-SettlemetAgreement(3-28-14).pdf. Although not signatories to the Settlement Agreement, the three intervenors agreed with the terms that the Company and the Division negotiated. The Settlement Agreement is attached hereto as Appendix A.

[41] *Id.*; Division Statement in Support of Settlement Agreement, http://www.ripuc.org/eventsactions/docket/4434-DPU-Statement-Settlement_4-4-14.pdf; United Statement in Support of Settlement Agreement, http://www.ripuc.org/eventsactions/docket/4434-UWRI-Statement-Settlement_4-9-14.pdf.

[42] Hr'g, Tr. at 27-32 April 14, 2014.

[43] *Id.* at 34-41.

[44] *Id.* at 42-43.

[45] *Id.* at 44-62.

[46] *Id.* at 62-68.

[47] *Id.* at 69-71.

[48] *Id.* at 72-92.

[49] *Id.* at 95-111.

[50] *Id.* at 136-150.

APPENDIX A

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: UNITED WATER RHODE ISLAND, INC.

DOCKET NO.: 4434

SETTLEMENT AGREEMENT

I. INTRODUCTION

United Water Rhode Island, Inc. (hereinafter "United Water") and the Division of Public Utilities and Carriers (hereinafter "Division") have reached an agreement on United Water's rate application filed on August 12, 2013. Thus, the Division and United Water jointly request that the State of Rhode Island Public Utilities Commission (hereinafter "Commission") approve this Settlement Agreement.

II. RECITALS

1. On August 12, 2013, United Water filed a rate application pursuant to R.I.G.L § 39-3-11 and Part II of the Commission's Rules of Practice and Procedure.
2. United Water's proposed rates were designed to collect $1,563,153 of additional operating revenue to support a total cost of service of $5,233,419. The impact of this request would have resulted in a 42.59 % increase in total cost of service. The proposed increase for all classes of customers would have been 43%. For a typical residential customer, the impact of this request would have resulted in an increase of $10.30 per month.
3. United Water filed direct and rebuttal testimony and schedules from the following witnesses in support of its application:

a. Gary S. Prettyman, Senior Director, Regulatory Business, United Water Management & Services, Inc.;

b. Timothy J. Michaelson, Director, United Water Management & Services, Inc.;

c. Elda Gil, Regulatory Specialist, United Water Management & Services, Inc.;

d. Obioma (Obie) N. Ugboaja, Rate Analyst, United Water Management & Services, Inc.;

e. Paula L. McEvoy, Director of Engineering, United Water New York.

f. Stanley J. Knox, General Manager, United Water Rhode Island, Inc.;

g. Pauline M. Ahern, Principal, AUS Consultants; and,

4. The Town of South Kingstown filed a Motion to Intervene in this Docket on August 21, 2013. United Water did not object.

5. The Town of Narragansett filed a Motion to Intervene in this Docket on August 30, 2013. United Water did not object.

6. The Union Fire District of South Kingstown filed a Motion to Intervene in this Docket on September 6, 2013. United Water did not object.

7. The Division investigated United Water's requested rate increase with assistance from its staff and outside expert consultants. The Division issued data requests and filed direct testimony from the following witnesses on February 3, 2014:

   a. Thomas S. Catlin, Principal, Exeter Associates, Inc.; and,

   b. Matthew I. Kahal

8. The Town of South Kingstown, The Town of Narragansett and The Union Fire District of South Kingstown jointly filed the testimony of David G. Bebyn, CPA, of B&E Consulting, LLC.

9. The Division and United Water engaged in settlement discussions after United Water submitted its rebuttal testimony on March 3, 2014.

10. The Division and United Water gave due consideration to the testimony, exhibits, schedules, data requests, data responses, settlement discussions, and other documentation in this Docket and agreed to a comprehensive settlement that resolves all issues relating to United Water's application to increase rates.

11. The Division and United Water agree this Settlement Agreement is a just and reasonable resolution of the issues in this proceeding and jointly request its approval by the Commission.

III. TERMS OF SETTLEMENT

12. The Division and United Water agree that the Joint Settlement Schedules attached as Exhibit 1 (Schedules 1 – 19) are accurate and reflect the agreement reached in this Docket.

13. The agreed rates allow United Water to collect additional operating revenue in the amount of $1,207,267 to support a total cost of service of $4,923,600.

14. The proposed increase is an "across the board" increase of 32.83% for all classes of customers.

15. The agreed upon capital structure is 46.9% total debt and 53.1% equity; the return on equity is 9.65%; and, the overall rate of return is 7.94%.

IV. EFFECT OF SETTLEMENT

16. This Settlement Agreement is the result of a negotiated agreement. The Division and United Water conducted the discussions that produced this Settlement

Agreement with the explicit understanding that all offers of settlement and discussion relating thereto are and shall be privileged, shall be without prejudice to the position of any party or participant presenting such offer or participating in any such discussion, and are not to be used in any manner in connection with these or any other proceedings.

17. The terms of this Settlement Agreement shall not be construed as an agreement to any matter of fact or law beyond the terms hereof. By entering into this Settlement Agreement, matters or issues other than those explicitly identified in this agreement have not been settled upon or conceded by any party to this Settlement Agreement, and nothing in this Settlement Agreement shall preclude any party from taking any position in any future proceeding regarding settled or unsettled matters.
18. This Settlement Agreement is the product of negotiation and compromise. The making of this Settlement Agreement does not establish any principle or precedent. This Settlement Agreement shall not be deemed to foreclose any party from making any contention in any future proceeding or investigation.
19. If the Commission rejects this Settlement Agreement, or modifies any provision herein, this Settlement Agreement shall be deemed withdrawn and shall be null and void in all respects.

IN WITNESS WHEREOF, the Parties agree that this Settlement Agreement is reasonable, in the public interest, in accordance with applicable law and regulatory policy, and is executed by their respective representatives, each being authorized to do so.

Dated this 28th day of March, 2014.

UNITED WATER
RHODE ISLAND, INC.
By its Attorney,

Joseph A. Keough, Jr., #4925
KEOUGH & SWEENEY, LTD.
100 Armistice Boulevard
Pawtucket, RI 02860
Tel: (401)-724-3600

Dated this 28th day of March, 2014.

DIVISION OF PUBLIC UTILITIES
AND CARRIERS,
By its Attorney,

Christy Hetherington

Christy Hetherington, #6693
Special Assistant Attorney General
150 South Main Street
Providence, RI 02903
Tel: 401-274-4400, ext. 2425

UNITED WATER RHODE ISLAND, INC.

Summary of Operating Income
Rate Year Ended December 31, 2014

	Amount per Company at Present Rates	Settlement Adjustments	Amount per Settlement at Present Rates	Revenue Increase/ (Decrease)	Amounts After Revenue Incr. / (Decr.)
Operating Revenues					
Retail Sales	$ 2,709,794	$ 37,642	$ 2,747,436	$ 901,759	$ 3,649,195
Sales for Resale	$ 447,403	7,817	455,220	148,232	603,452
Fire Protection	477,732	608	478,340	157,276	635,616
Other Operating Revenues	35,337	-	35,337	-	35,337
Total Operating Revenues	$ 3,670,266	$ 46,067	$ 3,716,333	$ 1,207,267	$ 4,923,600
Operating Expenses					
O&M Expense	$ 2,301,468	(75,121)	$ 2,226,347	3,781	$ 2,230,128
Depreciation Expense	600,370	-	600,370	-	600,370
Property Tax	315,024	(8,192)	306,832	-	306,832
Payroll Rax	59,265	(499)	58,766	-	58,766
Gross Receipts Tax	45,878	576	46,454	15,091	61,545
Income before Income Taxes	$ 348,261	$ 129,303	$ 477,564	$ 1,188,395	$ 1,665,959
Current Income Taxes	(152,784)	47,918	(104,866)	416,398	311,532
Deferred Federal Income Taxes	118,139	-	118,139		118,139
Amortization of ITCs	(4,662)	-	(4,662)	-	(4,662)
Total Operating Expenses	$ 3,282,698	$ (35,318)	$ 3,247,380	$ 435,270	$ 3,682,650
Utility Operating Income	$ 387,568	$ 81,385	$ 468,953	$ 771,997	$ 1,240,951
Rate Base	$ 15,859,819		$ 15,645,640		$ 15,645,640
Rate of Return	2.44%		3.00%		7.93%

UNITED WATER RHODE ISLAND, INC.

Determination of Revenue Increase
Rate Year Ended December 31, 2014

		Amount per Company (1)	Amount Per Settlement	Source
Proposed Rate Base		15,859,819	$ 15,645,640	Schedule 2
Required Rate of Return		8.75%	7.94%	
Net Operating Income Required		$ 1,387,734	$ 1,242,264	
Net Operating Income at Present Rates		387,568	468,953	Schedule 1, page 1
Net Income Surplus/(Deficiency)		$ (1,000,166)	$ (773,311)	
Revenue Multiplier (2)		1.5628923	1.5628923	
Base Rate Revenue Increase		$ 1,563,152	$ 1,208,601	
Variance due to Rate Rounding			$ (1,334)	Schedule 19, page 2
Net Increase in Revenue			$ 1,207,267	
Verification				
Revenue Increase/(Decrease)		$ 1,563,152	$ 1,208,601	
PUC Assessment	0.31317%	$ 4,895	$ 3,785	
Gross Receipts Tax	1.25%	19,539	15,108	
Federal Taxable Income		$ 1,538,717	$ 1,189,708	
Federal Income Tax	35.00%	538,551	416,398	
Net Income		$ (1,000,166)	$ (773,310)	

Notes:
(1) Per Exhibit 1 (Prettyman), Schedule 1.

(2) Calculation of Conversion Factor

	Tax Rates	
Revenues		1.000000
PUC Assessment	0.31317%	0.003132
Gross Receipts Tax	1.25%	0.012500
Net Federal Taxable Income		0.984368
Federal Income Tax	35.00%	0.344529
Revenue Conversion Factor		0.6398394
Revenue Multiplier		1.5628923

UNITED WATER RHODE ISLAND, INC.

Summary of Rate Base
Rate Year Ended December 31, 2014

Description	Amount per Company (1)	Settlement Adjustments (2)	Adjusted Per Settlement
Utility Plant in Service	$ 28,149,420		$ 28,149,420
Less: Accumulated Depreciation and Amortization	(7,003,970)		(7,003,970)
Net Utility Plant in Service	$ 21,145,450	$ -	$ 21,145,450
Materials and Supplies	86,062		86,062
Cash Working Capital	287,684	(14,813)	272,871
Deferred Tank Painting (net of Deferred Income Tax)	168,165		168,165
Deferred Rate Case Expense	199,366	(199,366)	-
Total Additions	$ 741,277	$ (214,179)	$ 527,098
	-	-	-
Contributions in Aid of Construction	(3,533,455)	-	(3,533,455)
Accumulated Deferred Income Taxes	(1,842,541)	-	(1,842,541)
Unamortized ITCs	(89,099)		(89,099)
Unfunded FAS 106 (net of Deferred Income Tax)	(561,813)	-	(561,813)
Total Deductions	$ (6,026,908)	$ -	$ (6,026,908)
Total Rate Base	$ 15,859,819	$ (214,179)	$ 15,645,640

Notes:
(1) Per Exhibit 3 (Michaelson), Schedule 1, page 4 of 4.

(2) Refer to page 2 of this Schedule.

UNITED WATER RHODE ISLAND, INC.

Summary of Adjustments to Rate Base
Rate Year Ended December 31, 2014

	Amount	Source
Rate Base per Company Filing	$ 15,859,819	Per Exhibit 3, Schedule 1, page 4
Settlement Adjustments		
Cash Working Capital	(14,813)	Schedule 5
Deferred Rate Case	(199,366)	Refer to Catlin Testimony
Accumulated Deferred Income Taxes	-	Schedule 6
Total Settlement Adjustments	$ (214,179)	
Adjusted Rate Base	$ 15,645,640	

UNITED WATER RHODE ISLAND, INC.

Summary of Adjustments to Net Income
Rate Year Ended December 31, 2014

	Amount	Source
Net Income per Company	$ 387,568	Exhibit 3 (Michaelson), Schedule 10
Settlement Adjustments		
Rate Year Revenue	29,476	Schedule-7
Wages and Benefits Charged to Expense	16,957	Schedule-8
Incentive Compensation-Company Employees	7,442	Schedule-9
Incentive Compensation-UWM&S Fees	10,377	Schedule-10
Chemicals Expense	5,879	Schedule-11
Power Expense	(14,640)	Schedule-12
PEPOB Transition Obligation	1,662	Schedule-13
Transportation Expense	3,158	Schedule-14
Outside Services Expense	17,106	Schedule-15
Inflation	1,306	Schedule-16
Property Taxes	5,325	Schedule-17
Interest Synchronization	(2,662)	Schedule-4
Total Adjustments	$ 81,385	
Net Income Per Settlement	$ 468,954	

UNITED WATER RHODE ISLAND, INC.

Summary of Adjustments to Net Income
Rate Year Ended December 31, 2014

	Revenues	O&M Expenses	Depreciation Expense	Taxes Other Than Oincome	Current Federal Income Taxes	Deferred Federal Income Taxes	ITC Amortization	Net Operating Income
Net Income per Company	$ 3,670,266	$ 2,301,468	$ 600,370	$ 420,167	$ (152,784)	$ 118,139	$ (4,662)	$ 387,568
Settlement Adjustments								
Rate Year Revenue	46,067	144	-	576	15,871	-	-	29,476
Wages and Benefits Charged to Expense		(26,088)			9,131	-	-	16,957
Incentive Compensation-Company Employees		(10,951)		(499)	4,007	-	-	7,442
Incentive Compensation-UWM&S Fees		(15,965)			5,588	-	-	10,377
Chemicals Expense		(9,044)			3,165	-	-	5,879
Power Expense		22,523			(7,883)	-	-	(14,640)
PEPOB Transition Obligation		(2,557)			895	-	-	1,662
Transportation Expense		(4,858)			1,700	-	-	3,158
Outside Services Expense		(26,317)			9,211	-	-	17,106
Inflation		(2,010)			703	-	-	1,306
Property Taxes				(8,192)	2,867	-	-	5,325
Interest Synchronization					2,662			(2,662)
Total Settlement Adjustments	$ 46,067	$ (75,121)	$ -	$ (8,116)	$ 47,918	$ -	$ -	$ 81,385
Adjusted Net Income per Settlement	$ 3,716,333	$ 2,226,347	$ 600,370	$ 412,051	$ (104,866)	$ 118,139	$ (4,662)	$ 468,954

Docket No. 4434
Exhibit 1 (Joint Settlement) Schedule 4

UNITED WATER RHODE ISLAND, INC.

Calculation of Current Income Tax
Rate Year Ended December 31, 2014

	Amount per Company at Present Rates (A)	Settlement Adjustments (B)	Adjusted per Settlement at Present Rates (C)	Revenue Increase/ (Decrease) (D)	Amounts After Revenue Increase (E)
Operating Revenue	$ 3,670,266	$ 46,067	$ 3,716,333	$ 1,208,601	$ 4,924,934
O&M Expense	2,301,468	(75,121)	2,226,347	3,785	2,230,132
Depreciation Expense	600,370	-	600,370	-	600,370
Property Tax	315,024	(8,192)	306,832		306,832
Payroll Tax	59,265	(499)	58,766		58,766
Gross Receipts Tax	45,878	576	46,454	15,108	61,561
Operating Income Before Income Taxes	$ 348,261	$ 129,303	$ 477,564	$ 1,189,708	$ 1,667,273
Interest Expense	447,247	(7,605)	439,642		439,642
Excess Tax Depreciation	337,539	-	337,539		337,539
Current Federal Taxable Income	(436,525)	136,908	(299,617)	1,189,708	890,092
Federal Income Tax at 35%	$ (152,784)	$ 47,918	$ (104,866)	$ 416,398	$ 311,532
Deferred Federal Income Tax	118,139	-	118,139	-	118,139
Investment Tax Credit Amortization	(4,662)	-	(4,662)	-	(4,662)
Total Federal Income Tax	$ (39,307)	$ 47,918	$ 8,611	$ 416,398	$ 425,009

Notes:

	(A)	(B)	(C)	(D)	(E)
(1) Calculation of Interest Deduction					
Rate Base	$ 15,859,819		$ 15,645,640		$ 15,645,640
Weighted Cost of Debt	2.82%		2.81%		2.81%
Interest Deduction	$ 447,247	$ (7,605)	$ 439,642		$ 439,642
		-			
Federal Income Tax Effect at 35%		2,662			
Interest Synchronization Adjustment		$ 2,662			

Docket No. 4434
Exhibit 1 (Joint Settlement) Schedule 5

UNITED WATER RHODE ISLAND, INC.

Cash Working Capital Analysis
Rate Year Ended December 31, 2014

	Expense Amount	Working Capital
O&M Expense per Company (1)	1,880,222	235,028
Settlement Adjustments (2)		
Exclude Tank Painting Amortization	(43,383)	(5,423)
Adjustment to Salaries and Wages	(15,931)	(1,991)
Adjustment to Benefits Transferred	(10,157)	(1,270)
Incentive Compensation-Company Employees	(10,951)	(1,369)
Incentive Compensation-UWM&S Fees	(15,965)	(1,996)
Chemicals Expense	(9,044)	(1,131)
Power Expense	22,523	2,815
PEPOB Transition Obligation	(2,557)	(320)
Transportation Expense	(4,858)	(607)
Outside Services Expense	(26,317)	(3,290)
Inflation	(2,010)	(251)
Regulatory Commission Assessment	144	18
Adjustment to Cash Working Capital		(14,813)
Cash Working Capital Per Settlement		$ 220,215

Notes:
(1) Per Exhibit 3 (Michaelson), Schedule 1, page 4 of 4.

(2) Reflects exclusion of tank painting amortization and Division adjsustments as summarizd on Schedule TSC-3.

Docket No. 4434
Exhibit 1 (Joint Settlement) Schedule 6

UNITED WATER RHODE ISLAND, INC.

Adjustment to Accumulated Deferred Income Taxes to
Reflect Federal Bonus Deprecaiton
Rate Year Ended December 31, 2014

	Balance of ADIT Due to Tax Depreciation	
	Per Settlement (1)	Per Company (2)
December 2013	$ 1,662,459	$ 1,662,459
January 2014	1,672,538	1,672,538
February	1,682,611	1,682,611
March	1,692,678	1,692,678
April	1,702,732	1,702,732
May	1,712,671	1,712,671
June	1,722,386	1,722,386
July	1,731,972	1,731,972
August	1,741,540	1,741,540
September	1,751,115	1,751,115
October	1,760,652	1,760,652
November	1,770,160	1,770,160
December 14	1,780,598	1,780,598
13 Month Average (3)	$ 1,721,855	1,721,855
Adjustment to ADIT	$ -	

Notes:
(1) Per response to Div. 2-49.

(2) Per Ehibit 4 (Michaelson), Schedule 5A, page 2 of 2.

(3) Amounts do not include ADIT related to AFUDC Equity or Cost of Removal.

Docket No. 4434
Exhibit 1 (Joint Settlement) Schedule 7
Page 1 of 2

UNITED WATER RHODE ISLAND, INC.

Determination of Water and Fire Service Revenues at Present Rates
Based on Settlement Units of Service
Rate Year Ended December 31, 2014

Quarterly Fixed Meter Revenue			
Meter Size	Pro Forma Year Normalized Bills	Service Charge	Fixed Meter Revenue
5/8"	29,627	24.01	$ 711,344
3/4"	15	25.72	386
1"	1,093	37.73	41,239
1 1/2"	293	63.45	18,591
2"	588	85.75	50,421
3"	39	114.91	4,481
4"	4	171.51	686
6"	25	296.72	7,418
8"	4	514.55	2,058
Total	**31,688**		**$ 836,625**

Monthly Fixed Meter Revenue			
Meter Size	Pro Forma Year Normalized Bills	Service Charge	Fixed Meter Revenue
5/8"	42	12.57	$ 528
3/4"	-	13.14	-
1"	48	17.14	823
1 1/2"	12	25.72	309
2"	111	33.15	3,680
3"	35	42.87	1,500
4"	12	61.74	741
6"	-	103.48	-
8"	-	176.09	-
Total	**260**		**$ 7,580**

Consumption Revenue			
	Consumption (CCF)	Rate ($/CCF)	Consumption Revenue
Residential			
0-24 CCF	410,230	2.276	$ 933,684
Over 24 CCF	124,770	2.853	355,968
Commercial	242,912	2.173	527,848
Industrial	2,857	2.173	6,208
Public Auth.	36,596	2.173	79,523
Total	**817,365**		**$ 1,903,231**

UNITED WATER RHODE ISLAND, INC.

Determination of Water and Fire Service Revenues at Present Rates
Based on Settlement Units of Service
Rate Year Ended December 31, 2014

Resale Revenue

Usage ('000 gallons)	Current Rate (Per '000 gallons)	Current Fixed Monthly Charge	Revenue
404,341	$ 1.124	$ 61.74	$ **455,220**

Fire Service Revenue

Connection Size	Pro Forma Units	Quarterly Rate	Annual Revenue
2 1/2"	6	22.00	$ 528
3"	-	32.00	-
4"	20	60.00	4,800
6"	139	162.00	90,072
8"	27	337.00	36,396
10"	-	601.00	-
12"	1	966.00	3,864
16"	-	2,050.00	-
Total Private Fire	193		$ 135,660
Fire Hydrants	**Pro Forma Units**	**Rate**	**Annual Revenue**
Public Hydrants-Quarterly	352	130.00	183,040
Public Hydrants-Semi-Annual	307	260.00	159,640
Total Public Fire	659		$ 342,680
Total Fire Service			$ **478,340**

Adjustment Summary

	Amount per Company	Amount per Division	Adjustment
Retail Sales	$ 2,709,794	$ 2,747,436	$ 37,642
Sales for Resale	447,403	455,220	7,817
Fire Protection	477,732	$ 478,340	608
Other Operating Revenues	35,337	35,337	-
Total Revenue	$ 3,670,266	$ 3,716,333	$ **46,067**
Increase in Regulatory Commission Assessment at 0.31317%			144
Increase in Gross Receipts Tax at 1.25%			576
Net Adjustment to Income before Taxes			$ 45,347

UNITED WATER RHODE ISLAND, INC.

Adjustment to Salaries and Wages and Benefits Expense
to Reflect Updated Percentage Charged to Expense
Rate Year Ended December 31, 2014

Wages		
Rate Year Salaries and Wages per Company (1)	$	711,022
Net Percentage Charged to O&M per Division (2)		82.08%
Wages Charged to O&M per Division	$	583,627
Amount per Company (1)		599,558
Adjustment to Rate Year Wage Expense	$	(15,931)

Benefits Transferred		
Rate Year Benefits per Company (3)	$	453,306
Net Percentage Capitalized/Transferred Out per Division (2)		17.92%
Benefits Transferred Out per Division	$	(81,220)
Amount per Company		(71,063)
Adjustment to Rate Year Benefits Expense	$	(10,157)

Notes:
(1) Per Exhibit 3 (Gil), Schedule 2.

(2) Refer to Page 2 of this Schedule.

(3) Per Exhibit 3 (Gil), Schedule 3.

UNITED WATER RHODE ISLAND, INC.

Calcuation of Normalized Percentage of Labor Costs Expensed and Capitalized
Based on 3-Year Average for 2011 through 2013

Rate Year Ended December 31, 2014

		2011 (1)	2012 (1)	2013 (2)	3 Yr Avg
Gross Payroll	(a)	$ 668,290	$ 692,066	$ 675,743	$ 678,700
Capitalized	(b)	(126,307)	(132,479)	(146,804)	(135,197)
Transferred to Other BU's	(c)	-	-	-	-
Net Payroll	(d)	$ 541,983	$ 559,587	$ 528,939	$ 543,503
Expense Rate	(d) / (a)	81.10%	80.86%	78.28%	80.08%
Capitalized/Transferred Out	(b)+(c)	$ (126,307)	$ (132,479)	$ (146,804)	$ (135,197)
Capitalized/Transferred Out Rate	(b)+(c)/(a)	18.90%	19.14%	21.72%	19.92%
Transferred in	(c)	$ 9,923	$ 11,618	$ 19,237	$ 13,593
Transferred in Rate	(c)/(a)	1.48%	1.68%	2.85%	2.00%

Notes:
(1) Per Exhibit 3 (Gil), Schedule 2A, page 4.

(2) Amounts per response to Div. 4-5.

Docket No. 4434
Exhibit 1 (Joint Settlement) Schedule 9

UNITED WATER RHODE ISLAND, INC.

Adjustment to Company Incentive Compensation Expense
Rate Year Ended December 31, 2014

Employee	2012 Base Salary (1)	Incentive Payment % (1)	Non Financial Percentage (2)	Recoverable Incentive Compensation
Manager Rhode Island	$ 104,653	15.00%	50.00%	$ 7,849
Superindentent	82,856	10.00%	50.00%	4,143
Supervisor Office	67,443	5.00%	60.00%	2,023
Total				$ 14,015
Amount per Company (1)				27,356
Reduction in Total Eligible Incentive Compensation				$ (13,341)
Amount Charged to Capital at 17.92% (3)				(2,390)
Adjustment to O&M Expense				$ (10,951)
Adjustment to FICA Taxes (4)				(499)
Total Adjustment to Rate Year Expense				$ (11,450)

Notes:
(1) Amounts per Exhibit 3 (Gil), Schedule 2A.

(2) Per response to Div. 2-17.

(3) Per Schedule TSC-7, page 2 of 2.

Docket No. 4434
Exhibit 1 (Joint Settlement) Schedule 10

UNITED WATER RHODE ISLAND, INC.

Adjustment to Incentive Compensation included in UWM&S Fees
Rate Year Ended December 31, 2014

		Amount
Financial Based Incentive Plan Costs in UWM&S Fees		
Short-Term Incentive Plan-Total (1)	$	16,260
Percent Attributable to Financial Goals (1)		40%
STIP Costs Attributable to Financial Goals in Test Year	$	6,504
Long-Term Incentive Plan for Test Year (1)		7,612
Total Incentive Compensation Attributable to Financial Goals	$	14,116
Increase to Rate Year at 5.06% (2)		714
Rate Year Incentive Compensation Attributable to Financial Goals	$	14,830
FICA Taxes at 7.65%		1,135
Adjustment to Rate Year UWM&S Fees	$	(15,965)

Notes:
(1) Per response to Div. 4-7.

(2) Per Exhibit 3 (Gil), Schedule 15A

Docket No. 4434
Exhibit 1 (Joint Settlement) Schedule 11

UNITED WATER RHODE ISLAND, INC.

Adjustment to Chemical Expense
Rate Year Ended December 31, 2014

Chemical Usage (1)				
Chemical Name	2011	2012	2013	Average (2)
Lime (pounds)	110,650	117,600	108,250	112,167
Sodium Hypochlorite (gallons)	8,101	8,849	8,270	.8,407
Nalco C-9 (pounds)	20,309	20,868	12,949	12,949

Production(MG) (Subject to Chemical Treatment) (1)				
	2011	2012	2013	Average
Production(MG) (Subject to Chemical Treatment)	1,082.74	1,144.40	1,044.90	1,090.68

Determination of Rate Year Expense				
Chemical Name	Average Usage Per MG (2)	Rate Year Production (3)	Rate Year Unit Cost (4)	Rate Year Costs
Lime (pounds)	102.84	1,065.30	$ 0.1730	$ 18,953
Sodium Hypochlorite (gallons)	7.71	1,065.30	1.6300	13,384
Nalco C-9 (pounds)	12.39	1,065.30	0.8600	11,354
Total Rate Year Chemicals Expense per Division				$ 43,691
Amount per Company (Exhibit 3 (Gil) Schedule 5A				52,735
Adjustment to Rate Year Expense				$ (9,044)

Notes:

(1) Per Exhibit 3 (Gil) Schedule 5A, except 2013 per response to Div. 4-13.

(2) Amounts reflect 3 year average of 2011 through 2013 except Nalco C-9, which is based on 2013 only to reflect reduced usage due to modified treatment program.

(3) Calclated based on projected rate year consumprion per Schedule TSC-7 and average level of non revenue producing water for 2011 through 2013 as shown below.

Rate Year Billed Consumption (MG) Per Schedule TSC-7	1,026.47
Non-revenue water %	3.65%
Total Production Subject to Chemical Treatment (MG)	1,065.30

Non-Revenue Water %:	
2011	3.76%
2012	6.17%
2013	1.01%
Three Year Average	3.65%

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Exhibit 1 (Joint Settlement) Schedule 12

UNITED WATER RHODE ISLAND, INC.

Adjustment to Power Supply Expense
Rate Year Ended December 31, 2014

Power - Account 50610					
Rate Year 2014	kWh Avg Usage (1)	Projected Water Production (MG) (2)	kWh	kWh Avg Cost (3)	Total Cost
Commodity (Constellation New Energy)	1,514.21	1,065.30	1,613,092	$ 0.09245	149,130
Distribution (National Grid)	1,514.21	1,065.30	1,613,092	$ 0.04918	79,329
Total Test Year Power Cost-Production Related					$ 228,460
Non-Production Related (4)					8,175
Rate Year Power Costs per Division					$ 236,635
Amount per Company (5)					$ 210,429
Adjustment to Power Costs--Acount 50610					$ 26,206

Other Utilities-Power - Account 50620	
2011 (4)(5)	40,347
2012 (4)	24,416
2013 (6)	20,781
Rate Year (3 year average)	$ 28,515
Amount per Company (4)	$ 32,197
Adjustment to Power Costs--Acount 50620	$ (3,682)

Notes:
(1) Calculated based on 2013 kWh for production of 1,582,200 divided by 2013 production of 1,044.9 million gallons. per Div. 4-9 and and 4-13.

	(a) kWh Use	(b) MG produced	(c)=(a)/(b) kWh/MG
kWh Average Usage per MG	1,582,200	1,044.90	1,514.21

(2) Reflects projected rate year consumption grossed up for average Non-Revenue Water. Refer to Schedule TSC-11 for calculation.
(3) Based on contract price for supply with Constellation Energy including taxes and on average cost per kWh in 2013 for delivery service from National Grid per Div. 4-9 and 4-10.
(4) Per Exhibit 3 (Gil) Schedule 4A.
(5) Adjusted to exclude additiona fuel and diesel costs resulting from the storm Irene per Div. 4-11.
(6) Per response to Div. 4-11.

Docket No. 4434
Exhibit 1 (Joint Settlement) Schedule 13

UNITED WATER RHODE ISLAND, INC.

Adjustment to PEBOP Transition Obligation
Rate Year Ended December 31, 2014

		Amount
Unamortized Balance of Initial Transition Obligation as of January 1, 2014 (1)	$	5,113
Division Recommended Amortization Period (Years)		2
Annual Amortiztion Expense per Division	$	2,557
Amortization Expense per Company (1)		5,113
Adjustment to Amortization Expense	$	(2,557)

Note:
(1) Per Exhibit 3 (Gil), Schedule 7 and response to Div 2-25.

Docket No. 4434
Exhibit 1 (Joint Settlement) Schedule 14

UNITED WATER RHODE ISLAND, INC.

Adjustment to Transportation Expense
Rate Year Ended December 31, 2014

	Company Rate Year Amount (1)	Settlement Rate Year Amount
Leases	$ 32,902	$ 32,902
Fuel (2)	36,104	35,794
Maintenance & Repair (2)	11,974	9,178
Insurance (2)	5,963	5,912
Depreciation	1,655	1,655
Other-Registration, plates, tolls, mileage, etc. (2)	2,580	2,558
Total Costs	$ 91,178	$ 88,000
Capitalized/Transferred Out (3)	(15,850)	(17,530)
Net Transportation Expense	$ 75,328	$ 70,471
Adjustment to Transportation expense		$ (4,858)

Notes:
(1) Per Exhibit 3 (Gil) Scheudle 10A
(2) Amounts are based upon three year average adjusted for inflation as follows:

	Company	Settlement
Fuel:		
3 Year Average	$ 34,150	$ 34,150
Apply inflation rate	5.722%	4.817%
Rate Year Amount	$ 36,104	$ 35,794
Maintenenace & Repair:		
2010	4,732	4,732
2011	5,414	5,414
2012 (4)	13,427	5,629
3 Year Average	7,858	$ 5,258
Apply inflation rate	5.722%	4.817%
Rate Year Amount	$ 8,307	$ 5,512
Extraordinary repairs to back-hoe--3yr. amortization	3,667	3,667
Total Maintenance and Repair	$ 11,974	$ 9,178
Insurance		
3 Year Average	5,641	$ 5,641
Apply inflation rate	5.722%	4.817%
Rate Year Amount	$ 5,963	$ 5,912
Other Misc:		
3 Year Average	2,441	$ 2,441
Apply inflation rate	5.722%	4.817%
Rate Year Amount	$ 2,580	$ 2,558

(3) Capitalized amount basedf on 17.38% per Company and 19.92% per Division.
(4) 2012 expense adjusted to exclude abnormal costs of $7,798 oer response to Div. 2-28.

Docket No. 4434
Exhibit 1 (Joint Settlement) Schedule 15

UNITED WATER RHODE ISLAND, INC.

Adjustment to Outside Services Expense
Rate Year Ended December 31, 2014

	Company Rate Year Amount (1)	Settlement Rate Year Amount
Accounting & Auditing (2)	4,220	$ 4,184
Legal (2)	2,088	2,070
Information Systems (2)	14,558	14,433
Temporary Help (3)	10,000	10,000
Other (2)	11,945	11,843
Management Fee (R&I Alliance) (2)	15,801	15,666
Efficeincy Well Testing (4)	3,325	1,425
Well Rehabilitation (5)	40,000	16,000
Total	$ 101,937	$ 75,620
Adjustment to Outside Services Expense		$ (26,317)

Notes:
(1) Company amounts per Exhibit 3 (Gil) Schedule 15A.

(2) Division amounts based on updated inflation rate of 2.997% as follows:

	Test Year	Rate Year
Accounting & Auditing	4,062	4,184
Legal	2,010	2,070
Information Systems	14,013	14,433
Other	11,498	11,843
Management Fee (R&I Alliance)	15,210	15,666

(3) Reflects inclusion of 50% of proposed allowance for summer help for hydrant painting.

(4) Division amount reflects corrected amount per response to Div. 4-17.

(5) Reflects normalization of costs based on frequency of every 2 to 3 years per response to Div. 4-18.

UNITED WATER RHODE ISLAND, INC.

Adjustment to Reflect Updated Inflation Factors
Rate Year Ended December 31, 2014

	Company Rate Year Amount (1)	Division Rate Year Amount (2)
Other Benefits Expense	$ 7,024	$ 6,965
Insurance	51,714	51,511
Customer Information/Billing	58,556	58,065
Other O&M	227,343	226,076
	$ 344,637	$ 342,617
Adjustment to Rate Year Expense		$ (2,020)
Less: Other Benefits reducttion Allocated to Capital		(11)
Net Reduction in Rate Year Expense (4)		$ (2,010)

Notes:

(1) Company amounts per Exhibit 3 (Gil) Schedule 15A.

(2) Settlement amounts reflect updated inflation rates as follows:

	Inflation Base	Inflation Amount (3)	Division Expense
Other Benefits Expense	$ 6,762	2.997%	$ 6,965
Insurance	50,700	1.600%	51,511
Customer Information/Billing	56,375	2.997%	58,065
Other O&M	219,498	2.997%	226,076

(3) Refer to page 2 of this schedule.

(4) The adjustment to Benefits Charged Out on Schedule TSC-7 was calculated based on UNWI's claimed benefits. This adjustment recognized that any reduction in benefits costs must be split between expense and capital.

UNITED WATER RHODE ISLAND, INC.

Adjustment to Reflect Updated Inflation Factors
Rate Year Ended December 31, 2014

Description	Inflation Factor
Inflation Rate for 2012 to 2014	2.997%
Inflation rate for 2013 to 2014	1.600%
Inflation rate for 3-yr average to 2014	4.817%

	Increase in GDP Price Index (1)	Compound Rate from 2012 to 2014
2013	1.375%	1.375%
2014	1.600%	1.622%
		2.997%

	Increase in GDP Price Index (1)	Compound Rate from 3 yr. avg to 2014
2010	1.575%	
2011	2.000%	
2012 (2)	1.725%	1.767%
2013 (3)	1.375%	3.166%
2014 (4)	**1.600%**	**4.817%**

Notes:
(1) Amounts per Blue Chip Financial Forecasts December 1, 2011 (Volume 30, No. 12) and Blue Chip Financial Forecasts January 10, 2013 (Volume 33, No. 1) 2010-2013 amounts are an average of the 4 quarters and 2014 is consensus forecast.
(2) Amount in compound rate column is average GDP price index for 2010, 2011, 2012.
(3) Compound rate from 3 year average GDP to 2013.
(4) Compound rate from 3 year average GDP to 2014.

Docket No. 4434
Exhibit 1 (Joint Settlement) Schedule 17

UNITED WATER RHODE ISLAND, INC.

Adjustment to Property Tax Expense
Rate Year Ended December 31, 2014

		Amount
Rate Year Property Taxes per Division (1)	$	306,832
Rate Year Property Taxes per Company (2)		315,024
Adjustement to Rate Year Property Tax Expense	$	(8,192)

Notes:

(1) Calculated based on 3-year historical average increase applied to 2013 property tax expense as follows:

Property Taxes		Amount	% Change
2010		257,385	
2011		263,652	2.43%
2012		270,476	2.59%
2013		293,644	8.57%
Average Annual Increase			4.49%
2014 Projected	$	306,832	

Docket No. 4434
Exhibit 1 (Joint Settlement) Schedule 18

UNITED WATER RHODE ISLAND, INC.

Determination of Overall Percentage Increase
Rate Year Ended December 31, 2014

Current Service Revenues per Division (1)	Amount
Retail Sales	$ 2,747,436
Sales for Resale	455,220
Fire Protection	478,340
Revenue at Present Rates	$ 3,680,996
Revenue Deficiency (2)	1,208,601
Revenues at Proposed Rates	4,889,597
Overall Percentage Increase	32.83%

Notes:
(1) Per Schedule TSC-1.

(2) Per Schedule TSC-2.

UNITED WATER RHODE ISLAND, INC.

Determination of Water and Fire Service Revenues at Proposed Rates
Based on Settlement Units of Service
Rate Year Ended December 31, 2014

Quarterly Fixed Meter Revenue

Meter Size	Current Rate	Proposed Rate	Pro Forma Year Normalized Bills	Fixed Meter Revenue
5/8"	$ 24.01	$ 31.89	29,627	$ 944,805
3/4"	25.72	34.16	15	512
1"	37.73	50.12	1,093	54,781
1 1/2"	63.45	84.28	293	24,694
2"	85.75	113.90	588	66,973
3"	114.91	152.64	39	5,953
4"	171.51	227.82	4	911
6"	296.72	394.14	25	9,854
8"	514.55	683.49	4	2,734
Total			**31,688**	**$ 1,111,218**

Monthly Fixed Meter Revenue

Meter Size	Current Rate	Proposed Rate	Pro Forma Year Normalized Bills	Fixed Meter Revenue
5/8"	12.57	$ 16.70	42	$ 701
3/4"	13.14	17.45	-	-
1"	17.14	22.77	48	1,093
1 1/2"	25.72	34.16	12	410
2"	33.15	44.03	111	4,887
3"	42.87	56.95	35	1,993
4"	61.74	82.01	12	984
6"	103.48	137.46	-	-
8"	176.09	233.91	-	-
Total			**260**	**$ 10,069**

Retail Consumption Revenue

	Current Rate ($/CCF)	Proposed Rate ($/CCF)	Consumption (CCF)	Consumption Revenue
Residential				
0-24 CCF	2.276	$ 3.023	410,230	$ 1,240,126
Over 24 CCF	2.853	3.790	124,770	472,877
				-
Commercial	2.173	2.886	242,912	701,044
Industrial	2.173	2.886	2,857	8,245
Public Auth.	2.173	2.886	36,596	105,616
Total			**817,365**	**$ 2,527,909**

Total Retail Sales Revenue	**$ 3,649,195**

UNITED WATER RHODE ISLAND, INC.

Determination of Water and Fire Service Revenues at Proposed Rates
Based on Settlement Units of Service
Rate Year Ended December 31, 2014

Resale Revenue

	Current Rate	Proposed Rate	Thousand Gallons/ 4" Services	Annual Revenue
Consumption--1,000 Gallons	$ 1.124	$ 1.490	404,341	$ 602,468
Service Charge	61.74	82.01	1	984
Total Resale				**$ 603,452**

Private Fire Service Revenue

Connection Size	Current Rate (Quarterly)	Proposed Rate (Quarterly)	Pro Forma Units	Annual Revenue
2 1/2"	22.00	29.22	6	$ 701
3"	32.00	42.51	-	-
4"	60.00	79.70	20	6,376
6"	162.00	215.19	139	119,646
8"	337.00	447.65	27	48,346
10"	601.00	798.33	-	-
12"	966.00	1,283.17	1	5,133
16"	2,050.00	2,723.09	-	-
Total Private Fire			**193**	**$ 180,202**

Public Fire Service Revenue

Fire Hydrants	Current Rate	Proposed Rate	Pro Forma Units	Annual Revenue
Quarterly	130.00	173.00	352	$ 243,584
Semi-Annual	260.00	345.00	307	211,830
Total Public Fire			**659**	**$ 455,414**
Total Fire Service				**$ 635,616**
Total Service Revenues				**$ 4,888,263**
Target Revenue				4,889,597
Variance				$ (1,334)

MOODY'S
INVESTORS SERVICE

Rating Action: Moody's changes outlooks on 25 US regulated utilities prir impacted by tax reform

Global Credit Research - 19 Jan 2018

New York, January 19, 2018 -- Moody's Investors Service, ("Moody's") changed the rating outlooks to negative from stable for 24 regulated utilities and utility holding companies; and to stable from positive fo utility holding company in the United States. The short and long-term ratings for all 25 companies we affirmed.

RATINGS RATIONALE

"Today's action primarily applies to companies that already had limited cushion in their rating for deteriorat in financial performance, will be incrementally impacted by changes in the tax law and where we expect key credit metrics to be lower for longer," said Jim Hempstead, a Managing Director at Moody's. "Utilities will work closely with state regulators to try to mitigate the negative impact of tax reform and in some cases the may seek to refine their corporate financial policies. Where successful, their rating outlooks could revert to stable."

Tax reform is credit negative for US regulated utilities because the lower 21% statutory tax rate reduces cas collected from customers, while the loss of bonus depreciation reduces tax deferrals, all else being equal. Moody's calculates that the recent changes in tax laws will dilute a utility's ratio of cash flow before chang working capital to debt by approximately 150 - 250 basis points on average, depending to some degree on size of the company's capital expenditure programs. From a leverage perspective, Moody's estimates that de to total capitalization ratios will increase, based on the lower value of deferred tax liabilities.

The change in outlook to negative from stable for the 24 companies affected in this rating action primarily reflects the incremental cash flow shortfall caused by tax reform on projected financial metrics that were already weak, or were expected to become weak, given the existing rating for those companies. The negat outlook also considers the uncertainty over the timing of any regulatory actions or other changes to corporate finance polices made to offset the financial impact.

The change in outlook to stable from positive for American Electric Power Company, Inc. (AEP, Baa1 stable reflects Moody's calculations that the projected ratio of cash flow before changes in working capital to debt, incorporating the effects of tax reform, will remain in the mid-teens range. At this level, Moody's believes AEF Baa1 rating is appropriate.

The vast majority of US regulated utilities, however, continue to maintain stable rating outlooks. We do not expect the cash flow reduction associated with tax reform to materially impact their credit profiles because sufficient cushion exists within projected financial metrics for their current ratings. Nonetheless, further ac could occur on a company specific basis.

Over the next 12 to 18 months, Moody's will continue to monitor the financial impact of tax reform on each company, including its regulatory approach to rate treatment and any changes to corporate finance strategies. This will include balance sheet changes due to the reclassification of excess deferred tax liabilities as a regulatory liability and the magnitude of any amounts to be refunded to customers. If the financial impact of ta reform is more severe than Moody's initial estimates or the companies fail to materially mitigate any weaknesses in their financial profiles, the ratings could be downgraded.

That said, Moody's expects that most utilities will attempt to manage any negative financial implications of reform through regulatory channels. Corporate financial policies could also change. The actions taken by utilities will be incorporated into the credit analysis on a prospective basis. As a result, it is conceivable th some companies will sufficiently defend their credit profiles. For these companies, it is possible for the outl to return to stable.

Potential regulatory offsets to tax-related cash leakage could include: accelerated cost recovery of certain regulatory assets or future investment; changes to the equity layer or allowed ROEs, and other actions. Changes to corporate financial policies could include changes to capitalization, the financing of future investments, dividend growth, or others. Some of these corporate measures could have a more immedia boost to projected metrics than certain regulatory provisions, which may take time to approve and implemen

Outlook Actions:

..Issuer: American Electric Power Company, Inc.

....Outlook, Changed To Stable From Positive

..Issuer: Avista Corp.

....Outlook, Changed To Negative From Stable

..Issuer: Avista Corp. Capital II

....Outlook, Changed To Negative From Stable

..Issuer: Duke Energy Corporation

....Outlook, Changed To Negative From Stable

..Issuer: Entergy Corporation

....Outlook, Changed To Negative From Stable

..Issuer: New Jersey Natural Gas Company

....Outlook, Changed To Negative From Stable

..Issuer: Northwest Natural Gas Company

....Outlook, Changed To Negative From Stable

..Issuer: ONE Gas, Inc

....Outlook, Changed To Negative From Stable

..Issuer: Piedmont Natural Gas Company, Inc.

....Outlook, Changed To Negative From Stable

..Issuer: Public Service Company of Oklahoma

....Outlook, Changed To Negative From Stable

..Issuer: Questar Gas Company

....Outlook, Changed To Negative From Stable

..Issuer: South Jersey Gas Company

....Outlook, Changed To Negative From Stable

..Issuer: Alabama Power Capital Trust V

....Outlook, Changed To Negative From Stable

..Issuer: Alabama Power Company

....Outlook, Changed To Negative From Stable

..Issuer: Southern Company (The)

....Outlook, Changed To Negative From Stable

..Issuer: Southern Elect Generating Co

....Outlook, Changed To Negative From Stable

..Issuer: Southwestern Public Service Company

....Outlook, Changed To Negative From Stable

..Issuer: Wisconsin Gas LLC

....Outlook, Changed To Negative From Stable

..Issuer: American Water Capital Corp.

....Outlook, Changed To Negative From Stable

Issuer: American Water Works Company, Inc.

....Outlook, Changed To Negative From Stable

Outlook Actions:

..Issuer: Consolidated Edison Company of New York, Inc.

....Outlook, Changed To Negative From Stable

..Issuer: Consolidated Edison, Inc.

....Outlook, Changed To Negative From Stable

..Issuer: Orange and Rockland Utilities, Inc.

....Outlook, Changed To Negative From Stable

..Issuer: Brooklyn Union Gas Company, The

....Outlook, Changed To Negative From Stable

..Issuer: KeySpan Gas East Corporation

....Outlook, Changed To Negative From Stable

Affirmations:

..Issuer: American Electric Power Company, Inc.

.... Commercial Paper, Affirmed P-2

....Senior Unsecured Shelf, Affirmed (P)Baa1

....Junior Subordinated Shelf, Affirmed (P)Baa2

....Senior Unsecured Regular Bond/Debenture, Affirmed Baa1

..Issuer: Avista Corp.

.... Issuer Rating, Affirmed Baa1

....Senior Secured First Mortgage Bonds, Affirmed A2

....Underlying Senior Secured First Mortgage Bonds, Affirmed A2

....Senior Secured Medium-Term Note Program, Affirmed (P)A2

....Senior Secured Regular Bond/Debenture, Affirmed A2

....Senior Unsecured Medium-Term Note Program, Affirmed (P)Baa1

..Issuer: Avista Corp. Capital II

....Pref. Stock Preferred Stock, Affirmed Baa2

..Issuer: Duke Energy Corporation

.... Issuer Rating, Affirmed Baa1

....Junior Subordinated Regular Bond/Debenture, Affirmed Baa2

....Senior Unsecured Shelf, Affirmed (P)Baa1

....Senior Unsecured Bank Credit Facility, Affirmed Baa1

....Senior Unsecured Commercial Paper, Affirmed P-2

....Senior Unsecured Regular Bond/Debenture, Affirmed Baa1

..Issuer: Entergy Corporation

.... Issuer Rating, Affirmed Baa2

....Senior Unsecured Commercial Paper, Affirmed P-2

....Senior Unsecured Regular Bond/Debenture, Affirmed Baa2

....Senior Unsecured Shelf, Affirmed (P)Baa2

..Issuer: New Jersey Natural Gas Company

.... Commercial Paper, Affirmed P-1

..Issuer: Northwest Natural Gas Company

.... Commercial Paper, Affirmed P-2

....Senior Secured Medium-Term Note Program, Affirmed (P)A1

....Senior Unsecured Medium-Term Note Program, Affirmed (P)A3

....Senior Secured Shelf, Affirmed (P)A1

....Senior Unsecured Shelf, Affirmed (P)A3

....Preferred Shelf, Affirmed (P)Baa2

....Senior Secured First Mortgage Bonds, Affirmed A1

....Senior Secured Regular Bond/Debenture, Affirmed A1

..Issuer: ONE Gas, Inc

....Senior Unsecured Commercial Paper, Affirmed P-1

....Senior Unsecured Regular Bond/Debenture, Affirmed A2

..Issuer: Piedmont Natural Gas Company, Inc.

....Senior Unsecured Commercial Paper, Affirmed P-1

....Senior Unsecured Regular Bond/Debenture, Affirmed A2

..Issuer: Public Service Company of Oklahoma

.... Issuer Rating, Affirmed A3

....Senior Unsecured Regular Bond/Debenture, Affirmed A3

..Issuer: Questar Gas Company

....Senior Unsecured Commercial Paper, Affirmed P-1

....Senior Unsecured Medium-Term Note Program, Affirmed (P)A2

....Senior Unsecured Regular Bond/Debenture, Affirmed A2

..Issuer: Alabama Power Capital Trust V

....Pref. Stock Preferred Stock, Affirmed A2

..Issuer: Alabama Power Company

.... Commercial Paper, Affirmed P-1

.... Issuer Rating, Affirmed A1

....Senior Unsecured Shelf, Affirmed (P)A1

....Preferred Shelf, Affirmed (P)A3

....Preference Shelf, Affirmed (P)A3

....Pref. Stock Preferred Stock, Affirmed A3

....Senior Unsecured Bank Credit Facility, Affirmed A1

....Senior Unsecured Commercial Paper, Affirmed P-1

....Senior Unsecured Regular Bond/Debenture, Affirmed A1

..Issuer: Columbia (Town of) AL, Industrial Dev. Board

....Senior Unsecured Revenue Bonds, Affirmed A1

....Senior Unsecured Revenue Bonds, Affirmed VMIG 1

..Issuer: Eutaw (City of) AL, Industrial Dev. Board

....Senior Unsecured Revenue Bonds, Affirmed A1

....Senior Unsecured Revenue Bonds, Affirmed VMIG 1

..Issuer: Mobile (City of) AL, I.D.B.

....Senior Unsecured Revenue Bonds, Affirmed A1

....Senior Unsecured Revenue Bonds, Affirmed VMIG 1

..Issuer: Walker County Econ & Ind Dev Authority

....Senior Unsecured Revenue Bonds, Affirmed A1

....Senior Unsecured Revenue Bonds, Affirmed VMIG 1

..Issuer: West Jefferson (Town of) AL, Ind. Devel. Bd.

....Senior Unsecured Revenue Bonds, Affirmed A1

....Senior Unsecured Revenue Bonds, Affirmed VMIG 1

..Issuer: Wilsonville (Town of) AL, I.D.B.

....Senior Unsecured Revenue Bonds, Affirmed A1

....Senior Unsecured Revenue Bonds, Affirmed VMIG 1

....Underlying Senior Unsecured Revenue Bonds, Affirmed A1

..Issuer: South Jersey Gas Company

.... Issuer Rating, Affirmed A2

....Senior Secured First Mortgage Bonds, Affirmed Aa3

....Senior Secured Medium-Term Note Program, Affirmed (P)Aa3

....Senior Secured Regular Bond/Debenture, Affirmed Aa3

....Senior Unsecured Commercial Paper, Affirmed P-1

..Issuer: New Jersey Economic Development Authority

....Senior Secured Revenue Bonds, Affirmed Aa3

....Underlying Senior Secured Revenue Bonds, Affirmed Aa3

....Senior Secured Revenue Bonds, Affirmed Aa2

....Underlying Senior Secured Revenue Bonds, Affirmed Aa2

..Issuer: Southern Company (The)

.... Commercial Paper, Affirmed P-2

....Junior Subordinated Regular Bond/Debenture, Affirmed Baa3

....Senior Unsecured Shelf, Affirmed (P)Baa2

....Junior Subordinated Shelf, Affirmed (P)Baa3

....Senior Unsecured Bank Credit Facility, Affirmed Baa2

....Senior Unsecured Regular Bond/Debenture, Affirmed Baa2

..Issuer: Southern Elect Generating Co

.... Issuer Rating, Affirmed A2

....Senior Unsecured Regular Bond/Debenture, Affirmed A1

..Issuer: Southwestern Public Service Company

.... Issuer Rating, Affirmed Baa1

....Senior Secured Shelf, Affirmed (P)A2

....Senior Unsecured Shelf, Affirmed (P)Baa1

....Senior Secured First Mortgage Bonds, Affirmed A2

....Senior Unsecured Bank Credit Facility, Affirmed Baa1

....Senior Unsecured Commercial Paper, Affirmed P-2

....Senior Unsecured Regular Bond/Debenture, Affirmed Baa1

..Issuer: Wisconsin Gas LLC

.... Commercial Paper, Affirmed P-1

....Senior Unsecured Regular Bond/Debenture, Affirmed A2

..Issuer: American Water Capital Corp.

.... Issuer Rating, Affirmed A3

....Senior Unsecured Shelf, Affirmed (P)A3

....Senior Unsecured Commercial Paper, Affirmed P-2

....Senior Unsecured Regular Bond/Debenture, Affirmed A3

..Issuer: American Water Works Company, Inc.

.... Issuer Rating, Affirmed A3

..Issuer: Berks County Industrial Development Auth., PA

....Senior Unsecured Revenue Bonds, Affirmed A3

..Issuer: California Pollution Control Financing Auth.

....Senior Unsecured Revenue Bonds, Affirmed A3

..Issuer: Illinois Development Finance Authority

....Senior Unsecured Revenue Bonds, Affirmed A3

..Issuer: Illinois Finance Authority

....Senior Unsecured Revenue Bonds, Affirmed A3

..Issuer: Indiana Finance Authority

....Senior Unsecured Revenue Bonds, Affirmed A3

..Issuer: MARICOPA COUNTY INDUSTRIAL DEVELOPMENT AUTHORITY,AZ

....Senior Unsecured Revenue Bonds, Affirmed A3

..Issuer: Northampton County I.D.A., PA

....Senior Unsecured Revenue Bonds, Affirmed A3

..Issuer: Owen (County of) KY

....Senior Unsecured Revenue Bonds, Affirmed A3

.Issuer: Consolidated Edison Company of New York, Inc.

.... Issuer Rating, Affirmed A2

....Senior Unsecured Shelf, Affirmed (P)A2

....Subordinate Shelf, Affirmed (P)A3

....Preferred Shelf, Affirmed (P)Baa1

....Senior Unsecured Commercial Paper, Affirmed P-1

....Senior Unsecured Regular Bond/Debenture, Affirmed A2

....Underlying Senior Unsecured Regular Bond/Debenture, Affirmed A2

..Issuer: New York State Energy Research & Dev. Auth.

....Senior Unsecured Revenue Bonds, Affirmed A2

....Underlying Senior Unsecured Revenue Bonds, Affirmed A2

..Issuer: New York State Research & Development Auth.

....Senior Unsecured Revenue Bonds, Affirmed A2

....Underlying Senior Unsecured Revenue Bonds, Affirmed A2

..Issuer: Consolidated Edison, Inc.

.... Issuer Rating, Affirmed A3

....Senior Unsecured Shelf, Affirmed (P)A3

....Senior Unsecured Commercial Paper, Affirmed P-2

....Senior Unsecured Regular Bond/Debenture, Affirmed A3

..Issuer: Orange and Rockland Utilities, Inc.

.... Issuer Rating, Affirmed A3

....Senior Unsecured Commercial Paper, Affirmed P-2

....Senior Unsecured Regular Bond/Debenture, Affirmed A3

..Issuer: Brooklyn Union Gas Company, The

....LT Issuer Rating, Affirmed A2

....Senior Unsecured Regular Bond/Debenture, Affirmed A2

..Issuer: New York State Energy Research & Dev. Auth.

....Backed LT IRB/PC Insured, Affirmed A2

...Underlying LT IRB/PC, Affirmed A2

Issuer: KeySpan Gas East Corporation

....LT Issuer Rating, Affirmed A2

....Senior Unsecured Regular Bond/Debenture, Affirmed A2

The principal methodology used in rating Public Service Company of Oklahoma, Southwestern Public Servic Company, Southern Company (The), Alabama Power Company, Alabama Power Capital Trust V, South Elect Generating Co, South Jersey Gas Company, Wisconsin Gas LLC, American Electric Power Company Inc., Duke Energy Corporation, Piedmont Natural Gas Company, Inc., Avista Corp., Avista Corp. Capital II, ONE Gas, Inc, New Jersey Natural Gas Company, Northwest Natural Gas Company, Questar Gas Compan Entergy Corporation, Consolidated Edison, Inc., Consolidated Edison Company of New York, Inc., Brooklyn Union Gas Company, The, KeySpan Gas East Corporation, and Orange and Rockland Utilities, Inc. was Regulated Electric and Gas Utilities published in June 2017. The principal methodology used in rating American Water Works Company, Inc. and American Water Capital Corp. was Regulated Water Utilities published in December 2015. Please see the Rating Methodologies page on www.moodys.com for a copy of these methodologies.

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The Narragansett Electric Company

Financial Statements

For the years ended March 31, 2018, 2017, and 2016

THE NARRAGANSETT ELECTRIC COMPANY

FINANCIAL STATEMENTS

FOR THE TWELVE MONTHS ENDED

MARCH 31, 2018

I hereby certify that I am Vice-President, NE Controller of The Narragansett Electric Company and that the enclosed financial statements for the twelve months ended March 31, 2018, 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.

Christopher McCusker, Vice-President, NE Controller

Date 7/19/18

THE NARRAGANSETT ELECTRIC COMPANY

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INDEPENDENT AUDITORS' REPORT

To the Board of Directors of
Narragansett Electric Company

We have audited the accompanying financial statements of The Narragansett Electric Company (the "Company"), which comprise the balance sheet and statement of capitalization as of March 31, 2018, and the related statements of income, comprehensive income, cash flows and changes in shareholders' equity for the year then ended, 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 audit. We conducted our audit 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 entity'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 entity'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, 2018, and the results of its operations and its cash flows for the year then ended in accordance with accounting principles generally accepted in the United States of America.

Predecessor Auditors' Opinion on 2017 and 2016 Financial Statements

The financial statements of the Company as of and for each of the two years ended March 31, 2017, were audited by other auditors, whose report, dated July 14, 2017, expressed an unmodified opinion on those statements.

Deloitte + Touche LLP

July 19, 2018

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

	Years Ended March 31,		
	2018	2017	2016
Operating revenues:			
Electric services	**$ 1,012,378**	$ 892,452	$ 944,547
Gas distribution	**432,647**	370,902	361,702
Operating revenues	**1,445,025**	1,263,354	1,306,249
Operating expenses:			
Purchased electricity	**359,726**	302,210	372,846
Purchased gas	**180,576**	132,919	139,547
Operations and maintenance	**474,341**	418,499	385,873
Depreciation	**105,686**	103,923	96,914
Other taxes	**132,057**	120,461	118,776
Total operating expenses	**1,252,386**	1,078,012	1,113,956
Operating income	**192,639**	185,342	192,293
Other income and (deductions):			
Interest on long-term debt	**(43,247)**	(43,758)	(43,963)
Other interest, including affiliate interest	**(3,619)**	(3,199)	(1,680)
Loss on sale of assets	**-**	(2,468)	-
Other (deductions) income, net	**(213)**	749	1,512
Total other deductions, net	**(47,079)**	(48,676)	(44,131)
Income before income taxes	**145,560**	136,666	148,162
Income tax expense	**22,249**	48,524	53,004
Net income	**$ 123,311**	$ 88,142	$ 95,158

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

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

	Years Ended March 31,		
	2018	2017	2016
Net income	**$ 123,311**	$ 88,142	$ 95,158
Other comprehensive income, net of taxes:			
Unrealized gains (losses) on securities	**26**	110	(62)
Change in pension and other postretirement obligations	**99**	(4)	9
Unrealized gains on hedges	**228**	471	494
Total other comprehensive income	**353**	577	441
Comprehensive income	**$ 123,664**	$ 88,719	$ 95,599
Related tax (expense) benefit:			
Unrealized (gains) losses on securities	**$ (38)**	$ (60)	$ 34
Change in pension and other postretirement obligations	**(29)**	2	(5)
Unrealized gains on hedges	**(93)**	(254)	(266)
Total tax expense	**$ (160)**	$ (312)	$ (237)

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,		
	2018	2017	2016
Operating activities:			
Net income	**$ 123,311**	$ 88,142	$ 95,158
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation	**105,686**	103,923	96,914
Regulatory amortizations	**235**	714	706
Provision for deferred income taxes	**41,290**	27,470	45,818
Bad debt expense	**19,136**	14,105	8,480
Amortization of debt discount and issuance costs	**293**	293	294
Net postretirement benefits (contributions) expense	**(19,904)**	3,886	(10,559)
Net environmental remediation payments	**(2,946)**	(4,889)	(3,058)
Changes in operating assets and liabilities:			
Accounts receivable and other receivable, net, and unbilled revenues	**(66,457)**	(35,989)	74,882
Inventory	**(1,604)**	4,330	(2,662)
Regulatory assets and liabilities, net	**(64,143)**	97,822	39,235
Derivative instruments	**7,364**	(23,469)	(6,897)
Prepaid and accrued taxes	**5,094**	5,418	(3,490)
Accounts payable and other liabilities	**73,334**	19,284	(46,330)
Other, net	**(30,543)**	(1,827)	(9,144)
Net cash provided by operating activities	**190,146**	299,213	279,347
Investing activities:			
Capital expenditures	**(269,344)**	(295,621)	(278,050)
Proceeds from restricted cash	**7,834**	58,044	73,370
Payments on restricted cash	**(7,357)**	(43,887)	(43,985)
Cost of removal	**(21,033)**	(17,883)	(17,959)
Other	**(517)**	1,250	376
Net cash used in investing activities	**(290,417)**	(298,097)	(266,248)
Financing activities:			
Preferred stock dividends	**(110)**	(110)	(110)
Payments on long-term debt	**(1,375)**	(1,375)	(1,375)
Intercompany money pool and affiliated receivables/payables, net	**100,339**	(6,238)	(16,514)
Net cash provided by (used in) financing activities	**98,854**	(7,723)	(17,999)
Net decrease in cash and cash equivalents	**(1,417)**	(6,607)	(4,900)
Cash and cash equivalents, beginning of year	**7,803**	14,410	19,310
Cash and cash equivalents, end of year	**$ 6,386**	$ 7,803	$ 14,410
Supplemental disclosures:			
Interest paid	**$ (44,492)**	(42,574)	(42,683)
Income taxes (paid) refunded	**(2,624)**	63	71
Significant non-cash items:			
Capital-related accruals	**18,987**	15,775	26,990
Parent tax loss allocation	**3,047**	-	-
Share based compensation	**2**	31	25

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

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

	March 31, 2018	March 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 6,386**	$ 7,803
Restricted cash and special deposits	**479**	956
Accounts receivable	**251,985**	212,572
Allowance for doubtful accounts	**(25,617)**	(25,192)
Accounts receivable from affiliates	**22,221**	6,354
Unbilled revenues	**66,150**	57,817
Inventory	**23,390**	24,216
Regulatory assets	**87,297**	52,446
Derivative instruments	**731**	6,189
Prepaid taxes	**13,246**	9,821
Other	**3,362**	1,805
Total current assets	**449,630**	354,787
Property, plant and equipment, net	**2,984,346**	2,785,811
Other non-current assets:		
Regulatory assets	**492,361**	464,135
Goodwill	**724,810**	724,810
Derivative instruments	**10**	167
Other	**37,166**	13,905
Total other non-current assets	**1,254,347**	1,203,017
Total assets	**$ 4,688,323**	$ 4,343,615

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

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

	March 31, 2018	March 31, 2017
LIABILITIES AND CAPITALIZATION		
Current liabilities:		
Accounts payable	**$ 170,458**	$ 124,895
Accounts payable to affiliates	**14,430**	80,085
Current portion of long-term debt	**15,839**	1,375
Taxes accrued	**34,534**	29,624
Customer deposits	**10,627**	12,514
Interest accrued	**5,417**	5,434
Regulatory liabilities	**109,484**	106,788
Intercompany money pool	**307,520**	125,659
Derivative instruments	**1,971**	392
Renewable energy certificate obligations	**5,746**	11,841
Other	**29,640**	20,701
Total current liabilities	**705,666**	519,308
Other non-current liabilities:		
Regulatory liabilities	**553,343**	245,856
Asset retirement obligations	**9,472**	10,150
Deferred income tax liabilities, net	**324,161**	538,229
Postretirement benefits	**83,234**	121,799
Environmental remediation costs	**137,677**	135,529
Derivative instruments	**1,394**	1,224
Other	**15,467**	25,230
Other tax liabilities	**562**	-
Total other non-current liabilities	**1,125,310**	1,078,017
Capitalization:		
Shareholders' equity	**2,030,903**	1,904,300
Long-term debt	**826,444**	841,990
Total capitalization	**2,857,347**	2,746,290
Total liabilities and capitalization	**$ 4,688,323**	$ 4,343,615

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

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

			March 31,	
			2018	2017
Total shareholders' equity			$ **2,030,903**	$ 1,904,300
Long-term debt:	Interest Rate	Maturity Date		
Unsecured notes:				
Senior Note	4.53%	March 15, 2020	**250,000**	250,000
Senior Note	5.64%	March 15, 2040	**300,000**	300,000
Senior Note	4.17%	December 10, 2042	**250,000**	250,000
			800,000	800,000
First Mortgage Bonds ("FMB"):				
FMB Series S	6.82%	April 1, 2018	**14,464**	14,464
FMB Series N	9.63%	May 30, 2020	**10,000**	10,000
FMB Series O	8.46%	September 30, 2022	**12,500**	12,500
FMB Series P	8.09%	September 30, 2022	**3,125**	3,750
FMB Series R	7.50%	December 15, 2025	**6,000**	6,750
			46,089	47,464
Total debt			**846,089**	847,464
Unamortized debt discount			**(2,076)**	(2,301)
Unamortized debt issuance costs			**(1,730)**	(1,798)
Current portion of long-term debt			**15,839**	1,375
Long-term debt			**826,444**	841,990
Total capitalization			**$ 2,857,347**	**$ 2,746,290**

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)

	Common Stock	Cumulative Preferred Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss): 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, 2015	**$ 56,624**	**$ 2,454**	**$ 1,354,952**	**$ 857**	**$ 1,197**	**$ (4,166)**	**$ (2,112)**	**$ 308,228**	**$ 1,720,146**
Net income	-	-	-	-	-	-	-	95,158	95,158
Other comprehensive income (loss):									
Unrealized losses on securities, net of $34 tax benefit	-	-	-	(62)	-	-	(62)	-	(62)
Change in pension and other postretirement obligations, net of $5 tax expense	-	-	-	-	9	-	9	-	9
Unrealized gains on hedges, net of $266 tax expense	-	-	-	-	-	494	494	-	494
Total comprehensive income									95,599
Share based compensation	-	-	25	-	-	-	-	-	25
Preferred stock dividends	-	-	-	-	-	-	-	(110)	(110)
Balance as of March 31, 2016	**$ 56,624**	**$ 2,454**	**$ 1,354,977**	**$ 795**	**$ 1,206**	**$ (3,672)**	**$ (1,671)**	**$ 403,276**	**$ 1,815,660**
Net income	-	-	-	-			-	88,142	88,142
Other comprehensive income (loss):									
Unrealized gains on securities, net of $60 tax expense	-	-	-	110	-	-	110	-	110
Change in pension and other postretirement obligations, net of $2 tax benefit	-	-	-	-	(4)	-	(4)	-	(4)
Unrealized gains on hedges, net of $254 tax expense	-	-	-	-	-	471	471	-	471
Total comprehensive income									88,719
Share based compensation	-	-	31	-	-	-	-	-	31
Preferred stock dividends	-	-	-	-	-	-	-	(110)	(110)
Balance as of March 31, 2017	**$ 56,624**	**$ 2,454**	**$ 1,355,008**	**$ 905**	**$ 1,202**	**$ (3,201)**	**$ (1,094)**	**$ 491,308**	**1,904,300**
Net income	-	-	-	-			-	123,311	123,311
Other comprehensive income:									
Unrealized gains on securities, net of $38 tax expense	-	-	-	26	-	-	26	-	26
Change in pension and other postretirement obligations, net of $29 tax expense	-	-	-	-	99	-	99	-	99
Unrealized gains on hedges, net of $93 tax expense	-	-	-	-	-	228	228	-	228
Total comprehensive income									123,664
Parent tax loss allocation	-	-	3,047	-	-	-	-	-	3,047
Share based compensation	-	-	2	-	-	-	-	-	2
Preferred stock dividends	-	-	-	-	-	-	-	(110)	(110)
Balance as of March 31, 2018	**$ 56,624**	**$ 2,454**	**$ 1,358,057**	**$ 931**	**$ 1,301**	**$ (2,973)**	**$ (741)**	**$ 614,509**	**$ 2,030,903**

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, 2018 and 2017.

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

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 502,000 customers and gas service to approximately 270,000 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.

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 Company has evaluated subsequent events and transactions through July 19, 2018, 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, 2018.

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. Actual results could differ from those estimates.

Regulatory Accounting

The Federal Energy Regulatory Commission ("FERC"), the Rhode Island Public Utilities Commission ("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 and RIPUC 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. 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 provided on a monthly billing cycle basis. The Company records unbilled revenues for the estimated amount of services rendered from the time meters were last read to the end of the accounting period.

As approved by the RIPUC, the Company is allowed to pass through commodity-related costs to customers and also bills for approved rate adjustment mechanisms. In addition, the Company has an electric revenue decoupling mechanism ("RDM") which requires the Company to adjust its base rates annually to reflect the over or under recovery of the Company's targeted base distribution revenues from the prior fiscal year. Further, the Company has a gas RDM, which requires the Company to adjust its base rates annually to reflect the over or under recovery of the Company's allowed revenue per customer for the year.

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).

The Company's policy is to accrue for property taxes on a calendar year basis, taking into account the assessment period. The Company had accrued for property taxes of $18.0 million and $17.7 million at March 31, 2018 and 2017, respectively.

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 sufficient 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

Restricted cash consists of collateral paid to the Company's counterparties for outstanding derivative instruments. The Company had restricted cash of $0.5 million and $1.0 million at March 31, 2018 and 2017, 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.

Inventory

Inventory is composed of materials and supplies as well as gas in storage. Materials and supplies are stated at weighted average cost, which represents net realizable value, and are expensed or capitalized as used. The Company's policy is to write-off obsolete inventory; there were no material write-offs of obsolete inventory for the years ended March 31, 2018, 2017, or 2016.

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 $11.8 million and $10.2 million, purchased renewable energy certificates ("RECs") of $5.1 million and $7.5 million, and gas in storage of $6.5 million and $6.5 million at March 31, 2018 and 2017, respectively. (See Renewable Energy Certificates below for more information on RECs).

Derivative Instruments

Commodity Derivative Instruments – Regulated Accounting

The Company uses various 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 their fair value. All commodity costs, including the impact of derivative instruments, are passed on to customers through the Company's commodity rate adjustment mechanisms. Therefore, gains or losses on the settlement of these contracts are initially deferred 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 in accordance with 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.

Commodity Derivative Instruments – Non-Regulated Accounting

The Company also uses derivative instruments related to storage optimization, such as gas purchase and swaps contracts to maximize the value of its storage and transportation assets and to reduce the cash flow variability associated with forecasted purchases and sales of various gas related commodities. The gains and losses on these contracts are shared between the Company and its customers. The Company does not apply regulatory accounting treatment on these contracts since this optimization program is not done solely on behalf of rate payers. All such derivative instruments are accounted for at fair value on the balance sheet with all changes in fair value reported in the accompanying statements of income.

Renewable Energy Certificate Obligations

RECs are stated at cost and are used to measure compliance with renewable energy standards. RECs are held primarily for consumption. At March 31, 2018 and 2017 the Company recorded purchased RECs of $5.1 million and $7.5 million within inventory and a compliance liability based on retail electricity sales of $5.7 million and $11.8 million.

Power Purchase Agreements

The Company enters into power purchase agreements to procure commodity to serve its electric service customers. The Company evaluates whether such agreements are leases, derivative instruments, or executory contracts. Power purchase agreements that do not qualify as leases or derivative instruments are accounted for as executory contracts and are, therefore, recognized as the electricity is purchased. In making its determination of the accounting for power purchase agreements, the Company considers many factors, including: the source of the electricity; the level of output from any specified facility that the Company is taking under the contract; the involvement, if any, that the Company has in operating the specified facility; and the pricing mechanisms in the contract.

Natural Gas Long-Term Arrangements

The Company enters into long-term gas contracts to procure commodity to serve its gas customers. Those contracts include Asset Management Agreements, Baseload, and Peaking gas contracts. Similar to the power purchase agreements noted above, the Company evaluates whether such agreements are derivative instruments or executory contracts and applies the appropriate accounting treatment.

Fair Value Measurements

The Company measures derivative instruments and available-for-sale securities 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; and
- 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.

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 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. 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").

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, 2018, 2017, and 2016 are as follows:

	Electric			Gas		
	Years Ended March 31,			Years Ended March 31,		
	2018	2017	2016	**2018**	2017	2016
Composite rates	**2.9%**	2.9%	3.0%	**3.4%**	3.2%	3.2%

Depreciation expense includes a component for estimated future 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 had cumulative costs recovered in excess of costs incurred of $217.0 million and $206.7 million at March 31, 2018 and 2017, 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. AFUDC equity is reported in the accompanying statements of income as non-cash income in other income, net and AFUDC debt 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 rate base and corresponding depreciation expense. The Company recorded AFUDC related to equity of $0.1 million, and $(0.1) million, and $(0.8) million reflecting adjustments to plant balances for the years ended 2018, 2017 and 2016; AFUDC related to debt was $1.4 million, $1.0 million, and $0.2 million for the years ended March 31, 2018, 2017, and 2016, respectively. The average AFUDC rates for the years ended March 31, 2018, 2017, and 2016 were 1.7%, 1.1%, and 0.7%, respectively.

Impairment of Long-Lived Assets

The Company tests the impairment of long-lived assets annually or when events or changes in circumstances indicate that the carrying amount of the asset may not be recoverable. The recoverability of an asset is determined by comparing its carrying value to the future 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 year ended 2018, there were no impairment losses recognized for long-lived assets. For the year ended March 31, 2017, there was $2.5 million of impairment losses recognized for long-lived assets. For the year ended 2016, there were no impairment losses recognized for long-lived assets.

Goodwill

The Company tests goodwill for impairment annually on January 1, and when events occur or circumstances change that would more likely than not reduce the fair value of the Company below its carrying amount. The Company has early adopted ASU 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. The one-step approach 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 considered not 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 allocated amount of goodwill.

Historically the fair value of the Company was calculated for the annual goodwill impairment test utilizing both the income and market based approaches. The Company’s fair value was calculated utilizing the income approach. The Company believes that due to the recent rate case filing currently in process with its regulator, this approach provides the most reliable information. Based on the fair value resulting from the annual analyses performed, the Company determined that no adjustment to the goodwill carrying value was required at March 31, 2018 or 2017.

Available-For-Sale Securities

The Company provides certain executives with nonqualified retirement and deferred compensation benefits which have been partially secured through separate fund arrangements. As a result, the Company holds available-for-sale securities that include equities, municipal bonds, and corporate bonds. These investments are recorded at fair value and are included in other non-current assets on the balance sheet. Changes in the fair value of these assets are recorded within other comprehensive income.

Asset Retirement Obligations

Asset retirement obligations are recognized for legal obligations associated with the retirement of property, plant and equipment primarily associated with the Company's distribution facilities. Asset retirement obligations are recorded at fair value in the period in which the obligation is incurred, if the fair value can be reasonably estimated. In the period in which new asset retirement obligations, or changes to the timing or amount of existing retirement obligations are recorded, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. In each subsequent period the asset retirement obligation is accreted to its present value. The Company applies regulatory accounting guidance and both the depreciation and accretion costs associated with asset retirement obligation are recorded as increases to regulatory assets on the balance sheet. These regulatory assets represent timing differences between the recognition of costs in accordance with U.S. GAAP and costs recovered through the ratemaking process.

The following table represents the changes in the Company's asset retirement obligations:

	Years Ended March 31,	
	2018	2017
	(in thousands of dollars)	
Balance as of the beginning of the year	**$ 10,150**	$ 10,080
Accretion expense	**385**	389
Liabilities settled	**(626)**	(319)
Balance as of the end of the year	**$ 9,909**	$ 10,150

The Company had a current portion of asset retirement obligations of $0.4 million included in other current liabilities on the balance sheet at March 31, 2018.

Employee Benefits

The Company participates with other 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 the year-end date. Pension and PBOP plan assets are measured at fair value, using the year-end market value of those assets.

Going Concern

Current U.S. GAAP guidance requires management to evaluate whether there is substantial doubt surrounding an entity's ability to continue as a going concern. If management concludes that substantial doubt exists additional disclosures relating to management's evaluation and conclusion are required. Management is not aware of any indicators giving rise to substantial doubt about the Company's ability to continue to operate and to meet its obligations as they become due.

New and Recent Accounting Guidance

Accounting Guidance Recently Adopted

Measurement of Inventory

In July 2015, the FASB issued ASU No. 2015-11, "Simplifying the Measurement of Inventory." The new guidance requires that inventory be measured at the lower of cost and net realizable value (other than inventory measured using "last-in, first out" and the "retail inventory method"). The application of this guidance did not have a material impact on the results of operations, cash flows, or financial position of the Company since the Company's inventory was stated at cost upon adoption and the cost represents the net realizable value. The adoption of the guidance did not change the Company's methodology of measuring inventory.

Employee Share-Based Payment Accounting

In March 2016, the FASB issued ASU No. 2016-09, "Improvements to Employee Share-Based Payment Accounting (Topic 718)," which simplifies several aspects of the accounting for share-based payment transactions, including the accounting for income taxes, forfeitures and statutory tax withholding requirements, as well as classification in the statement of cash flows. Most notably, entities are required to recognize all excess tax benefits and shortfalls as income tax expense or benefit in the income statement within the reporting period in which they occur. The application of this guidance did not have a material impact on the results of operations, cash flows, or financial position of the Company.

Goodwill

In January 2017, the FASB issued ASU No. 2017-04, which eliminates Step 2 from the goodwill impairment test. For the Company, the requirements of the new standard will be effective for the fiscal year ended March 31, 2022, with early adoption permitted. The Company early adopted the ASU in the year ended March 31, 2018 for its annual goodwill impairment testing. Based on the resulting fair value from the annual analyses, the Company determined that no adjustment to the goodwill carrying value was required at March 31, 2018 or 2017.

Derivatives and Hedging

In March 2016, the FASB issued ASU No. 2016-05, "Derivatives and Hedging (Topic 815): Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships." This update clarifies that a change in the counterparty to a derivative instrument that has been designated as a hedging instrument under Accounting Standards Codification ("ASC") 815, "Derivatives and Hedging," does not require dedesignation of that hedging relationship provided that all other hedge accounting criteria in accordance with ASC 815-20-35 through ASC 815-35-18 continue to be met. The application of this guidance did not have a material impact on the results of operations, cash flows, or financial position of the Company.

Accounting Guidance Not Yet Adopted

Derivatives and Hedging

In August 2017, the FASB issued ASU No. 2017-12, "Targeted Improvements to Accounting for Hedging Activities," which will be effective for the fiscal year ended March 31, 2020, with early adoption permitted. The amendments in this update expand and refine hedge accounting for both financial and nonfinancial risk components and align the recognition and presentation of the effects of the hedging instrument and the hedged item in the financial statements. This update also includes changes to certain targeted improvements to ease the application of current guidance related to the assessment of hedge effectiveness. The Company is currently evaluating the impact of the new guidance on the results of its operations, cash flows, and financial position.

Pension and Postretirement Benefits

In March 2017, the FASB issued ASU No. 2017-07, “Compensation Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost,” which changes certain presentation and disclosure requirements for employers that sponsor defined benefit pension and other postretirement benefit plans. The ASU requires the service cost component of the net benefit cost to be in the same line item as other compensation in operating income and the other components of net benefit cost to be presented outside of operating income on a retrospective basis. In addition, only the service cost component will be eligible for capitalization when applicable, on a prospective basis. For the Company, the requirements of the new standard will be effective for the fiscal year ended March 31, 2019, and interim periods within the reporting period, with early adoption permitted. The implementation of the ASU will not have a material impact on the net income of the Company since the Company defers the difference between actual pension costs and the amounts used to establish rates (See Note 8, “Employee Benefits” for additional details).

Statement of Cash Flows

In November 2016, the FASB issued ASU No. 2016-18, "Statement of Cash Flows (Topic 230): Restricted Cash (a consensus of the FASB Emerging Issues Task Force)," which requires entities to show the changes in the total of cash, cash equivalents, restricted cash, and restricted cash equivalents in the statement of cash flows.

In August 2016, the FASB issued ASU No. 2016-15, "Classification of Certain Cash Receipts and Cash Payments (Topic 230)," which provides guidance about the classification of certain cash receipts and payments within the statement of cash flows, including debt prepayment or extinguishment costs, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims and policies, and distributions received from equity method investments.

For the Company, the requirements of the new standards will be effective for the fiscal year ended March 31, 2019, and interim periods therein, with early adoption permitted. The application of this guidance is not expected to have a material impact on the results of operations, cash flows, or financial position of the Company.

Income Taxes

In October 2016, the FASB issued ASU No. 2016-16, "Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory," which eliminates the exception for all intra-entity sales of assets other than inventory. As a result, a reporting entity would recognize the tax expense from the sale of the asset in the seller’s tax jurisdiction when the transfer occurs, even though the pre-tax effects of that transaction are eliminated in consolidation. For the Company, the requirements of the new standard will be effective for the fiscal year ended March 31, 2019, and interim periods thereafter, with early adoption permitted. The application of this guidance is not expected to have a material impact on the results of operations, cash flows, or financial position of the Company.

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 Instruments." The amendment replaces the incurred loss impairment methodology in current U.S. GAAP with a methodology that reflects expected credit losses and requires consideration of a broader range of reasonable and supportable information to inform credit loss estimates. For the Company, the requirements of the new standard will be effective for the fiscal year ended March 31, 2022, and interim periods within, with early adoption permitted from the fiscal year ended March 31, 2020 and interim periods within. The Company is currently evaluating the impact of the new guidance on the presentation, results of its operations, cash flows, and financial position.

Revenue Recognition

In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)." The underlying principle of this ASU is that an entity will recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to, in exchange for those goods or services. For the Company, the new guidance is effective for the fiscal year ended March 31, 2019, including interim periods therein, and will be adopted using a modified retrospective approach.

The FASB has issued a number of additional recent ASUs related to revenue recognition, whose effective date and transition requirements are the same as those for ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)." In March 2016, the FASB issued ASU No. 2016-08, "Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net)," which clarifies the implementation guidance on principal versus agent considerations. In April 2016, the FASB issued ASU No. 2016-10, "Revenue from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing," which provides guidance in the new revenue standard on identifying performance obligations and accounting for licenses of intellectual property. In May 2016, the FASB issued ASU No. 2016-12, "Revenue from Contracts with Customers (ASC 606) Narrow-Scope Improvements and Practical Expedients," providing additional clarity on various aspects of Topic 606, including a) Assessing the Collectability Criterion and Accounting for Contracts That Do Not Meet the Criteria for Step 1, b) Presentation of Sales Taxes and Other Similar Taxes Collected from Customers, c) Noncash Consideration, d) Contract Modifications at Transition, e) Completed Contracts at Transition, and f) Technical Correction. Lastly, in December 2016, the FASB issued ASU No. 2016-20, "Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers." The amendments in this update cover a variety of corrections and improvements to the Codification related to the new revenue recognition standard (ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)").

The Company has undertaken detailed reviews of its revenue arrangements and is in the process of finalizing its assessment of the impact of the new standard. Based on work to date, the Company does not believe that the standard will have a material impact on the presentation of the results of its operations, cash flows, or financial position. However, the Company will be required to make significant additional qualitative and quantitative financial statement disclosures under ASC 606, "Revenue from Contracts with Customers," pertaining to its revenue earning mechanisms.

Leases

In February 2016, the FASB issued a new lease accounting standard, ASU No. 2016-02, "Leases (Topic 842)." The key objective of the new standard is to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. Lessees will need to recognize a right-of-use asset and a lease liability for virtually all of their leases (other than leases that meet the definition of a short-term lease). For income statement purposes, a dual model has been retained, with leases to be designated as operating leases or finance leases. Expenses will be recognized on a straight-line basis for operating leases, and a front-loaded basis for finance leases. For the Company, the new standard is effective for the fiscal year ended March 31, 2020, and interim periods thereafter, with early adoption permitted. The new standard must be adopted using a modified retrospective transition, and provides for certain practical expedients. The Company is currently evaluating the impact of the new guidance on the results of its operations, cash flows, and financial position.

Financial Instruments – Classification and Measurement

In January 2016, the FASB issued ASU No. 2016-01, "Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Financial Liabilities." The new guidance principally affects the accounting for equity investments and financial liabilities where the fair value option has been elected, as well as the disclosure requirements for financial instruments. For the Company, the new guidance is effective for the fiscal year ended March 31, 2019, and interim periods thereafter, with early adoption permitted for fiscal years or interim periods that have not yet been issued. The application of this guidance is not expected to have a material impact on the presentation, results of its operations, cash flows, and financial position.

Stock Compensation

In May 2017, the FASB issued ASU No. 2017-09, "Stock Compensation (Topic 718): Scope of Modification Accounting," which provides clarity on the application of modification accounting upon a change to the terms or conditions of a share-based payment award. For the Company, the requirements of the new standard will be effective for the fiscal year ended March 31, 2019, with early adoption permitted. The Company is currently evaluating the impact of the new guidance on the presentation, results of its operations, cash flows, and financial position.

3. 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 sheet:

	March 31,	
	2018	2017
	(in thousands of dollars)	
Regulatory assets:		
Current:		
Derivative instruments	**$ 2,784**	$ -
Gas costs adjustment	**35,159**	1,246
Rate adjustment mechanisms	**34,890**	37,395
Renewable energy certificates	**642**	4,307
Revenue decoupling mechanism	**13,822**	9,498
Total	**87,297**	52,446
Non-current:		
Environmental response costs	**140,002**	139,024
Postretirement benefits	**187,087**	201,626
Storm costs	**142,269**	93,764
Other	**23,003**	29,721
Total	**492,361**	464,135
Regulatory liabilities:		
Current:		
Derivative Instruments	**-**	4,525
Energy efficiency	**43,089**	39,897
Rate adjustment mechanisms	**51,106**	51,300
Revenue decoupling mechanism	**15,289**	10,839
Other	**-**	227
Total	**109,484**	106,788
Non-current:		
Cost of removal	**216,983**	206,750
Environmental response fund	**12,840**	6,916
Postretirement benefits	**14,904**	10,910
Regulatory tax liability, net	**276,728**	-
Other	**31,888**	21,280
Total	**553,343**	245,856
Net regulatory liabilities (assets)	**$ (83,169)**	$ 163,937

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 at a level of $3.1 million per year, 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 actual revenues and the underlying cost being recovered or differences between actual revenues and targeted amounts as approved by the RIPUC. These amounts will be refunded to, or recovered from, customers over the next year.

Postretirement benefits: The regulatory asset represents the Company's deferral related to the underfunded status of its pension and PBOP plans. The regulatory liability primarily represents the excess of amounts received in rates over actual costs of the Company's pension and PBOP plans to be refunded 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 recently enacted Tax Cuts and Jobs Act ("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 an electric RDM which allows for an annual adjustment to the Company's delivery rates as a result of the reconciliation between annual target revenue and actual billed delivery service revenue. Any difference between the annual target revenue and actual billed delivery service revenue is recorded as a regulatory asset or regulatory liability. The Company also has a gas RDM which allows for an annual adjustment to the Company's delivery rates as a result of the reconciliation between allowed revenue per customer and actual revenue per customer. Any difference between the allowed revenue per customer and the actual revenue per customer 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 cost yet to be recovered. See Note 4 Rate Matters for additional information regarding recovery of storm costs.

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. Carrying charges are not recorded on items for which expenditures have not yet been made.

4. RATE MATTERS

General Rate Case

On February 1, 2013, the RIPUC approved a settlement agreement among the Division, the Department of the Navy, and the Company, which provided for an increase in electric base distribution revenue of $21.5 million and an increase in gas base distribution revenue of $11.3 million based on a 9.5% allowed return on equity (“ROE”) and a common equity ratio of approximately 49.1%, effective February 1, 2013. This rate agreement remained through March 31, 2018.

On June 5, 2018, the Company reached a settlement with the Division and several other intervening parties to increase distribution revenue for its electric and gas operations over the three year period commencing September 1, 2018, subject to the approval of the RIPUC. This settlement is an agreement that was reached in response to the base distribution revenue increase requests that the Company filed with the RIPUC on November 27, 2017. Pursuant to the settlement, electric distribution revenue will increase by approximately $19 million, $8 million, and $4 million, annually commencing September 1, 2018, and gas distribution revenue will increase by approximately $7 million, $6 million, and $4 million annually commencing September 1, 2018. The settlement reflects an allowed ROE rate of 9.275% based on a common equity ratio of approximately 51%.

These revenue increases are intended to fund significant systems-related investments including the replacement of several aging operational systems used in our gas business with newer integrated systems that will be shared by the Company and its gas affiliates. The settlement introduces new incentive-only Performance Incentive Mechanisms of 30 to 50 basis points to address important state policy goals around modernizing the Company’s energy delivery systems and achieving clean energy targets, as well as a new electric capital efficiency mechanism that includes both incentives and penalties resulting from the Company’s ability to manage annual spending in its electric Infrastructure, Safety, and Reliability (“ISR”) Plan. The increases set in place for the second and third years of this rate plan may be reopened for recovery of the implementation of advanced metering and grid modernization costs.

Evidentiary hearings on the settlement are scheduled to be completed by late June 2018, with a RIPUC deliberation and ruling on the settlement to take place in mid-August 2018.

Recovery of Transmission Costs

New England Power (“NEP” a company affiliate) operates the transmission facilities of its New England affiliates as a single integrated system and reimburses the Company for the cost of its transmission facilities in Rhode Island, including a return on those facilities under NEP’s Tariff No. 1. In turn, these costs are allocated among transmission customers in New England in accordance with the ISO New England 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 certain transmission assets. The amounts reimbursed to the Company by NEP for the years ended March 31, 2018, 2017, and 2016 were $155.1 million, $143.0 million, and $129.3 million, respectively, which are included 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 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%. Due to this vacatur, on June 5, 2017, NETO made a filing with FERC to reinstate the base ROE of 11.14% effective June 6, 2017. The final resolution of procedural posture of ROE complaints is unclear at this time.

Tax Cuts and Jobs Act

On March 15, 2018 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 2017. Of the proceedings initiated relevant to the Company is the Notice of Inquiry ("NOI") seeking comments on the effects of the Tax Cuts and Jobs Act on all Commission-jurisdiction rates. This NOI will be used by FERC to build a record on the tax issues affecting FERC jurisdictional rates and will be used to determine whether additional action is needed.

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 ROE investment component of revenue 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%. The Company intends to reduce its revenue requirement in its pending distribution electric and gas rate cases for the impacts of the Tax Act as appropriate.

Storm Contingency Fund

On December 29, 2016, the Company filed with the RIPUC a petition to implement a Storm Fund Replenishment Factor effective July 1, 2017 to collect approximately $84.3 million over a four-year period to be credited to the Company's Storm Contingency Fund ("Storm Fund"), to restore the Storm Fund to a positive balance. In addition, the Company also requested to extend the annual $3.0 million of supplemental base distribution rate contributions beyond the current expiration date of January 31, 2019, to coincide with the four-year replenishment period. The RI Division of Public Utilities and Carriers (Division), which is the primary intervener in Rhode Island on rate matters, filed testimony challenging the recovery of $10.6 million of the $84.3 million being sought through the Storm Fund Replenishment Factor ("SFRF"). On June 21, 2017, the RIPUC unanimously approved the Company's request to collect the $84.3 million. On April 27, 2018, the RIPUC approved the Joint Proposal Settlement Agreement which proposed a Storm Fund Deficit balance reduction of $2 million instead of $10.6 million previously challenged. The SFRF is applicable to all retail delivery service customers for effect July 1, 2017, for a four-year period. In addition, the RIPUC unanimously approved the Company's request to extend the annual $3.0 million of supplemental base distribution rate contributions to the Storm Fund, which the RIPUC authorized in the Company's last rate case, for an additional 26-month period beyond its current expiration to March 31, 2021.

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 a number of reliability problems in Connecticut, Massachusetts, and Rhode Island. The Company's share of the NEEWS-related transmission investment was approximately $575 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.

5. PROPERTY, PLANT AND EQUIPMENT

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

	March 31,	
	2018	2017
	(in thousands of dollars)	
Plant and machinery	**$ 3,637,419**	$ 3,451,718
Land and buildings	**118,334**	111,808
Assets in construction	**152,852**	135,537
Software and other intangibles	**20,513**	20,611
Property held for future use	**15,028**	15,028
Total property, plant and equipment	**3,944,146**	3,734,702
Accumulated depreciation and amortization	**(959,800)**	(948,891)
Property, plant and equipment, net	**$ 2,984,346**	$ 2,785,811

6. 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.

Volumes

Volumes of outstanding commodity derivative instruments measured in dekatherms ("dths") are as follows:

	March 31,	
	2018	2017
	(in thousands)	
Gas future contracts	**-**	2,600
Gas purchase contracts	**2,929**	3,318
Gas swap contracts	**34,716**	27,415
Total	**37,645**	33,333

Amounts Recognized on the Balance Sheet

	Asset Derivatives			Liability Derivatives	
	March 31,			March 31,	
	2018	2017		**2018**	2017
	(in thousands of dollars)			*(in thousands of dollars)*	
Current assets:			Current liabilities:		
Rate recoverable contracts:			Rate recoverable contracts:		
Gas future contracts	$ -	$ 329	Gas future contracts	$ -	$ 24
Gas purchase contracts	502	-	Gas purchase contracts	**462**	344
Gas swap contracts	171	5,643	Gas swap contracts	**1,440**	22
Contracts not subject to rate recovery:			Contracts not subject to rate recovery:		
Gas purchase contracts	**10**	10	Gas purchase contracts	**8**	-
Gas swap contracts	**48**	207	Gas swap contracts	**61**	2
	731	6,189		**1,971**	392
Other non-current assets:			Other non-current liabilities:		
Rate recoverable contracts:			Rate recoverable contracts:		
Gas future contracts	**-**	-	Gas future contracts	**-**	-
Gas swap contracts	**10**	167	Gas swap contracts	**430**	337
Gas purchase contracts	**-**	-	Gas purchase contracts	**964**	887
	10	167		**1,394**	1,224
Total	**$ 741**	$ 6,356	Total	**$ 3,365**	$ 1,616

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. For the years ended March 31, 2018, 2017, and 2016, the Company recorded a loss of $0.2 million, a gain of $0.2 million and a loss of $0.4 million, respectively, within purchased gas in the accompanying statements of income for changes in fair value for contracts not subject to rate recovery.

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 commodity transactions on the New York Mercantile Exchange ("NYMEX"). The NYMEX clearing houses act as the counterparty to each trade. Transactions on the NYMEX must adhere to comprehensive collateral and margining requirements. As a result, transactions on the NYMEX are significantly collateralized and have limited counterparty credit risk.

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. The Company enters into enabling agreements that allow for payment netting with its counterparties, which reduce its exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. 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, normal purchase normal sale contracts, and applicable payables and receivables, net of collateral, and instruments that are subject to master netting agreements, was a liability of $2.8 million and $5.3 million as of March 31, 2018 and 2017, respectively.

The aggregate fair value of the Company's commodity derivative instruments with credit-risk-related contingent features that were in a liability position at March 31, 2018 and 2017 was $1.7 million and $0.05 million, respectively. The Company had no collateral posted for these instruments at March 31, 2018 and 2017. The cash collateral in the table below reflects margin posted on the Gas Futures contracts with exchange brokers. 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 $2.2 million and $0.06 million additional collateral to its counterparties at March 31, 2018 and 2017, respectively.

Offsetting Information for Derivative Instruments Subject to Master Netting Arrangements

March 31, 2018

Gross Amounts Not Offset in the Balance Sheets

(in thousands of dollars)

ASSETS:	Gross amounts of recognized assets *A*	Gross amounts offset in the Balance Sheets *B*	Net amounts of assets presented in the Balance Sheets *C=A+B*	Financial Instruments *Da*	Cash collateral received *Db*	Net amount *E=C-D*
Derivative instruments						
Gas future contracts	$ -	$ -	$ -	$ -	$ -	$ -
Gas purchase contracts	512	-	512	-	-	512
Gas swap contracts	229	-	229	-	-	229
Total	$ 741	$ -	$ 741	$ -	$ -	$ 741

LIABILITIES:	Gross amounts of recognized liabilities *A*	Gross amounts offset in the Balance Sheets *B*	Net amounts of liabilites presented in the Balance Sheets *C=A+B*	Financial Instruments *Da*	Cash collateral paid *Db*	Net amount *E=C-D*
Derivative instruments						
Gas future contracts	$ -	$ -	$ -	$ -	$ -	$ -
Gas purchase contracts	1,434	-	1,434	-	-	1,434
Gas swap contracts	1,931	-	1,931	-	-	1,931
Total	$ 3,365	$ -	$ 3,365	$ -	$ -	$ 3,365

March 31, 2017
Gross Amounts Not Offset in the Balance Sheets
(in thousands of dollars)

ASSETS:	Gross amounts of recognized assets A	Gross amounts offset in the Balance Sheets B	Net amounts of assets presented in the Balance Sheets C=A+B	Financial Instruments Da	Cash collateral received Db	Net amount E=C-D
Derivative instruments						
Gas future contracts	$ 329	$ -	$ 329	$ -	$ 329	$ -
Gas purchase contracts	10	-	10	-	-	10
Gas swap contracts	6,016	-	6,016	-	-	6,016
Total	$ 6,355	$ -	$ 6,355	$ -	$ 329	$ 6,026

LIABILITIES:	Gross amounts of recognized liabilities A	Gross amounts offset in the Balance Sheets B	Net amounts of liabilites presented in the Balance Sheets C=A+B	Financial Instruments Da	Cash collateral paid Db	Net amount E=C-D
Derivative instruments						
Gas future contracts	$ 24	$ -	$ 24	$ -	$ 24	$ -
Gas purchase contracts	1,231	-	1,231	-	-	1,231
Gas swap contracts	361	-	361	-	-	361
Total	$ 1,616	$ -	$ 1,616	$ -	$ 24	$ 1,592

7. 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, 2018 and 2017:

	March 31, 2018			
	Level 1	Level 2	Level 3	Total
		(in thousands of dollars)		
Assets:				
Derivative instruments				
Gas future contracts	$ -	$ -	$ -	$ -
Gas purchase contracts	-	10	502	512
Gas swap contracts	-	229	-	229
Available-for-sale securities	2,614	3,591	-	6,205
Total	$ 2,614	$ 3,830	$ 502	$ 6,946
Liabilities:				
Derivative instruments				
Gas future contracts	$ -	$ -	$ -	$ -
Gas purchase contracts	-	9	1,425	1,434
Gas swap contracts	-	1,931	-	1,931
Total	-	1,940	1,425	3,365
Net (liabilities) assets	$ 2,614	$ 1,890	$ (923)	$ 3,581

	March 31, 2017							
	Level 1		Level 2		Level 3		Total	
			(in thousands of dollars)					
Assets:								
Derivative instruments								
Gas future contracts	$	329	$	-	$	-	$	329
Gas purchase contracts		-		10		-		10
Gas swap contracts		-		6,016		-		6,016
Available-for-sale securities		2,500		3,286		-		5,786
Total	$	2,829	$	9,312	$	-	$	12,141
Liabilities:								
Derivative instruments								
Gas future contracts	$	24	$	-	$	-	$	24
Gas purchase contracts		-		-		1,231		1,231
Gas swap contracts		-		361		-		361
Total		24		361		1,231		1,616
Net (liabilities) assets	$	2,805	$	8,951	$	(1,231)	$	10,525

Derivative instruments: The Company's Level 1 fair value derivative instruments consist of active exchange-based derivative instruments (e.g. natural gas futures traded on NYMEX) valued based on quoted prices (unadjusted) in active markets for identical assets or liabilities at the measurement date.

The Company's Level 2 fair value derivative instruments consist of over-the-counter ("OTC") gas swaps and purchase contracts with pricing inputs obtained from the 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 OTC gas purchase contracts, 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. A derivative is designated Level 3 when it is valued based on a forward curve that is internally developed, extrapolated, or derived from market observable curves with correlation coefficients less than 95%, where optionality is present, or if non-economic assumptions are made.

Available-for-sale securities: Available-for-sale 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).

Changes in Level 3 Derivative Instruments

	Years Ended March 31, 2018	2017
	(in thousands of dollars)	
Balance as of the beginning of the year	**$ (1,231)**	$ 16
Net losses	**(126)**	**(1,454)**
Settlements:		
included in earnings	**-**	**(33)**
included in regulatory assets and liabilities	**434**	**240**
Balance as of the end of the year	**$ (923)**	$ (1,231)
The amount of total gains or losses for the year included in net income attributed to the change in unrealized gains or losses related to non-regulatory assets and liabilities at year-end	$ -	$ -

A transfer into Level 3 represents existing assets or liabilities that were previously categorized at a higher level for which the inputs became unobservable during the year. A transfer out of Level 3 represents assets and liabilities that were previously classified as Level 3 for which the inputs became observable based on the criteria discussed previously for classification in Level 2. These transfers, which are recognized at the end of each period, result from changes in the observability of forward curves from the beginning to the end of each reporting period. There were no transfers between Level 1 and Level 2, and no transfers into or out of Level 3, during the years ended March 31, 2018, 2017, or 2016.

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.

Quantitative Information About Level 3 Fair Value Measurements

The following tables provide information about the Company's Level 3 valuations:

Commodity	Level 3 Position	Fair Value as of March 31, 2018			Valuation Technique(s)	Significant Unobservable Input	Range
		Assets	(Liabilities)	Total			
		(thousands of dollars)					
Gas	Purchase contracts	$ 502	$ (1,425)	$ (923)	Discounted Cash Flow	LNG Forward Curve	$3.96-$10.68/dth
	Total	$ 502	$ (1,425)	$ (923)			

Commodity	Level 3 Position	Fair Value as of March 31, 2017			Valuation Technique(s)	Significant Unobservable Input	Range
		Assets	(Liabilities)	Total			
		(thousands of dollars)					
Gas	Purchase contracts	$ -	$ (1,231)	$ (1,231)	Discounted Cash Flow	LNG Forward Curve	$9.84-$10.89/dth
	Total	$ -	$ (1,231)	$ (1,231)			

The significant unobservable inputs listed above would have a direct impact on the fair values of the Level 3 instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of the Company's gas purchase derivative instruments are forward liquefied natural gas commodity prices and gas forward curves. A relative change in commodity price at various locations underlying the open positions can result in significantly different fair value estimates.

Other Fair Value Measurements

The Company's balance sheet reflects long-term debt at amortized cost. The fair value of the Company's long-term debt was based on quoted market prices when available, or estimated using quoted market prices for similar debt. The fair value of this debt at March 31, 2018 and 2017 was $0.9 billion and $0.9 billion, respectively.

All other financial instruments on the balance sheet such as accounts receivable, accounts payable, and the intercompany money pool are stated at cost, which approximates fair value.

8. EMPLOYEE BENEFITS

The Company participates with other NGUSA subsidiaries in a qualified and non-qualified non-contributory defined benefit plan (the "Pension Plans") and PBOP plan (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 the Company's proportionate share of the Plan's projected benefit obligation. The Plan's costs are first directly charged to the Company based on the Company's employees that participate in the Plan. 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 pension costs and amounts used to establish rates are deferred and collected from, or refunded to, customers in subsequent periods. Pension and PBOP expense are included within operations and maintenance expense 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 Pension Plan is a defined benefit plan which provides 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, 2018, 2017, and 2016, the Company made contributions of approximately $28.9 million, $13.2 million, and $20.6 million, respectively, to the qualified pension plans. The Company expects to contribute approximately $12.0 million to the qualified pension plan during the year ending March 31, 2019.

Benefit payments to Pension Plan participants for the years ended March 31, 2018, 2017, and 2016 were approximately $29.5 million, $24.0 million, and $38.5 million, respectively.

PBOP Plans

The PBOP plan provides 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. During the years ended March 31, 2018, 2017, and 2016, the Company made contributions of approximately $9.7 million, $3.3 million, and $10.0 million, respectively, to the PBOP Plans. The Company does not expect to contribute to the PBOP Plans during the year ending March 31, 2019.

Benefit payments to PBOP plan participants for the years ended March 31, 2018, 2017, and 2016 were approximately $10.5 million, $9.9 million, and $10.3 million, respectively.

Net Periodic Benefit Costs

The Company's total pension cost for the years ended March 31, 2018, 2017, and 2016 are $9.9 million, $12.2 million, and $15.9 million, respectively.

The Company's total PBOP cost for the years ended March 31, 2018, 2017, and 2016 are $3.5 million, $6.9 million, and $7.3 million, respectively.

Amounts Recognized in AOCI and Regulatory Assets

The following tables summarize the Company's changes in actuarial gains/losses and prior service costs recognized primarily in regulatory assets as well as accumulated other comprehensive income for the years ended March 31, 2018, 2017, and 2016:

	Pension Plans		
	Years Ended March 31,		
	2018	2017	2016
		(in thousands of dollars)	
Net actuarial loss (gain)	**$ 2,080**	$ (14,509)	$ 6,095
Amortization of net actuarial loss	**(9,565)**	(10,917)	(12,212)
Amortization of prior service cost, net	**(20)**	(20)	(20)
Total	**$ (7,505)**	$ (25,446)	$ (6,137)
Included in regulatory assets	**$ (7,377)**	$ (25,453)	$ (6,123)
Included in AOCI	**(128)**	7	(14)
Total	**$ (7,505)**	$ (25,446)	$ (6,137)

	PBOP Plans		
	Years Ended March 31,		
	2018	2017	2016
	(in thousands of dollars)		
Net actuarial (gain) loss	**$ (3,869)**	$ (33,082)	$ 9,178
Amortization of net actuarial loss	**(1,730)**	(3,952)	(4,074)
Amortization of prior service cost, net	**23**	225	225
Total	**$ (5,576)**	$ (36,809)	$ 5,329
Included in regulatory assets	**$ (5,576)**	$ (36,809)	$ 5,329
Total	**$ (5,576)**	$ (36,809)	$ 5,329

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 other comprehensive income on the balance sheet that have not yet been recognized as components of net actuarial loss at March 31, 2018, 2017, and 2016:

	Pension Plans		
	Years Ended March 31,		
	2018	2017	2016
	(in thousands of dollars)		
Net actuarial loss	**155,601**	$ 163,086	$ 188,512
Prior service cost	**37**	57	77
Total	**$ 155,638**	$ 163,143	$ 188,589
Included in regulatory assets	**$ 155,502**	$ 162,879	$ 188,332
Included in AOCI	**136**	264	257
Total	**$ 155,638**	$ 163,143	$ 188,589

	PBOP Plans		
	Years Ended March 31,		
	2018	2017	2016
	(in thousands of dollars)		
Net actuarial loss	**$ 27,798**	$ 33,397	$ 70,431
Prior service cost	**(45)**	(68)	(293)
Total	**$ 27,753**	$ 33,329	$ 70,138
Included in regulatory assets	**$ 27,753**	$ 33,329	$ 70,138
Total	**$ 27,753**	$ 33,329	$ 70,138

The amount of net actuarial loss and prior service cost to be amortized from regulatory assets during the year ending March 31, 2019 for the Pension Plans is $10.1 million and $0, respectively, and net actuarial loss and prior service benefit to be amortized from regulatory assets during the year ending March 31, 2019 for the PBOP Plans is $1.7 million and $0, respectively.

Amounts Recognized on the Balance Sheet

The following table summarizes the portion of the funded status above that is recognized on the Company's balance sheet at March 31, 2018 and 2017:

	Pension Plans		PBOP Plans	
	March 31,		March 31,	
	2018	2017	**2018**	2017
	(in thousands of dollars)			
Projected benefit obligation	**$ (560,190)**	$ (539,583)	**$ (223,753)**	$ (219,669)
Allocated fair value of plan assets	**534,883**	487,654	**165,530**	149,504
Total	**$ (25,307)**	$ (51,929)	**$ (58,223)**	$ (70,165)
Current liabilities	**$ (149)**	$ (146)	**$ (147)**	$ (150)
Other non-current liabilities	**(25,158)**	(51,783)	**(58,076)**	(70,015)
Total	**$ (25,307)**	$ (51,929)	**$ (58,223)**	$ (70,165)

Expected Benefit Payments

Based on current assumptions, the following benefit payments are expected subsequent to March 31, 2018 in respect of the Company:

(in thousands of dollars) **Years Ended March 31,**	**Pension Plans**	**PBOP Plans**
2019	$ 34,372	$ 10,631
2020	35,499	11,019
2021	36,643	11,481
2022	37,875	11,916
2023	39,266	12,204
2024-2028	215,888	64,652
Total	**$ 399,543**	**$ 121,903**

Assumptions Used for Employee Benefits Accounting

	Pension Plans		
	Years Ended March 31,		
	2018	2017	2016
Benefit Obligations:			
Discount rate	**4.10%**	4.30%	4.25%
Rate of compensation increase	**3.50%**	3.50%	3.50%
Expected return on plan assets	6.25%	6.50%	6.50%
Net Periodic Benefit Costs:			
Discount rate	**4.30%**	4.25%	4.10%
Rate of compensation increase	**3.50%**	3.50%	3.50%
Expected return on plan assets	**6.50%**	6.50%	6.25%

	PBOP Plans		
	Years Ended March 31,		
	2018	2017	2016
Benefit Obligations:			
Discount rate	**4.10%**	4.30%	4.25%
Rate of compensation increase	**n/a**	n/a	n/a
Expected return on plan assets	**6.25%-6.75%**	6.50%-6.75%	6.50%-6.75%
Net Periodic Benefit Costs:			
Discount rate	**4.30%**	4.25%	4.10%
Rate of compensation increase	**n/a**	n/a	n/a
Expected return on plan assets	**6.50%-6.75%**	6.50%-6.75%	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 Hewitt AA Above Median 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,	
	2018	2017
Health care cost trend rate assumed for next year		
Pre 65	**7.50%**	7.00%
Post 65	**5.75%**	6.00%
Prescription	**10.25%**	10.25%
Rate to which the cost trend is assumed to decline (ultimate)	**4.50%**	4.50%
Year that rate reaches ultimate trend		
Pre 65	**2028**	2025
Post 65	**2026**	2024
Prescription	**2027**	2025

Plan Assets

NGUSA, as the Plans' sponsor, manages the benefit plan investments to minimize the long-term cost of operating the Plans, with a reasonable level of risk. Risk tolerance is determined as a result of a periodic asset/liability study which analyzes the Plans' liabilities and funded status and results in the determination of the allocation of assets across equity and fixed income securities. Equity investments are broadly diversified across U.S. and non-U.S. stocks, as well as across growth, value, and small and large capitalization stocks. Likewise, the fixed income portfolio is broadly diversified across market segments. Small investments are also approved for private equity, real estate, and infrastructure with the objective of 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 allocation study. Investment risk and return are reviewed by NGUSA's investment committee on a quarterly basis.

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 NGUSA. Life insurance and medical benefits are provided for eligible retirees, dependents, and surviving spouses of NGUSA.

The target asset allocations for the benefit plans as of March 31, 2018 and 2017 are as follows:

	Pension Plans		PBOP Union		PBOP Non-Union	
	March 31,		March 31,		March 31,	
	2018	2017	**2018**	2017	**2018**	2017
			(in thousands of dollars)			
US Equities	**20%**	20%	**34%**	34%	**45%**	45%
Global equities (including US)	**7%**	7%	**12%**	12%	**0%**	0%
Global tactical asset allocation	**10%**	10%	**17%**	17%	**0%**	0%
Non-US equities	**10%**	10%	**17%**	17%	**25%**	25%
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%
Total	**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, 2018				
	Level 1	Level 2	Level 3	Not Categorized	Total
			(in thousands of dollars)		
Pension Assets:					
Cash and cash equivalents	$ 575	$ 15,518	$ -	$ 28,149	$ 44,242
Accounts receivable	88,162	-	-	-	88,162
Accounts payable	(133,593)	-	-	-	(133,593)
Equity	303,037	(16)	-	651,355	954,376
Fixed income securities	-	553,463	-	338,944	892,407
Preferred securities	-	5,972	-	-	5,972
Private equity	-	-	-	133,785	133,785
Real estate	-	-	-	110,551	110,551
Other	1,329	-	-	178,235	179,564
Total	**$ 259,510**	**$ 574,937**	**$ -**	**$ 1,441,019**	**$ 2,275,466**
PBOP Assets:					
Cash and cash equivalents	$ 9,111	$ 16	$ -	$ 598	$ 9,725
Accounts receivable	1,998	-	-	-	1,998
Accounts payable	(183)	-	-	-	(183)
Equity	189,026	-	-	281,678	470,704
Fixed income securities	-	165,705	-	-	165,705
Other	14,030	-	-	78,622	92,652
Total	**$ 213,982**	**$ 165,721**	**$ -**	**$ 360,898**	**$ 740,601**

	March 31, 2017				
	Level 1	Level 2	Level 3	Not Categorized	Total
	(in thousands of dollars)				
Pension Assets:					
Cash and cash equivalents	$ 1,319	$ 559	$ -	$ 32,822	$ 34,700
Accounts receivable	21,974	-	-	-	21,974
Accounts payable	(22,054)	-	-	-	(22,054)
Equity	317,258	-	-	594,349	911,607
Global tactical asset allocation	-	-	-	-	-
Fixed income securities	-	599,858	-	205,392	805,250
Preferred securities	-	3,756	-	-	3,756
Private equity	-	-	-	131,865	131,865
Real estate	-	-	-	117,692	117,692
Other	350	-	-	102,857	103,207
Total	**$ 318,847**	**$ 604,173**	**$ -**	**$ 1,184,977**	**$ 2,107,997**
PBOP Assets:					
Cash and cash equivalents	$ 11,203	$ -	$ -	$ 651	$ 11,854
Accounts receivable	1,526	-	-	-	1,526
Accounts payable	(3,483)	-	-	-	(3,483)
Equity	164,420	-	-	268,140	432,560
Fixed income securities	234	145,904	-	-	146,138
Other	13,177	-	-	74,922	88,099
Total	**$ 187,077**	**$ 145,904**	**$ -**	**$ 343,713**	**$ 676,694**

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

Cash and cash equivalents: Cash and cash equivalents that can be priced daily are classified as Level 1. Active reserve funds, reserve deposits, commercial paper, repurchase agreements, and commingled cash equivalents are classified as Level 2. Cash and cash equivalents invested in commingled money market investment funds which have Net Asset Value "NAV" pricing per fund share are excluded from the fair value hierarchy.

Accounts receivable and accounts payable: Accounts receivable and accounts payable are classified as Level 1. Such amounts are short-term and settle within a few days of the measurement date.

Equity and preferred securities: Common stocks, preferred stocks, and real estate investment trusts are valued using the official close of the primary market on which the individual securities are traded. Equity securities are primarily comprised of securities issued by public companies in domestic and foreign markets plus investments in commingled funds, which are valued on a daily basis. The Company can exchange shares of the publicly traded securities and the fair values are primarily sourced from the closing prices on stock exchanges where there is active trading, in which case they are classified as Level 1 investments. If there is less active trading, then the publicly traded securities would typically be priced using observable data, such as bid and ask prices, and these measurements are classified as Level 2 investments. Mutual funds with publicly quoted prices and active trading are classified as Level 1 investments. For investments in commingled funds that are not publicly traded and have ongoing subscription and redemption activity, the fair value of the investment is the NAV per fund share, derived from the underlying securities' quoted prices in active markets, and they are excluded from the fair value hierarchy. Investments in commingled funds with redemption restrictions and that use NAV are excluded from the fair value hierarchy.

Global tactical asset allocation: Assets held in global tactical asset allocation funds are managed by investment managers who use both top-down and bottom-up valuation methodologies to value asset classes, countries, industrial sectors, and individual securities in order to allocate and invest assets opportunistically. Mutual funds with publicly quoted prices and active trading are classified as Level 1 investments. For commingled funds that are not publicly traded and have ongoing subscription and redemption activity, the fair value of the investment is the NAV per fund share, and are excluded from the fair value hierarchy. Investments with redemption restrictions and that use NAV are excluded from the fair value hierarchy.

Fixed income securities: Fixed income securities (which include corporate debt securities, municipal fixed income securities, U.S. Government and Government agency securities including government mortgage backed securities, index linked government bonds, and state and local bonds) convertible securities, and investments in securities lending collateral (which include repurchase agreements, asset backed securities, floating rate notes and time deposits) are valued with an institutional bid valuation. A bid valuation is an estimated price at which a dealer would pay for a security (typically in an institutional round lot). Oftentimes, these evaluations are based on proprietary models which pricing vendors establish for these purposes. In some cases there may be manual sources when primary vendors do not supply prices. Fixed income investments are primarily comprised of fixed income securities and fixed income commingled funds. The prices for direct investments in fixed income securities are generated on a daily basis. Prices generated from less active trading with wider bid ask prices are classified as Level 2 investments. Mutual funds with publicly quoted prices and active trading are classified as Level 1 investments. For commingled funds that are not publicly traded and have ongoing subscription and redemption activity, the fair value of the investment is the NAV per fund share, and are excluded from the fair value hierarchy. Investments in commingled funds with redemption restrictions and that use NAV are excluded from the fair value hierarchy.

Private equity and real estate: Commingled equity funds, commingled special equity funds, limited partnerships, real estate, venture capital, and other investments are valued using evaluations (NAV per fund share) based on proprietary models, or based on the NAV. Investments in private equity and real estate funds are primarily invested in privately held real estate investment properties, trusts, and partnerships as well as equity and debt issued by public or private companies. The Company's interest in the fund or partnership is estimated based on the NAV. The Company's interest in these funds cannot be readily redeemed due to the inherent lack of liquidity and the primarily long-term nature of the underlying assets. Distribution is made through the liquidation of the underlying assets. The Company views these investments as part of a long-term investment strategy. These investments are valued by each investment manager based on the underlying assets. The funds utilize valuation techniques consistent with the market, income, and cost approaches to measure the fair value of certain real estate investments. The majority of the underlying assets are valued using significant unobservable inputs and often require significant management judgment or estimation based on the best available information. Market data includes observations of the trading multiples of public companies considered comparable to the private companies being valued. Investments in limited partnerships with redemption restrictions and that use NAV are excluded from the fair value hierarchy.

While management believes its valuation methodologies are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the NAV as a practical expedient could result in a different fair value measurement at the reporting date.

Defined Contribution Plan

NGUSA has a defined contribution pension plan that covers substantially all employees. For the years ended March 31, 2018, 2017, and 2016, the Company recognized an expense in the accompanying statements of income of $3.1 million, $2.8 million, and $2.8 million, respectively, for matching contributions.

Other Benefits

At March 31, 2018 and 2017, the Company had accrued workers compensation, auto, and general insurance claims which have been incurred but not yet reported ("IBNR") of $2.9 million and $3.5 million, respectively. IBNR reserves have been established for claims and/or events that have transpired, but have not yet been reported to the Company for payment.

9. ACCUMULATED OTHER COMPREHENSIVE INCOME

The following table represents the changes in the Company's AOCI for the years ended March 31, 2018 and 2017:

	Unrealized Gain (Loss) on Available-For-Sale Securities	Pension and Other Postretirement Benefits	Hedging Activity	Total
		(in thousands of dollars)		
Balance as of March 31, 2016	**$ 795**	**$ 1,206**	**$ (3,672)**	**$ (1,671)**
Other comprehensive income before reclassifications:				
Unrecognized net actuarial loss (net of $11 tax benefit)	-	(21)	-	(21)
Gain on investment (net of $83 tax benefit)	265	-	-	265
Amounts reclassified from other comprehensive income (loss):				
Amortization of net actuarial loss (net of $9 tax expense) [1]	-	17	-	17
Amortization of treasury lock (net of $254 tax expense) [2]	-	-	471	471
Gain on investment (net of $143 tax benefit) [1]	(155)	-	-	(155)
Net current period other comprehensive income	110	(4)	471	577
Balance as of March 31, 2017	**$ 905**	**$ 1,202**	**$ (3,201)**	**$ (1,094)**
Other comprehensive income before reclassifications:				
Unrecognized net actuarial loss (net of $21 tax expense)	-	79	-	79
Gain on investment (net of $61 tax benefit)	133	-	-	133
Amounts reclassified from other comprehensive income (loss):				
Amortization of net actuarial loss (net of $8 tax expense) [1]	-	20	-	20
Amortization of treasury lock (net of $93 tax expense) [2]	-	-	228	228
Gain on investment (net of $99 tax expense) [1]	(107)	-	-	(107)
Net current period other comprehensive (loss) income	26	99	228	353
Balance as of March 31, 2018	**$ 931**	**$ 1,301**	**$ (2,973)**	**$ (741)**

(1) Amounts are reported as other income, net in the accompanying statements of income.
(2) Amounts are reported as interest on long-term debt in the accompanying statements of income.

10. CAPITALIZATION

The aggregate maturities of long-term debt for the years subsequent to March 31, 2018 are as follows:

(in thousands of dollars) Years Ending March 31,	
2019	$ 15,839
2020	251,375
2021	11,375
2022	1,375
2023	13,875
Thereafter	552,250
Total	$ 846,089

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. During the years ended March 31, 2018 and

2017, the Company was in compliance with all such covenants.

Debt Authorizations

Since January 12, 2015, the Company had regulatory approval from the FERC to issue up to $400 million of short-term debt. The authorization was effective for a period of two years which expired on January 11, 2017 and which has now been extended to January 10, 2019. The Company had no short-term debt outstanding to third-parties as of March 31, 2018 or 2017.

First Mortgage Bonds

At March 31, 2018, the Company had $46.1 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. During the years ended March 31, 2018 and 2017, 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 at March 31, 2018 or 2017**.**

Cumulative Preferred Stock

The Company has certain issues of non-participating cumulative preferred stock outstanding which 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	**2018**	2017	**2018**	2017	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, 2018, 2017, or 2016. The annual dividend requirement for cumulative preferred stock was $0.1 million for each of the years ended March 31, 2018, 2017, and 2016.

11. INCOME TAXES

Components of Income Tax Expense

	Years Ended March 31,		
	2018	2017	2016
	(in thousands of dollars)		
Current federal income tax expense (benefit)	**$ (19,040)**	$ 21,054	$ 7,186
Deferred federal tax expense (benefit)	**41,351**	27,576	45,963
Amortized investment tax credits (1)	**(62)**	(106)	(145)
Total deferred tax expense	**41,289**	27,470	45,818
Total income tax expense	**$ 22,249**	$ 48,524	$ 53,004

(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 rate for the years ended March 31, 2018, 2017 and 2016 are 15.2 %, 35.5% and 35.8%, respectively. The following table presents a reconciliation of income tax expense at the federal statutory tax rate of 31.55%, 35%, and 35%, respectively, to the actual tax expense:

	Years Ended March 31,		
	2018	2017	2016
	(in thousands of dollars)		
Computed tax	**$ 45,923**	$ 47,833	$ 51,856
Change in computed taxes resulting from:			
Temporary difference flowed through	**695**	834	1,075
Federal Rate Change	**(23,497)**	-	-
Other items, net	**(872)**	(143)	73
Total Changes	**(23,674)**	691	1,148
Total income tax expense	**$ 22,249**	$ 48,524	$ 53,004

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.

On December 22, 2017, the Tax Act was signed into law. The Tax Act includes significant changes to various federal tax provisions applicable to the Company, including provisions specific to regulated public utilities. The most significant changes include the reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018 and the limitation of the net operating loss deduction for net operating losses generated in tax years starting after December 31, 2017 to 80% of taxable income with an indefinite carryforward period. The Tax Act provisions related to regulated public utilities eliminate bonus depreciation for certain property acquired or placed in service after September 27, 2017 and extend the normalization requirements for ratemaking treatment of excess deferred taxes.

In accordance with ASC 740, "Income Taxes," the effect of changes in tax law are required to be recognized in the period of enactment, which for the Company is the period ended March 31, 2018. Since the Company's fiscal year end is March 31, the statutory rate applicable for the Company's fiscal year ended March 31, 2018, is a blended tax rate of 31.55%. In subsequent periods, the federal income tax rate will be 21%. In addition, ASC 740 requires deferred income tax assets and liabilities to be measured at the enacted tax rate expected to apply when temporary differences are to be realized or settled. As a result, the Company remeasured its federal deferred income tax assets and liabilities using the newly enacted tax rate of 21%.

The Company recognized a decrease in its net deferred income tax liability in the amount of $250 million, with $23.7 million of the benefit recorded to deferred income tax expense and $226.3 million recorded as a regulatory liability, for the refund of excess income taxes to the ratepayers.

On December 22, 2017, the Securities Exchange Commission issued Staff Accounting Bulletin ("SAB") 118, which provides guidance on accounting for the effects of the Tax Act. The FASB staff subsequently issued guidance stating that private companies may apply SAB 118 to the financial statements. SAB 118 provides a measurement period that should not extend beyond one year from the Tax Act enactment date to complete the accounting under ASC 740. To the extent that a company's accounting for certain income tax effects of the Tax Act is incomplete, a company can determine a reasonable estimate for those effects and record a provisional estimate in the financial statements. If a company cannot determine a provisional amount, the company should continue to apply existing accounting guidance for income taxes based on provisions of the tax laws that were in effect immediately prior to the enactment of the Tax Act.

The Company has made a reasonable estimate for the measurement and accounting of the effects of the Tax Act which has been reflected in the March 31, 2018 financial statements based on management's interpretation of the Tax Act and information available. The items reflected as provisional amounts are related to accelerated depreciation for tax purposes of certain property placed in service after September 27, 2017, the allocation of excess deferred taxes between customers and shareholders, and certain property related temporary differences. The final impact may differ from the recorded amounts to the extent refinements are made as a result of changes in management's interpretations and assumptions, additional guidance or technical corrections that may be issued.

Deferred Tax Components

	March 31, 2018	March 31, 2017
	(in thousands of dollars)	
Deferred tax assets:		
Environmental remediation costs	**$ 28,912**	$ 47,435
Net operating losses	**50,076**	119,984
Postretirement benefits and other employee benefits	**20,731**	47,831
Regulatory liabilities - other	**21,693**	41,932
Regulatory liabilities - taxes	**58,116**	
Other items	**11,796**	20,876
Total deferred tax assets	**191,324**	278,058
Deferred tax liabilities:		
Amortization of goodwill	**36,613**	54,767
Property related differences	**366,609**	584,330
Regulatory assets - environmental	**26,704**	46,238
Regulatory assets - postretirement benefits	**35,954**	66,071
Regulatory assets - other	**14,841**	25,649
Regulatory assets - storm costs	**30,716**	34,217
Other items	**4,031**	4,936
Total deferred tax liabilities	**515,468**	816,208
Net deferred income tax liabilities	**324,144**	538,150
Deferred investment tax credits	**17**	79
Deferred income tax liabilities, net	**$ 324,161**	$ 538,229

Net Operating Losses

The amounts and expiration dates of the Company's net operating loss carryforwards as of March 31, 2018 are as follows:

	Carryforward Amount	Expiration Period
	(in thousands of dollars)	
Federal	$ 338,575	2029-2036

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 net operating loss carryforwards reflected on the income tax returns.

The Company recognizes interest related to unrecognized tax benefits in other interest, including affiliate interest and related penalties, if applicable, in other deductions, net in the accompanying statements of income. During the years ended March 31, 2018, 2017, and 2016 the Company recorded no interest expense. No tax penalties were recognized during the years ended March 31, 2018, 2017, or 2016.

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.

The Company is included in NGNA and subsidiaries' administrative appeal with the Internal Revenue Service ("IRS") related to the issues disputed in the examination cycles for the years ended August 24, 2007, March 31, 2008, and March 31, 2009. The Company is expecting to reach a settlement with the IRS in the next fiscal year. The Company does not believe that the outcome of the settlement will have a material impact to its results of operations, financial position, or cash flows. The IRS continues its examination of the next cycle which includes income tax returns for the years ended March 31, 2010 through March 31, 2012. The examination is not expected to conclude in the next fiscal year. The income tax returns for the years ended March 31, 2013 through March 31, 2018 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, 2010

The Company is not subject to state income taxes since the State of Rhode Island does not impose an income tax on public utility companies.

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 numerous sites. 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, 2018, 2017, and 2016 were $2.9 million, $4.9 million, and $3.1 million, respectively.

The Company estimated the remaining costs of environmental remediation activities were $137.7 million and $135.5 million at March 31, 2018 and 2017, respectively. These costs are expected to be incurred over approximately 40 years. 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 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, 2018 and 2017, the Company has recorded environmental regulatory assets of $140.0 million and $139.0 million, respectively, and environmental regulatory liabilities of $12.8 million and $6.9 million, respectively.

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. In addition, the Company has various capital commitments related to the construction of property, plant and equipment.

The Company's commitments under these long-term contracts for the years subsequent to March 31, 2018 are summarized in the table below:

(in thousands of dollars) Years Ending March 31,	Energy Purchases
2019	308,160
2020	97,296
2021	34,243
2022	25,229
2023	17,160
Thereafter	129,054
Total	$ 611,142

The Company purchases additional energy to meet load requirements from independent power producers, other utilities, energy merchants or the ISO-NE at market prices.

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, 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 an operating lease. The Company also negotiated a Transmission Facilities Purchase Agreement ("Facilities Purchase Agreement") with Deepwater Wind Block Island Transmission, LLC ("Deepwater") to purchase from Deepwater 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 Facilities Purchase Agreement 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.

Annual Solicitations

The 2009 Rhode Island law 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.
- 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 will need to backfill the MW capacity from that project to meet the 90 MW minimum long-term capacity requirements under the state statute.
- 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.

As approved by the RIPUC, the Company is allowed to pass through commodity-related / purchased power costs to customers. The cost of these contracts is accounted for as part of these costs.

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.

14. 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 net 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,	
	2018	2017	**2018**	2017
	(in thousands of dollars)			
Massachusetts Electric Company	**$ -**	$ -	**$ -**	$ 53,278
New England Power Company	**22,221**	4,322	**-**	-
NGUSA Service Company	**-**	1,816	**12,224**	22,387
Other	**-**	216	**2,206**	4,420
Total	**$ 22,221**	$ 6,354	**$ 14,430**	$ 80,085

Advance from Affiliate

In December 2008, the Company entered into an agreement with NGUSA whereby the Company can borrow up to $250 million as deemed necessary for working capital needs. The advance is non-interest bearing. At March 31, 2018 and 2017, the Company had no outstanding advance from affiliate.

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 and accounts receivable from affiliates and accounts payable to affiliates balances are reflected as investing or financing activities in the accompanying statements of cash flows. In addition, 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 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 borrowings of $307.5 million and $125.7 million at March 31, 2018 and 2017, respectively. The average interest rates for the intercompany money pool were 1.6%, 1.1% and 0.7% for the years ended March 31, 2018, 2017, and 2016, respectively.

Service Company Charges

The affiliated service companies of NGUSA provide certain services to the Company at their cost. 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, including but not limited to non-power goods and services, to the Company for the years ended March 31, 2018, 2017, and 2016 were $201.3 million, $229.9 million, and $217.8 million, respectively.

JUNE 23, 2017

INFRASTRUCTURE

MOODY'S INVESTORS SERVICE

RATING METHODOLOGY

Regulated Electric and Gas Utilities

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This rating methodology replaces "Regulated Electric and Gas Utilities" last revised on December 23, 2013. We have updated some outdated links and removed certain issuer-specific information.

Summary

This rating methodology explains our approach to assessing credit risk for regulated electric and gas utilities globally. This document does not include an exhaustive treatment of all factors that are reflected in our ratings but should enable the reader to understand the qualitative considerations and financial information and ratios that are usually most important for ratings in this sector. [1]

This report includes a detailed rating grid which is a reference tool that can be used to approximate credit profiles within the regulated electric and gas utility sector in most cases. The grid provides summarized guidance for the factors that are generally most important in assigning ratings to companies in the regulated electric and gas utility industry. However, the grid is a summary that does not include every rating consideration. The weights shown for each factor in the grid represent an approximation of their importance for rating decisions but actual importance may vary substantially. In addition, the grid in this document uses historical results while ratings are based on our forward-looking expectations. As a result, the grid-indicated rating is not expected to match the actual rating of each company.

[1] This update may not be effective in some jurisdictions until certain requirements are met.

The grid contains four key factors that are important in our assessment for ratings in the regulated electric and gas utility sector:

1. Regulatory Framework
2. Ability to Recover Costs and Earn Returns
3. Diversification
4. Financial Strength

Some of these factors also encompass a number of sub-factors. There is also a notching factor for holding company structural subordination.

This rating methodology is not intended to be an exhaustive discussion of all factors that our analysts consider in assigning ratings in this sector. We note that our analysis for ratings in this sector covers factors that are common across all industries such as ownership, management, liquidity, corporate legal structure, governance and country related risks which are not explained in detail in this document, as well as factors that can be meaningful on a company-specific basis. Our ratings consider these and other qualitative considerations that do not lend themselves to a transparent presentation in a grid format. The grid used for this methodology reflects a decision to favor a relatively simple and transparent presentation rather than a more complex grid that might map grid-indicated ratings more closely to actual ratings.

Highlights of this report include:

» An overview of the rated universe

» A summary of the rating methodology

» A discussion of the key rating factors that drive ratings

» Comments on the rating methodology assumptions and limitations, including a discussion of rating considerations that are not included in the grid

The Appendices show the full grid (Appendix A), our approach to ratings within a utility family (Appendix B), a description of the various types of companies rated under this methodology (Appendix C), key industry issues over the intermediate term (Appendix D), regional and other considerations (Appendix E), and treatment of power purchase agreements (Appendix F).

This methodology describes the analytical framework used in determining credit ratings. In some instances our analysis is also guided by additional publications which describe our approach for analytical considerations that are not specific to any single sector. Examples of such considerations include but are not limited to: the assignment of short-term ratings, the relative ranking of different classes of debt and hybrid securities, how sovereign credit quality affects non-sovereign issuers, and the assessment of credit support from other entities. A link to documents that describe our approach to such cross-sector credit rating methodological considerations can be found in the Related Research section of this report.

About the Rated Universe

The Regulated Electric and Gas Utilities rating methodology applies to rate-regulated[2] electric and gas utilities that are not Networks[3]. Regulated Electric and Gas Utilities are companies whose predominant[4][5] business is the sale of electricity and/or gas or related services under a rate-regulated framework, in most cases to retail customers. Also included under this methodology are rate-regulated utilities that own generating assets as any material part of their business, utilities whose charges or bills to customers include a meaningful component related to the electric or gas commodity, utilities whose rates are regulated at a sub-sovereign level (e.g. by provinces, states or municipalities), and companies providing an independent system operator function to an electric grid. Companies rated under this methodology are primarily rate-regulated monopolies or, in certain circumstances, companies that may not be outright monopolies but where government regulation effectively sets prices and limits competition.

This rating methodology covers regulated electric and gas utilities worldwide. These companies are engaged in the production, transmission, coordination, distribution and/or sale of electricity and/or natural gas, and they are either investor owned companies, commercially oriented government owned companies or, in the case of independent system operators, not-for-profit or similar entities. As detailed in Appendix C, this methodology covers a wide variety of companies active in the sector, including vertically integrated utilities, transmission and distribution utilities with retail customers and/or sub-sovereign regulation, local gas distribution utility companies (LDCs), independent system operators, and regulated generation companies. These companies may be operating companies or holding companies.

An over-arching consideration for regulated utilities is the regulatory environment in which they operate. While regulation is also a key consideration for networks, a utility's regulatory environment is in comparison often more dynamic and more subject to political intervention. The direct relationship that a regulated utility has with the retail customer, including billing for electric or gas supply that has substantial price volatility, can lead to a more politically charged rate-setting environment. Similarly, regulation at the sub-sovereign level is often more accessible for participation by interveners, including disaffected customers and the politicians who want their votes. Our views of regulatory environments evolve over time in accordance with our observations of regulatory, political, and judicial events that affect issuers in the sector.

This methodology pertains to regulated electric and gas utilities and excludes the following types of issuers, which are covered by separate rating methodologies: Regulated Networks, Unregulated Utilities and Power Companies, Public Power Utilities, Municipal Joint Action Agencies, Electric Cooperatives, Regulated Water Companies and Natural Gas Pipelines.[5]

The Regulated Electric and Gas Utility sector is predominantly investment grade, reflecting the stability generally conferred by regulation that typically sets prices and also limits competition, such that defaults have been lower than in many other non-financial corporate sectors. However, the nature of regulation can

2 Companies in many industries are regulated. We use the term rate-regulated to distinguish companies whose rates (by which we also mean tariffs or revenues in general) are set by regulators.

3 Regulated Electric and Gas Networks are companies whose predominant business is purely the transmission and/or distribution of electricity and/or natural gas without involvement in the procurement or sale of electricity and/or gas; whose charges to customers thus do not include a meaningful commodity cost component; which sell mainly (or in many cases exclusively) to non-retail customers; and which are rate-regulated under a national framework.

4 We generally consider a company to be predominantly a regulated electric and gas utility when a majority of its cash flows, prospectively and on a sustained basis, are derived from regulated electric and gas utility businesses. Since cash flows can be volatile (such that a company might have a majority of utility cash flows simply due to a cyclical downturn in its non-utility businesses), we may also consider the breakdown of assets and/or debt of a company to determine which business is predominant.

5 A link to credit rating methodologies covering these and other sectors can be found in the Related Research section of this report.

vary significantly from jurisdiction to jurisdiction. Most issuers at the lower end of the ratings spectrum operate in challenging regulatory environments.

About this Rating Methodology

This report explains the rating methodology for regulated electric and gas utilities in six sections, which are summarized as follows:

1. Identification and Discussion of the Rating Factors in the Grid

The grid in this rating methodology focuses on four rating factors. The four factors are comprised of sub-factors that provide further detail:

Factor / Sub-Factor Weighting - Regulated Utilities

Broad Rating Factors	Broad Rating Factor Weighting	Rating Sub-Factor	Sub-Factor Weighting
Regulatory Framework	25%	Legislative and Judicial Underpinnings of the Regulatory Framework	12.5%
		Consistency and Predictability of Regulation	12.5%
Ability to Recover Costs and Earn Returns	25%	Timeliness of Recovery of Operating and Capital Costs	12.5%
		Sufficiency of Rates and Returns	12.5%
Diversification	10%	Market Position	5%*
		Generation and Fuel Diversity	5%**
Financial Strength, Key Financial Metrics	40%		
		CFO pre-WC + Interest/ Interest	7.5%
		CFO pre-WC / Debt	15.0%
		CFO pre-WC – Dividends / Debt	10.0%
		Debt/Capitalization	7.5%
Total	100%		100%
Notching Adjustment			
Holding Company Structural Subordination			0 to -3

*10% weight for issuers that lack generation; **0% weight for issuers that lack generation

2. Measurement or Estimation of Factors in the Grid

We explain our general approach for scoring each grid factor and show the weights used in the grid. We also provide a rationale for why each of these grid components is meaningful as a credit indicator. The information used in assessing the sub-factors is generally found in or calculated from information in company financial statements, derived from other observations or estimated by our analysts.[6] All of the quantitative credit metrics incorporate Moody's standard adjustments to income statement, cash flow statement and balance sheet amounts for restructuring, impairment, off-balance sheet accounts, receivable securitization programs, under-funded pension obligations, and recurring operating leases.[7]

[6] For definitions of our most common ratio terms, please see "Moody's Basic Definitions for Credit Statistics, User's Guide," a link to which may be found in the Related Research section of this report.

[7] Our standard adjustments are described in "Financial Statement Adjustments in the Analysis of Non-Financial Corporations". A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Our ratings are forward-looking and reflect our expectations for future financial and operating performance. However, historical results are helpful in understanding patterns and trends of a company's performance as well as for peer comparisons. We utilize historical data (in most cases, an average of the last three years of reported results) in the rating grid. However, the factors in the grid can be assessed using various time periods. For example, rating committees may find it analytically useful to examine both historical and expected future performance for periods of several years or more, or for individual twelve month periods.

3. Mapping Factors to the Rating Categories

After estimating or calculating each sub-factor, the outcomes for each of the sub-factors are mapped to a broad Moody's rating category (Aaa, Aa, A, Baa, Ba, B, or Caa).

4. Assumptions, Limitations and Rating Considerations Not Included in the Grid

This section discusses limitations in the use of the grid to map against actual ratings, some of the additional factors that are not included in the grid but can be important in determining ratings, and limitations and assumptions that pertain to the overall rating methodology.

5. Determining the Overall Grid-Indicated Rating[8]

To determine the overall grid-indicated rating, we convert each of the sub-factor ratings into a numeric value based upon the scale below.

Aaa	Aa	A	Baa	Ba	B	Caa	Ca
1	3	6	9	12	15	18	20

The numerical score for each sub-factor is multiplied by the weight for that sub-factor with the results then summed to produce a composite weighted-factor score. The composite weighted factor score is then mapped back to an alphanumeric rating based on the ranges in the table below.

Grid-Indicated Rating

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Aaa	$x < 1.5$
Aa1	$1.5 \leq x < 2.5$
Aa2	$2.5 \leq x < 3.5$
Aa3	$3.5 \leq x < 4.5$
A1	$4.5 \leq x < 5.5$
A2	$5.5 \leq x < 6.5$
A3	$6.5 \leq x < 7.5$
Baa1	$7.5 \leq x < 8.5$
Baa2	$8.5 \leq x < 9.5$
Baa3	$9.5 \leq x < 10.5$

[8] In general, the grid-indicated rating is oriented to the Corporate Family Rating (CFR) for speculative-grade issuers and the senior unsecured rating for investment-grade issuers. For issuers that benefit from ratings uplift due to parental support, government ownership or other institutional support, the grid-indicated rating is oriented to the baseline credit assessment. For an explanation of baseline credit assessment, please refer to our rating methodology on government-related issuers. Individual debt instrument ratings also factor in decisions on notching for seniority level and collateral. The documents that provide broad guidance for these notching decisions are our rating methodologies on loss given default for speculative grade non-financial companies and for aligning corporate instrument ratings based on differences in security and priority of claim. The link to these and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Grid-Indicated Rating

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Ba1	10.5 ≤ x < 11.5
Ba2	11.5 ≤ x < 12.5
Ba3	12.5 ≤ x < 13.5
B1	13.5 ≤ x < 14.5
B2	14.5 ≤ x < 15.5
B3	15.5 ≤ x < 16.5
Caa1	16.5 ≤ x < 17.5
Caa2	17.5 ≤ x < 18.5
Caa3	18.5 ≤ x < 19.5
Ca	x ≥ 19.5

For example, an issuer with a composite weighted factor score of 11.7 would have a Ba2 grid-indicated rating.

6. Appendices

The Appendices present a full grid and provide additional commentary and insights on our view of credit risks in this industry.

Discussion of the Grid Factors

Our analysis of electric and gas utilities focuses on four broad factors:

» Regulatory Framework

» Ability to Recover Costs and Earn Returns

» Diversification

» Financial Strength

There is also a notching factor for holding company structural subordination.

Factor 1: Regulatory Framework (25%)

Why It Matters

For rate-regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations. The regulatory environment is comprised of two rating factors - the Regulatory Framework and its corollary factor, the Ability to Recover Costs and Earn Returns. Broadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation. The Ability to Recover Costs and Earn Returns relates more directly to the actual decisions, including their timeliness and the rate-setting outcomes.

Utility rates[9] are set in a political/regulatory process rather than a competitive or free-market process; thus, the Regulatory Framework is a key determinant of the success of utility. The Regulatory Framework has many components: the governing body and the utility legislation or decrees it enacts, the manner in which regulators are appointed or elected, the rules and procedures promulgated by those regulators, the judiciary that interprets the laws and rules and that arbitrates disagreements, and the manner in which the utility manages the political and regulatory process. In many cases, utilities have experienced credit stress or default primarily or at least secondarily because of a break-down or obstacle in the Regulatory Framework – for instance, laws that prohibited regulators from including investments in uncompleted power plants or plants not deemed "used and useful" in rates, or a disagreement about rate-making that could not be resolved until after the utility had defaulted on its debts.

How We Assess Legislative and Judicial Underpinnings of the Regulatory Framework for the Grid

For this sub-factor, we consider the scope, clarity, transparency, supportiveness and granularity of utility legislation, decrees, and rules as they apply to the issuer. We also consider the strength of the regulator's authority over rate-making and other regulatory issues affecting the utility, the effectiveness of the judiciary or other independent body in arbitrating disputes in a disinterested manner, and whether the utility's monopoly has meaningful or growing carve-outs. In addition, we look at how well developed the framework is – both how fully fleshed out the rules and regulations are and how well tested it is – the extent to which regulatory or judicial decisions have created a body of precedent that will help determine future rate-making. Since the focus of our scoring is on each issuer, we consider

[6] In jurisdictions where utility revenues include material government subsidy payments, we consider utility rates to be inclusive of these payments, and we thus evaluate sub-factors 1a, 1b, 2a and 2b in light of both rates and material subsidy payments. For example, we would consider the legal and judicial underpinnings and consistency and predictability of subsidies as well as rates.

how effective the utility is in navigating the regulatory framework – both the utility's ability to shape the framework and adapt to it.

A utility operating in a regulatory framework that is characterized by legislation that is credit supportive of utilities and eliminates doubt by prescribing many of the procedures that the regulators will use in determining fair rates (which legislation may show evidence of being responsive to the needs of the utility in general or specific ways), a long history of transparent rate-setting, and a judiciary that has provided ample precedent by impartially adjudicating disagreements in a manner that addresses ambiguities in the laws and rules will receive higher scores in the Legislative and Judicial Underpinnings sub-factor. A utility operating in a regulatory framework that, by statute or practice, allows the regulator to arbitrarily prevent the utility from recovering its costs or earning a reasonable return on prudently incurred investments, or where regulatory decisions may be reversed by politicians seeking to enhance their populist appeal will receive a much lower score.

In general, we view national utility regulation as being less liable to political intervention than regulation by state, provincial or municipal entities, so the very highest scoring in this sub-factor is reserved for this category. However, we acknowledge that states and provinces in some countries may be larger than small nations, such that their regulators may be equally "above-the-fray" in terms of impartial and technically-oriented rate setting, and very high scoring may be appropriate.

[9] In jurisdictions where utility revenues include material government subsidy payments, we consider utility rates to be inclusive of these payments, and we thus evaluate sub-factors 1a, 1b, 2a and 2b in light of both rates and material subsidy payments. For example, we would consider the legal and judicial underpinnings and consistency and predictability of subsidies as well as rates.

The relevant judicial system can be a major factor in the regulatory framework. This is particularly true in litigious societies like the United States, where disagreements between the utility and its state or municipal regulator may eventually be adjudicated in federal district courts or even by the US Supreme Court. In addition, bankruptcy proceedings in the US take place in federal courts, which have at times been able to impose rate settlement agreements on state or municipal regulators. As a result, the range of decisions available to state regulators may be effectively circumscribed by court precedent at the state or federal level, which we generally view as favorable for the credit- supportiveness of the regulatory framework.

Electric and gas utilities are generally presumed to have a strong monopoly that will continue into the foreseeable future, and this expectation has allowed these companies to have greater leverage than companies in other sectors with similar ratings. Thus, the existence of a monopoly in itself is unlikely to be a driver of strong scoring in this sub-factor. On the other hand, a strong challenge to the monopoly could cause lower scoring, because the utility can only recover its costs and investments and service its debt if customers purchase its services. There have some instances of incursions into utilities' monopoly, including municipalization, self-generation, distributed generation with net metering, or unauthorized use (beyond the level for which the utility receives compensation in rates). Incursions that are growing significantly or having a meaningful impact on rates for customers that remain with the utility could have a negative impact on scoring of this sub-factor and on factor 2 - Ability to Recover Costs and Earn Returns.

The scoring of this sub-factor may not be the same for every utility in a particular jurisdiction. We have observed that some utilities appear to have greater sway over the relevant utility legislation and promulgation of rules than other utilities – even those in the same jurisdiction. The content and tone of publicly filed documents and regulatory decisions sometimes indicates that the management team at one utility has better responsiveness to and credibility with its regulators or legislators than the management at another utility.

While the underpinnings to the regulatory framework tend to change relatively slowly, they do evolve, and our factor scoring will seek to reflect that evolution. For instance, a new framework will typically become tested over time as regulatory decisions are issued, or perhaps litigated, thereby setting a body of precedent. Utilities may seek changes to laws in order to permit them to securitize certain costs or collect interim rates, or a jurisdiction in which rates were previously recovered primarily in base rate proceedings may institute riders and trackers. These changes would likely impact scoring of sub-factor 2b - Timeliness of Recovery of Operating and Capital Costs, but they may also be sufficiently significant to indicate a change in the regulatory underpinnings. On the negative side, a judiciary that had formerly been independent may start to issue decisions that indicate it is conforming its decisions to the expectations of an executive branch that wants to mandate lower rates.

Factor 1a: Legislative and Judicial Underpinnings of the Regulatory Framework (12.5%)

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based on legislation that provides the utility a nearly absolute monopoly (see note 1) within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward-looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.

Ba	B	Caa
Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor-unfriendly nationalization or other significant intervention in utility markets or rate-setting.

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

How We Assess Consistency and Predictability of Regulation for the Grid

For the Consistency and Predictability sub-factor, we consider the track record of regulatory decisions in terms of consistency, predictability and supportiveness. We evaluate the utility's interactions in the regulatory process as well as the overall stance of the regulator toward the utility.

In most jurisdictions, the laws and rules seek to make rate-setting a primarily technical process that examines costs the utility incurs and the returns on investments the utility needs to earn so it can make investments that are required to build and maintain the utility infrastructure - power plants, electric transmission and distribution systems, and/or natural gas distribution systems. When the process remains technical and transparent such that regulators can support the financial health of the utility while balancing their public duty to assure that reliable service is provided at a reasonable cost, and when the utility is able to align itself with the policy initiatives of the governing jurisdiction, the utility will receive higher scores in this sub-factor. When the process includes substantial political intervention, which could take the form of legislators or other government officials publically second- guessing regulators, dismissing regulators who have approved unpopular rate increases, or preventing the implementation of rate increases, or when regulators ignore the laws/rules to deliver an outcome that appears more politically motivated, the utility will receive lower scores in this sub-factor.

As with the prior sub-factor, we may score different utilities in the same jurisdiction differently, based on outcomes that are more or less supportive of credit quality over a period of time. We have observed that some utilities are better able to meet the expectations of their customers and regulators, whether through better service, greater reliability, more stable rates or simply more effective regulatory outreach and communication. These utilities typically receive more consistent and credit supportive outcomes, so they will score higher in this sub-factor. Conversely, if a utility has multiple rapid rate increases, chooses to submit major rate increase requests during a sensitive election cycle or a severe economic downturn, has chronic customer service issues, is viewed as frequently providing incomplete information to regulators, or is tone deaf to the priorities of regulators and politicians, it may receive less consistent and supportive outcomes and thus score lower in this sub-factor.

In scoring this sub-factor, we will primarily evaluate the actions of regulators, politicians and jurists rather than their words. Nonetheless, words matter when they are an indication of future action. We seek to differentiate between political rhetoric that is perhaps oriented toward gaining attention for the viewpoint of the speaker and rhetoric that is indicative of future actions and trends in decision- making.

Factor 1b: Consistency and Predictability of Regulation (12.5%)

Aaa	Aa	A	Baa
The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.

Ba	B	Caa
We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for some material decisions.	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.

Factor 2: Ability to Recover Costs and Earn Returns (25%)

Why It Matters

This rating factor examines the ability of a utility to recover its costs and earn a return over a period of time, including during differing market and economic conditions. While the Regulatory Framework looks at the transparency and predictability of the rules that govern the decision-making process with respect to utilities, the Ability to Recover Costs and Earn Returns evaluates the regulatory elements that directly impact the ability of the utility to generate cash flow and service its debt over time. The ability to recover prudently incurred costs on a timely basis and to attract debt and equity capital are crucial credit considerations. The inability to recover costs, for instance if fuel or purchased power costs ballooned during a rate freeze period, has been one of the greatest drivers of financial stress in this sector, as well as the cause of some utility defaults. In a sector that is typically free cash flow negative (due to large capital expenditures and dividends) and that routinely needs to refinance very large maturities of long-term debt, investor concerns about a lack of timely cost recovery or the sufficiency of rates can, in an extreme scenario, strain access to capital markets and potentially lead to insolvency of the utility (as was the case when "used and useful" requirements threatened some utilities that experienced years of delay in completing nuclear power plants in the 1980s). While our scoring for the Ability to Recover Costs and Earn Returns may primarily be influenced by our assessment of the regulatory relationship, it can also be highly impacted by the management and business decisions of the utility.

How We Assess Ability to Recover Costs and Earn Returns

The timeliness and sufficiency of rates are scored as separate sub-factors; however, they are interrelated. Timeliness can have an impact on our view of what constitutes sufficient returns, because a strong assurance of timely cost recovery reduces risk. Conversely, utilities may have a strong assurance that they will earn a full return on certain deferred costs until they are able to collect them, or their generally strong returns may allow them to weather some rate lag on recovery of construction-related capital expenditures. The timeliness of cost recovery is particularly important in a period of rapidly rising costs. During the past five years, utilities have benefitted from low interest rates and generally decreasing fuel costs and purchased power costs, but these market conditions could easily reverse. For example, fuel is a large component of total costs for vertically integrated utilities and for natural gas utilities, and fuel prices are highly volatile, so the timeliness of fuel and purchased power cost recovery is especially important.

While Factors 1 and 2 are closely inter-related, scoring of these factors will not necessarily be the same. We have observed jurisdictions where the Regulatory Framework caused considerable credit concerns – perhaps it was untested or going through a transition to de-regulation, but where the track record of rate case outcomes was quite positive, leading to a higher score in the Ability to Recover Costs and Earn Returns. Conversely, there have been instances of strong Legislative and Judicial Underpinnings of the Regulatory Framework where the commission has ignored the framework (which would affect Consistency and Predictability of Regulation as well as Ability to Recover Costs and Earn Returns) or has used extraordinary measures to prevent or defer an increase that might have been justifiable from a cost perspective but would have caused rate shock.

One might surmise that Factors 2 and 4 should be strongly correlated, since a good Ability to Recover Costs and Earn Returns would normally lead to good financial metrics. However, the scoring for the Ability to Recover Costs and Earn Returns sub-factor places more emphasis on our expectation of timeliness and sufficiency of rates over time; whereas financial metrics may be impacted by one-time events, market conditions or construction cycles - trends that we believe could normalize or even reverse.

How We Assess Timeliness of Recovery of Operating and Capital Costs for the Grid

The criteria we consider include provisions and cost recovery mechanisms for operating costs, mechanisms that allow actual operating and/or capital expenditures to be trued-up periodically into rates without having to file a rate case (this may include formula rates, rider and trackers, or the ability to periodically adjust rates for construction work in progress) as well as the process and timeframe of general tariff/base rate cases – those that are fully reviewed by the regulator, generally in a public format that includes testimony of the utility and other stakeholders and interest groups. We also look at the track record of the utility and regulator for timeliness. For instance, having a formula rate plan is positive, but if the actual process has included reviews that are delayed for long periods, it may dampen the benefit to the utility. In addition, we seek to estimate the lag between the time that a utility incurs a major construction expenditures and the time that the utility will start to recover and/or earn a return on that expenditure.

How We Assess Sufficiency of Rates and Returns for the Grid

The criteria we consider include statutory protections that assure full cost recovery and a reasonable return for the utility on its investments, the regulatory mechanisms used to determine what a reasonable return should be, and the track record of the utility in actually recovering costs and earning returns. We examine outcomes of rate cases/tariff reviews and compare them to the request submitted by the utility, to prior rate cases/tariff reviews for the same utility and to recent rate/tariff decisions for a peer group of comparable utilities. In this context, comparable utilities are typically utilities in the same or similar jurisdiction. In cases where the utility is unique or nearly unique in its jurisdiction, comparison will be made to other peers with an adjustment for local differences, including prevailing rates of interest and returns on capital, as well as the timeliness of rate-setting. We look at regulatory disallowances of costs or investments, with a focus on their financial severity and also on the reasons given by the regulator, in order to assess the likelihood that such disallowances will be repeated in the future.

Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

Aaa	Aa	A	Baa
Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward-looking costs.	Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward-looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non-refundable interim rates) can be collected, and permit inclusion of important forward-looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.

Ba	B	Caa	
There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.	

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

Factor 2b: Sufficiency of Rates and Returns (12.5%)

Aaa	Aa	A	Baa
Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.

Ba	B	Caa	
Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.	

Factor 3: Diversification (10%)

Why It Matters

Diversification of overall business operations helps to mitigate the risk that economic cycles, material changes in a single regulatory regime or commodity price movements will have a severe impact on cash flow and credit quality of a utility. While utilities' sales volumes have lower exposure to economic recessions than many non-financial corporate issuers, some sales components, including industrial sales, are directly affected by economic trends that cause lower production and/or plant closures. In addition, economic activity plays a role in the rate of customer growth in the service territory and (absent energy efficiency and conservation) can often impact usage per customer. The economic strength or weakness of the service territory can affect the political and regulatory environment for rate increase requests by the utility. For utilities in areas prone to severe storms and other natural disasters, the utility's geographic diversity or concentration can be a key determinant for creditworthiness.

Diversity among regulatory regimes can mitigate the impact of a single unfavorable decision affecting one part of the utility's footprint.

For utilities with electric generation, fuel source diversity can mitigate the impact (to the utility and to its rate-payers) of changes in commodity prices, hydrology and water flow, and environmental or other regulations affecting plant operations and economics. We have observed that utilities' regulatory environments are most likely to become unfavorable during periods of rapid rate increases (which are more important than absolute rate levels) and that fuel diversity leads to more stable rates over time.

For that reason, fuel diversity can be important even if fuel and purchased power expenses are an automatic pass-through to the utility's ratepayers. Changes in environmental, safety and other regulations have caused vulnerabilities for certain technologies and fuel sources during the past five years. These vulnerabilities have varied widely in different countries and have changed over time.

How We Assess Market Position for the Grid

Market position is comprised primarily of the economic diversity of the utility's service territory and the diversity of its regulatory regimes. We also consider the diversity of utility operations (e.g., regulated electric, gas, water, steam) when there are material operations in more than one area.

Economic diversity is a typically a function of the population, size and breadth of the territory and the businesses that drive its GDP and employment. For the size of the territory, we typically consider the number of customers and the volumes of generation and/or throughput. For breadth, we consider the number of sizeable metropolitan areas served, the economic diversity and vitality in those metropolitan areas, and any concentration in a particular area or industry. In our assessment, we may consider various information sources. For example, in the US, information sources on the diversity and vitality of economies of individual states and metropolitan areas may include Moody's Economy.com. We also look at the mix of the utility's sales volumes among customer types, as well as the track record of volume sales and any notable payment patterns during economic cycles. For diversity of regulatory regimes, we typically look at the number of regulators and the percentages of revenues and utility assets that are under the purview of each. While the highest scores in the Market Position sub-factor are reserved for issuers regulated in multiple jurisdictions, when there is only one regulator, we make a differentiation of regimes perceived as having lower or higher volatility.

Issuers with multiple supportive regulatory jurisdictions, a balanced sales mix among residential, commercial, industrial and governmental customers in a large service territory with a robust and diverse economy will generally score higher in this sub-factor. An issuer with a small service territory economy that has a high dependence on one or two sectors, especially highly cyclical industries, will generally score lower in this sub-factor, as will issuers with meaningful exposure to economic dislocations caused by natural disasters.

For issuers that are vertically integrated utilities having a meaningful amount of generation, this sub- factor has a weighting of 5%. For electric transmission and distribution utilities without meaningful generation and for natural gas local distribution companies, this sub-factor has a weighting of 10%.

How We Assess Generation and Fuel Diversity for the Grid

Criteria include the fuel type of the issuer's generation and important power purchase agreements, the ability of the issuer economically to shift its generation and power purchases when there are changes in fuel prices, the degree to which the utility and its rate-payers are exposed to or insulated from changes in commodity prices, and exposure to Challenged Source and Threatened Sources (see the explanations for how we generally characterize these generation sources in the table below). A regulated utility's capacity mix may not in itself be an indication of fuel diversity or the ability to shift fuels, since utilities may keep old and inefficient plants (e.g., natural gas boilers) to serve peak load. For this reason, we do not incorporate set percentages reflecting an "ideal" or "sub-par" mix for capacity or even generation. In addition to looking at a utility's generation mix to evaluate fuel diversity, we consider the efficiency of the utility's plants, their placement on the regional dispatch curve, and the demonstrated ability/inability of the utility to shift its generation mix in accordance with changing commodity prices.

Issuers having a balanced mix of hydro, coal, natural gas, nuclear and renewable energy as well as low exposure to challenged and threatened sources of generation will score more highly in this sub-factor. Issuers that have concentration in one or two sources of generation, especially if they are threatened or challenged sources, will incur lower scores.

In evaluating an issuer's degree of exposure to challenged and threatened sources, we will consider not only the existence of those plants in the utility's portfolio, but also the relevant factors that will determine the impact on the utility and on its rate-payers. For instance, an issuer that has a fairly high percentage of its generation from challenged sources could be evaluated very differently if its peer utilities face the same magnitude of those issues than if its peers have no exposure to challenged or threatened sources. In evaluating threatened sources, we consider the utility's progress in its plan to replace those sources, its reserve margin, the availability of purchased power capacity in the region, and the overall impact of the replacement plan on the issuer's rates relative to its peer group. Especially if there are no peers in the same jurisdiction, we also examine the extent to which the utility's generation resources plan is aligned with the relevant government's fuel/energy policy.

Factor 3: Diversification (10%)

Weighting 10%	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5.00% *	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies.	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies.	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles.	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates.
Generation and Fuel Diversity	5.00% **	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below).	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern.	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable.

	Sub-Factor Weighting	Ba	B	Caa	Definiitons
Market Position	5.00% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.	Challenged Sources are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.

Generation and Fuel Diversity	5.00% **	Modest diversification in generation and/or fuel sources such that the utility or rate-payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de-activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 4: Financial Strength (40%)

Why It Matters

Electric and gas utilities are regulated, asset-based businesses characterized by large investments in long-lived property, plant and equipment. Financial strength, including the ability to service debt and provide a return to shareholders, is necessary for a utility to attract capital at a reasonable cost in order to invest in its generation, transmission and distribution assets, so that the utility can fulfill its service obligations at a reasonable cost to rate-payers.

How We Assess It for the Grid

In comparison to companies in other non-financial corporate sectors, the financial statements of regulated electric and gas utilities have certain unique aspects that impact financial analysis, which is further complicated by disparate treatment of certain elements under US Generally Accepted Accounting Principles (GAAP) versus International Financial Reporting Standards (IFRS). Regulatory accounting may permit utilities to defer certain costs (thereby creating regulatory assets) that a non- utility corporate entity would have to expense. For instance, a regulated utility may be able to defer a substantial portion of costs related to recovery from a storm based on the general regulatory framework for those expenses, even if the utility does not have a specific order to collect the expenses from ratepayers over a set period of time. A regulated utility may be able to accrue and defer a return on equity (in addition to capitalizing interest) for construction-work-in-progress for an approved project based on the assumption that it will be able to collect that deferred equity return once the asset comes into service. For this reason, we focus more on a utility's cash flow than on its reported net income.

Conversely, utilities may collect certain costs in rates well ahead of the time they must be paid (for instance, pension costs), thereby creating regulatory liabilities. Many of our metrics focus on Cash Flow from Operations Before Changes in Working Capital (CFO Pre-WC) because, unlike Funds from Operations (FFO), it captures the changes in long-term regulatory assets and liabilities.

However, under IFRS the two measures are essentially the same. In general, we view changes in working capital as less important in utility financial analysis because they are often either seasonal (for example, power demand is generally greatest in the summer) or caused by changes in fuel prices that are typically a relatively automatic pass-through to the customer. We will nonetheless examine the impact of working capital changes in analyzing a utility's liquidity (see Other Rating Considerations – Liquidity).

Given the long-term nature of utility assets and the often lumpy nature of their capital expenditures, it is important to analyze both a utility's historical financial performance as well as its prospective future performance, which may be different from backward-looking measures. Scores under this factor may be higher or lower than what might be expected from historical results, depending on our view of expected future performance. Multi-year periods are usually more representative of credit quality because utilities can experience swings in cash flows from one-time events, including such items as rate refunds, storm cost deferrals that create a regulatory asset, or securitization proceeds that reduce a regulatory asset. Nonetheless, we also look at trends in metrics for individual periods, which may influence our view of future performance and ratings.

For this scoring grid, we have identified four key ratios that we consider the most consistently useful in the analysis of regulated electric and gas utilities. However, no single financial ratio can adequately convey the relative credit strength of these highly diverse companies. Our ratings consider the overall financial strength of a company, and in individual cases other financial indicators may also play an important role.

CFO Pre-Working Capital Plus Interest/Interest or Cash Flow Interest Coverage

The cash flow interest coverage ratio is an indicator for a utility's ability to cover the cost of its borrowed capital. The numerator in the ratio calculation is the sum of CFO Pre-WC and interest expense, and the denominator is interest expense.

CFO Pre-Working Capital / Debt

This important metric is an indicator for the cash generating ability of a utility compared to its total debt. The numerator in the ratio calculation is CFO Pre-WC, and the denominator is total debt.

CFO Pre-Working Capital Minus Dividends / Debt

This ratio is an indicator for financial leverage as well as an indicator of the strength of a utility's cash flow after dividend payments are made. Dividend obligations of utilities are often substantial, quasi- permanent outflows that can affect the ability of a utility to cover its debt obligations, and this ratio can also provide insight into the financial policies of a utility or utility holding company. The higher the level of retained cash flow relative to a utility's debt, the more cash the utility has to support its capital expenditure program. The numerator of this ratio is CFO Pre-WC minus dividends, and the denominator is total debt.

Debt/Capitalization

This ratio is a traditional measure of balance sheet leverage. The numerator is total debt and the denominator is total capitalization. All of our ratios are calculated in accordance with our standard adjustments[10], but we note that our definition of total capitalization includes deferred taxes in addition to total debt, preferred stock, other hybrid securities, and common equity. Since the presence or absence of deferred taxes is a function of national tax policy, comparing utilities using this ratio may be more meaningful among utilities in the same country or in countries with similar tax policies. High debt levels in comparison to capitalization can indicate higher interest obligations, can limit the ability of a utility to raise additional financing if needed, and can lead to leverage covenant violations in bank credit facilities or other financing agreements[11]. A high ratio may result from a regulatory framework that does not permit a robust cushion of equity in the capital structure, or from a material write-off of an asset, which may not have impacted current period cash flows but could affect future period cash flows relative to debt.

There are two sets of thresholds for three of these ratios based on the level of the issuer's business risk – the Standard Grid and the Lower Business Risk (LBR) Grid. In our view, the different types of utility entities covered under this methodology (as described in Appendix E) have different levels of business risk.

Generation utilities and vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation, so we apply the Standard Grid. We view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays.

Other types of utilities may have lower business risk, such that we believe that they are most appropriately assessed using the LBR Grid, due to factors that could include a generally greater transfer of risk to customers, very strong insulation from exposure to commodity price movements, good protection from volumetric risks, fairly limited capex needs and low exposure to storms, major accidents and natural

10 In certain circumstances, analysts may also apply specific adjustments.

11 We also examine debt/capitalization ratios as defined in applicable covenants (which typically exclude deferred taxes from capitalization) relative to the covenant threshold level.

disasters. For instance, we tend to view many US natural gas local distribution companies (LDCs) and certain US electric transmission and distribution companies (T&Ds, which lack generation but generally retain some procurement responsibilities for customers), as typically having a lower business risk profile than their vertically integrated peers. In cases of T&Ds that we do not view as having materially lower risk than their vertically integrated peers, we will apply the Standard grid. This could result from a regulatory framework that exposes them to energy supply risk, large capital expenditures for required maintenance or upgrades, a heightened degree of exposure to catastrophic storm damage, or increased regulatory scrutiny due to poor reliability, or other considerations. The Standard Grid will also apply to LDCs that in our view do not have materially lower risk; for instance, due to their ownership of high pressure pipes or older systems requiring extensive gas main replacements, where gas commodity costs are not fully recovered in a reasonably contemporaneous manner, or where the LDC is not well insulated from declining volumes.

The four key ratios, their weighting in the grid, and the Standard and LBR scoring thresholds are detailed in the following table.

Factor 4: Financial Strength

Weighting 40%	Sub-Factor Weighting		Aaa	Aa	A	Baa	Ba	B	Caa
CFO pre-WC + Interest / Interest	7.50%		≥ 8.0x	6.0x - 8.0x	4.5x - 6.0x	3.0x - 4.5x	2.0x - 3.0x	1.0x - 2.0x	< 1.0x
CFO pre-WC / Debt	15.00%	Standard Grid	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
		Low Business Risk Grid	≥ 38%	27% - 38%	19% - 27%	11% - 19%	5% - 11%	1% - 5%	< 1%
CFO pre-WC - Dividends / Debt	10.00%	Standard Grid	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5%) - 0%	< (5%)
		Low Business Risk Grid	≥ 34%	23% - 34%	15% - 23%	7% - 15%	0% - 7%	(5%) - 0%	< (5%)
Debt / Capitalization	7.50%	Standard Grid	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
		Low Business Risk Grid	< 29%	29% - 40%	40% - 50%	50% - 59%	59% - 67%	67% - 75%	≥ 75%

Notching for Structural Subordination of Holding Companies

Why It Matters

A typical utility company structure consists of a holding company ("HoldCo") that owns one or more operating subsidiaries (each an "OpCo"). OpCos may be regulated utilities or non-utility companies. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries that are structured as advances, debt, or even hybrid securities.

Most HoldCos present their financial statements on a consolidated basis that blurs legal considerations about priority of creditors based on the legal structure of the family, and grid scoring is thus based on consolidated ratios. However, HoldCo creditors typically have a secondary claim on the group's cash flows and assets after OpCo creditors. We refer to this as structural subordination, because it is the corporate legal structure, rather than specific subordination provisions, that causes creditors at each of the utility and non-utility subsidiaries to have a more direct claim on the cash flows and assets of their respective OpCo obligors. By contrast, the debt of the HoldCo is typically serviced primarily by dividends that are upstreamed by the OpCos[12]. Under normal circumstances, these dividends are made from net income, after payment of the OpCo's interest and preferred dividends. In most non- financial corporate sectors where cash often moves freely between the entities in a single issuer family, this distinction may have less of an impact. However, in the regulated utility sector, barriers to movement of cash among companies in the corporate family can be much more restrictive, depending on the regulatory framework. These barriers can lead to significantly different probabilities of default for HoldCos and OpCos. Structural subordination also affects loss given default. Under most default[1310] scenarios, an OpCo's creditors will be satisfied from the value residing at that OpCo before any of the OpCo's assets can be used to satisfy claims of the HoldCo's creditors. The prevalence of debt issuance at the OpCo level is another reason that structural subordination is usually a more serious concern in the utility sector than for investment grade issuers in other non-financial corporate sectors.

The grids for factors 1-4 are primarily oriented to OpCos (and to some degree for HoldCos with minimal current structural subordination; for example, there is no current structural subordination to debt at the operating company if all of the utility family's debt and preferred stock is issued at the HoldCo level, although there is structural subordination to other liabilities at the OpCo level). The additional risk from structural subordination is addressed via a notching adjustment to bring grid outcomes (on average) closer to the actual ratings of HoldCos.

How We Assess It

Grid-indicated ratings of holding companies may be notched down based on structural subordination. The risk factors and mitigants that impact structural subordination are varied and can be present in different combinations, such that a formulaic approach is not practical and case-by-case analyst judgment of the interaction of all pertinent factors that may increase or decrease its importance to the credit risk of an issuer are essential.

Some of the potentially pertinent factors that could increase the degree and/or impact of structural subordination include the following:

» Regulatory or other barriers to cash movement from OpCos to HoldCo

» Specific ring-fencing provisions

» Strict financial covenants at the OpCo level

» Higher leverage at the OpCo level

» Higher leverage at the HoldCo level[14]

» Significant dividend limitations or potential limitations at an important OpCo

» HoldCo exposure to subsidiaries with high business risk or volatile cash flows

Strained liquidity at the HoldCo level

» The group's investment program is primarily in businesses that are higher risk or new to the group

Some of the potentially mitigating factors that could decrease the degree and/or impact of structural subordination include the following:

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12 The HoldCo and OpCo may also have intercompany agreements, including tax sharing agreements, that can be another source of cash to the HoldCo.

13 Actual priority in a default scenario will be determined by many factors, including the corporate and bankruptcy laws of the jurisdiction, the asset value of each OpCo, specific financing terms, inter-relationships among members of the family, etc.

14 While higher leverage at the HoldCo does not increase structural subordination per se, it exacerbates the impact of any structural subordination that exists

» Substantial diversity in cash flows from a variety of utility OpCos

» Meaningful dividends to HoldCo from unlevered utility OpCos

» Dependable, meaningful dividends to HoldCo from non-utility OpCos

» The group's investment program is primarily in strong utility businesses

» Inter-company guarantees - however, in many jurisdictions the value of an upstream guarantee may be limited by certain factors, including by the value that the OpCo received in exchange for granting the guarantee

Notching for structural subordination within the grid may range from 0 to negative 3 notches. Instances of extreme structural subordination are relatively rare, so the grid convention does not accommodate wider differences, although in the instances where we believe it is present, actual ratings do reflect the full impact of structural subordination.

A related issue is the relationship of ratings within a utility family with multiple operating companies, and sometimes intermediate holding companies. Some of the key issues are the same, such as the relative amounts of debt at the holding company level compared to the operating company level (or at one OpCo relative to another), and the degree to which operating companies have credit insulation due to regulation or other protective factors. Appendix B has additional insights on ratings within a utility family.

Rating Methodology Assumptions, Limitations, and Other Rating Considerations

The grid in this rating methodology represents a decision to favor simplicity that enhances transparency and to avoid greater complexity that might enable the grid to map more closely to actual ratings. Accordingly, the four rating factors and the notching factor in the grid do not constitute an exhaustive treatment of all of the considerations that are important for ratings of companies in the regulated electric and gas utility sector. In addition, our ratings incorporate expectations for future performance, while the financial information that is used in the grid in this document is mainly historical. In some cases, our expectations for future performance may be informed by confidential information that we can't disclose. In other cases, we estimate future results based upon past performance, industry trends, competitor actions or other factors. In either case, predicting the future is subject to the risk of substantial inaccuracy.

Assumptions that may cause our forward-looking expectations to be incorrect include unanticipated changes in any of the following factors: the macroeconomic environment and general financial market conditions, industry competition, disruptive technology, regulatory and legal actions.

Key rating assumptions that apply in this sector include our view that sovereign credit risk is strongly correlated with that of other domestic issuers, that legal priority of claim affects average recovery on different classes of debt, sufficiently to generally warrant differences in ratings for different debt classes of the same issuer, and the assumption that lack of access to liquidity is a strong driver of credit risk.

In choosing metrics for this rating methodology grid, we did not explicitly include certain important factors that are common to all companies in any industry such as the quality and experience of management, assessments of corporate governance and the quality of financial reporting and information disclosure. Therefore ranking these factors by rating category in a grid would in some cases suggest too much precision in the relative ranking of particular issuers against all other issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that have a meaningful effect in differentiating credit quality only in some cases, but not all. Such factors include financial controls, exposure to uncertain licensing regimes and possible government interference in some countries.

Regulatory, litigation, liquidity, technology and reputational risk as well as changes to consumer and business spending patterns, competitor strategies and macroeconomic trends also affect ratings. While these are important considerations, it is not possible precisely to express these in the rating methodology grid without making the grid excessively complex and significantly less transparent.

Ratings may also reflect circumstances in which the weighting of a particular factor will be substantially different from the weighting suggested by the grid.

This variation in weighting rating considerations can also apply to factors that we choose not to represent in the grid. For example, liquidity is a consideration frequently critical to ratings and which may not, in other circumstances, have a substantial impact in discriminating between two issuers with a similar credit profile. As an example of the limitations, ratings can be heavily affected by extremely weak liquidity that magnifies default risk. However, two identical companies might be rated the same if their only differentiating feature is that one has a good liquidity position while the other has an extremely good liquidity position.

Other Rating Considerations

We consider other factors in addition to those discussed in this report, but in most cases understanding the considerations discussed herein should enable a good approximation of our view on the credit quality of companies in the regulated electric and gas utilities sector. Ratings consider our assessment of the quality of management, corporate governance, financial controls, liquidity management, event risk and seasonality. The analysis of these factors remains an integral part of our rating process.

Liquidity and Access to Capital Markets

Liquidity analysis is a key element in the financial analysis of electric and gas utilities, and it encompasses a company's ability to generate cash from internal sources as well as the availability of external sources of financing to supplement these internal sources. Liquidity and access to financing are of particular importance in this sector. Utility assets can often have a very long useful life- 30, 40 or even 60 years is not uncommon, as well as high price tags. Partly as a result of construction cycles, the utility sector has experienced prolonged periods of negative free cash flow – essentially, the sum of its dividends and its capital expenditures for maintenance and growth of its infrastructure frequently exceeds cash from operations, such that a portion of capital expenditures must routinely be debt financed. Utilities are among the largest debt issuers in the corporate universe and typically require consistent access to the capital markets to assure adequate sources of funding and to maintain financial flexibility. Substantial portions of capex are non-discretionary (for example, maintenance, adding customers to the network, or meeting environmental mandates); however, utilities were swift to cut or defer discretionary spending during the 2007-2009 recession. Dividends represent a quasi-permanent outlay, since utilities typically only rarely will cut their dividend. Liquidity is also important to meet maturing obligations, which often occur in large chunks, and to meet collateral calls under any hedging agreements.

Due to the importance of liquidity, incorporating it as a factor with a fixed weighting in the grid would suggest an importance level that is often far different from the actual weight in the rating. In normal circumstances most companies in the sector have good access to liquidity. The industry generally requires, and for the most part has, large, syndicated, multi-year committed credit facilities. In addition, utilities have demonstrated strong access to capital markets, even under difficult conditions. As a result, liquidity generally has not been an issue for most utilities and a utility with very strong liquidity may not warrant a rating distinction compared to a utility with strong liquidity. However, when there is weakness in liquidity or liquidity management, it can be the dominant consideration for ratings.

Our assessment of liquidity for regulated utilities involves an analysis of total sources and uses of cash over the next 12 months or more, as is done for all corporates. Using our financial projections of the utility and our analysis of its available sources of liquidity (including an assessment of the quality and reliability of alternate liquidity such as committed credit facilities), we evaluate how its projected sources of cash (cash from operations, cash on hand and existing committed multi-year credit facilities) compare to its projected uses (including all or most capital expenditures, dividends, maturities of short and long-term debt, our projection of potential liquidity calls on financial hedges, and important issuer-specific items such as special tax payments). We assume no access to capital markets or additional liquidity sources, no renewal of existing credit facilities, and no cut to dividends. We examine a company's liquidity profile under this scenario, its ability to make adjustments to improve its liquidity position, and any dependence on liquidity sources with lower quality and reliability.

Management Quality and Financial Policy

The quality of management is an important factor supporting the credit strength of a regulated utility or utility holding company. Assessing the execution of business plans over time can be helpful in assessing management's business strategies, policies, and philosophies and in evaluating management performance relative to performance of competitors and our projections. A record of consistency provides us with insight into management's likely future performance in stressed situations and can be an indicator of management's tendency to depart significantly from its stated plans and guidelines.

We also assess financial policy (including dividend policy and planned capital expenditures) and how management balances the potentially competing interests of shareholders, fixed income investors and other stakeholders. Dividends and discretionary capital expenditures are the two primary components over which management has the greatest control in the short term. For holding companies, we consider the extent to which management is willing stretch its payout ratio (through aggressive increases or delays in needed decreases) in order to satisfy common shareholders. For a utility that is a subsidiary of a parent company with several utility subsidiaries, dividends to the parent may be more volatile depending on the cash generation and cash needs of that utility, because parents typically want to assure that each utility maintains the regulatory debt/equity ratio on which its rates have been set. The effect we have observed is that utility subsidiaries often pay higher dividends when they have lower capital needs and lower dividends when they have higher capital expenditures or other cash needs. Any dividend policy that cuts into the regulatory debt/equity ratio is a material credit negative.

Size – Natural Disasters, Customer Concentration and Construction Risks

The size and scale of a regulated utility has generally not been a major determinant of its credit strength in the same way that it has been for most other industrial sectors. While size brings certain economies of scale that can somewhat affect the utility's cost structure and competitiveness, rates are more heavily impacted by costs related to fuel and fixed assets. Particularly in the US, we have not observed material differences in the success of utilities' regulatory outreach based on their size. Smaller utilities have sometimes been better able to focus their attention on meeting the expectations of a single regulator than their multi-state peers.

However, size can be a very important factor in our assessment of certain risks that impact ratings, including exposure to natural disasters, customer concentration (primarily to industrial customers in a single sector) and construction risks associated with large projects. While the grid attempts to incorporate the first two of these into Factor 3, for some issuers these considerations may be sufficiently important that the rating reflects a greater weight for these risks. While construction projects always carry the risk of cost over-runs and delays, these risks are materially heightened for projects that are very large relative to the size of the utility.

Interaction of Utility Ratings with Government Policies and Sovereign Ratings

Compared to most industrial sectors, regulated utilities are more likely to be impacted by government actions. Credit impacts can occur directly through rate regulation, and indirectly through energy, environmental and tax policies. Government actions affect fuel prices, the mix of generating plants, the certainty and timing of revenues and costs, and the likelihood that regulated utilities will experience financial stress. While our evolving view of the impact of such policies and the general economic and financial climate is reflected in ratings for each utility, some considerations do not lend themselves to incorporation in a simple ratings grid.[15]

Diversified Operations at the Utility

A small number of regulated utilities have diversified operations that are segments within the utility company, as opposed to the more common practice of housing such operations in one or more separate affiliates. In general, we will seek to evaluate the other businesses that are material in accordance with the appropriate methodology and the rating will reflect considerations from such methodologies. There may be analytical limitations in evaluating the utility and non-utility businesses when segment financial results are not fully broken out and these may be addressed through estimation based on available information. Since regulated utilities are a relatively low risk business compared to other corporate sectors, in most cases diversified non-utility operations increase the business risk profile of a utility. Reflecting this tendency, we note that assigned ratings are typically lower than grid- indicated ratings for such companies.

Event Risk

We also recognize the possibility that an unexpected event could cause a sudden and sharp decline in an issuer's fundamental creditworthiness. Typical special events include mergers and acquisitions, asset sales, spin-offs, capital restructuring programs, litigation and shareholder distributions.

Corporate Governance

Among the areas of focus in corporate governance are audit committee financial expertise, the incentives created by executive compensation packages, related party transactions, interactions with outside auditors, and ownership structure.

Investment and Acquisition Strategy

In our credit assessment we take into consideration management's investment strategy. Investment strategy is benchmarked with that of the other companies in the rated universe to further verify its consistency. Acquisitions can strengthen a company's business. Our assessment of a company's tolerance for acquisitions at a given rating level takes into consideration (1) management's risk appetite, including the likelihood of further acquisitions over the medium term; (2) share buy-back activity; (3) the company's commitment to specific leverage targets; and (4) the volatility of the underlying businesses, as well as that of the business acquired. Ratings can often hold after acquisitions even if leverage temporarily climbs above normally acceptable ranges. However, this depends on (1) the strategic fit; (2) pro-forma capitalization/leverage

15 See also the cross-sector methodology "How Sovereign Credit Quality May Affect Other Ratings." A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

following an acquisition; and (3) our confidence that credit metrics will be restored in a relatively short timeframe.

Financial Controls

We rely on the accuracy of audited financial statements to assign and monitor ratings in this sector. Such accuracy is only possible when companies have sufficient internal controls, including centralized operations, the proper tone at the top and consistency in accounting policies and procedures.

Weaknesses in the overall financial reporting processes, financial statement restatements or delays in regulatory filings can be indications of a potential breakdown in internal controls.

Appendix A: Regulated Electric and Gas Utilities Methodology Factor Grid

Factor 1a: Legislative and Judicial Underpinnings of the Regulatory Framework (12.5%)

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based onlegislation that provides the utility a nearly absolutemonopoly (see note 1_ within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make andrecover all necessary investments, an extremely high degreeof clarity as to the manner in which utilities will be regulated and prescriptive methods and proceduresfor setting rates. Existing utility law is comprehensiveand supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward-looking so as to address problems before theyoccurred. There is an independent judiciary that canarbitrate disagreements between the regulator and theutility should they occur, including access to nationalcourts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expectthese conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in amanner that will permit the utility to make and recover all necessary investments, a very high degree of clarity asto the manner in which utilities will be regulated and reasonably prescriptive methods and procedures forsetting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of theissuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator andthe utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.

Ba	B	Caa
Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor- unfriendly nationalization or other significant intervention in utility markets or rate-setting.

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 1b: Consistency and Predictability of Regulation (12.5%)

Aaa	Aa	A	Baa
The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.

Ba	B	Caa
We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.

Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

Aaa	Aa	A	Baa
Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward -looking costs.	Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward- looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non- refundable interim rates) can be collected, and permit inclusion of important forward -looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.

Ba	B	Caa
There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

Factor 2b: Sufficiency of Rates and Returns (12.5%)

Aaa	Aa	A	Baa
Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.

Ba	B	Caa
Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.

Factor 3: Diversification (10%)

Weighting 10%	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5% *	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies.	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies.	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles.	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates.
Generation and Fuel Diversity	5% **	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below).	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern.	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable.

	Sub-Factor Weighting	Ba	B	Caa	Definitions
Market Position	5% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.	Challenged Sources are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.
Generation and Fuel Diversity	5% **	Modest diversification in generation and/or fuel sources such that the utility or rate- payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de- activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 4: Financial Strength

Weighting 40%	Sub-Factor Weighting		Aaa	Aa	A	Baa	Ba	B	Caa
CFO pre-WC + Interest / Interest	7.5%		≥ 8x	6x - 8x	4.5x - 6x	3x - 4.5x	2x - 3x	1x - 2x	< 1x
		Standard Grid	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
CFO pre-WC / Debt	15%								
		Low Business Risk Grid	≥ 38%	27% - 38%	19% - 27%	11% - 19%	5% - 11%	1% - 5%	< 1%
		Standard Grid	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5%) - 0%	< (5%)
CFO pre-WC - Dividends / Debt	10%								
		Low Business Risk Grid	≥ 34%	23% - 34%	15% - 23%	7% - 15%	0% - 7%	(5%) - 0%	< (5%)
		Standard Grid	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
Debt / Capitalization	7.5%								
		Low Business Risk Grid	< 29%	29% - 40%	40% - 50%	50% - 59%	59% - 67%	67% - 75%	≥ 75%

Appendix B: Approach to Ratings within a Utility Family

Typical Composition of a Utility Family

A typical utility company structure consists of a holding company ("HoldCo") that owns one or more operating subsidiaries (each an "OpCo"). OpCos may be regulated utilities or non-utility companies. Financing of these entities varies by region, in part due to the regulatory framework. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries or minority interests in other companies. However, in certain cases there may be material operations at the HoldCo level. Financing can occur primarily at the OpCo level, primarily at the HoldCo level, or at both HoldCo and OpCos in varying proportions. When a HoldCo has multiple utility OpCos, they will often be located in different regulatory jurisdictions. A HoldCo may have both levered and unlevered OpCos.

General Approach to a Utility Family

In our analysis, we generally consider the stand-alone credit profile of an OpCo and the credit profile of its ultimate parent HoldCo (and any intermediate HoldCos), as well as the profile of the family as a whole, while acknowledging that these elements can have cross-family credit implications in varying degrees, principally based on the regulatory framework of the OpCos and the financing model (which has often developed in response to the regulatory framework).

In addition to considering individual OpCos under this (or another applicable) methodology, we typically[1614] approach a HoldCo rating by assessing the qualitative and quantitative factors in this methodology for the consolidated entity and each of its utility subsidiaries. Ratings of individual entities in the issuer family may be pulled up or down based on the interrelationships among the companies in the family and their relative credit strength.

In considering how closely aligned or how differentiated ratings should be among members of a utility family, we assess a variety of factors, including:

» Regulatory or other barriers to cash movement among OpCos and from OpCos to HoldCo

» Differentiation of the regulatory frameworks of the various OpCos

» Specific ring-fencing provisions at particular OpCos

» Financing arrangements – for instance, each OpCo may have its own financing arrangements, or the sole liquidity facility may be at the parent; there may be a liquidity pool among certain but not all members of the family; certain members of the family may better be able to withstand a temporary hiatus of external liquidity or access to capital markets

» Financial covenants and the extent to which an Event of Default by one OpCo limits availability of liquidity to another member of the family

» The extent to which higher leverage at one entity increases default risk for other members of the family

» An entity's exposure to or insulation from an affiliate with high business risk

» Structural features or other limitations in financing agreements that restrict movements of funds, investments, provision of guarantees or collateral, etc.

[16] See paragraph at the end of this section for approaches to Hybrid HoldCos.

» The relative size and financial significance of any particular OpCo to the HoldCo and the family

See also those factors noted in Notching for Structural Subordination of Holding Companies.

Our approach to a Hybrid HoldCo (see definition in Appendix C) depends in part on the importance of its non-utility operations and the availability of information on individual businesses. If the businesses are material and their individual results are fully broken out in financial disclosures, we may be able to assess each material business individually by reference to the relevant Moody's methodologies to arrive at a composite assessment for the combined businesses. If non-utility operations are material but are not broken out in financial disclosures, we may look at the consolidated entity under more than one methodology. When non-utility operations are less material but could still impact the overall credit profile, the difference in business risks and our estimation of their impact on financial performance will be qualitatively incorporated in the rating.

Higher Barriers to Cash Movement with Financing Predominantly at the OpCos

Where higher barriers to cash movement exist on an OpCo or OpCos due the regulatory framework or debt structural features, ratings among family members are likely to be more differentiated. For instance, for utility families with OpCos in the US, where regulatory barriers to free cash movement are relatively high, greater importance is generally placed on the stand-alone credit profile of the OpCo.

Our observation of major defaults and bankruptcies in the US sector generally corroborates a view that regulation creates a degree of separateness of default probability. For instance, Portland General Electric (Baa1 RUR-up) did not default on its securities, even though its then-parent Enron Corp. entered bankruptcy proceedings. When Entergy New Orleans (Ba2 stable) entered into bankruptcy, the ratings of its affiliates and parent Entergy Corporation (Baa3 stable) were unaffected. PG&E Corporation (Baa1 stable) did not enter bankruptcy proceedings despite bankruptcies of two major subsidiaries - Pacific Gas & Electric Company (A3 stable) in 2001 and National Energy Group in 2003.

The degree of separateness may be greater or smaller and is assessed on a case by case basis, because situational considerations are important. One area we consider is financing arrangements. For instance, there will tend to be greater differentiation if each member of a family has its own bank credit facilities and difficulties experienced by one entity would not trigger events of default for other entities. While the existence of a money pool might appear to reduce separateness between the participants, there may be regulatory barriers within money pools that preserve separateness. For instance, non-utility entities may have access to the pool only as a borrower, only as a lender, and even the utility entities may have regulatory limits on their borrowings from the pool or their credit exposures to other pool members. If the only source of external liquidity for a money pool is borrowings by the HoldCo under its bank credit facilities, there would be less separateness, especially if the utilities were expected to depend on that liquidity source. However, the ability of an OpCo to finance itself by accessing capital markets must also be considered. Inter-company tax agreements can also have an impact on our view of how separate the risks of default are.

For a HoldCo, the greater the regulatory, economic, and geographic diversity of its OpCos, the greater its potential separation from the default probability of any individual subsidiary. Conversely, if a HoldCo's actions have made it clear that the HoldCo will provide support for an OpCo encountering some financial stress (for instance, due to delays and/or cost over-runs on a major construction project), we would be likely to perceive less separateness.

Even where high barriers to cash movement exist, onerous leverage at a parent company may not only give rise to greater notching for structural subordination at the parent, it may also pressure an OpCo's rating, especially when there is a clear dependence on an OpCo's cash flow to service parent debt.

While most of the regulatory barriers to cash movement are very real, they are not absolute. Furthermore, while it is not usually in the interest of an insolvent parent or its creditors to bring an operating utility into a bankruptcy proceeding, such an occurrence is not impossible.

The greatest separateness occurs where strong regulatory insulation is supplemented by effective ring-fencing provisions that fully separate the management and operations of the OpCo from the rest of the family and limit the parent's ability to cause the OpCo to commence bankruptcy proceedings as well as limiting dividends and cash transfers. Typically, most entities in US utility families (including HoldCos and OpCos) are rated within 3 notches of each other. However, it is possible for the HoldCo and OpCos in a family to have much wider notching due to the combination of regulatory imperatives and strong ring-fencing that includes a significant minority shareholder who must agree to important corporate decisions, including a voluntary bankruptcy filing.

Lower Barriers to Cash Movement with Financing Predominantly at the OpCos

Our approach to rating issuers within a family where there are lower regulatory barriers to movement of cash from OpCos to HoldCos (e.g., many parts of Asia and Europe) places greater emphasis on the credit profile of the consolidated group. Individual OpCos are considered based on their individual characteristics and their importance to the family, and their assigned ratings are typically banded closely around the consolidated credit profile of the group due to the expectation that cash will transit relatively freely among family entities.

Some utilities may have OpCos in jurisdictions where cash movement among certain family members is more restricted by the regulatory framework, while cash movement from and/or among OpCos in other jurisdictions is less restricted. In these situations, OpCos with more restrictions may vary more widely from the consolidated credit profile while those with fewer restrictions may be more tightly banded around the other entities in the corporate family group.

Appendix C: Brief Descriptions of the Types of Companies Rated Under This Methodology

The following describes the principal categories of companies rated under this methodology:

Vertically Integrated Utility: Vertically integrated utilities are regulated electric or combination utilities (see below) that own generation, distribution and (in most cases) electric transmission assets. Vertically integrated utilities are generally engaged in all aspects of the electricity business. They build power plants, procure fuel, generate power, build and maintain the electric grid that delivers power from a group of power plants to end-users (including high and low voltage lines, transformers and substations), and generally meet all of the electric needs of the customers in a specific geographic area (also called a service territory). The rates or tariffs for all of these monopolistic activities are set by the relevant regulatory authority.

Transmission & Distribution Utility: Transmission & Distribution utilities (T&Ds) typically operate in deregulated markets where generation is provided under a competitive framework. T&Ds own and operate the electric grid that transmits and/or distributes electricity within a specific state or region.

T&Ds provide electrical transportation and distribution services to carry electricity from power plants and transmission lines to retail, commercial, and industrial customers. T&Ds are typically responsible for billing customers for electric delivery and/or supply, and most have an obligation to provide a standard supply or provider-of-last-resort (POLR) service to customers that have not switched to a competitive supplier. These factors distinguish T&Ds from Networks, whose customers are retail electric suppliers and/or other electricity companies. In a smaller number of cases, T&Ds rated under this methodology may not have an obligation to provide POLR services, but are regulated in sub- sovereign jurisdictions. The rates or tariffs for these monopolistic T&D activities are set by the relevant regulatory authority.

Local Gas Distribution Company: Distribution is the final step in delivering natural gas to customers. While some large industrial, commercial, and electric generation customers receive natural gas directly from high capacity pipelines that carry gas from gas producing basins to areas where gas is consumed, most other users receive natural gas from their local gas utility, also called a local distribution company (LDC). LDCs are regulated utilities involved in the delivery of natural gas to consumers within a specific geographic area. Specifically, LDCs typically transport natural gas from delivery points located on large-diameter pipelines (that usually operate at fairly high pressure) to households and businesses through thousands of miles of small-diameter distribution pipe (that usually operate at fairly low pressure). LDCs are typically responsible for billing customers for gas delivery and/or supply, and most also have the responsibility to procure gas for at least some of their customers, although in some markets gas supply to all customers is on a competitive basis. These factors distinguish LDCs from gas networks, whose customers are retail gas suppliers and/or other natural gas companies. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

Integrated Gas Utility: Integrated gas regulated utilities are regulated utilities that deliver gas to all end users in a particular service territory by sourcing the commodity; operating transport infrastructure that often combines high pressure pipelines with low pressure distribution systems and, in some cases, gas storage, re-gasification or other related facilities; and performing other supply-related activities, such as customer billing and metering. The rates or tariffs for the totality of these activities are set by the relevant regulatory authority. Many integrated gas utilities are national in scope.

Combination Utility: Combination utilities are those that combine an LDC or Integrated Gas Utility with either a vertically integrated utility or a T&D utility. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

Regulated Generation Utility: Regulated generation utilities (Regulated Gencos) are utilities that almost exclusively have generation assets, but their activities are generally regulated like those of vertically integrated utilities. In the US, this means that the purchasers of their output (typically other investor-owned, municipal or cooperative utilities) pay a regulated rate based on the total allowed costs of the Regulated Genco, including a return on equity based on a capital structure designated by the regulator (primarily FERC). Companies that have been included in this group include certain generation companies (including in Korea and China) that are not rate regulated in the usual sense of recovering costs plus a regulated rate of return on either equity or asset value. Instead, we have looked at a combination of governmental action with respect to setting feed-in tariffs and directives on how much generation will be built (or not built) in combination with a generally high degree of government ownership, and we have concluded that these companies are currently best rated under this methodology. Future evolution in our view of the operating and/or regulatory environment of these companies could lead us to conclude that they may be more appropriately rated under a related methodology (for example, Unregulated Utilities and Power Companies).

Independent System Operator: An Independent System Operator (ISO) is an organization formed in certain regional electricity markets to act as the sole chief coordinator of an electric grid. In the areas where an ISO is established, it coordinates, controls and monitors the operation of the electrical power system to assure that electric supply and demand are balanced at all times, and, to the extent possible, that electric demand is met with the lowest-cost sources. ISOs seek to assure adequate transmission and generation resources, usually by identifying new transmission needs and planning for a generation reserve margin above expected peak demand. In regions where generation is competitive, they also seek to establish rules that foster a fair and open marketplace, and they may conduct price-setting auctions for energy and/or capacity. The generation resources that an ISO coordinates may belong to vertically integrated utilities or to independent power producers. ISOs may not be rate-regulated in the traditional sense, but fall under governmental oversight. All participants in the regional grid are required to pay a fee or tariff (often volumetric) to the ISO that is designed to recover its costs, including costs of investment in systems and equipment needed to fulfill their function. ISOs may be for profit or not-for-profit entities.

In the US, most ISOs were formed at the direction or recommendation of the Federal Energy Regulatory Commission (FERC), but the ISO that operates solely in Texas falls under state jurisdiction. Some US ISOs also perform certain additional functions such that they are designated as Regional Transmission Organizations (or RTOs).

Transmission-Only Utility: Transmission-only utilities are solely focused on owning and operating transmission assets. The transmission lines these utilities own are typically high-voltage and allow energy producers to transport electric power over long distances from where it is generated (or received) to the transmission or distribution system of a T&D or vertically integrated utility. Unlike most of the other utilities rated under this methodology, transmission-only utilities primarily provide services to other utilities and ISOs. Transmission-only utilities in most parts of the world other than the US have been rated under the Regulated Networks methodology.

Utility Holding Company (Utility HoldCo): As detailed in Appendix B, regulated electric and gas utilities are often part of corporate families under a parent holding company. The operating subsidiaries of Utility Holdcos are overwhelmingly regulated electric and gas utilities.

Hybrid Holding Company (Hybrid HoldCo): Some utility families contain a mix of regulated electric and gas utilities and other types of companies, but the regulated electric and gas utilities represent the majority of the consolidated cash flows, assets and debt. The parent company is thus a Hybrid HoldCo.

Appendix D: Key Industry Issues Over the Intermediate Term

Political and Regulatory Issues

As highly regulated monopolistic entities, regulated utilities continually face political and regulatory risk, and managing these risks through effective outreach to key customers as well as key political and regulatory decision-makers is, or at least should be, a core competency of companies in this sector. However, largerwaves of change in the political, regulatory or economic environment have the potential to cause substantial changes in the level of risk experienced by utilities and their investors in somewhat unpredictable ways.

One of the more universal risks faced by utilities currently is the compression of allowed returns. A longperiod of globally low interest rates, held down by monetary stimulus policies, has generally benefittedutilities, since reductions in allowed returns have been slower than reductions in incurred capital costs.Essentially all regulated utilities face a ratcheting down of allowed and/or earned returns. More difficult topredict is how regulators will respond when monetary stimulus reverses, and how well utilities will farewhen fixed income investors require higher interest rates and equity investors require higher total returnsand growth prospects.

The following global snapshot highlights that regulatory frameworks evolve over time. On an overall basis in the US over the past several years, we have noted some incremental positive regulatory trends, including greater use of formula rates, trackers and riders, and (primarily for natural gas utilities) de-coupling of returns from volumetric sales. In Canada, the framework has historically been viewed as predictable and stable, which has helped offset somewhat lower levels of equity in the capital structure, but the compressionof returns has been relatively steep in recent years. In Japan, the regulatory authorities are working throughthe challenges presented by the decision to shut down virtually all of the country's nuclear generationcapacity, leading to uncertainty regarding the extent to which increased costs will be reflected in rate increases sufficient to permit returns on capital to return to prior levels. China's regulatory framework has continued to evolve, with fairly low transparency and some time-to-time shifts in favored versus less-favoredgeneration sources balanced by an overall state policy of assuring sustainability of the sector, adequate supply of electricity and affordability to the general public. Singapore and Hong Kong have fairly well developedand supportive regulatory frameworks despite a trend towards lower returns, whereas Malaysia, Korea andThailand have been moving towards a more transparent regulatory framework. The Philippines is in theprocess of deregulating its power market, while Indian power utilities continue to grapple with structuralchallenges. In Latin America, there is a wide dispersion among frameworks, ranging from the more stable,long established and predictable framework in Chile to the decidedly unpredictable framework in Argentina. Generally, as Latin American economies have evolved to more stable economic policies,regulatory frameworks for utilities have also shown greater stability and predictability.

All of the other issues discussed in this section have a regulatory/political component, either as the driver of change or in reaction to changes in economic environments and market factors.

Economic and Financial Market Conditions

As regulated monopolies, electric and gas utilities have generally been quite resistant to unsettled economic and financial market conditions for several reasons. Unlike many companies that face direct market-based competition, their rates do not decrease when demand decreases. The elasticity of demand for electricity and gas is much lower than for most products in the consumer economy.

When financial markets are volatile, utilities often have greater capital market access thanindustrial companies in competitive sectors, as was the case in the 2007-2009 recession. However,regulated electric and gas utilities are by no means immune to a protracted or severe recession.

Severe economic malaise can negatively affect utility credit profiles in several ways. Falling demand for electricity or natural gas may negatively impact margins and debt service protection measures, especially when rates are designed such that a substantial portion of fixed costs is in theory recovered through volumetric charges. The decrease in demand in the 2007-2009 recession was notable in comparison to prior recessions, especially in the residential sector. Poor economic conditions can make it more difficult for regulators to approve needed rate increases or provide timely cost recovery for utilities, resulting in higher cost deferrals and longer regulatory lag. Finally, recessions can coincide with a lack of confidence in the utility sector that impacts access to capital markets for a period of time. For instance, in the Great Depression and (to a lesser extent) in the 2001 recession, access for some issuers was curtailed due to the sector's generally higher leverage than other corporate sectors, combined with a concerns over a lack of transparency in financial reporting.

Fuel Price Volatility and the Global Impact of Shale Gas

The ability of most utilities to pass through their fuel costs to end users may insulate a utility from exposure to price volatility of these fuels, but it does not insulate consumers. Consumers and regulators complained vociferously about utility rates during the run-up in hydro-carbon prices in 2005-2008 (oil, natural gas and, to a lesser extent, coal). The steep decline in US natural gas prices since 2009, caused in large part by the development of shale gas and shale oil resources, has been a material benefit to US utilities, because many have been able to pass through substantial base rate increases during a period when all-in rates were declining. Shale hydro-carbons have also had a positive impact, albeit one that is less immediate and direct, on non-US utilities. In much of the eastern hemisphere, natural gas prices under long-term contracts have generally been tied to oil prices, but utilities and other industrial users have started to have some success in negotiating to de-link natural gas from oil. In addition, increasing US production of oil has had a noticeable impact on world oil prices, generally benefitting oil and gas users.

Not all utilities will benefit equally. Utilities that have locked in natural gas under high-priced long- term contracts that they cannot re-negotiate are negatively impacted if they cannot pass through their full contracted cost of gas, or if the high costs cause customer dissatisfaction and regulatory backlash. Utilities with large coal fleets or utilities constructing nuclear power plants may also face negative impacts on their regulatory environment, since their customers will benefit less from lower natural gas prices.

Distributed Generation Versus the Central Station Paradigm

The regulation and the financing of electric utilities are based on the premise that the current model under which electricity is generated and distributed to customers will continue essentially unchanged for many decades to come. This model, called the central station paradigm (because electricity is generated in large, centrally located plants and distributed to a large number of customers, who may in fact be hundreds of miles away), has been in place since the early part of the 20th century. The model has worked because the economies of scale inherent to very large power plants has more than offset the cost and inefficiency (through power losses) inherent to maintaining a grid for transmitting and distributing electricity to end users.

Despite rate structures that only allow recovery of invested capital over many decades (up to 60 years), utilities can attract capital because investors assume that rates will continue to be collected for at least that long a period. Regulators and politicians assume that taxes and regulatory charges levied on electricity usage will be paid by a broad swath of residences and businesses and will not materially discourage usage of electricity in a way that would decrease the amount of taxes collected. A corollary assumption is that the number of customers taking electricity from the system during that period will continue to be high enough such that rates will be reasonable and generally more attractive than other alternatives. In the event that consumers were to switch en masse to alternate sources of generating or receiving power (for instance distributed generation), rates for remaining customers would either not cover the utility's costs, or rates would need to be increased so much that more customers may be incentivized to leave the system. This scenario has been experienced in the regulated US copper wire telephone business, where rates have increased quite dramatically for users who have not switched to digital or wireless telephone service. While this scenario continues to be unlikely for the electricity sector, distributed generation, especially from solar panels, has made inroads in certain regions.

Distributed generation is any retail-scale generation, differentiated from self-generation, which generally describes a large industrial plant that builds its own reasonably large conventional power plant to meet its own needs. While some residential property owners that install distributed generation may choose to sever their connection to the local utility, most choose to remain connected, generating power into the grid when it is both feasible and economic to do so, and taking power from the grid at other times. Distributed generation is currently concentrated in roof-top photovoltaic solar panels, which have benefitted from varying levels of tax incentives in different jurisdictions.

Regulatory treatment has also varied, but some rate structures that seek to incentivize distributed renewable energy are decidedly credit negative for utilities, in particular net metering.

Under net metering, a customer receives a credit from the utility for all of its generation at the full (or nearly full) retail rate and pays only for power taken, also at the retail rate, resulting in a materially reduced monthly bill relative to a customer with no distributed generation. The distributed generation customer has no obligation to generate any particular amount of power, so the utility must stand ready to generate and deliver that customer's full power needs at all times. Since most utility costs, including the fixed costs of financing and maintaining generation and delivery systems, are currently collected through volumetric rates, a customer owning distributed generation effectively transfers a portion of the utility's costs of serving that customer to other customers with higher net usage, notably to customers that do not own distributed generation. The higher costs may incentivize more customers to install solar panels, thereby shifting the utility's fixed costs to an even smaller group of rate-payers. California is an example of a state employing net solar metering in its rate structure, whereas in New Jersey, which has the second largest residential solar program in the US, utilities buy power at a price closer to their blended cost of generation, which is much lower than the retail rate.

To date, solar generation and net metering have not had a material credit impact on any utilities, but ratings could be negatively impacted if the programs were to grow and if rate structures were not amended so that each customer's monthly bill more closely approximated the cost of serving that customer.

In our current view, the possibility that there will be a widespread movement of electric utility customers to sever themselves from the grid is remote. However, we acknowledge that new technologies, such as the development of commercially viable fuel cells and/or distributed electric storage, could disrupt materially the central station paradigm and the credit quality of the utility sector.

Nuclear Issues

Utilities with nuclear generation face unique safety, regulatory, and operational issues. The nuclear disaster at Fukushima Daiichi had a severely negative credit impact on its owner, Tokyo Electric Power Company, Incorporated, as well as all the nuclear utilities in the country. Japan previously generated about 30% of its power from 50 reactors, but all are currently either idled or shut down, and utilities in the country face materially higher costs of replacement power, a credit negative.

Fukushima Daiichi also had global consequences. Germany's response was to require that all nuclear power plants in the country be shut by 2022. Switzerland opted for a phase-out by 2031. (Most European nuclear plants are owned by companies rated under other the Unregulated Utilities and Power Companies methodology.) Even in countries where the regulatory response was more moderate, increased regulatory scrutiny has raised operating costs, a credit negative, especially in the US, where low natural gas prices have rendered certain primarily smaller nuclear plants uneconomic. Nonetheless, we view robust and independent nuclear safety regulation as a credit-positive for the industry.

Other general issues for nuclear operators include higher costs and lower reliability related to the increasing age of the fleet. In 2013, Duke Energy Florida, Inc. decided to shut permanently Crystal River Unit 3 after it determined that a de-lamination (or separation) in the concrete of the outer wall of the containment building was uneconomic to repair. San Onofre Nuclear Generating Station was closed permanently in 2013 after its owners, including Southern California Edison Company (A3, RUR-up) and San Diego Gas & Electric Company (A2, RUR-up), decided not to pursue a re-start in light of operating defects in two steam generators that had been replaced in 2010 and 2011.

Korea Hydro and Nuclear Power Company Limited and its parent, Korea Electric Power Corporation, faced a scandal related to alleged corruption and acceptance of falsified safety documents provided by its parts suppliers for nuclear plants. Korean prosecutors' widening probe into KHNP's use of substandard parts at many of its 23 nuclear power plants caused three plants to be shut down temporarily.

Appendix E: Regional and Other Considerations

Notching Considerations for US First Mortgage Bonds

In most regions, our approach to notching between different debt classes of the same regulated utility issuer follows the guidance in the publication "Updated Summary Guidance for Notching Bonds, Preferred Stocks and Hybrid Securities of Corporate Issuers," including a one notch differential between senior secured and senior unsecured debt.[17] However, in most cases we have two notches between the first mortgage bonds and senior unsecured debt of regulated electric and gas utilities in the US.

Wider notching differentials between debt classes may also be appropriate in speculative grade. Additional insights for speculative grade issuers are provided in the publication "Loss Given Default for Speculative-Grade Companies."[18]

First mortgage bond holders in the US generally benefit from a first lien on most of the fixed assets used to provide utility service, including such assets as generating stations, transmission lines, distribution lines, switching stations and substations, and gas distribution facilities, as well as a lien on franchise agreements. In our view, the critical nature of these assets to the issuers and to the communities they serve has been a major factor that has led to very high recovery rates for this class of debt in situations of default, thereby justifying a two notch uplift. The combination of the breadth of assets pledged and the bankruptcy-tested recovery experience has been unique to the US.

In some cases, there is only a one notch differential between US first mortgage bonds and the senior unsecured rating. For instance, this is likely when the pledged property is not considered critical infrastructure for the region, or if the mortgage is materially weakened by carve-outs, lien releases or similar creditor-unfriendly terms.

Securitization

The use of securitization, a financing technique utilizing a discrete revenue stream (typically related to recovery of specifically defined expenses) that is dedicated to servicing specific securitization debt, has primarily been used in the US, where it has been quite pervasive in the past two decades. The first generation of securitization bonds were primarily related to recovery of the negative difference between the market value of utilities' generation assets and their book value when certain states switched to competitive electric supply markets and utilities sold their generation (so-called stranded costs). This technique was then used for significant storm costs (especially hurricanes) and was eventually broadened to include environmental related expenditures, deferred fuel costs, or even deferred miscellaneous expenses. States that have implemented securitization frameworks include Arkansas, California, Connecticut, Illinois, Louisiana, Maryland, Massachusetts, Mississippi, New Hampshire, New Jersey, Ohio, Pennsylvania, Texas and West Virginia. In its simplest form, a securitization isolates and dedicates a stream of cash flow into a separate special purpose entity (SPE). The SPE uses that stream of revenue and cash flow to provide annual debt service for the securitized debt instrument. Securitization is typically underpinned by specific legislation to segregate the securitization revenues from the utility's revenues to assure their continued collection, and the details of the enabling legislation may vary from state to state. The utility benefits from the securitization because it receives an immediate source of cash (although it gives up the opportunity to earn a return on the corresponding asset), and ratepayers benefit because the cost of the

[17] A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.
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securitized debt is lower than the utility's cost of debt and much lower than its all-in cost of capital, which reduces the revenue requirement associated with the cost recovery.

In the presentation of US securitization debt in published financial ratios, we make our own assessment of the appropriate credit representation but in most cases follows the accounting in audited statements under US Generally Accepted Accounting Principles (GAAP), which in turn considers the terms of enabling legislation. As a result, accounting treatment may vary. In most states utilities have been required to consolidate securitization debt under GAAP, even though it is technically non- recourse.

In general, we view securitization debt of utilities as being on-credit debt, in part because the rates associated with it reduce the utility's headroom to increase rates for other purposes while keeping all-in rates affordable to customers. Thus, where accounting treatment is off balance sheet, we seek to adjust the company's ratios by including the securitization debt and related revenues for our analysis. Where the securitized debt is on balance sheet, our credit analysis also considers the significance of ratios that exclude securitization debt and related revenues. Since securitization debt amortizes mortgage-style, including it makes ratios look worse in early years (when most of the revenue collected goes to pay interest) and better in later years (when most of the revenue collected goes to pay principal).

Strong levels of government ownership in Asia Pacific (ex-Japan) provide rating uplift

Strong levels of government ownership have dominated the credit profiles of utilities in Asia Pacific (excluding Japan), generally leading to ratings that are a number of notches above the Baseline Credit Assessment. Regulated electric and gas utilities with significant government ownership are rated using this methodology in conjunction with the Joint Default Analysis approach in our methodology for Government-Related Issuers.[19]

Support system for large corporate entities in Japan can provide ratings uplift, with limits

Our ratings for large corporate entities in Japan reflect the unique nature of the country's support system, and they are higher than they would otherwise be if such support were disregarded. This is reflected in the tendency for ratings of Japanese utilities to be higher than their grid implied ratings. However, even for large prominent companies, our ratings consider that support will not be endless and is less likely to be provided when a company has questionable viability rather than being in need of temporary liquidity assistance.

[19] A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Appendix F: Treatment of Power Purchase Agreements ("PPAs")

Although many utilities own and operate power stations, some have entered into PPAs to source electricity from third parties to satisfy retail demand. The motivation for these PPAs may be one or more of the following: to outsource operating risks to parties more skilled in power station operation, to provide certainty of supply, to reduce balance sheet debt, to fix the cost of power, or to comply with regulatory mandates regarding power sourcing, including renewable portfolio standards. While we regard PPAs that reduce operating or financial risk as a credit positive, some aspects of PPAs may negatively affect the credit of utilities. The most conservative treatment would be to treat a PPA as a debt obligation of the utility as, by paying the capacity charge, the utility is effectively providing the funds to service the debt associated with the power station. At the other end of the continuum, the financial obligations of the utility could also be regarded as an ongoing operating cost, with no long-term capital component recognized.

Under most PPAs, a utility is obliged to pay a capacity charge to the power station owner (which may be another utility or an Independent Power Producer – IPP); this charge typically covers a portion of the IPP's fixed costs in relation to the power available to the utility. These fixed payments usually help to cover the IPP's debt service and are made irrespective of whether the utility calls on the IPP to generate and deliver power. When the utility requires generation, a further energy charge, to cover the variable costs of the IPP, will also typically be paid by the utility. Some other similar arrangements are characterized as tolling agreements, or long-term supply contracts, but most have similar features to PPAs and are thus we analyze them as PPAs.

PPAs are recognized qualitatively to be a future use of cash whether or not they are treated as debt-like obligations in financial ratios

The starting point of our analysis is the issuer's audited financial statements – we consider whether the utility's accountants determine that the PPA should be treated as a debt equivalent, a capitalized lease, an operating lease, or in some other manner. PPAs have a wide variety of operational and financial terms, and it is our understanding that accountants are required to have a very granular view into the particular contractual arrangements in order to account for these PPAs in compliance with applicable accounting rules and standards. However, accounting treatment for PPAs may not be entirely consistent across US GAAP, IFRS or other accounting frameworks. In addition, we may consider that factors not incorporated into the accounting treatment may be relevant (which may include the scale of PPA payments, their regulatory treatment including cost recovery mechanisms, or other factors that create financial or operational risk for the utility that is greater, in our estimation, than the benefits received). When the accounting treatment of a PPA is a debt or lease equivalent (such that it is reported on the balance sheet, or disclosed as an operating lease and thus included in our adjusted debt calculation), we generally do not make adjustments to remove the PPA from the balance sheet.

However, in relevant circumstances we consider making adjustments that impute a debt equivalent to PPAs that are off-balance sheet for accounting purposes.

Regardless of whether we consider that a PPA warrants or does not warrant treatment as a debt obligation, we assess the totality of the impact of the PPA on the issuer's probability of default. Costs of a PPA that cannot be recovered in retail rates creates material risk, especially if they also cannot be recovered through market sales of power.

Additional considerations for PPAs

PPAs have a wide variety of financial and regulatory characteristics, and each particular circumstance may be treated differently by Moody's. Factors which determine where on the continuum we treat a particular PPA include the following:

» Risk management: An overarching principle is that PPAs have normally been used by utilities as a risk management tool and we recognize that this is the fundamental reason for their existence. Thus, we will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature.

» Pass-through capability: Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly we regard these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive or if regulatory support for cost recovery deteriorates, the ability to pass through costs may decrease and, as circumstances change, our treatment of PPA obligations will alter accordingly.

» Price considerations: The price of power paid by a utility under a PPA can be substantially above or below the market price of electricity. A below-market price will motivate the utility to purchase power from the IPP in excess of its retail requirements, and to sell excess electricity in the spot market. This can be a significant source of cash flow for some utilities. On the other hand, utilities that are compelled to pay capacity payments to IPPs when they have no demand for the power or at an above-market price may suffer a financial burden if they do not get full recovery in retail rates. We will focus particularly on PPAs that have mark-to-market losses, which typically indicates that they have a material impact on the utility's cash flow.

» Excess Reserve Capacity: In some jurisdictions there is substantial reserve capacity and thus a significant probability that the electricity available to a utility under PPAs will not be required by the market. This increases the risk to the utility that capacity payments will need to be made when there is no demand for the power. We may determine that all of a utility's PPAs represent excess capacity, or that a portion of PPAs are needed for the utility's supply obligations plus a normal reserve margin, while the remaining portion represents excess capacity. In the latter case, we may impute debt to specific PPAs that are excess or take a proportional approach to all of the utility's PPAs.

» Risk-sharing: Utilities that own power plants bear the associated operational, fuel procurement and other risks. These must be balanced against the financial and liquidity risk of contracting for the purchase of power under a PPA. We will examine on a case-by case basis the relative credit risk associated with PPAs in comparison to plant ownership.

» Purchase requirements: Some PPAs are structured with either options or requirements to purchase the asset at the end of the PPA term. If the utility has an economically meaningful requirement to purchase, we would most likely consider it to be a debt obligation. In most such cases, the obligation would already receive on-balance sheet treatment under relevant accounting standards.

» Default provisions: In most cases, the remedies for default under a PPA do not include acceleration of amounts due, and in many cases PPAs would not be considered as debt in a bankruptcy scenario and could potentially be cancelled. Thus, PPAs may not materially increase Loss Given Default for the utility.

In addition, PPAs are not typically considered debt for cross- default provisions under a utility's debt and liquidity arrangements. However, the existence of non-standard default provisions that are debt-like would have a large impact on our treatment of a PPA. In addition, payments due under PPAs are senior unsecured obligations, and any inability of the utility to make them materially increases default risk.

Each of these factors will be considered by our analysts and a decision will be made as to the importance of the PPA to the risk analysis of the utility.

Methods for estimating a liability amount for PPAs

According to the weighting and importance of the PPA to each utility and the level of disclosure, we may approximate a debt obligation equivalent for PPAs using one or more of the methods discussed below. In each case we look holistically at the PPA's credit impact on the utility, including the ability to pass through costs and curtail payments, the materiality of the PPA obligation to the overall business risk and cash flows of the utility, operational constraints that the PPA imposes, the maturity of the PPA obligation, the impact of purchased power on market-based power sales (if any) that the utility will engage in, and our view of future market conditions and volatility.

» Operating Cost: If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, we may view the PPA as being most akin to an operating cost. Provided that the accounting treatment for the PPA is, in this circumstance, off-balance sheet, we will most likely make no adjustment to bring the obligation onto the utility's balance sheet.

» Annual Obligation x 6: In some situations, the PPA obligation may be estimated by multiplying the annual payments by a factor of six (in most cases). This method is sometimes used in the capitalization of operating leases. This method may be used as an approximation where the analyst determines that the obligation is significant but cannot otherwise be quantified otherwise due to limited information.

» Net Present Value: Where the analyst has sufficient information, we may add the NPV of the stream of PPA payments to the debt obligations of the utility. The discount rate used will be our estimate of the cost of capital of the utility.

» Debt Look-Through: In some circumstances, where the debt incurred by the IPP is directly related to the off-taking utility, there may be reason to allocate the entire debt (or a proportional part related to share of power dedicated to the utility) of the IPP to that of the utility.

» Mark-to-Market: In situations in which we believe that the PPA prices exceed the market price and thus will create an ongoing liability for the utility, we may use a net mark-to-market method, in which the NPV of the utility's future out-of-the-money net payments will be added to its total debt obligations.

» Consolidation: In some instances where the IPP is wholly dedicated to the utility, it may be appropriate to consolidate the debt and cash flows of the IPP with that of the utility. If the utility purchases only a portion of the power from the IPP, then that proportion of debt might be consolidated with the utility.

If we have determined to impute debt to a PPA for which the accounting treatment is not on-balance sheet, we will in some circumstances use more than one method to estimate the debt equivalent obligations imposed by the PPA, and compare results. If circumstances (including regulatory treatment or market conditions) change over time, the approach that is used may also vary.

Moody's Related Research

The credit ratings assigned in this sector are primarily determined by this credit rating methodology. Certain broad methodological considerations (described in one or more credit rating methodologies) may also be relevant to the determination of credit ratings of issuers and instruments in this sector. Potentially related sector and cross-sector credit rating methodologies can be found here.

For data summarizing the historical robustness and predictive power of credit ratings assigned using this credit rating methodology, see link.

Please refer to Moody's Rating Symbols & Definitions, which is available here, for further information. Definitions of Moody's most common ratio terms can be found in "Moody's Basic Definitions for Credit Statistics, User's Guide", accessible via this link.

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U.S. Utilities Ratings Analysis Now Portrayed In The S&P Corporate Ratings Matrix

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U.S. Utilities Ratings Analysis Now Portrayed In The S&P Corporate Ratings Matrix

The electric, gas, and water utility ratings ranking lists published today by Standard & Poor's U.S. Utilities & Infrastructure Ratings practice are categorized under the business risk/financial risk matrix used by the Corporate Ratings group. This is designed to present our rating conclusions in a clear and standardized manner across all corporate sectors. Incorporating utility ratings into a shared framework to communicate the fundamental credit analysis of a company furthers the goals of transparency and comparability in the ratings process. Table 1 shows the matrix.

Table 1

Business Risk/Financial Risk

	Financial Risk Profile				
Business Risk Profile	**Minimal**	**Modest**	**Intermediate**	**Aggressive**	**Highly leveraged**
Excellent	AAA	AA	A	BBB	BB
Strong	AA	A	A-	BBB-	BB-
Satisfactory	A	BBB+	BBB	BB+	B+
Weak	BBB	BBB-	BB+	BB-	B
Vulnerable	BB	B+	B+	B	B-

The utilities rating methodology remains unchanged, and the use of the corporate risk matrix has not resulted in any changes to ratings or outlooks. The same five factors that we analyzed to produce a business risk score in the familiar 10-point scale are used in determining whether a utility possesses an "Excellent," "Strong," "Satisfactory," "Weak," or "Vulnerable" business risk profile:

- Regulation,
- Markets,
- Operations,
- Competitiveness, and
- Management.

Regulated utilities and holding companies that are utility-focused virtually always fall in the upper range ("Excellent" or "Strong") of business risk profiles. The defining characteristics of most utilities--a legally defined service territory generally free of significant competition, the provision of an essential or near-essential service, and the presence of regulators that have an abiding interest in supporting a healthy utility financial profile--underpin the business risk profiles of the electric, gas, and water utilities.

As the matrix concisely illustrates, the business risk profile loosely determines the level of financial risk appropriate for any given rating. Financial risk is analyzed both qualitatively and quantitatively, mainly with financial ratios and other metrics that are calculated after various analytical adjustments are performed on financial statements prepared under GAAP. Financial risk is assessed for utilities using, in part, the indicative ratio ranges in table 2.

Table 2

Financial Risk Indicative Ratios - U.S. Utilities			
(Fully adjusted, historically demonstrated, and expected to consistently continue)			
	Cash flow		**Debt leverage**
	(FFO/debt) (%)	**(FFO/interest) (x)**	**(Total debt/capital) (%)**
Modest	40 - 60	4.0 - 6.0	25 - 40
Intermediate	25 - 45	3.0 - 4.5	35 - 50
Aggressive	10 - 30	2.0 - 3.5	45 - 60
Highly leveraged	Below 15	2.5 or less	Over 50

The indicative ranges for utilities differ somewhat from the guidelines used for their unregulated counterparts because of several factors that distinguish the financial policy and profile of regulated entities. Utilities tend to finance with long-maturity capital and fixed rates. Financial performance is typically more uniform over time, avoiding the volatility of unregulated industrial entities. Also, utilities fare comparatively well in many of the less-quantitative aspects of financial risk. Financial flexibility is generally quite robust, given good access to capital, ample short-term liquidity, and the like. Utilities that exhibit such favorable credit characteristics will often see ratings based on the more accommodative end of the indicative ratio ranges, especially when the company's business risk profile is solidly within its category. Conversely, a utility that follows an atypical financial policy or manages its balance sheet less conservatively, or falls along the lower end of its business risk designation, would have to demonstrate an ability to achieve financial metrics along the more stringent end of the ratio ranges to reach a given rating.

Note that even after we assign a company a business risk and financial risk, the committee does not arrive by rote at a rating based on the matrix. The matrix is a guide--it is not intended to convey precision in the ratings process or reduce the decision to plotting intersections on a graph. Many small positives and negatives that affect credit quality can lead a committee to a different conclusion than what is indicated in the matrix. Most outcomes will fall within one notch on either side of the indicated rating. Larger exceptions for utilities would typically involve the influence of related unregulated entities or extraordinary disruptions in the regulatory environment.

We will use the matrix, the ranking list, and individual company reports to communicate the relative position of a company within its business risk peer group and the other factors that produce the ratings.

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May 27, 2009

Criteria | Corporates | General:

Criteria Methodology: Business Risk/Financial Risk Matrix Expanded

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Criteria | Corporates | General:

Criteria Methodology: Business Risk/Financial Risk Matrix Expanded

*(**Editor's Note:** In the previous version of this article published on May 26, certain of the rating outcomes in the table 1 matrix were missated. A corrected version follows.)*

Standard & Poor's Ratings Services is refining its methodology for corporate ratings related to its business risk/financial risk matrix, which we published as part of 2008 Corporate Ratings Criteria on April 15, 2008, on RatingsDirect at www.ratingsdirect.com and Standard & Poor's Web site at www.standardandpoors.com.

This article amends and supersedes the criteria as published in Corporate Ratings Criteria, page 21, and the articles listed in the "Related Articles" section at the end of this report.

This article is part of a broad series of measures announced last year to enhance our governance, analytics, dissemination of information, and investor education initiatives. These initiatives are aimed at augmenting our independence, strengthening the rating process, and increasing our transparency to better serve the global markets.

We introduced the business risk/financial risk matrix four years ago. The relationships depicted in the matrix represent an essential element of our corporate analytical methodology.

We are now expanding the matrix, by adding one category to both business and financial risks (see table 1). As a result, the matrix allows for greater differentiation regarding companies rated lower than investment grade (i.e., 'BB' and below).

Table 1

Business And Financial Risk Profile Matrix

Business Risk Profile	Financial Risk Profile					
	Minimal	Modest	Intermediate	Significant	Aggressive	Highly Leveraged
Excellent	AAA	AA	A	A-	BBB	--
Strong	AA	A	A-	BBB	BB	BB-
Satisfactory	A-	BBB+	BBB	BB+	BB-	B+
Fair	--	BBB-	BB+	BB	BB-	B
Weak	--	--	BB	BB-	B+	B-
Vulnerable	--	--	--	B+	B	CCC+

These rating outcomes are shown for guidance purposes only. Actual rating should be within one notch of indicated rating outcomes.

The rating outcomes refer to issuer credit ratings. The ratings indicated in each cell of the matrix are the midpoints of a range of likely rating possibilities. This range would ordinarily span one notch above and below the indicated rating.

Business Risk/Financial Risk Framework

Our corporate analytical methodology organizes the analytical process according to a common framework, and it divides the task into several categories so that all salient issues are considered. The first categories involve fundamental business analysis; the financial analysis categories follow.

Our ratings analysis starts with the assessment of the business and competitive profile of the company. Two companies with identical financial metrics can be rated very differently, to the extent that their business challenges and prospects differ. The categories underlying our business and financial risk assessments are:

Business risk

- Country risk
- Industry risk
- Competitive position
- Profitability/Peer group comparisons

Financial risk

- Accounting
- Financial governance and policies/risk tolerance
- Cash flow adequacy
- Capital structure/asset protection
- Liquidity/short-term factors

We do not have any predetermined weights for these categories. The significance of specific factors varies from situation to situation.

Updated Matrix

We developed the matrix to make explicit the rating outcomes that are typical for various business risk/financial risk combinations. It illustrates the relationship of business and financial risk profiles to the issuer credit rating.

We tend to weight business risk slightly more than financial risk when differentiating among investment-grade ratings. Conversely, we place slightly more weight on financial risk for speculative-grade issuers (see table 1, again). There also is a subtle compounding effect when both business risk and financial risk are aligned at extremes (i.e., excellent/minimal and vulnerable/highly leveraged.)

The new, more granular version of the matrix represents a refinement--not any change in rating criteria or standards--and, consequently, holds no implications for any changes to existing ratings. However, the expanded matrix should enhance the transparency of the analytical process.

Financial Benchmarks

Table 2

Financial Risk Indicative Ratios (Corporates)

	FFO/Debt (%)	Debt/EBITDA (x)	Debt/Capital (%)
Minimal	greater than 60	less than 1.5	less than 25
Modest	45-60	1.5-2	25-35
Intermediate	30-45	2-3	35-45
Significant	20-30	3-4	45-50
Aggressive	12-20	4-5	50-60
Highly Leveraged	less than 12	greater than 5	greater than 60

How To Use The Matrix--And Its Limitations

The rating matrix indicative outcomes are what we typically observe--but are not meant to be precise indications or guarantees of future rating opinions. Positive and negative nuances in our analysis may lead to a notch higher or lower than the outcomes indicated in the various cells of the matrix.

In certain situations there may be specific, overarching risks that are outside the standard framework, e.g., a liquidity crisis, major litigation, or large acquisition. This often is the case regarding credits at the lowest end of the credit spectrum--i.e., the 'CCC' category and lower. These ratings, by definition, reflect some impending crisis or acute vulnerability, and the balanced approach that underlies the matrix framework just does not lend itself to such situations.

Similarly, some matrix cells are blank because the underlying combinations are highly unusual--and presumably would involve complicated factors and analysis.

The following hypothetical example illustrates how the tables can be used to better understand our rating process (see tables 1 and 2).

We believe that Company ABC has a satisfactory business risk profile, typical of a low investment-grade industrial issuer. If we believed its financial risk were intermediate, the expected rating outcome should be within one notch of 'BBB'. ABC's ratios of cash flow to debt (35%) and debt leverage (total debt to EBITDA of 2.5x) are indeed characteristic of intermediate financial risk.

It might be possible for Company ABC to be upgraded to the 'A' category by, for example, reducing its debt burden to the point that financial risk is viewed as minimal. Funds from operations (FFO) to debt of more than 60% and debt to EBITDA of only 1.5x would, in most cases, indicate minimal.

Conversely, ABC may choose to become more financially aggressive--perhaps it decides to reward shareholders by borrowing to repurchase its stock. It is possible that the company may fall into the 'BB' category if we view its financial risk as significant. FFO to debt of 20% and debt to EBITDA 4x would, in our view, typify the significant financial risk category.

Still, it is essential to realize that the financial benchmarks are guidelines, neither gospel nor guarantees. They can vary in nonstandard cases: For example, if a company's financial measures exhibit very little volatility, benchmarks may be somewhat more relaxed.

Moreover, our assessment of financial risk is not as simplistic as looking at a few ratios. It encompasses:

- a view of accounting and disclosure practices;
- a view of corporate governance, financial policies, and risk tolerance;
- the degree of capital intensity, flexibility regarding capital expenditures and other cash needs, including acquisitions and shareholder distributions; and
- various aspects of liquidity--including the risk of refinancing near-term maturities.

The matrix addresses a company's standalone credit profile, and does not take account of external influences, which would pertain in the case of government-related entities or subsidiaries that in our view may benefit or suffer from affiliation with a stronger or weaker group. The matrix refers only to local-currency ratings, rather than foreign-currency ratings, which incorporate additional transfer and convertibility risks. Finally, the matrix does not apply to project finance or corporate securitizations.

Related Articles

Industrials' Business Risk/Financial Risk Matrix--A Fundamental Perspective On Corporate Ratings, published April 7, 2005, on RatingsDirect.

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Criteria | Corporates | General:

Methodology: Business Risk/Financial Risk Matrix Expanded

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Criteria | Corporates | General:

Methodology: Business Risk/Financial Risk Matrix Expanded

1. Standard & Poor's Ratings Services is refining its methodology for corporate ratings related to its business risk/financial risk matrix, which we published as part of "2008 Corporate Ratings Criteria" on April 15, 2008. We subsequently updated this matrix in the article "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," published May 27, 2009. In order to provide greater transparency on the methodology used to evaluate corporate ratings, this article updates table 1 of the May 27, 2009, article to reflect how we analyze companies with an excellent business risk profile and minimal financial risk profile, as well as companies with a vulnerable business risk profile and a highly leveraged financial risk profile. This article amends and supersedes both the 2008 and 2009 articles mentioned above. This article is related to "Principles Of Credit Ratings," published on Feb. 16, 2011.

2. We introduced the business risk/financial risk matrix in 2005. The relationships depicted in the matrix represent an essential element of our corporate analytical methodology (see table 1).

Table 1

Business And Financial Risk Profile Matrix

Business Risk Profile	--Financial Risk Profile--					
	Minimal	Modest	Intermediate	Significant	Aggressive	Highly Leveraged
Excellent	AAA/AA+	AA	A	A-	BBB	--
Strong	AA	A	A-	BBB	BB	BB-
Satisfactory	A-	BBB+	BBB	BB+	BB-	B+
Fair	--	BBB-	BB+	BB	BB-	B
Weak	--	--	BB	BB-	B+	B-
Vulnerable	--	--	--	B+	B	B- or below

These rating outcomes are shown for guidance purposes only. Actual rating should be within one notch of indicated rating outcomes.

3. The rating outcomes refer to issuer credit ratings. The ratings indicated in each cell of the matrix are the midpoints of a range of likely rating possibilities. This range would ordinarily span one notch above and below the indicated rating.

Business Risk/Financial Risk Framework

4. Our corporate analytical methodology organizes the analytical process according to a common framework, and it divides the task into several categories so that all salient issues are considered. The first categories involve fundamental business analysis; the financial analysis categories follow.

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Financial risk

- Accounting
- Financial governance and policies/risk tolerance
- Cash flow adequacy
- Capital structure/asset protection
- Liquidity/short-term factors

6. We do not have any predetermined weights for these categories. The significance of specific factors varies from situation to situation.

Updated Matrix

7. We developed the matrix to make explicit the rating outcomes that are typical for various business risk/financial risk combinations. It illustrates the relationship of business and financial risk profiles to the issuer credit rating.

8. We tend to weight business risk slightly more than financial risk when differentiating among investment-grade ratings. Conversely, we place slightly more weight on financial risk for speculative-grade issuers (see table 1, again).

9. This version of the matrix represents a refinement--not any change in rating criteria or standards--and, consequently, no rating changes are expected. However, the expanded matrix should enhance the transparency of the analytical process.

Financial Benchmarks

Table 2

Financial Risk Indicative Ratios (Corporates)

	FFO/Debt (%)	Debt/EBITDA (x)	Debt/Capital (%)
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Aggressive	12-20	4-5	50-60
Highly Leveraged	less than 12	greater than 5	greater than 60

How To Use The Matrix--And Its Limitations

10. The rating matrix indicative outcomes are what we typically observe--but are not meant to be precise indications or

guarantees of future rating opinions. Positive and negative nuances in our analysis may lead to a notch higher or lower than the outcomes indicated in the various cells of the matrix.

11. In certain situations there may be specific, overarching risks that are outside the standard framework, e.g., a liquidity crisis, major litigation, or large acquisition. This often is the case regarding issuers at the lowest end of the credit spectrum--i.e., the 'CCC' category and lower. These ratings, by definition, reflect some impending crisis or acute vulnerability, and the balanced approach that underlies the matrix framework just does not lend itself to such situations.

12. Similarly, some matrix cells are blank because the underlying combinations are highly unusual--and presumably would involve complicated factors and analysis.

13. The following hypothetical example illustrates how the tables can be used to better understand our rating process (see tables 1 and 2).

14. We believe that Company ABC has a satisfactory business risk profile, typical of a low investment-grade industrial issuer. If we believed its financial risk were intermediate, the expected rating outcome should be within one notch of 'BBB'. ABC's ratios of cash flow to debt (35%) and debt leverage (total debt to EBITDA of 2.5x) are indeed characteristic of intermediate financial risk.

15. It might be possible for Company ABC to be upgraded to the 'A' category by, for example, reducing its debt burden to the point that financial risk is viewed as minimal. Funds from operations (FFO) to debt of more than 60% and debt to EBITDA of only 1.5x would, in most cases, indicate minimal financial risk.

16. Conversely, ABC may choose to become more financially aggressive--perhaps it decides to reward shareholders by borrowing to repurchase its stock. It is possible that the company may fall into the 'BB' category if we view its financial risk as significant. FFO to debt of 20% and debt to EBITDA of 4x would, in our view, typify the significant financial risk category.

17. Still, it is essential to realize that the financial benchmarks are guidelines, neither gospel nor guarantees. They can vary in nonstandard cases: For example, if a company's financial measures exhibit very little volatility, benchmarks may be somewhat more relaxed.

18. Moreover, our assessment of financial risk is not as simplistic as looking at a few ratios. It encompasses:

- A view of accounting and disclosure practices;
- A view of corporate governance, financial policies, and risk tolerance;
- The degree of capital intensity, flexibility regarding capital expenditures and other cash needs, including acquisitions and shareholder distributions; and
- Various aspects of liquidity--including the risk of refinancing near-term maturities.

19. The matrix addresses a company's standalone credit profile, and does not take account of external influences, which would pertain in the case of government-related entities or subsidiaries that in our view may benefit or suffer from affiliation with a stronger or weaker group. The matrix refers only to local-currency ratings, rather than foreign-currency ratings, which incorporate additional transfer and convertibility risks. Finally, the matrix does not

apply to project finance or corporate securitizations.

Related Criteria And Research

- Principles Of Credit Ratings, Feb. 16, 2011
- Criteria Methodology: Business Risk/Financial Risk Matrix Expanded, May 27, 2009
- 2008 Corporate Ratings Criteria, April 15, 2008

20. These criteria represent the specific application of fundamental principles that define credit risk and ratings opinions. Their use is determined by issuer- or issue-specific attributes as well as Standard & Poor's Ratings Services' assessment of the credit and, if applicable, structural risks for a given issuer or issue rating. Methodology and assumptions may change from time to time as a result of market and economic conditions, issuer- or issue-specific factors, or new empirical evidence that would affect our credit judgment.