BEFORE THE
STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

In the Matter of

THREE-YEAR RATE PROPOSAL FOR ELECTRIC RATES AND CHARGES SUBMITTED BY THE LONG ISLAND POWER AUTHORITY AND SERVICE PROVIDER, PSEG LONG ISLAND LLC.

Matter Number 15-00262

June 2015

Prepared Revised Exhibits of:

Staff Finance and Public Power Panel

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Relied Upon Responses to Information Requests

Matter No. 15-00262

LIPA/PSEG LI Electric Rates

Staff of the Department of Public Service

Interrogatory/Document Request

Request No.: DPS-TF-106

Requested By: Patrick Piscitelli

Date of Request: February 18, 2015

Reply Date: February 19, 2015

Witness: LIPA Thomas Falcone

Subject: Interest Rate Assumptions

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106. The January 5, 2015 Public Financial Management report titled "Interest Rate Assumptions for Budgeting and Rate Setting" submitted to DPS as file "LIPA Interest Rate Assumptions for the 2016 to 2018 Planning Period" provides the interest rate assumptions used to project future interest rates for the rate plan. The first sentence states that "LIPA has historically requested that Public Service Financial Management ("PFM") provide reasonable expectations of future interest rates that LIPA could use in developing budgetary assumptions for various budgetary components that are influenced by interest rates."

Provide all the referenced historical future interest rate projections that PFM has provided to LIPA.

Response:

The Authority has historically adopted annual Operating Budgets at the December Board meeting for the coming year. As such, only the interest rate assumption used in the budget for the coming year impacted financial performance (to the extent that an assumption varied from budget). The out year

Respondent Name (witness or panel): Thomas Falcone

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assumptions were used for multi-year planning and updated each year, and as such, tended to be conservative. For the 3-year rate plan filing, the three-year forward projection for 2016, 2017 and 2018 all have financial implications to revenue requirements. In the attached Excel spreadsheet, the Authority has summarized the budget assumptions for interest rates used in the 2011, 2012, 2013, and 2014 budget cycles.

Respondent Name (witness or panel): Thomas Falcone

Public Financial Management
Financial and Investment Advisors

January 5, 2015

Memorandum

To: LIPA

From: Public Financial Management

Re: **Interest Rate Assumptions for Budgeting and Rate Setting**

LIPA has historically requested that Public Financial Management ("PFM") provide reasonable expectations of future interest rates that LIPA could use in developing budgetary assumptions for various budget components that are influenced by interest rates. PFM has traditionally provided conservative assumptions that have included interest rates that were above current market rates at the time the assumptions were developed. In the past, LIPA's annual financial results would not have been heavily impacted if actual interest rates were different than the assumed rates. This is because LIPA had moderate amounts of un-hedged, variable-rate debt. Most of LIPA's variable-rate debt is hedged with interest rate swaps, or is partially hedged by invested funds for which variations in interest earnings will offset much of the variation from changing interest rates on the un-swapped, variable-rate debt. PFM also provided assumed borrowing costs on LIPA's projected new debt issuance for the upcoming budget year. The variations between expected and actual borrowing costs for the year were also limited – due to the fact that LIPA's new interest costs in any budget year were small compared to the overall LIPA budget. As a result of the circumstances described above, and the conservative nature of the budgeting assumptions, LIPA rarely incurred net interest costs that were materially above budgeted levels.

With LIPA's transition to a three-year rate setting process, and the desire to take into account the potential for significant refinancing savings during this longer budget period; future budget results will be more sensitive to interest rate assumptions and variations than they have been in the past.

For this reason, LIPA has requested that PFM develop reasonable interest rate assumptions that will provide the basis for LIPA's longer budgeting period, and also serve as the basis for refunding savings expectations for the budget period.

PFM's planning assumptions take into account the following information:

1 – Current interest rates,

2 – Historical interest rate averages that cover periods of time roughly equal to that of the forward projections period,

3 – The theoretical forward yield curve derived from the current curve of yields-to-maturity for the A Rated MMD Curve, and

4 – The consensus of interest rate projections and expectations from a range of economists (such as the Bloomberg average of economist interest rate projections, and expectations for Federal Funds rates from the members of the Federal Reserve Board of Governors) that consistently call for a rising interest environment over the next several years.

5 – Historical risk premiums on the S&P Index, for the purposes of estimating returns on funds that will be partially invested in equities.

Based on this information, and the LIPA's description of its upcoming rate setting objectives, PFM proposes the following summary interest rate and earnings assumptions as reasonable planning assumptions for LIPA's three year budgeting process:

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PFM
Public Financial Management
Financial and Investment Advisors

Financial Assumptions for 2014/2018 Budget and Five-Year Plan

Rate Stabilization Fund	2015	2016	2017	2018	2019	
Investment Income						
Operating Fund	0.500%	1.500%	2.750%	3.500%	3.500%	
Rate Stabilization Fund	0.625%	1.750%	3.000%	3.500%	3.500%	
5 Year Treasury (Yielding 1.61% on 1/2/2015)	2.000%	2.750%	3.500%	3.750%	4.000%	**Assumed yield, not return on invested portfolio**
20 Year Average Annualized S&P Index Total Return	9.000%	9.000%	9.000%	9.000%	9.000%	
Assumed Dividend Yield	2.000%	2.000%	2.000%	2.000%	2.000%	
NMP2 Nuclear Decommissioning Account TOTAL RETURN	4.450%	4.938%	5.425%	5.588%	5.750%	**Assumed 65% 5 Yr Treas and 35% S&P index TR**
NMP2 Nuclear Decommissioning Account TOTAL INCOME	2.000%	2.488%	2.975%	3.138%	3.300%	**Assumed 65% 5 Yr Treas and 35% S&P index DY**
OPEB Account TOTAL RETURN	6.550%	6.813%	7.075%	7.163%	7.250%	**Assumed 35% 5 Yr Treas and 65% S&P index TR**
OPEB Account INCOME	2.000%	2.263%	2.525%	2.613%	2.700%	**Assumed 35% 5 Yr Treas and 65% S&P index DY**
Debt						
LIPA Variable Rate and Commercial Paper	0.375%	1.100%	2.000%	2.500%	2.500%	**Before adding credit enhancement fees**
LIPA FRNS Base 70% of LIBOR Rate	0.350%	1.050%	1.925%	2.450%	2.450%	**Before adding 65BP Spread**
Assumed LIPA 25 Yr AveLife Fixed Rate New Money YTM	**4.50%**	**4.70%**	**4.85%**	**5.00%**	**5.00%**	**YTM Assuming Premium Coupon**
Resulting LIPA YTM Increase	~25BP	~45BP	~60BP	~75BP	~75BP	
Assumed MMD YTC Upward Move	**~50BP**	**~75BP**	**~100BP**	**~125BP**	**~125BP**	
Calculated Implied Forward YTM Increase	~15BP	~40BP				
Current LIPA 25 Yr YTM	4.25%					**YTM Assuming Premium Coupon**
Current LIPA 25 Yr YTC	3.75%					
Assumed USDA Refunding YTMs	3.75%	3.90%				**YTM Assuming UDSA and Premium Coupon**
Resulting UDSA YTM Increase	~35BP	~50BP				
Assumed MMD YTC Upward Move	**~50BP**	**~75BP**				
Calculated Implied Forward YTM Increase	~15BP	~40BP				
Current 17 Year UDSA YTM	3.40%					
Current UDSA YTC	2.80%					
One-Month LIBOR Rate	0.500%	1.500%	2.750%	3.500%	3.500%	
Fed Governors Median Fed Funds Expectation for Year End	**1.125%**	**2.500%**	**3.625%**	**3.750%**	**3.750%**	
SIFMA	0.375%	1.100%	2.000%	2.500%	2.500%	
(SIFMA/LIBOR Ratio)	75%	73%	73%	71%	71%	
Inflation	1.50%	2.00%	2.00%	2.50%	2.50%	
Fed Governors Median Fed Funds Expectation for Year End	**1.600%**	**2.000%**	**2.000%**			

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LIPA/PSEG LI Electric Rates

Staff of the Department of Public Service

Interrogatory/Document Request

Request No.: DPS-TF-453

Requested By: Kwaku Duah

Date of Request: April 30, 2015

Reply Date: May 5, 2015

Witness: LIPA - Thomas Falcone

Subject: Variable Rate Debt and Senior CP Interest Rates As of April 27, 2015

Regarding the current interest rates for LIPA's existing Variable Rate Debt (VRD) and Senior Commercial Paper (CP) debt instruments. Please confirm that the current rates (as of April 27,2015) for the 2012C, 2012D, 2014D, and the Senior CP are 0.12%,0.12%, 0.78%, and 0.12%, respectively as shown in the Table below.

Date	2012C	2012D	2014C	Senior CP
4/27/2015	0.12%	0.12%	0.78%	0.12%

Libor 1 Month (WSJ, 4/27/2015)	0.18%
70% of Libor 1 Month	0.13%
Plus 65 bps	0.78%

Response:

Since the beginning of 2015, LIPA's Commercial Paper programs have had interest rates of between 12 and 19 basis points, depending on the term of the maturity (as CP is sold to maturities of various lengths of between 1 and 270 days). The currently outstanding maturities (and thus the interest rates as of April 27, 2015) bear interest at 17-19 basis points for terms of between one and three months (at their time of sale). Of note, LIPA has both senior and subordinate lien Commercial Paper programs; however, the bonds bear approximately the same yields (the difference is in the cost of the letter of credit enhancement, which is greater for the subordinate lien program).

Respondent Name (witness or panel): Thomas Falcone

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During 2015, the 2012C and 2012D variable rate demand bonds have had interest rates of between 2 and 10 basis points. The currently outstanding rate (and thus the interest rate as of April 27, 2015) is 10 basis points for 2012C and 11 basis points for 2012D.

During 2015, the 2014C bonds have had interest rates of between 76 and 78 basis points. The currently outstanding rate (and thus the interest rate as of April 27, 2015) is 78 basis points.

Each of these types of bonds is subject to frequent interest rate reset depending upon prevailing market interest rates, generally every 7-90 days.

Respondent Name (witness or panel): Thomas Falcone

	Per company's Original Filing		
	2016 (x1000)	**2017 (x1000)**	**2018 (x1000)**
Consolidated Debt Service	$623,569	$681,242	$742,395
LIPA Debt Service	$297,426	$248,005	$235,924
UDSA Debt Service	$204,748	$270,340	$301,698
Coverage Requirement	$121,395	$162,897	$204,772
Interest Rate for CAPEX funding	4.50%	4.70%	4.85%
Interest Rate for Senior CP	1.10%	2.00%	2.50%
2014C Series Variable Rate debt	1.75%	2.65%	3.15%
2012C Series Variable Rate debt	1.10%	2.00%	2.50%
2012D Series Variable Rate debt	1.45%	2.33%	2.85%
Series 1A Variable Rate Debt	1.45%	2.33%	2.85%
Series 2B Variable Rate Debt	1.10%	2.00%	2.50%
Consolidated Coverage Ratio	1.15 x	1.20 x	1.25 x
	Per Staff: June 8 Versus (May 14,2015) Filing		
	2016 (x1000)	**2017 (x1000)**	**2018 (x1000)**
Interest Rate Impact			
Consolidated Debt Service	$605,184 ($607,791)	$637,879 ($643,014)	$688,151 ($695,110)
LIPA Debt Service	$286,616 ($288,791)	$226,850 ($230,813)	$207,983 ($212,958)
UDSA Debt Service	$199,322 ($199,322)	$254,390 ($254,390)	$286,543 ($286,543)
Coverage Requirement	$119,246 ($119,678)	$156,638 ($157,810)	$193,625 ($195,610)
Interest Rate for CAPEX funding	4.12%	4.12%	4.12%
Interest Rate for Senior CP	0.19%	0.19%	0.19%
2014C Series Variable Rate debt	0.78%	0.78%	0.78%
2012C Series Variable Rate debt	0.10%	0.10%	0.10%
2012D Series Variable Rate debt	0.11%	0.11%	0.11%
Series 1A Variable Rate Debt	0.10%	0.10%	0.10%
Series 2B Variable Rate Debt	0.10%	0.10%	0.10%
Consolidated Coverage Ratio	1.15 x	1.20 x	1.25 x
Staff CAPEX Adjustment Impact			
LIPA Debt Service	(44.6)	(1,980.4)	(3,958.6)
UDSA Debt Service	0.0	0.0	0.0
Coverage Requirement	(8.9)	(594.1)	(1,583.4)
Staff Energy Efficiency Adjustment Impact			
LIPA Debt Service	(13.5)	(598.5)	(1,245.6)
UDSA Debt Service	0.0	0.0	0.0
Coverage Requirement	(2.7)	(179.6)	(498.2)
Phase-in GAAP OPEB/Pension Impact			
LIPA Debt Service	$0 ($73)	$0 ($85)	$0 ($454)
UDSA Debt Service	$0 ($0)	$0 ($0)	$0 ($0)
Coverage Requirement	$0 ($15)	$0 ($25)	$0 ($181)

	Per Staff: June 8 Versus (May 14,2015) Filing		
Total Impact	**2016 (x1000)**	**2017 (x1000)**	**2018 (x1000)**
Consolidated Debt Service	$605,114 ($607,633)	$634,526 ($639,550)	$680,865 ($687,189)
LIPA Debt Service	$286,558 ($288,660)	$224,271 ($228,149)	$202,779 ($207,300)
UDSA Debt Service	$199,322 ($199,322)	$254,390 ($254,390)	$286,543 ($286,543)
Coverage Requirement	$119,234 ($119,652)	$155,864 ($157,011)	$191,543 ($193,347)

	Per Staff: June 8 Versus (May 14,2015) Filing		
	2016 (x1000)	**2017 (x1000)**	**2018 (x1000)**
SWAP Payments	$39,728 ($34,349)	$39,641 ($29,177)	$39,640 ($26,117)
Other Income & Deductions	-$32,297 (-$37,622)	-$33,928 (-$43,940)	-$35,087 (-$47,537)

MOODY'S
INVESTORS SERVICE

Public Power Electric Utility Medians and Methodology Scorecard Factors:

Stable financial metrics underpin stable sector outlook and provide key credit differentiation

The stable financial metrics (liquidity, leverage, coverage) of public power electric utilities demonstrates that they have been willing to use their strong local rate-setting authority to adjust rates to meet financial targets. This stability has underpinned the stable outlook the sector has retained throughout the recession and recovery. These sector fundamentals are important as electric utilities transition to a less carbon-intensive energy supply. Our analysis of key financial ratios of Moody's rated public power electric utilities indicates:

- Stable financial performance underscores the stable sector outlook throughout the recession and recovery.
- Medians by rating category reflect utility generation profile and related credit risks.
- Large public power electric utilities own their power generation assets in addition to their transmission and distribution system, driving leverage higher
- Financial metrics drive credit rating differences given similar underlying credit fundamentals.
- Large generators' strong cost recovery and willingness to adjust rates have maintained relatively stable financial metrics to date, despite industry challenges.

Stable financial performance underscores the stable sector outlook throughout the recession and recovery

Stable median financial metrics from 2009 to 2012 demonstrate that public power electric utilities have willingly used their local rate setting authority to adjust rates to maintain their financial strength. This willingness to use their recovery mechanisms was tested during the recession and subsequent slow recovery, as well as through additional sector pressures including low power market prices, unusual weather events, weakening user demand post recession, and clean air and water environmental regulations. Despite these external factors, coverage, leverage and liquidity levels have changed little, with a few exceptions. We expect utilities to continue to use their local authority to adjust rates to maintain financial performance as they transition to a fuel mix with less carbon emissions.

The median rating for the sector remains at A1, despite some outliers that have migrated down the rating scale like Puerto Rico Electric Power Authority (Ba2, negative) and City Water, Light & Power of Springfield, IL (A3, stable)

EXHIBIT 1

Generators - Medians:

	2010	2011	2012	3-Year AVG
Assets ($'000)	180,619	184,033	194,197	186,283
Debt Outstanding ($'000)	71,576	67,787	63,884	67,749
Operating Revenue ($'000)	63,525	63,866	64,251	63,881
Senior Lien Debt Service Coverage (x) (Post Transfers/PILOTs)	1.95	2.07	1.96	1.99
Total Debt Service Coverage (x) (Post Transfers/PILOTs)	1.90	1.97	1.85	1.91
Fixed Obligation Charge Coverage (x)	1.68	1.69	1.70	1.69
Debt Ratio (%)	43	43	40	42
Debt to Operating Revenues (x)	1.09	1.07	1.00	1.05
Total Days Cash on Hand (days)	159	174	182	172
Adjusted Days Liquidity on Hand (incl. Bank Lines)(days)	164	179	195	179
Peak Demand (MW)	138	140	151	143
Total Sales (mWh)	758,554	766,382	764,736	763,224
Average System Retail Rate (c/kWh)	8.80	9.06	9.41	9.09

EXHIBIT 2

Distributors - Medians:

	2010	2011	2012	3-Year AVG
Assets ($'000)	65,546	69,478	73,583	69,536
Debt Outstanding ($'000)	17,990	17,640	20,360	18,663
Operating Revenue ($'000)	38,090	40,355	38,555	39,000
Senior Lien Debt Service Coverage (x) (Post Transfers/PILOTs)	2.89	3.06	3.12	3.02
Total Debt Service Coverage (x) (Post Transfers/PILOTs)	2.72	2.90	3.00	2.87
Debt Ratio (%)	29	29	30	29
Debt to Operating Revenues (x)	0.47	0.43	0.47	0.46
Total Days Cash on Hand (days)	107	116	117	113
Peak Demand (MW)	101	100	97	99
Total Sales (mWh)	458,772	438,870	440,630	446,091
Average System Retail Rate (c/kWh)	9.00	9.61	9.60	9.40

EXHIBIT 3

Combined Medians: Generators and Distributors

	2010	2011	2012	3-Year AVG
Assets ($'000)	95,758	98,560	106,621	100,313
Debt Outstanding ($'000)	33,540	30,536	30,660	31,579
Operating Revenue ($'000)	47,933	51,166	49,625	49,575
Senior Lien Debt Service Coverage (x) (Post Transfers/PILOTs)	2.31	2.44	2.39	2.38
Total Debt Service Coverage (x) (Post Transfers/PILOTs)	2.20	2.25	2.26	2.24
Fixed Obligation Charge Coverage (x)	1.99	2.11	2.07	2.06
Debt Ratio (%)	35	35	34	35
Debt to Operating Revenues (x)	0.74	0.76	0.74	0.74
Total Days Cash on Hand (days)	130	144	149	141
Peak Demand (MW)	114	115	115	115
Total Sales (mWh)	582,627	580,266	587,917	583,603
Average System Retail Rate (c/kWh)	8.92	9.42	9.60	9.31

Medians by rating category reflect different generation profiles and related credit risks

The differences in the medians for the three key financial metrics we use in our rating methodology – leverage, coverage, and liquidity – correspond closely with the cutoffs for each rating category. A few issuers have moved downward through the rating categories over the years. These lower-rated entities carry high debt levels, resulting in narrow debt service coverage and low internally held liquidity.

The different generation profiles of the public power electric utilities define their fundamental business risk that leads to the differentiation of their ratings. Public power utilities that own a material amount of generation assets, directly or indirectly through a Joint Action Agency, have higher debt levels than electric distribution utilities because they issue bonds to build or purchase power generation assets or both. Distributors have lower relative debt levels given that they purchase the majority of their power from other utilities under long-term contracts. As a result, most distributors have relatively low business risk profiles as compared to the generators.

The liquidity levels we deem as adequate for a rating category are lower for distributors than for generators. Therefore, a generator that has the same rating as a distributor will have a credit quality that benefits from higher liquidity that acts as a cushion and mitigates its overall higher business risk profile. Liquidity for the majority of public power utilities is provided in the form of cash, with only a handful using commercial paper programs or bank lines of credit for working capital.

The lower capital needs of the distributors decrease the amount of debt they issue for capital expenditures, resulting in lower debt levels and higher debt service coverage ratios as compared to the generators. The higher debt service coverage ratios (DSCRs) generate excess cash flow that the distributors primarily use to fund capital expenditures.

Generators: (See Appendix I for complete chart)

In terms of ratings, Baa and Ba rated generators tend to have relatively high leverage, narrow debt service coverage and low liquidity. Near the top of the rating scale, Aa-rated generators manage their debt levels despite large, capitally intensive operations by maintaining higher total fixed obligation coverage ratios in order to cash-fund a portion of their capital expenditures. The Aa-rated generators also maintain strong liquidity to mitigate their higher business risk profile as generation asset owners. The majority of Aa-rated generators are also larger in scale, 80% have over $200 million in annual revenues compared to only 18% of A-rated generators.

In contrast, the majority (70%) of A-rated generators are smaller with less than $100 million in annual revenues. The smaller A-rated generators have lower direct debt levels, which drives down the median debt ratio for the category. However, they have higher indirect debt through off balance sheet financing of generation assets through a joint action agency. The lower median fixed obligation debt service coverage ratio for A-rated generators as compared to that for Aa-rated generators captures this off-balance-sheet asset ownership. Rating levels also correspond to liquidity, with the higher rated generators generally maintaining stronger liquidity levels.

EXHIBIT 4

High leverage correlates with lower credit ratings for direct generation asset owners

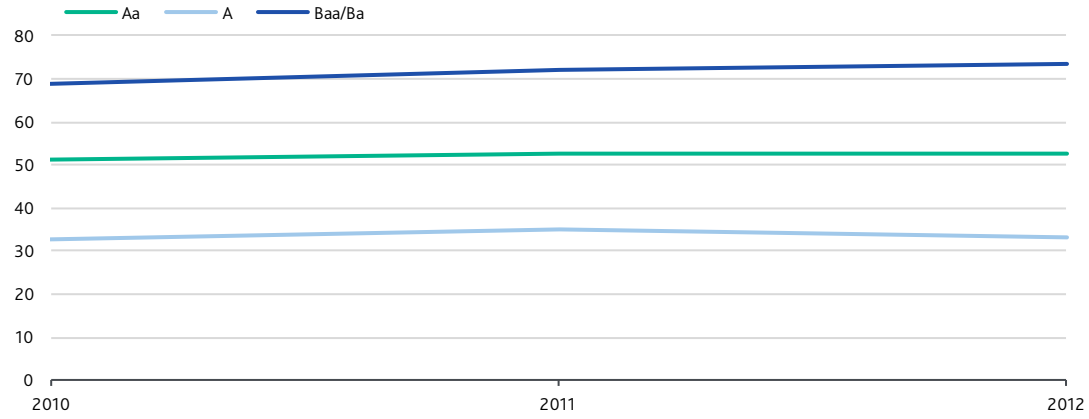


EXHIBIT 5

Low rated generators maintain debt service coverage ratios closer to 1.0 times

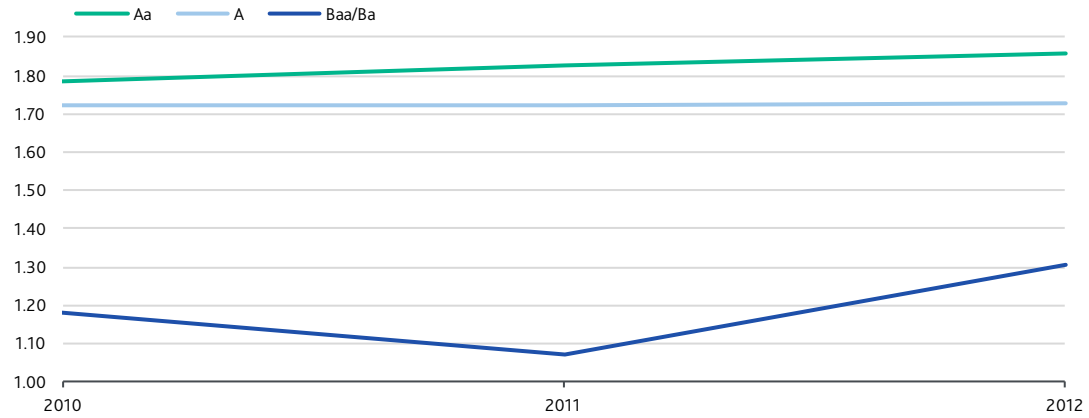
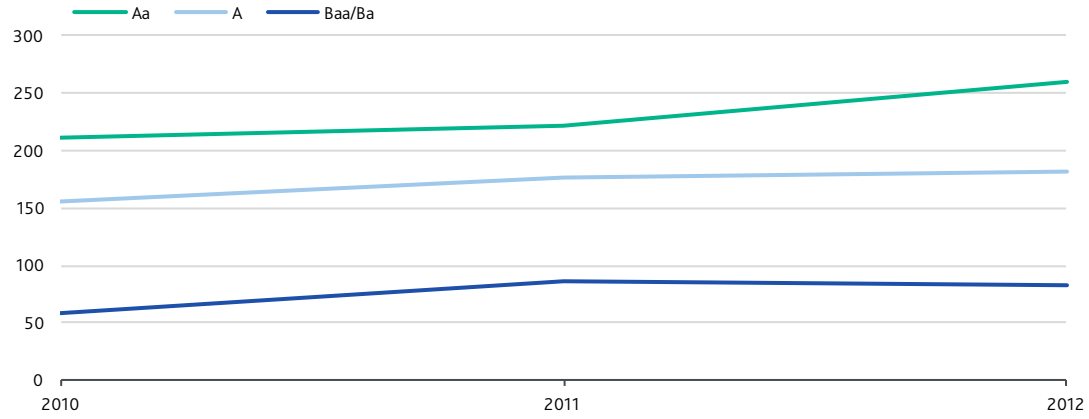


EXHIBIT 6

As liquidity weakens, credit quality deteriorates



Distributors: (See Appendix II for complete chart)

Among the distributors, debt service coverage and the debt ratio are the financial metrics that primarily differentiate rating categories given that liquidity levels are relatively the same. Aa-rated distributors have lower leverage and higher debt service coverage than A-rated distributors. The median liquidity level of Aa- and A-rated distributors tends to be similar in the range of 100 to 130 days cash on hand. A-rated distributors have modestly higher liquidity levels that compensates for their relatively smaller size of operations compared to the larger Aa-rated distributors.

The rated portfolio is evenly divided between the Aa and A rating categories, outside of the two Baa-rated distributors.

EXHIBIT 7

Total Debt Service Coverage Ratios – Aa are higher relative to A rated distributors

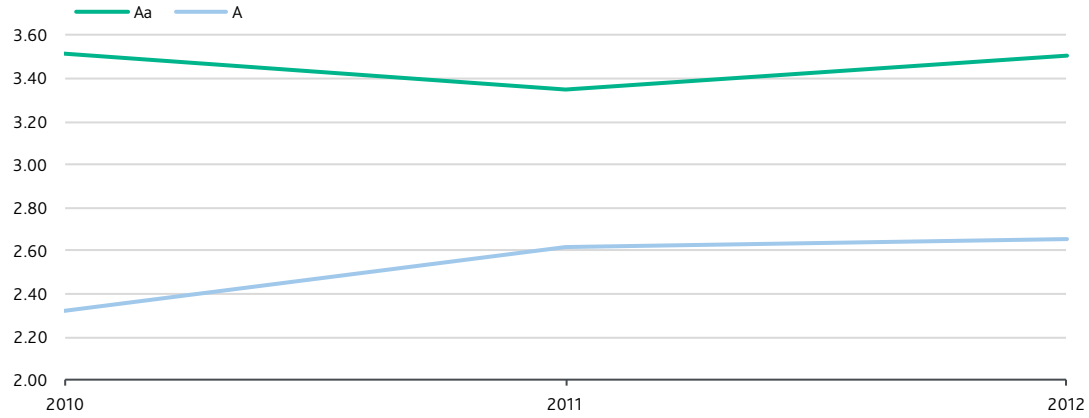
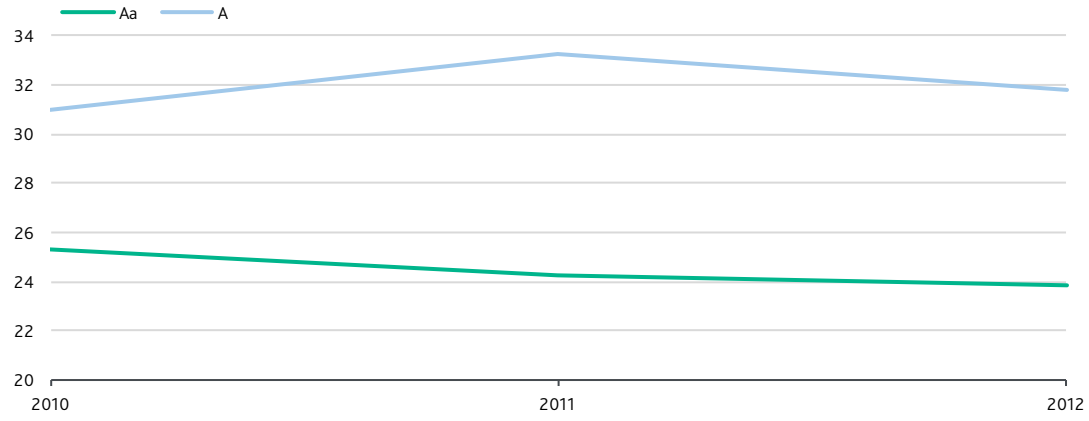


EXHIBIT 8

Debt Ratios are lower for Aa than for A rated distributors – supports higher DSCRs for Aa distributors



Large public power electric utilities own generation assets, raising leverage

As generation asset owners, large public power electric utilities have higher debt levels than distributors. This is due to the fact that public power electric utilities issue debt to finance the purchase or construction of power-generating assets and the transmission-and-distribution system. These generation assets require significant ongoing capital investment and operating expertise, which fundamentally increase the business risk profile relative to a public power distributor that purchases the majority of its power. To mitigate this higher risk profile, large public power generation asset owners maintain higher levels of internal liquidity and strong debt service coverage ratios relative to those of the largest distributors. The largest distributors are smaller than the large generators, which tend to serve sizeable metropolitan areas, regions, or states. These large distributors tend to be major customers of wholesale power generators such as Tennessee Valley Authority (TVA), Bonneville Power Administration (BPA) or an investor-owned utility via an all requirements power purchase contract.

EXHIBIT 9

Large Public Power Utilities with Generation Asset Ownership Exposure

			Debt Outstanding (millions)			Adjusted Debt Service Coverage (x) (Post Transfers/ PILOTs - Senior Lien)			Adjusted Debt Service Coverage (x) (Post Transfers/ PILOTs - All Debt)			Fixed Obligation Charge Coverage (if applicable)(x)			Debt Ratio (%)			Days Liquidity on hand		
	State	Rating	2011	2012	2013	2011	2012	2013	2011	2012	2013	2011	2012	2013	2011	2012	2013	2011	2012	2013
San Antonio Combined Utility (CPS)	TX	Aa1	4,836	4,655	4,941	1.64	1.53	1.66	1.59	1.45	1.53	1.59	1.45	1.53	58	58	58	313	238	218
Salt River Project	AZ	Aa1	4,559	4,942	4,102	2.83	1.62	2.50	2.58	1.62	2.50	2.58	1.62	2.50	52	53	45	250	254	180
Bonneville Power Administration	WA	Aa1	13,566	14,534	15,013	2.17	2.07	1.73	1.06	1.11	1.06	1.06	1.11	1.06	99	97	96	143	132	117
New York State Power Authority	NY	Aa2	3,038	2,991	2,910	2.41	2.33	2.52	2.41	2.33	2.52	2.41	2.33	2.52	52	51	48	249	278	
Omaha Public Power District	NE	Aa2	2,086	2,296	2,267	2.59	2.48	2.39	2.18	2.12	2.07	2.18	2.12	2.07	53	56	56	208	287	218
Seattle Electric	WA	Aa2	1,680	1,779	1,863	1.99	1.48	1.42	1.99	1.48	1.42	1.99	1.48	1.42	67	63	62	218	205	204
Colorado Springs Combined Utility	CO	Aa2	2,224	2,254	2,330	1.68	2.04	1.86	1.68	2.04	1.86	1.68	2.04	1.86	60	59	59	95	200	221
Orlando Utilities Commission	FL	Aa2	1,774	1,663	1,563	1.94	1.94	1.90	1.94	1.94	1.90	1.75	1.73	1.70	61	58	56	284	307	293
JEA	FL	Aa2	3,107	2,973	2,838	4.11	5.32	4.15	1.99	2.55	1.93	1.99	2.55	1.93	84	81	76	165	235	288
Los Angeles Dept of Water & Power	CA	Aa3	6,677	6,601	7,744	2.38	2.85	1.76	2.38	2.85	1.76	1.92	2.14	1.49	75	68	74	202	219	242
Grant County Public Utility District 2	WA	Aa3	1,073	1,081	*	1.67	1.76	*	1.67	1.76	*	1.67	1.76	*	55	52	*	342	481	*
Austin Electric	TX	A1	1,410	1,412	1,399	1.39	1.12	1.62	1.39	1.12	1.62	1.39	1.12	1.62	45	45	45	94	77	97
Sacramento Municipal Utility District	CA	A1	2,868	2,915	2,919	2.34	3.00	2.27	2.34	3.00	2.27	1.75	2.19	1.70	76	71	69	132	192	235
Nebraska Public Power District	NE	A1	2,218	2,212	2,072	1.33	1.30	1.45	1.21	1.25	1.29	1.21	1.25	1.29	74	73	67	205	197	231
South Carolina Public Service Authority	SC	A1	5,468	5,887	6,703	1.53	1.36	1.43	1.53	1.36	1.43	1.53	1.36	1.43	93	87	91	73	127	199
Lower Colorado River Authority	TX	A1	3,219	3,327	3,393	1.40	1.50	1.56	1.40	1.50	1.56	1.40	1.50	1.56	78	80	73	167	146	261
Lower Colorado River Authority Transmission Services Corporation	TX	A2	1,556	1,694	1,889	1.43	1.41	1.56	1.43	1.41	1.56	1.43	1.41	1.56	87	85	83	295	302	404
Turlock Irrigation District	CA	A2	1,222	1,230	1,093	1.42	1.79		1.36	1.61	1.29	1.31	1.54	1.26	79	79	67	248	268	272
Long Island Power Authority	NY	Baa1	9,725	9,555	9,693	1.08	0.94	1.19	1.08	0.94	1.19	1.08	0.94	1.19	137	135	131	68	48	124
Puerto Rico Electric Power Authority	PR	Ba2	8,089	8,936	8,896	0.95	1.39	0.88	0.95	1.39	0.88	0.95	1.39	0.88	106	111	113	6	17	11

*2013 audit not available

EXHIBIT 10

Large Public Power electric distribution only utilities

			Debt Outstanding (millions)			Adjusted Debt Service Coverage (x) (Post Transfers/ PILOTs - Senior Lien)			Adjusted Debt Service Coverage (x) (Post Transfers/ PILOTs - All Debt)			Debt Ratio (%)			Days Liquidity on hand		
	State	Rating	2011	2012	2013	2011	2012	2013	2011	2012	2013	2011	2012	2013	2011	2012	2013
Metropolitan Government of Nashville & Davidson County Electric Enterprise	TN	Aa2	482	570	555	2.63	2.47	2.02	2.63	2.47	2.02	45	44	45	54	72	77
Knoxville Electric Enterprise	TN	Aa2	168	159	187	3.80	2.59	3.03	3.80	2.59	3.03	37	36	38	53	44	60
Concord Combined Utility Enterprise	NC	Aa2	106	94	88	1.73	3.55	2.69	1.73	3.55	2.69	31	27	24	301	348	376
Clarksville Electric Enterprise	TN	Aa2	85	83	81	4.76	4.77	4.02	4.76	4.77	4.02	40	38	36	33	71	99
Richmond Combined Utility Enterprise	KY	Aa3	82	81	78	2.44	2.22	2.22	1.90	1.63	1.60	58	56	53	182	269	269
Mason County Public Utility District 3	WA	Aa3	81	80	*	2.85	1.49	*	2.85	1.49	*	40	40	*	232	199	*
Winter Park Electric Enterprise	FL	Aa3	78	77	74	3.10	2.61	2.17	3.10	2.61	2.17	100	92	88	16	45	45
Reedy Creek Improvement District Combined Utility Enterprise	FL	A1	301	307	275	1.18	1.27	1.24	1.18	1.27	1.24	81	78	70	43	37	27
Lubbock Electric Enterprise	TX	A1	136	125	122	1.59	1.46	1.41	1.59	1.46	1.41	40	38	37	158	135	113
Grays Harbor County Public Utility District 1	WA	A1	121	118	*	1.70	1.51	*	1.70	1.51	*	46	47	*	93	87	*

*2013 audit not available

Financial metrics drive credit rating differences given similar underlying credit fundamentals

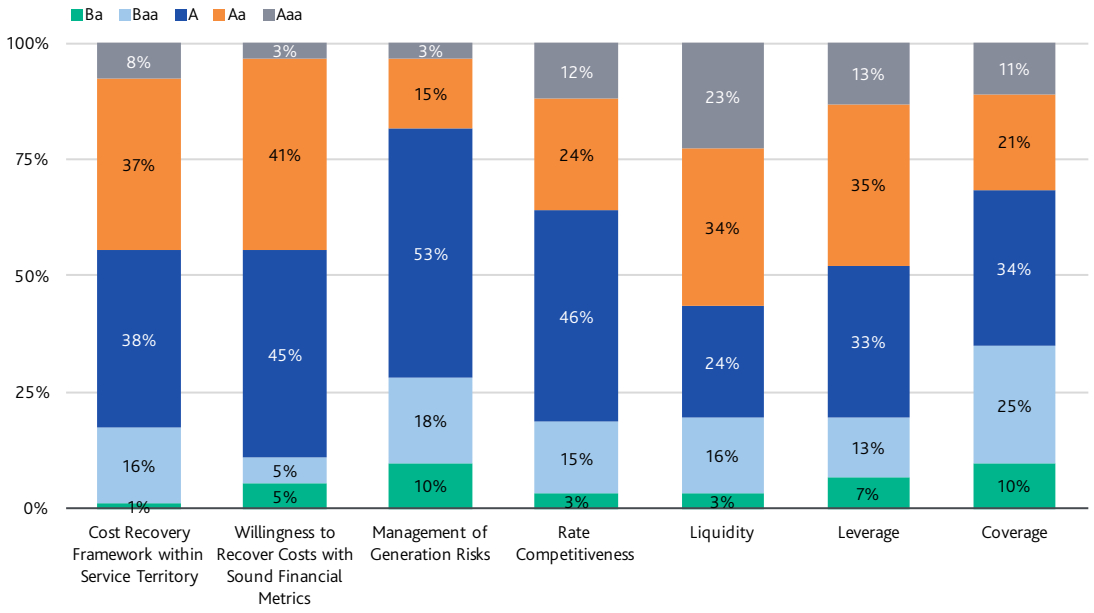
Financial metrics are the key factor driving differences in ratings among the public power utilities. Underlying fundamentals are similar across the sector because the utilities all have a similar underlying fundamental cost recovery framework – the monopolistic provision of an essential service with local rate setting authority. In our US Public Power Electric Utilities with Generation Ownership Exposure methodology, nearly 80% of all public power utilities receive a score of an A or Aa for Factors 1, 2, 3, and 4, establishing that underlying fundamental credit qualities are commensurate with the A to Aa rating range, which is captured in the sector median rating of A1. Factor 5, the utility's financial metrics, provides greater credit differentiation given the range of financial performance, as Exhibit 11 illustrates. The first four factors thus determine the utilities' fundamental credit profile, while the financial metrics can be the key differentiating rating factor within the broad A or Aa rating category, all else equal.

Given the importance of financial performance to utility credit quality, we also tie the second methodology factor to the utility's financial metrics. This connection emphasizes that public power utilities have local rate setting control and can decide what level of financial performance to target and achieve.

**In the October 2011 methodology update, Moody's introduced a scorecard for public power utilities with generation asset ownership exposure. The published scorecards to date have all been within about one notch of the actual rating.*

EXHIBIT 11

Financial metrics provide key credit differentiation given similar underlying fundamentals



Large generators' strong cost recovery and willingness to adjust rates have maintained stable financial metrics

Exhibit 13 has the published scorecard factors for some of the largest generators, which collectively account for about $85 billion or about 80% of the debt outstanding for public power generation and distribution utilities, excluding joint action agencies. The table illustrates that lower financial metrics tend to correlate with lower ratings.

EXHIBIT 12

Factor	Weight	Commentary
Factor 1 – Cost Recovery Framework within Service Territory	25%	These large generators have local rate setting authority and sizeable service territories with diverse economies that have proven resilient through economic cycles coupled with. Thus, they mostly score in the Aa and Aaa for this factor. A strong economic base will generally score in the Aa to Aaa range, unless the utility rates are state regulated. Rate regulation by the state public utility commission is unique for the public power sector and may drive the scoring of this factor downward when present. Only a small number of utilities score Aaa or Ba for this first factor. The strongest score Aaa and include the utilities for Austin, Seattle, San Antonio, and Omaha that have very diverse and large customer bases that performed well during the recent economic recession. On the other hand, Puerto Rico and Virgin Islands have isolated and volatile economic bases that were heavily impacted by the recession, so they score Ba for this factor.
Factor 2 – Willingness and Ability to Recover Costs with Sound Financial Metrics	25%	This factor is viewed in the context of the actual financial metrics of the utility, which tend to be strong for large, higher rated public power generators. The vast majority of large generators score Aa for this factor due to their long history of adequately and timely adjusting their rates to meet financial targets in line with their rating categories. PREPA and LIPA have a history of narrow financial metrics which weighs down their score on this factor.
Factor 3 – Management of Generation Risks and Costs and Reliability of Supply	10%	The majority of these large generators have a relatively diverse generation fleet with varying degrees of asset and fuel concentration. Those with more concentration score an A versus Aa. Those with significant coal-fired generation in their power supply mix score in the Baa to Ba category.
Factor 4 – Rate Competitiveness	10%	Public power utilities have a strong cost advantage in the northwest given their low cost hydro generation and a several large city-owned utilities also have very competitive rates (San Antonio and LADWP), but the majority of the others tend to have retail rates near the state average. For those utilities that are primarily wholesalers (NPPD, LCRA, Santee Cooper), we also consider the wholesale power rate relative to regional market prices and other wholesale utilities in the region.
Factor 5 – Financial Strength (3 year averages): **(a) coverage (10%)** **(b) leverage (10%)** **(c) liquidity (10%)**	30%	Financial metrics weaken as you go down the rating scale. The majority have coverage ratios over 1.5 times, in line with their ratings that mostly exceed A1. Half of the large utilities have over 200 days liquidity on hand and all but two have over 100 days cash on hand, illustrating strong liquidity to balance generation asset ownership risks. All but two of the large electric utilities have debt ratios over 50% given the capital intensive nature of their operations and the use of debt to finance these costs.
Notching Considerations: (up or down)		The majority of the downward notching applied is due to weak debt service reserve fund requirements and construction risk. Conversely, the upward notching is for extraordinary support in the form of pooled liquidity or government support.

EXHIBIT 13

Methodology Scorecard Factors for Large Public Power Electric Utilities with Generation Asset Ownership

	State	Current Rating	Outlook	Factor 1: Cost Recovery Framework within Service Territory	Factor 2: Willing-ness to Recover Costs with Sound Financial Metrics	Factor 3: Managem ent of Generatio n Risks	Factor 4: Rate Competi tiveness	Factor 5: Adjusted days liquidity on hand (3-year avg) (days)	Factor 5: Debt Ratio (3-year avg) (%)	Factor 5: Debt Service Coverage (3-year avg) (x)	Grid Indicated Rating (before notching)	Total Notches	Scorecard Indicated Rating (after notching)
Salt River Project	AZ	Aa1	STA	Aaa	Aa	Aa	Aa	236	52%	2.30	Aa2	0	Aa2
San Antonio Combined Utility	TX	Aa1	STA	Aaa	Aa	Aa	Aa	245	59%	1.51	Aa2	0	Aa2
Bonneville Power Administration	OR	Aa1	STA	Aa	A	Aa	Aa	131	98%	1.08	A2	2.5	Aa2
New York Power Authority	NY	Aa2	STA	Aa	Aa	Aa	Aa	263	48%	2.18	Aa2	0	Aa2
Omaha Public Power District	NE	Aa2	STA	Aaa	Aa	A	A	248	54%	2.13	Aa2	0	Aa2
Seattle Electric Enterprise	WA	Aa2	STA	Aaa	Aa	A	A	172	66%	1.64	Aa3	1	Aa2
Colorado Springs Combined Utility	CO	Aa2	STA	Aa	Aa	Aa	Aa	136	60%	1.91	Aa3	0	Aa3
Orlando Utilities Commission	FL	Aa2	STA	Aa	Aa	Aa	A	234	62%	1.69	Aa3	-0.5	Aa3
JEA	FL	Aa2	STA	Aa	Aa	Aa	A	229	81%	2.16	Aa3	-0.5	Aa3
Los Angeles Dept of Water & Power	CA	Aa3	STA	Aa	Aa	Aa	Aa	221	72%	1.85	Aa3	-0.5	Aa3
Grant County Public Utility District 2	WA	Aa3	STA	A	Aa	A	Ba	386	54%	1.55	Aa3	-0.5	A1
Austin Electric Enterprise	TX	A1	STA	Aaa	A	Aa	A	125	44%	1.21	Aa3	-1	A1
Sacramento Municipal Utility District	CA	A1	STA	Aa	Aa	A	Aa	159	75%	1.80	Aa3	-0.5	A1
Nebraska Public Power District	NE	A1	STA	A	Aa	Aa	A	231	72%	1.25	A1	-0.5	A1
South Carolina Public Service Authority	SC	A1	STA	Aa	Aa	A	A	133	90%	1.50	A1	-1	A2
Lower Colorado River Authority	TX	A1	NEG	A	Aa	Aa	A	172	77%	1.50	A1	-1	A2
Lower Colorado River Authority Transmission Services Corporation	TX	A2	STA	A	A	Aaa	A	334	85%	1.46	A2	0	A2
Turlock Irrigation District	CA	A2	STA	A	Aa	A	A	229	82%	1.33	A2	0	A2
Long Island Power Authority	NY	Baa1	NEG	Aa	Baa	A	A	62	137%	1.05	Baa1	-1	Baa2
Puerto Rico Electric Power Authority	PR	Ba2	NEG	Baa	Baa	Ba	Ba	11	103%	1.25	Baa3	-1	Ba1

Appendix I – Generator medians by rating category

		2010	2011	2012	3 YR AVG
Aa	Assets ($'000)	1,544,288	1,627,339	1,652,104	1,607,910
	Debt Outstanding ($'000)	714,901	716,968	682,269	704,712
	Operating Revenue ($'000)	365,012	358,446	335,295	352,917
	Senior Lien Debt Service Coverage (x) (Post Transfers/PILOTs)	1.91	2.17	1.98	2.02
	Total Debt Service Coverage (x) (Post Transfers/PILOTs)	1.89	1.96	1.87	1.90
	Fixed Obligation Charge Coverage (x)	1.79	1.83	1.86	1.82
	Debt Ratio (%)	51	52	53	52
	Debt to Operating Revenues (x)	1.66	1.71	1.85	1.74
	Total Days Cash on Hand (days)	199	218	207	208
	Adjusted Days Liquidity on Hand (incl. Bank Lines)(days)	212	222	260	231
	Peak Demand (MW)	662	664	669	665
	Total Sales (mWh)	4,195,765	4,667,172	4,628,387	4,497,108
	Average System Retail Rate (c/kWh)	8.07	8.38	8.58	8.34

		2010	2011	2012	3 YR AVG
A	Assets ($'000)	117,263	121,634	124,269	121,055
	Debt Outstanding ($'000)	40,395	37,020	40,971	39,462
	Operating Revenue ($'000)	54,270	53,393	51,423	53,029
	Senior Lien Debt Service Coverage (x) (Post Transfers/PILOTs)	2.09	2.14	2.16	2.13
	Total Debt Service Coverage (x) (Post Transfers/PILOTs)	2.09	2.12	2.03	2.08
	Fixed Obligation Charge Coverage (x)	1.72	1.72	1.73	1.72
	Debt Ratio (%)	33	35	33	34
	Debt to Operating Revenues (x)	0.86	0.93	0.85	0.88
	Total Days Cash on Hand (days)	154	173	180	169
	Adjusted Days Liquidity on Hand (incl. Bank Lines)(days)	156	176	182	171
	Peak Demand (MW)	97	98	102	99
	Total Sales (mWh)	565,482	575,342	554,479	565,101
	Average System Retail Rate (c/kWh)	8.92	9.19	9.51	9.20

		2010	2011	2012	3 YR AVG
Baa and Ba	Assets ($'000)	112,896	110,568	108,147	110,537
	Debt Outstanding ($'000)	43,212	42,415	41,508	42,378
	Operating Revenue ($'000)	41,187	41,993	42,482	41,888
	Senior Lien Debt Service Coverage (x) (Post Transfers/PILOTs)	1.44	1.22	1.46	1.37
	Total Debt Service Coverage (x) (Post Transfers/PILOTs)	1.18	1.07	1.31	1.19
	Fixed Obligation Charge Coverage (x)	1.18	1.07	1.31	1.19
	Debt Ratio (%)	69	72	74	72
	Debt to Operating Revenues (x)	1.59	1.64	1.59	1.61
	Total Days Cash on Hand and Adjusted Days Liquidity on Hand (days)	58	87	83	76
	Peak Demand (MW)	63	56	58	59
	Total Sales (mWh)	266,704	268,787	303,916	279,802
	Average System Retail Rate (c/kWh)	10.00	9.91	11.48	10.46

Appendix II – Distributor medians by rating category

		2010	2011	2012	3 YR AVG
Aa	Assets ($'000)	91,536	92,975	94,408	92,973
	Debt Outstanding ($'000)	21,223	23,016	24,105	22,781
	Operating Revenue ($'000)	53,372	54,823	54,955	54,383
	Senior Lien Debt Service Coverage (x) (Post Transfers/PILOTs)	3.65	3.35	3.55	3.52
	Total Debt Service Coverage (x) (Post Transfers/PILOTs)	3.52	3.35	3.51	3.46
	Debt Ratio (%)	25	24	24	24
	Debt to Operating Revenues (x)	0.35	0.32	0.35	0.34
	Total Days Cash on Hand (days)	104	102	117	108
	Peak Demand (MW)	139	139	143	140
	Total Sales (mWh)	631,436	628,151	619,253	626,280
	Average System Retail Rate (c/kWh)	9.17	9.73	9.82	9.57

		2010	2011	2012	3 YR AVG
A	Assets ($'000)	49,323	50,655	54,509	51,496
	Debt Outstanding ($'000)	11,322	10,795	10,996	11,038
	Operating Revenue ($'000)	25,774	28,885	28,604	27,754
	Senior Lien Debt Service Coverage (x) (Post Transfers/PILOTs)	2.34	2.69	2.84	2.62
	Total Debt Service Coverage (x) (Post Transfers/PILOTs)	2.32	2.62	2.65	2.53
	Debt Ratio (%)	31	33	32	32
	Debt to Operating Revenues (x)	0.62	0.62	0.61	0.62
	Total Days Cash on Hand (days)	115	132	126	124
	Peak Demand (MW)	74	71	72	72
	Total Sales (mWh)	359,925	316,942	336,914	337,927
	Average System Retail Rate (c/kWh)	8.80	9.55	9.09	9.15

Appendix III – US Public Power Electric Utilities with Generation Ownership Exposure Methodology Grid

Factor	Weight	Aaa	Aa	A	Baa	Ba
1. Cost Recovery Framework Within Service Territory	25%	Monopoly with unregulated rate setting; Very strong service area economy	Monopoly with unregulated rate setting; Strong service area credit economy	Monopoly with unregulated rate setting; Average service area economy	Regulation of rates by State; Weak service area economy	Regulation of rates by State; Very weak service area economy
2. Willingness and Ability to Recover Costs with Sound Financial Metrics	25%	Excellent rate-setting record; Rates, fuel, & purchased power cost adjustments less than 10 days; No political intervention in past or extremely high support from related government; Very limited General Fund transfers governed by policy	Strong rate-setting record; Rates, fuel, & purchased power cost adjustments 10 to 30 days; Limited political intervention in past or high support from related government; Conservative and well-defined General Fund transfers governed by policy	Adequate rate-setting record; Rates, fuel, & purchased power cost adjustments 31 to 60 days; Some political intervention in past or average support from related government; Moderate General Fund transfers	Below average rate-setting record; Rates, fuel, & purchased power cost adjustments 61 to 99 days; Persistent political intervention or below average support from related government; Large General Fund transfer not governed by policy	Consistent record of insufficiently setting rates; Rates, fuel, & purchased power cost adjustments 100 days or more; Highly political climate or no support from related government; Sizeable General Fund transfer not governed by policy
3. Management of Generation Risks and Cost and Reliability of Power Supply	10%	Very strong management of generation risks; High degree of diversification of generation and/or fuel sources; Well insulated from commodity price changes; Single generation asset provides less than 20% of power; and/or up to 20% of energy from coal-fired generation with carbon mitigation strategy	Strong management of generation risks; Some diversification of generation and/or fuel sources; Minimally affected by commodity price changes; Single generation asset provides less than 40% of power; and/or 21% to 40% of energy from coal-fired generation with carbon mitigation strategy	Average management of generation risks; Some reliance in one type of generation or fuel source, but diversified with purchased power sources; Modest exposure to commodity price changes; Single generation asset may provide 40% to 55% of power; and/or 41% to 55% of energy from coal-fired generation with carbon mitigation strategy	Below average management of generation risks; Reliance on a single type of generation or fuel source, with limited diversification via purchased power; Moderate exposure to commodity prices; Single generation asset provides 56% to 75% of power; and/or 56% to 70% of of energy from coal-fired generation with no carbon mitigation strategy	Poor management of generation risks; High concentration in a single type of generation or highly reliant on a single fuel source, with minimal diversification via purchased power; Notably exposed to commodity price shocks; Single generation asset provides over 75% of power; and/or 71% to 100% of energy from coal-fired generation with no carbon mitigation strategy
4. Rate Competitiveness (compared to state average)	10%	25% or more below average	25% to 7.51% below average	7.5% below average to 7.5% above average	7.51% to 25% above average	25% or more above average
5. Financial Strength (3-yr average)						
(a) Adjusted days liquidity on hand	10%	≥ 250 days	≥ 150 days to 249 days	≥ 90 days to 149 days	≥ 30 days to 89 days	Less than 30 days
(b) Debt ratio (%)	10%	Less than 25%	≥ 25% less than 50%	≥ 50% less than 75%	≥ 75% less than 100%	≥ 100%
(c) Adjusted Debt Service Coverage OR Fixed Obligation Coverage (x)	10%	≥ 2.50x	≥ 2.00x to 2.49x	≥ 1.50x to 1.99x	≥ 1.10x to 1.49x	Below 1.10x

Notching Factors: Operational - Customer concentration; additional borrowing; construction risk; **Financial** – Debt Service Reserve Fund below MADS; Covenant violation; liquidity risks; **Other** – as appropriate

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MOODY'S
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U.S. Public Power Electric Utilities with Generation Ownership Exposure

Summary

This methodology describes Moody's approach to credit ratings assigned to revenue bonds of U.S. public power electric utilities whose credit profile is largely influenced by power generation ownership. This methodology replaces the April 2008 U.S. Public Power Electric Utilities Methodology and governs the ratings assigned to 135 public power electric utilities rated by Moody's that own generation either directly or through a municipal joint power agency (JPA) (see Appendix A). A separate update to the 2008 methodology for credit ratings assigned to public power electric and gas distribution utilities will be forthcoming.

While reflecting on similar core principles in the previous approach, the updated methodology identifies the following five key rating drivers:

» Cost Recovery Framework Within Service Territory
» Willingness to Recover Costs With Sound Financial Metrics
» Management of Generation Risks
» Competitiveness
» Financial Strength

The goal of this rating methodology is to improve the transparency in how Moody's arrives at utility revenue bond ratings, what factors we consider most important, and how these factors map to specific rating outcomes. Our objective is for users of this methodology to be able to estimate a utility's senior lien rating within one to two alpha-numeric rating notches.

Moody's does not anticipate any rating changes as a direct result of the implementation of this update to the Public Power methodology for generators or application of the new scorecard.

The credit quality of the public power sector has been stable due to its fundamental strength which benefits from the near monopoly provision of an essential service with unregulated rate-setting ability, in most cases. This business model suggests a fundamentally high probability of continued payment of debt service, despite possible economic and regulatory changes in the power industry or fiscal distress that an individual utility might suffer. However, Moody's recognizes that there are political and operating risks that can affect credit quality as economic pressures increase and regulatory reform challenges the industry.

This publication includes the following sections:

» **About the Rated Universe:** An overview of the public power electric utility sector

» **About the Rating Methodology :** A description of our rating methodology, including a detailed explanation of each of the key factors that drive our ratings

» **Assumptions and Limitations:** Comments on the rating methodology's assumptions and limitations, including a discussion of other rating considerations that are not included in the grid

» **Appendices:** Tables including the scorecard, the issuers covered in this update, definitions of key ratios, an industry overview, and a discussion of the key issues facing the industry over the intermediate term.

About the Rated Universe

Moody's currently maintains published ratings on debt issued by some 300 U.S. public power electric utilities with over $110 billion of revenue bond debt outstanding. Of this group, public power electric utilities that have direct ownership of generation have debt outstanding of approximately $80 billion, while participants in JPAs are obligated to about $35 billion of JPA debt. This rating methodology covers the 135 U.S. public power electric utilities that own generation directly or through a JPA.

Moody's incorporates the view that public power electric utilities that either own significant generation assets or obtain at least 20% of their electricity from directly owned power generation assets and/or from JPA participation generally have more fundamental credit risks including exposure to commodity markets, environmental regulation and capital requirements, when compared to other essential purpose enterprises including public power electric utilities that do not own generation assets.

The 135 public power electric utility generators in this methodology are part of the larger rated public power sector, which also includes 46 municipal joint power agencies and 120 municipal electric distributors. These two groups are rated under separate rating methodologies.

Most of the electric revenue bond debt outstanding for the public power sector has been issued by public power electric utility generators, like the Los Angeles Department of Water and Power (rated Aa3) or San Antonio CPS (rated Aa1), that own their transmission, distribution and power generation facilities, and correspondingly have ongoing capital programs. Some public power electric utilities are organized as autonomous public authorities. These are typically integrated utilities, like the Salt River Agricultural Improvement and Power District (Salt River Project) (rated Aa1), which serves a large geographic area and owns and operates generation, transmission and distribution facilities. This rating methodology also includes public power electric utilities that own generation via take-or-pay contracts through a joint power agency, such as Hamilton, Ohio (rated A3). Hamilton is a participant in generation projects of AMP, Inc.

Our rating assessment of a public power electric utility's revenue debt begins with the recognition of:

» Near monopoly position in providing an essential service

» Unregulated and independent local rate-setting authority

» Lower cost structure due to the ability to issue lower cost tax-exempt debt and, for some, the availability under federal statute of federal low cost preference power

» Lack of profit motive or need to generate a return on equity

» **There have been limited bond defaults and no bankruptcies in the past 50 years reflecting the public power electric utility sector's fundamental strengths.**

The rating distribution for the 74 public power electric utilities that own generation directly is reflected in Figure 1.

FIGURE 1
Rating Distribution of Public Power Generators

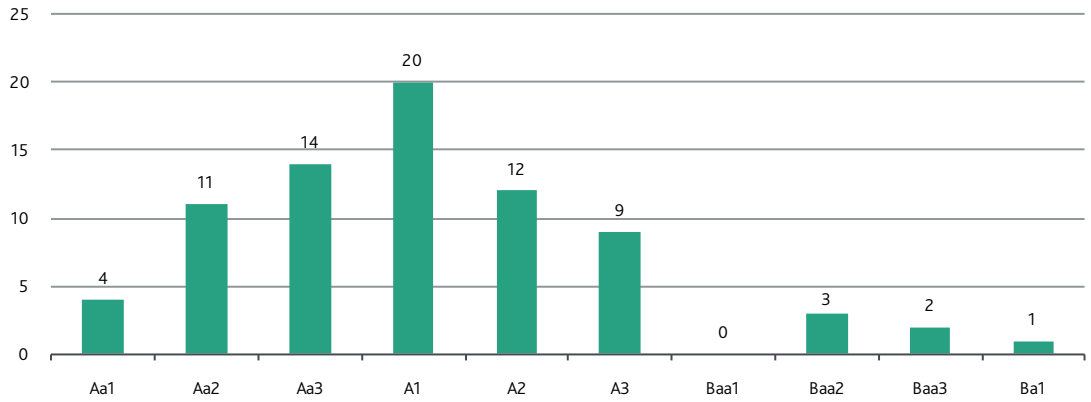
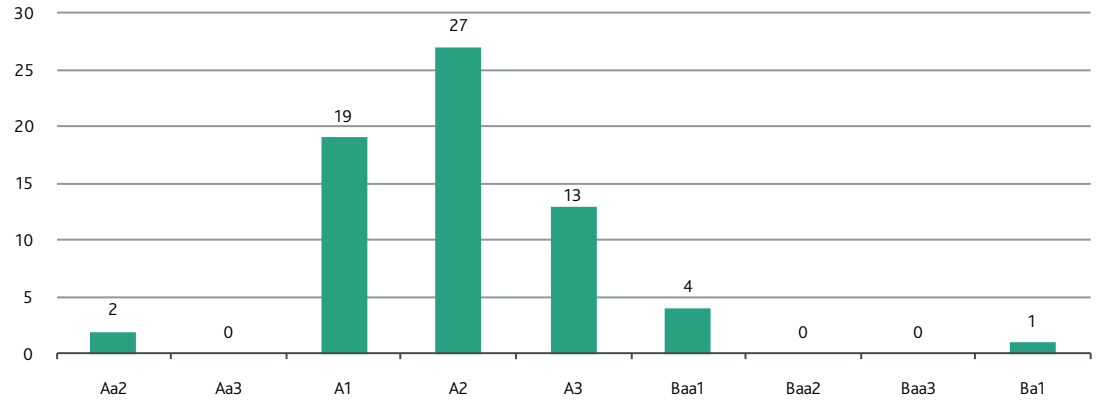


Figure 2 reflects the rating distribution for the 61 public power electric utilities that are participants in JPAs and receive more than 20% of their power supply through an agreement with a JPA. The public power electric utility shares in the risks associated with JPA generation. While there have been no rated bond defaults or bankruptcies over the past 50 years of public power electric utilities that have generation ownership through JPAs, the Washington Public Power Supply System (WPPSS), itself a JPA, did default on $2.25 billion of revenue bonds in 1983. However, the WPPSS participants did not default on their own electric revenue bonds.

FIGURE 2
Rating Distribution of Distributors with more than 20% of generation through JPA ownership



Essential Service Revenue Bonds and Public Power

We believe that public power electric utilities that own generation have a higher degree of business complexity than other essential services, such as water, sewer, and stormwater systems. Specifically, generation owning electric utilities have greater operating risk in an environment subject to ongoing regulatory changes. While there remain many similarities with other essential purpose revenue bonds such as governance, bondholder security provisions and rate-setting flexibility, Moody's maintains the challenging operating environment for a generation owning electric utility is more pronounced as a rating factor.

Broad industry changes continue to introduce uncertainty to the public power sector, such as deregulation initiatives that introduced a degree of competition, climate change policies, and supply and demand factors. Public power electric utilities that own generation are capital intensive and must make decisions which result in long-term obligations amidst a changing operating environment.

About this Rating Methodology

Moody's approach to rating public power electric utilities that own generation, as outlined in this rating methodology, incorporates the following steps:

1. Identification of the Key Rating Factors

Generally, many of the factors included in Moody's 2008 U.S. Public Power Electric Utilities Methodology are incorporated in this update. This methodology update includes the assignment of percentage weights to the five broad rating factors in order to better reflect the relative importance of each one. A change in our assessment of one or more of the factors or sub-factors influences the grid-indicated rating depending on the weighting and the degree of change in our assessment.

We have identified the following five key rating factors when assigning ratings to public power electric utility issuers with generation ownership.

Summary Table of Rating Grid Factors

Broad Rating Factors	Description	Factor Weighting
Total Weight		**100%**
1. Cost Recovery Framework Within Service Territory	- Monopoly with unregulated rate-setting - Service area characteristics - Customer base stability	25%
2. Willingness to Recover Costs with Sound Financial Metrics	- Political risk - Timeliness of recovery - Rate-setting record - Local government supportiveness -General Fund transfer policy	25%
3. Management of Generation Risks	- Diversity of supply - Reliability and cost of supply & distribution - Resource planning	10%
4. Competitiveness	- Rate Competitiveness	10%
5. Financial Strength		
(a) Liquidity	- Adjusted days liquidity on hand (3-year average) (days)	10%
(b) Leverage	- Debt ratio (3-year average) (%)	10%
(c) Operating Resiliency	- Adjusted debt service coverage OR Fixed obligation charge coverage ratio (3-year average) (x)	10%

These factors are critical to the analysis of public power electric utilities and, in most cases, can be benchmarked across the public power sector.

2. Measurement of the Key Rating Factors in the Grid

We next explain the elements we consider and the metrics we use to measure relative performance on each of the five broad factors. Many of the measures are quantitative and can be specifically defined. However, for other factors, qualitative judgment or observation is necessary to determine what we believe to be the appropriate rating category.

Moody's ratings are forward looking and incorporate our expectations for future financial and operating performance. In assigning ratings, Moody's attempts to look through the power industry's characteristically volatile financial metrics, which can be caused by weather variations and fuel or commodity price changes. The rating process also makes extensive use of historic financial statements. Such historic results help us understand the pattern of a utility's financial and operating performance and how a utility compares to its peers. Analysts will use three-year average results to assess financial metrics, in order to mitigate one-time factors that might skew results. Moody's also utilizes financial projections to better ascertain management's planning capability, as well as expectations for future financial performance, rate levels, and capital and debt requirements. While our ratings reflect our expectations of future financial results, the financial metrics used in this methodology update reflect historic results. All financial measures incorporate Moody's standard adjustments to the balance sheet

and income statement. This methodology adopts some of the changes in financial metrics introduced in 2011 during a detailed comment period.[1]

3. Mapping Factors to Rating Categories

After identifying the measurement criteria for each factor, we match a utility's performance on each factor and sub-factor to one of the broad Moody's rating categories (Aaa, Aa, A, Baa, and Ba). In this report, we provide a range or description for each of the measurement criteria. For example, we specify what level of adjusted debt service coverage is generally acceptable for a Aa versus an A credit. In other words, there is only one rating from the grid for each factor, multiple rating choices for sub-factors are not incorporated.

4. Determining the Overall Grid-Indicated Rating

To determine the overall grid-indicated rating, each of the assigned scores for the factors and sub-factors is converted into a numeric value based on the following scale:

Ratings Scale

Aaa	Aa	A	Baa	Ba
1	3	6	9	12

Each factor or sub-factor numeric value is multiplied by its assigned weight and then summed to produce a composite weighted average score. This weighted average score is then mapped to the ranges specified in the table below, and the alpha-numeric rating is determined based on where the total score falls within the ranges.

Composite Rating

Indicated Rating	Aggregate Weighted Factor Score
Aaa	<1.5
Aa	1.5 < 4.5
A	4.5 <7.5
Baa	7.5 < 10.5
Ba	10.5 < 13.5

As an example of how the grid works, an issuer with a composite weighting factor of 5.8 would have a grid-indicated rating of A2. We use the same procedure to derive the grid-indicated rating for each of the factors that are embedded in the discussion of the methodology. **The composite weighted grid-indicated rating is then reviewed against the current rating and any of the outlier factors that may have skewed the rating higher or lower to better understand the reasoning behind why a particular factor was weighed the way it was.**

5. Discussion of Assumptions, Limitations and Other Rating Considerations That Are Not in the Grid

This section discusses limitations in the use of the scorecard to map against actual ratings, as well as limitations and key assumptions that pertain to the overall rating methodology.

[1] Moody's Considers Use Of New Financial Metrics In U.S. Public Power Electric Utility Rating Methodology, June 2011

The Five Broad Rating Factors

Moody's analysis of public power electric utility generators focuses on five broad factors:

1. Cost Recovery Framework Within Service Territory
2. Willingness to Recover Costs with Sound Financial Metrics
3. Management of Generation Risks
4. Rate Competitiveness
5. Financial Strength

Rating Factor 1 – Cost Recovery Framework within Service Territory (25% weight)

Why it Matters

Fundamental to the credit rating of U.S. public power electric utilities is the near monopoly control the utility has in providing electricity, an essential service to its customers. In addition, most public power electric utilities have the statutory authority to establish their own rates and charges locally without external regulation, providing greater certainty to timely and full cost recovery. This strength is further bolstered for most utilities by minimum bond security covenants that require current revenues to match current expenses, including payment of debt service.

Additionally, the strength and diversity of the service territory can indirectly influence a public power electric utility's cost recovery framework. Larger more diverse service areas with greater economic wealth have a stronger cost recovery framework than smaller, less diverse service areas. Collectively these three factors, [1] near monopoly control over a service area, [2] unregulated rate raising ability, and [3] the strength of a public power utility's customer base and service area economy are core characteristics in assessing this rating factor.

How We Measure the Cost Recovery Framework for the Grid

In the U.S., public power electric utilities have maintained a near monopoly role in their service area, limiting competitive threats to their customer base. This monopoly control, coupled with the unregulated rate setting process provides greater certainty of the utility's ability to access the economic resources of the region served.

Moody's believes that regulation of a public power electric utility's rates is a material weakness since it acts as a constraint on rate-setting. Public power electric utilities have amortizing debt, so a regulatory lag that creates cost recovery uncertainty would be a significant issue. Most state regulatory boards also have limited experience with public sector enterprises. Some states, like Wisconsin and Indiana, regulate public power electric utilities, but the regulation has been supportive and regulators are required to consider bond covenants in their rulemaking. As reflected in the grid, regardless of other considerations in this factor, including service area economic strength and customer concentration, should a public power electric utility fall under typical state regulation (as normally applied to investor owned utilities) our assessment of this rating factor would be negatively influenced.

When evaluating the credit characteristics of the utility's service area, Moody's considers population, employment trends, wealth indicators, and local economic diversity and growth projections. Moody's will utilize Moody's Economy.com, for example, for an up-to-date assessment of economic strength of a particular service area and projected economic strength. Weak economic characteristics and limited

economic diversity weigh heavily as well. For example, the key rating factor of a limited economy is a major driver in Guam Power Authority's Ba1 rating, which is one of two below investment grade U.S. public power electric utilities.

In particular, we evaluate the wealth indicators of the population that a utility serves to gauge the ability of customers to pay their electric bills, both currently and in the future, should rates rise. Affluent residential customers generally have a higher tolerance for higher overall rates, since the electric bill is a small part of their disposable income.

Another important sub-factor is the stability of the customer base. Public power electric utilities that serve a primarily residential customer base (more than 50% residential sales) should benefit from more stable load and revenue trends given the typical usage pattern for this customer class. A customer base dominated by industrial load could prove prone to economic cycles and demand changes, which could affect revenue stability and our assessment of this factor.

Rating Factor 1 – Cost Recovery Framework within Service Territory (25% weight)

Aaa	Aa	A	Baa	Ba
Monopoly with unregulated rate setting; Very strong service area economy	Monopoly with unregulated rate setting; Strong service area credit economy	Monopoly with unregulated rate setting; Average service area economy	Regulation of rates by State; Weak service area economy	Regulation of rates by State; Very weak service area economy

Rating Factor 2 – Willingness to Recover Costs with Sound Financial Metrics (25% weight)

Why it Matters

Independent and local rate-setting authority guided by sound bond covenants and governance is a fundamental credit strength and a heavily weighted rating factor. We believe credit risk increases in the absence of the stability and certainty that this business model provides by prioritizing a financial buffer to help mitigate the impact of modest credit stress events. Political risk, for example, can result in an unwillingness or inability to establish sufficient rates to maintain sound financial metrics. Generally, the willingness to implement rate increases will, at some point, affect the relative financial performance of the utility as measured in Factor 5. Without sound rate-setting that is predictable and timely, debt service coverage margins or financial liquidity may be compromised. As such, we believe that this rating factor is often a leading indicator of the direction of future financial performance for a public power electric utility. This highlights that some entities may have a high tolerance for exposure to risks readily anticipated through more conservative management practices and policies.

Another important consideration is the degree of support, or lack thereof, from a related governmental entity, since most public power electric utilities are owned by local governments. If the utility and the governmental entity are closely related, the local government rating may be a positive weight in the score assigned to this factor, if the local government has a record of supporting the utility in times of fiscal stress. This matters because a city may use its broader governance authority or financial resources to prevent financial deterioration of the utility, which serves to protect revenue bond holders. The essentiality of electric service is a key consideration in the degree of supportiveness and how much weight we ascribe to this sub- factor.

How We Measure Willingness to Recover Costs for the Grid

Moody's evaluates the governing board's rate-setting process for its transparency and timeliness in setting the rates and charges necessary to ensure costs, including debt service, are fully recovered. A key measure is the number of days it takes to implement new rates and collect the additional revenues. A demonstrated record of willingness to charge the rates required to recover operating and capital costs, provide a cushion for debt service coverage, and maintain sound liquidity, is a credit positive and likely to result in a higher score on this factor.

Moody's continues to believe the rate-setting process will be tested in the next several years as power supply costs rise due to increased environmental regulation, demand growth remains slow due to the slow economic recovery, and utilities shift to cleaner and more expensive fuels.

A city council typically holds two readings with a final public hearing before new rates can be implemented and collected on the customer's bill. This process is typically concluded within 60 to 90 days. The longer and more complicated the process, the more pressure the delay may put on a public power utility's liquidity. A mitigating factor for many utilities, which we factor into our ratings assessment, is the use of fuel hedging programs and enterprise risk management strategies, which, if effective, may be a positive credit factor in controlling costs while a new rate policy is being considered. In the end, the willingness to establish timely new rates to meet the appropriate cost recovery requirement is weighted heavily in this rating factor. This is of particular importance when considering a utility's capital program and whether future rates will be sufficient to manage increased debt service requirements.

While always an important rating consideration, the ability to automatically adjust rates for fuel or power purchase cost increases has become a more notable credit factor in the past decade given the fluctuations in natural gas prices, ongoing hydrology risk, and the volatility of the wholesale power market. Utilities that have an automatic fuel and purchased power cost adjustment mechanism are able to recover these costs on a timely basis. Such adjustment mechanisms serve to narrow the potential drain on liquidity and the resulting impact on credit quality and are of particular importance should there be a fuel price spike or a forced outage of a generating unit.

Political risk that impedes a utility's willingness to enact rates and charges sufficiently and quickly to maintain the associated financial metrics for a utility's rating category would result in a lower score assigned to this rating factor. In cases where a utility's management has established planning targets for financial metrics that are lower than the associated financial metrics for a utility's rating category and the utility has consistently met those targets, Moody's may score the utility's willingness at a level higher than its financial metrics may indicate.

A key consideration in Factor 2 is the relationship of the local government to the electric utility. This will not always be a factor, as some utilities have no fiscal relationship with a local government or the utility may have been established as a separate and independent authority. We consider who governs the utility, who sets its rates, and who issues the revenue bonds for the utility, as well as the degree to which the general government is responsible for supporting the utility in times of financial stress. Local governments have a strong record of supporting their public power electric utilities in times of fiscal stress. For example, during the 2001 Western Energy Crisis, the City of Seattle (rated Aaa) used its significant liquidity to assist the city utility, Seattle Light (rated Aa2), to recover from a short-term cash flow problem. The city then implemented rate surcharges in a timely fashion to bolster utility finances.

General Fund Transfer (GFT) policies are also an important issue Moody's evaluates since the policy is an example of the relationship between a utility and their local government. The GFT is the transfer of surplus utility revenues from the utility to the city's General Fund. Moody's believes an established GFT transfer policy that is accepted by both the utility and the local government adds credit strength for both entities as it increases the predictability of the transfer amount. However, when a transfer policy is established after a contentious debate and represents a substantial portion of the utility's own revenues, this could have a negative rating impact if it produces uncompetitive electric rates or leaves limited internal funds available for utility operations, maintenance, and repairs.

Rating Factor 2 – Willingness to Recover Costs with Sound Financial Metrics (25% weight)

Aaa	Aa	A	Baa	Ba
Excellent rate-setting record; Rates, fuel, & purchased power cost adjustments less than 10 days; No political intervention in past or extremely high support from related government; Very limited General Fund transfers governed by policy	Strong rate-setting record; Rates, fuel, & purchased power cost adjustments 10 to 30 days; Limited political intervention in past or high support from related government; Conservative and well-defined General Fund transfers governed by policy	Adequate rate-setting record; Rates, fuel, & purchased power cost adjustments 31 to 60 days; Some political intervention in past or average support from related government; Moderate General Fund transfers	Below average rate-setting record; Rates, fuel, & purchased power cost adjustments 61 to 99 days; Persistent political intervention or below average support from related government; Large General Fund transfer not governed by policy	Consistent record of insufficiently setting rates; Rates, fuel, & purchased power cost adjustments 100 days or more; Highly political climate or no support from related government; Sizeable General Fund transfer not governed by policy

Rating Factor 3 – Management of Generation Risks (10% weight)

Why it Matters

As an owner of power generating assets, the management of the generation risks and power supply costs and reliability has an influence on other rating factors like the utility's financial metrics and competitiveness. How the utility meets its current electricity demand and plans for future demand has direct bearing on the utility's leverage, customer satisfaction on rates and service reliability, and often the political support for the utility. Political support rooted in customer satisfaction can translate into greater willingness to establish the revenue requirements needed to keep the utility in sound financial condition. Public power electric utilities must keep the confidence of their governing board and the community. A lack of operational success could lead to questions as to why the public power electric utility is in this business in the first place.

The electric industry is a capital intensive industry and a public power electric utility's short-term decisions often have an impact on the utility's long-term success. Management's successful resource planning is fundamental to the utility's outlook given the need to provide low cost reliable power supply to its customers. Today this factor is becoming increasingly more challenging to manage given looming environmental regulations related to clean air and renewable standards.

How We Measure Management of Generation Risks for the Grid

When evaluating the management of generation risks, Moody's considers the diversity of a utility's power supply and the cost and reliability of each source. Maintaining a diverse fuel and resource mix increases the utility's flexibility to manage peak demand while limiting the utility's exposure to volatile commodity and energy market prices, disruptions in the delivery of a single fuel source, or increased costs associated with a particular asset, like the cost of environmental compliance. To the extent possible we review the utility's generation performance record, including availability (% of time a unit is operational); capacity factor (% of rated capacity the generation unit runs); and heat rates (efficiency of a generator to convert fuel into electrical energy). Moody's will evaluate these performance

measurements in the context of the utility's overall power supply mix and the associated impact on the all-in cost of power supply, which drives the overall retail price charged to the end-use customer. Above market power supply costs could lead to higher retail charges to end-use customers, which would be a negative rating pressure.

Moody's considers the type of power generation used by the utility, since each type introduces its own set of challenges, which must be properly managed. Specific risks include the forecasted fuel price, transportation issues, and other factors unique to each fuel type; for example, Nuclear Regulatory Commission (NRC) safety regulations for nuclear generation facilities, hydrology risks for hydroelectric generating units, and environmental compliance issues for coal-fired generating units.

After we identify the risks associated with the utility's generation assets, we then look at mitigating measures in place or that are anticipated to be used by management to reduce these risks. Flexibility to switch fuels, transportation routes or fuel storage lower exposure to price volatility and financial losses. A favorable power resource reserve margin allows a utility to better manage an unexpected forced outage of a large generating facility. Risk exposures that are not adequately mitigated would result in a lower score on this factor. See Appendix E for Generation Risks for Major Fuels and Mitigation Table.

Those public power electric utilities with limited diversification or that are heavily reliant on a single type of generation and fuel source will score lower on this factor. Hydrology risk may be pronounced if a utility has significant reliance on hydroelectric generation. This may be mitigated somewhat by the cost competitiveness of the fuel source and by ready access to alternative sources of generation. Utilities with a high reliance on coal-fired generation are likely to score lower on this factor due to their vulnerability to future EPA regulation, including potential future greenhouse gas regulations.

Rating Factor 3 – Management of Generation Risks (10% weight)

Aaa	Aa	A	Baa	Ba
Very strong management of generation risks; High degree of diversification of generation and/or fuel sources; Well insulated from commodity price changes; Single generation asset typically provides less than 20% of power; and/or up to 20% of energy from coal-fired generation with carbon mitigation strategy	Strong management of generation risks; Some diversification of generation and/or fuel sources; Minimally affected by commodity price changes; Single generation asset typically provides less than 40% of power; and/or 21% to 40% of energy from coal-fired generation with carbon mitigation strategy	Average management of generation risks; Some reliance in one type of generation or fuel source, but diversified with purchased power sources; Modest exposure to commodity price changes; Single generation asset typically provides 40% to 55% of power; and/or 41% to 55% of energy from coal-fired generation with carbon mitigation strategy	Below average management of generation risks; Reliance on a single type of generation or fuel source, with limited diversification via purchased power; Moderate exposure to commodity prices; Single generation asset typically provides 56% to 75% of power; and/or 56% to 70% of energy from coal-fired generation with no carbon mitigation strategy	Poor management of generation risks; High concentration in a single type of generation or highly reliant on a single fuel source, with minimal diversification via purchased power; Notably exposed to commodity price shocks; Single generation asset typically provides over 75% of power; and/or 71% to 100% of energy from coal-fired generation with no carbon mitigation strategy

Rating Factor 4 – Competitiveness (10% weight)

Why it Matters

Despite the closed retail market for almost all public power electric utilities, an important advantage of the sector is its price competitiveness for the power it sells to its retail and/or wholesale customers. We would expect increased political risks if the utility has uncompetitive rates, leading to a potentially

more challenging rate setting environment. High retail rates cause pressure on the governing board to lower rates, which could affect the utility's ability to recover costs and weaken debt service coverage. In addition, high rates also may discourage economic development and contribute to a stagnant or declining revenue base, which could impact debt service coverage in the long-run. Public power electric utilities that have large customers in industries where energy is a large portion of the company's operating budget and contribute significantly to a utility's net income, could face pressure from high industrial or commercial retail rates and decide to relocate elsewhere. This relocation could place additional upward pressure on electric rates for the remaining customers.

How We Measure Competitiveness for the Grid

Moody's will compare a utility's average system retail rate against the regional or state average rate, as well as the utility's competitiveness versus neighboring utilities. A comparison of retail rates is generally expressed in terms of the average revenue per kilowatt hour (cents/kwh). This unit measure has limitations since it doesn't distinguish between different load factor customers. Nevertheless, this measure is a useful benchmark that can allow comparisons within regional markets. Rate competitiveness is measured against state averages in the grid, but the assigned scores may be adjusted for a utility's competitiveness against other regional utilities or in specific customer classes. We will also compare wholesale rates where appropriate against regional benchmarks to assess the competitive position of the wholesale part of the utility's business.

Rating Factor 4 – Competitiveness (10% weight)

Aaa	Aa	A	Baa	Ba
System retail rates more than 25% below average	25% to 7.51% below average	7.50% below average to 7.5% above average	7.51% to 25% above average	More than 25% above average

Rating Factor 5 – Financial Strength (30% weight)

We have identified four key financial ratios that we consider the most useful in evaluating a U.S. public power electric utility generator financial profile. The four ratios measure liquidity, leverage, and coverage and consist of:

1. Adjusted Days Liquidity on Hand Ratio

2. Debt Ratio

3. Adjusted Debt Service Coverage Ratio OR Fixed Obligation Charge Coverage Ratio

Why it Matters

Public power electric utilities that own generation are typically capital intensive enterprises and have an ongoing need to invest in new and existing generation assets. Utilities that own generation are large debt issuers and typically require consistent access to the capital markets to assure adequate sources of funding and to maintain financial flexibility. As such, a utility's financial strength is key to its long-term viability. Moody's also evaluates the financial performance and position of public power electric utilities to determine their ability to manage their specific business risks while assuring timely payment of debt service and compliance with certain financial legal covenants specified in the bond documents.

Although financial ratio analysis is useful in comparing one utility's performance to that of another, no single financial ratio can adequately communicate the relative credit strength of these diverse entities.

The relative strength of a utility's financial ratios must be viewed in the context of its business risks identified by the more qualitative factors in the methodology such as in Factor 3.

How We Measure Financial Strength for the Grid

Financial Strength: Liquidity

Adjusted Days Liquidity on Hand Ratio (10% weight)

The assessment of liquidity is a key element in the financial analysis of public power electric utilities and includes the ability to generate cash from internal sources, as well as accounting for the availability of external sources of liquidity. The sources of funds are compared to the utility's operating cash flow needs over the next year and beyond. This assessment considers the ability to pass through costs that tend to be an immediate drain on liquidity, including fuel and purchased power costs. Also, the strength of the utility's enterprise risk management program will be considered since a successful program could limit immediate use of liquidity.

Moody's will continue to use current days cash on hand to evaluate liquidity, which takes a conservative view of a public power utility's liquidity profile by only including available cash and unrestricted investments in the calculation. Moody's has augmented this approach with a new ratio called the Adjusted Days Liquidity on Hand Ratio. This ratio incorporates acceptable bank lines and certain legally required reserves. In addition, unused commercial paper capacity will be counted only if backed by a liquidity facility that meets Moody's P-1 rating criteria with no Material Adverse Change (MAC) clauses or other similar limiting provisions. The Adjusted Days Liquidity on Hand Ratio is calculated based on a utility's available adjusted liquidity including unrestricted cash and investments and acceptable bank lines of credit times 365 days divided by the utility's annual operating and maintenance expenses.

The highest "Aaa" and "Aa" scores under this sub-factor would be assigned to those utilities that are financially strong with strong levels of internal liquidity and modest reliance on external funding sources. We will review each bank line agreement on a case by case basis to determine whether or not the agreement satisfies our criteria in order to be included in our assessment of a utility's liquidity.

Evaluation of a Bank Line

Moody's will incorporate available bank lines into the calculation of a public power electric utility's liquidity only to the extent Moody's believes the terms of the bank line are acceptable to ensure the line's availability at the time of a potential draw on the facility. The existence of a MAC clause is one source of weakness in a bank line agreement. A MAC is a legal provision within a credit agreement that gives lenders the right to refuse to fund a commitment, should the borrower experience adverse business or economic developments. These adverse conditions can include numerous undefined factors the bank could cite to delay the funding requirement. Typically, the bank lines we will include are used for operating cash flow or for the prefunding of capital expenditures. We will not include credit facilities utilized as liquidity support for commercial paper note programs or other variable rate debt instruments. However, we will include unused commercial paper capacity in the adjusted liquidity calculation.

The strength of the bank line is determined by three main factors: the tenor; the counterparty's credit; and the line's availability during periods of unexpected market or utility stress. Our analysis includes a review of loan documentation for any language that might weaken the quality of the facility by potentially blocking a borrower's access.

Moody's will evaluate the tenor of the agreement to match the line availability against the period covered by the forecasted cash flow requirements. Should the expiration date fall in advance of such requirements, then renewal risk would be an issue. Longer dated tenors are more favorable from a credit perspective.

Financial Strength: Leverage

Debt Ratio (10% weight)

Moody's utilizes the debt ratio to measure a public power electric utility's leverage (the ratio of net funded debt divided by net fixed assets plus net working capital). We also compare the absolute level of the utility's current debt ratio to the median for similar utilities and evaluate the likely future trend in the ratio. Net working capital is defined as cash and investments plus receivables expected to be collected minus current liabilities unrelated to debt.

It is important to point out that a public power electric utility's capital structure is heavily reliant on debt, which contrasts with the substantial private shareholder equity that investor owned utilities (IOUs) share. As a result, a public power electric utility's debt to equity ratio is usually much worse than the rest of the U.S. electric industry. Moody's accepts higher relative leverage because of the sector's unregulated and timely cost recovery process, coupled with a sound record in support of debt service coverage on amortizing debt.

Public power utilities that own generation and transmission assets will be more heavily leveraged against their depreciated assets than distribution systems. For example, utilities that own generation have a median debt ratio of about 60%. The higher amount of debt does not mean that rates will be higher than a distributor's rates, it simply reflects a different cost structure.

A public power electric utility that owns generation and is leveraged well above the median may have less financial flexibility and higher rates that are not as competitive as less leveraged utilities with similar amounts of owned-generation relative to their size. High leverage may also prevent or limit a utility's ability to construct new generation facilities or maintain existing facilities.

Financial Strength: Financial Operating Resiliency

Adjusted Debt Service Coverage Ratio OR Fixed Obligation Charge Coverage Ratio (10% weight)

Moody's analyzes short and long-term trends in financial performance to assess the stability and resiliency of the utility. We use the adjusted debt service coverage ratio or fixed obligation charge coverage ratio to measure a utility's ability to repay annual debt service costs from recurring revenues net of recurring expenses, excluding one-time revenues or extraordinary charges. Consistent and stable debt service coverage provides increased resiliency to withstand revenue and expense volatility. Stable or improving debt service coverage is an important indicator of financial stability; whereas, declines in the coverage ratio could be indicative of financial strain or an unwillingness or inability to raise rates to fully recover the cost of service, which in turn could contribute to a weakening in credit quality.

Moody's has made a standard adjustment to the traditional debt service coverage ratio called the "Adjusted Debt Service Coverage Ratio", which recognizes that most public power utilities transfer a portion of their surplus revenues to a municipal government, typically to a city or county at an agreed upon level. While the transfers come after debt service in the legal flow of funds, practically, the transfer is a requirement and in many cases the transfer is made on a monthly basis. Therefore, Moody's Adjusted Debt Service Coverage Ratio treats the transfer as an operating expense, whereas the traditional or bond ordinance debt service coverage ratio does not.

Moody's will utilize the adjusted debt service coverage ratio as the key coverage metric because it provides a better explanation of a utility's operating results and greater comparability amongst public power electric utilities. Moody's calculates the adjusted debt service coverage ratio by dividing annual net revenues (gross revenue and income minus operating and maintenance expenses net of depreciation but including General Fund transfers) by total debt service costs.

Fixed Obligation Charge Coverage Ratio

When applicable, Moody's makes another adjustment to the adjusted debt service coverage ratio to incorporate "debt like "obligations related to the ownership of generation assets through a joint power agency (JPA) under a take-or-pay contracts. This new adjusted ratio is called the "Fixed Obligation Charge Coverage Ratio". Moody's notes that many public power enterprises finance the development or purchase of generation assets through JPA's to increase power reliability, diversify the power resource mix, and lower power costs. Moody's views these contractual obligations as fixed and the annual payments as "debt like". Moody's Fixed Obligation Charge Coverage Ratio subtracts the debt potion of the take-or-pay contractual payment from the utility's operating expenses when calculating net revenues, and subsequently adds the take-or-pay contractual payment to the total debt service costs when calculating coverage.

The Fixed Obligation Charge Coverage Ratio facilitates uniform comparisons of utilities that finance generation assets on balance sheet with utilities that finance assets off balance sheet through JPAs. Moody's uses the Fixed Obligation Charge Coverage Ratio in its analysis of financial results to provide a more consistent comparison of utilities, regardless of the approach to financing generation asset ownership.

Rating Factor 5 – Financial Strength (30% weight)

Liquidity: Adjusted Days Liquidity on Hand (3 year average) (days) – (10% weight)				
Aaa	**Aa**	**A**	**Baa**	**Ba**
≥ 250 days	≥ 150 days to 249 days	≥ 90 days to 149 days	≥ 30 days to 89 days	less than 30 days
Leverage: Debt Ratio (3 year average) (%) – (10% weight)				
Aaa	**Aa**	**A**	**Baa**	**Ba**
Less than 25%	≥ 25% to 50%	≥ 50% to 75%	≥ 75% to 100%	≥ 100%
Financial Operating Resiliency: Adjusted Debt Service Coverage or Fixed Obligation Charge Coverage Ratio (3 year average) (x) – (10% weight)				
Aaa	**Aa**	**A**	**Baa**	**Ba**
≥ 2.50x	≥ 2.00x to 2.49x	≥ 1.50x to 1.99x	≥ 1.10x to 1.49x	Below 1.10 x

Other Rating Considerations

Notching Conventions

While the factors and sub-factors within the grid are designed to include the key rating drivers reflecting the fundamental risks of public power electric utilities that own generation, the grid alone cannot capture some of the wide ranging variables that may impact the credit rating.

The notching factors are designed to adjust, either upwards or downwards, a utility's indicated rating based on other considerations not adequately addressed in the rating grid. Moody's analysts may or

may not assign a notch upwards or downwards to a rating as this is a case by case assessment determined by rating committee.

Debt Service Reserve Funds

Public power utilities have vastly different approaches to debt service reserve funds. Moody's believes that fully funded maximum annual debt service reserve funds are an important part of revenue bondholder security, particularly given the recent uncertain credit markets. The lack of a debt service reserve fund could result in a grid-indicated rating adjustment downward. Some utilities have fully cash funded reserves equal to a full year's debt service requirements, others have no debt service reserve fund, and the rest have something in-between. The grid-indicated rating may be adjusted down by a one to one-half a notch for utilities that have less than a full year debt service reserve fund, depending on the utility's level of liquidity. In cases where the utility has maintained at least 100 days of liquidity on hand, Moody's may lessen the downward notching for the lack of a reserve fund.

Customer Concentration

Large customer concentration could be a credit factor and result in a grid-indicated rating adjustment downward, particularly for smaller public power electric utilities. Credit pressure could result if a single large customer departed without compensating the utility for any outstanding debt issued to construct facilities needed to serve that customer and may leave the utility with excess power it may have to sell into the market at a lower rate. Moody's considers whether there is a positive margin earned from the large customer above the cost of service, and whether the utility has any contractual recourse to offset any loss for capital improvements that were undertaken to connect and serve the large customer prior to departure from the system. Moody's downward adjustment for concentration also considers whether fixed system costs have to be shared with the remaining customer base, requiring significant rate increases. Customer concentration with relatively stable university, government, and health care institutions is not viewed as negatively as concentration with a more volatile corporate customer.

Construction Risk

Moody's assesses each utility's construction risks and may adjust the grid-indicated rating if there is unmitigated risk. We look to third-party consulting engineers to provide an assessment of the risks associated with a particular project. Review of a well defined project feasibility study is often a critical component of our assessment. Risk mitigation may include fixed-price contracts with liquidated damages, performance and payment bonds, and program management oversight. Technological risk may also be a notching consideration for first-in-kind engineering risks.

Debt Structure and Financial Engineering

Moody's will evaluate the existing and projected debt structure and may adjust the grid-indicated rating if unmitigated risks are identified. Moody's will look at the bond covenanted legal protections, the amortization schedule, and the exposure to variable rate debt and interest rate swap agreements. We will evaluate debt management and interest rate swap policies, board oversight of interest rate swaps, and a utility's disclosure of the risks and exposures associated with its debt.

We evaluate exposure to unhedged variable rate instruments in relation to the utility's liquidity and its debt management record, including the absolute level of variable rate debt. We also closely evaluate the potential for financial stress related to a change in short-term interest rates, credit market volatility, and/or a tightening of available internal and external liquidity. We assess the utility's interest rate swap derivatives and the circumstances under which the utility will be required to post collateral and the

right of the utility's swap counterparty to terminate the swap should certain events occur, such as a downgrade of the utility below a certain rating level.

Moody's will also review the utility's bond security provisions and if they are weak against the norm this may affect the credit rating. For example, rate covenants that are absent of at least one times coverage will be viewed as a credit negative.

Unmitigated Exposure to Wholesale Power Markets

Public power electric utilities that have excess power supply or were established to supply wholesale power have potential additional credit risks should the utility's financial operations not include mitigation factors to limit the impact of wholesale market price volatility. Typically, public power electric utilities have long-term wholesale power supply contracts with established counterparties that ensure cost recovery. However, some utilities that have excess supply often utilize margins earned from selling this excess power into wholesale energy markets to limit retail rate increases on native customers. The problem with this strategy has been that there is no certainty that such wholesale energy sale margins will always be available. For example, in the past couple of years reduced wholesale energy market earnings and inadequate retail rate increases has reduced the debt service coverage ratio for several public power electric utilities. Exposure to the wholesale power market may result in an adjustment to the grid-indicated rating unless it is mitigated by wholesale power contracts with sound counterparties, strong available liquidity that could withstand a period of lower wholesale energy margins, and/or a timely and transparent retail rate-setting process.

Rating Methodology Assumptions and Limitations, and Other Rating Considerations

The rating methodology grid incorporates a trade-off between simplicity that enhances transparency and greater complexity that would enable the grid to map more closely to actual ratings. The five rating factors in the grid do not constitute an exhaustive treatment of all the considerations that are important for ratings of public power electric utilities that own generation. Our ratings incorporate expectations for future performance, while the financial information that is used to illustrate the mapping in the grid is mainly historical. In some cases, our expectations for future performance may be informed by confidential information that we cannot publish. In other cases, we estimate future results based upon past performance, industry trends, demand and price outlooks, peer actions and other factors.

In choosing the factors for this rating methodology grid, we did not include certain important factors that are common to all utilities in any industry, such as quality and experience of management. Assessment of a utility's governance can be highly subjective and ranking them by rating category in a grid would, in some cases, suggest too much precision in the relative ranking of particular issuers that are rated in the different industry sectors.

Ratings may include additional factors that are difficult to quantify or that only have a meaningful effect in differentiating credit quality in some cases. Such factors include environmental compliance, nuclear decommissioning trust obligations, and financial controls.

Actual ratings assigned may also reflect circumstances in which the weighting of a particular factor will be different from the weighting suggested by the grid. For example, Factor 1 addresses the cost recovery framework; however, there may be instances where the effects of a public power electric utility's financial metrics will be given greater consideration in the assigned rating than what is indicated by the weighting in the grid.

Appendix A: Issuers Included in Methodology Update

Rated Issuers Sorted by Rating Category

Obligor Name	State	Electric Enterprise Rating	Outlook	Debt Outstanding ($'000)
San Antonio (City Of) Tx Combined Utility Enterprise	TX	Aa1	STA	4,835,820
Salt River Agriculture Improvement & Power District, Az	AZ	Aa1	STA	4,558,734
Omaha Public Power District, Ne	NE	Aa1	STA	2,011,969
Orlando Utilities Commission, Fl	FL	Aa1	NEG	1,823,711
Jea, Fl	FL	Aa2	STA	4,277,698
Colorado Springs (City Of) Co Combined Utility Enterprise	CO	Aa2	NEG	2,267,325
New York State Power Authority	NY	Aa2	STA	1,941,000
Seattle (City Of) Wa Electric Enterprise	WA	Aa2	STA	1,536,775
Chelan County Public Utility District 1, Wa	WA	Aa2	NEG	1,027,620
Gainesville (City Of) Fl Combined Utility Enterprise	FL	Aa2	STA	956,770
Memphis (City Of) Tn Electric Enterprise	TN	Aa2	STA	848,305
Lincoln (City Of) Ne Electric Enterprise	NE	Aa2	STA	584,050
Rochester (City Of) Mn Electric Enterprise	MN	Aa2	STA	90,100
Arizona Power Authority	AZ	Aa2	STA	41,750
Los Angeles Department Of Water & Power, CA	CA	Aa3	STA	5,711,209
South Carolina Public Service Authority	SC	Aa3	STA	5,154,620
Grant County Public Utility District 2, WA	WA	Aa3	STA	1,068,685
Springfield (City Of) Mo Combined Utility Enterprise	MO	Aa3	STA	773,571
Tallahassee (City Of) Fl Electric Enterprise	FL	Aa3	STA(m)	630,150
Snohomish County Public Utility District 1, WA Electric Enterprise	WA	Aa3	STA	627,616
Tacoma (City Of) Wa Electric Enterprise	WA	Aa3	STA	612,615
Douglas County Public Utility District 1, Wa	WA	Aa3	STA	273,700
Lansing Board Of Water & Light, Mi	MI	Aa3	STA	177,787
Glendale (City Of) Ca Electric Enterprise	CA	Aa3	NOO	121,500
Fayetteville Public Works Commission, Nc	NC	Aa3	POS	150,480
Cedar Falls (City Of) Ia Electric Enterprise	IA	Aa3	NOO	56,310
Lower Colorado River Authority	TX	A1	STA	3,085,151
Sacramento Municipal Utility District	CA	A1	STA	2,811,850
Nebraska Public Power District	NE	A1	STA	2,275,745
Austin (City Of) Tx Electric Enterprise	TX	A1	STA	1,412,630
Anaheim (City Of) Ca Electric Enterprise	CA	A1	STA	647,365
Lakeland (City Of) Fl Electric Enterprise	FL	A1	NEG	520,399
Imperial Irrigation District, Ca	CA	A1	STA	299,827
Kissimmee Utility Authority, Fl	FL	A1	NOO	223,525
Santa Clara (City Of) Ca Electric Enterprise	CA	A1	STA	223,170

Rated Issuers Sorted by Rating Category

Obligor Name	State	Electric Enterprise Rating	Outlook	Debt Outstanding ($'000)
Denton (City Of) Tx Combined Utility Enterprise	TX	A1	NOO	209,885
Columbia (City Of) Mo Combined Utility Enterprise	MO	A1	NOO	192,364
Lafayette (City Of) La Combined Utilities Enterprise	LA	A1	STA	191,400
Bryan (City Of) Tx Electric Enterprise	TX	A1	NOO	175,835
Cowlitz County Public Utility District 1	WA	A1	NOO	149,100
Ocala (City Of) Fl Combined Utility Enterprise	FL	A1	NOO	142,860
Burbank (City Of) Ca Combined Utility Enterprise	CA	A1	STA	113,055
Manitowoc (City Of) Wi Electric Enterprise	WI	A1	STA	76,158
Greenville Utilities Commission, Nc	NC	A1	NOO	68,990
St. George (City Of) Ut Electric Enterprise	UT	A1	NOO	64,180
Vero Beach (City Of) FL Electric Enterprise	FL	A1	NOO	57,155
Springfield (City Of) IL Electric Enterprise	IL	A1	NEG	42,311
Jacksonville Beach (City Of) Fl Combined Utility Enterprise	FL	A1	NOO	41,589
Holyoke Gas And Electric Department	MA	A1	STA	41,548
Grand Island (City Of) Ne Electric Enterprise	NE	A1	STA	29,915
Independence (City Of) Mo Combined Utility Enterprise	MO	A1	NOO	28,557
Farmington (City Of) Nm Combined Utility Enterprise	NM	A1	STA	27,916
Batavia (City Of) Il Electric Enterprise	IL	A1	STA	26,290
Geneva (City Of) Il Electric Enterprise	IL	A1	STA	19,198
Moorhead (City Of) Mn Combined Utility Enterprise	MN	A1	NOO	17,044
Jonesboro (City Of) Ar Combined Utility Enterprise	AR	A1	NOO	16,035
Provo (City Of) Ut Electric Enterprise	UT	A1	NOO	15,411
Spencer (City Of) Ia Electric Enterprise	IA	A1	NOO	12,325
Owatonna Public Utilities Commission	MN	A1	NOO	8,500
Sun Prairie (City Of) Wi Combined Utility Enterprise	WI	A1	NOO	7,192
Atlantic (City Of) Ia Electric Enterprise	IA	A1	NOO	6,850
Waverly (City Of) Ia	IA	A1	NOO	6,736
Zeeland (City Of) Mi Electric Enterprise	MI	A1	NOO	3,330
Jackson (City Of) Mo Electric Enterprise	MO	A1	NOO	1,835
Turlock Irrigation District, Ca	CA	A2	STA	966,700
Modesto Irrigation District, Ca	CA	A2	STA	860,199
Grand River Dam Authority, Ok	OK	A2	STA	834,596
Clark County Public Utility District 1, Wa	WA	A2	STA	407,215
Unified Government Of Wyandotte County/Kansas City,Ks Combined Utility Enterprise	KS	A2	NEG	360,193
Brownsville (City Of) Tx	TX	A2	STA	299,210
Roseville (City Of) Ca Electric Enterprise	CA	A2	NEG	268,432
Cleveland (City Of) Oh Electric Enterprise	OH	A2	STA	266,313
Bryan Rural Electric System	TX	A2	NOO	181,890

Rated Issuers Sorted by Rating Category

Obligor Name	State	Electric Enterprise Rating	Outlook	Debt Outstanding ($'000)
Paducah (City Of) Ky Electric Enterprise	KY	A2	NEG	173,690
Rock Hill (City Of) Sc Combined Utility Enterprise	SC	A2	NOO	124,857
Lodi (City Of) Electric Public Power	CA	A2	STA	80,525
Key West Utility Board, Fl	FL	A2	STA	79,758
Colton (City Of) Ca Electric Enterprise	CA	A2	NOO	56,029
Easley (City Of) Sc Combined Utility Enterprise	SC	A2	NOO	55,685
Monroe (City Of) Nc Combined Utility Enterprise	NC	A2	NOO	51,479
Los Alamos (County Of) Nm Combined Utility Enterprise	NM	A2	NOO	47,406
Hastings (City Of) Ne Electric Enterprise	NE	A2	STA	40,570
Leesburg (City Of) Fl Electric Enterprise	FL	A2	NOO	40,220
Newnan Water, Sewerage & Light Commission, Ga	GA	A2	NOO	36,642
Greer Commission Of Public Works, Sc	SC	A2	NOO	35,209
Plymouth (City Of) Wi Combined Utility Enterprise	WI	A2	NOO	24,770
Monroe (City Of) Ga Combined Utility Enterprise	GA	A2	NOO	24466
Greenville (City Of) Tx Electric Enterprise	TX	A2	NEG	23,610
Shakopee Public Utilities Commission, Mn	MN	A2	NOO	21,470
Murray City (City Of) Ut Electric Enterprise	UT	A2	NOO	21,190
Algona (City Of) Ia Electric Enterprise	IA	A2	NOO	16,100
Pella (City Of) Ia Electric Enterprise	IA	A2	NOO	13,220
Indianola (City Of) Ia Electric Enterprise	IA	A2	NOO	12,568
Waunakee (Village Of) Wi Combined Utility Enterprise	WI	A2	NOO	8,590
Stoughton (City Of) Wi	WI	A2	NOO	6,630
Oconomowoc (City Of) Wi Electric Utility Enterprise	WI	A2	NOO	5,480
Alexandria (City Of) Mn Electric Enterprise	MN	A2	NOO	5,130
River Falls (City Of) Wi Electric Enterprise	WI	A2	NOO	3,575
New Richmond (City Of) Wi Electric Enterprise	WI	A2	NOO	2,305
Long Island Power Authority, Ny	NY	A3	NEG	9,622,960
Puerto Rico Electric Power Authority	PR	A3	NEG	8,230,982
Vernon (City Of) Ca Electric Enterprise	CA	A3	NEG	458,165
Hamilton (City Of) Oh Electric Enterprise	OH	A3	STA	168,775
Owensboro (City Of) Ky Electric Enterprise	KY	A3	NEG	149,878
Pend Oreille County Public Utility District 1, Wa	WA	A3	NEG	140,534
Griffin (City Of) Ga Combined Utility Enterprise	GA	A3	NOO	67,677
Confederated Tribes Warm Springs Reservation	OR	A3	STA	57,130
Marshall (City Of) Mn Combined Utility Enterprise	MN	A3	NOO	39,355
Kaukauna (City Of) Wi Electric Enterprise	WI	A3	NOO	33,540
Rochelle (City Of) Il Electric Enterprise	IL	A3	STA	14,245
Elberton (City Of) Ga Combined Utility Enterprise	GA	A3	NOO	13,913

Rated Issuers Sorted by Rating Category

Obligor Name	State	Electric Enterprise Rating	Outlook	Debt Outstanding ($'000)
Princeton (City Of) Mn Combined Utility Enterprise	MN	A3	NOO	13,739
Waupun (City Of) Wi Combined Utility Enterprise	WI	A3	NOO	12,790
Harlan Municipal Utilities, Ia	IA	A3	NOO	11,930
Gaffney (City Of) Sc Combined Utility Enterprise	SC	A3	NOO	11,150
St. Peter (City Of) Mn Electric Enterprise	MN	A3	NOO	10,110
Azusa (City Of) Electric (Light) Fund	CA	A3	NOO	9,525
Morgan City (City Of) La Combined Utility Enterprise	LA	A3	NOO	8,540
Coldwater (City Of) Mi Electric Enterprise	MI	A3	NOO	6,956
Henderson Municipal Power & Light	KY	A3	STA	5,433
Redwood Falls (City Of) Mn Electric Enterprise	MN	A3	STA	1,920
Glenwood Springs (City Of) Co Electric Enterprise	CO	A3	NOO	310
Princeton (City Of) Ky	KY	Baa1	NOO	45,258
Shelby (City Of) Nc Combined Utility Enterprise	NC	Baa1	NOO	33,734
Washington City (City Of) Ut Electric Enterprise	UT	Baa1	NOO	6,410
Clinton (City Of) Sc Combined Utility Enterprise	SC	Baa1	NOO	6,123
Detroit Lakes (City Of) Mn Electric Enterprise	MN	Baa1	NOO	3,720
Virgin Islands Water & Power Authority	VI	Baa2	STA	190,270
Lakeview Light And Power	WA	Baa2	NEG	93,140
Burlington (City Of) Vt Electric Enterprise	VT	Baa2	NEG	36,370
Benson (City Of) Mn Electric Enterprise	MN	Baa2	NOO	6,442
Merced Irrigation District, Ca	CA	Baa3	NOO	88,090
Green Island Power Authority, Ny	NY	Baa3	NEG	18,320
Guam Power Authority	GU	Ba1	STA	587,240
Santa Clara (City Of) Ut Electric Enterprise	UT	Ba1	NEG	5,302

Rated Issuers Sorted by Debt Outstanding

Obligor Name	State	Actual Rating	Outlook	Debt Outstanding ($'000)
Long Island Power Authority, Ny	NY	A3	NEG	9,622,960
Puerto Rico Electric Power Authority	PR	A3	NEG	8,230,982
Los Angeles Department Of Water & Power, Ca Electric Enterprise	CA	Aa3	STA	5,711,209
South Carolina Public Service Authority	SC	Aa3	STA	5,154,620
San Antonio (City Of) Tx Combined Utility Enterprise	TX	Aa1	STA	4,835,820
Salt River Agriculture Improvement & Power District, Az	AZ	Aa1	STA	4,558,734
Jea, Fl	FL	Aa2	STA	4,277,698
Lower Colorado River Authority, Texas	TX	A1	STA	3,085,151
Sacramento Municipal Utility District, Ca	CA	A1	STA	2,811,850
Nebraska Public Power District	NE	A1	STA	2,275,745
Colorado Springs (City Of) Co Combined Utility Enterprise	CO	Aa2	NEG	2,267,325
Omaha Public Power District, Ne	NE	Aa1	STA	2,011,969
New York State Power Authority	NY	Aa2	STA	1,941,000
Orlando Utilities Commission, Fl	FL	Aa1	NEG	1,823,711
Seattle (City Of) Wa Electric Enterprise	WA	Aa2	STA	1,536,775
Austin (City Of) Tx Electric Enterprise	TX	A1	STA	1,412,630
Grant County Public Utility District 2, Wa	WA	Aa3	STA	1,068,685
Chelan County Public Utility District 1, Wa	WA	Aa2	NEG	1,027,620
Turlock Irrigation District, Ca	CA	A2	STA	966,700
Gainesville (City Of) Fl Combined Utility Enterprise	FL	Aa2	STA	956,770
Modesto Irrigation District, Ca	CA	A2	STA	860,199
Memphis (City Of) Tn Electric Enterprise	TN	Aa2	STA	848,305
Grand River Dam Authority, Ok	OK	A2	STA	834,596
Springfield (City Of) Mo Combined Utility Enterprise	MO	Aa3	STA	773,571
Anaheim (City Of) Ca Electric Enterprise	CA	A1	STA	647,365
Tallahassee (City Of) Fl Electric Enterprise	FL	Aa3	STA(m)	630,150
Snohomish County Public Utility District 1, Wa Electric Enterprise	WA	Aa3	STA	627,616
Tacoma (City Of) Wa Electric Enterprise	WA	Aa3	STA	612,615
Guam Power Authority	GU	Ba1	STA	587,240
Lincoln (City Of) Ne Electric Enterprise	NE	Aa2	STA	584,050
Lakeland (City Of) Fl Electric Enterprise	FL	A1	NEG	520,399
Vernon (City Of) Ca Electric Enterprise	CA	A3	NEG	458,165
Clark County Public Utility District 1, Wa	WA	A2	STA	407,215
Unified Government Of Wyandotte County/Kansas City,Ks Combined Utility Enterprise	KS	A2	NEG	360,193
Imperial Irrigation District, Ca	CA	A1	STA	299,827
Brownsville (City Of) Tx	TX	A2	STA	299,210
Douglas County Public Utility District 1, Wa	WA	Aa3	STA	273,700
Roseville (City Of) Ca Electric Enterprise	CA	A2	NEG	268,432
Cleveland (City Of) Oh Electric Enterprise	OH	A2	STA	266,313

Rated Issuers Sorted by Debt Outstanding

Obligor Name	State	Actual Rating	Outlook	Debt Outstanding ($'000)
Kissimmee Utility Authority, Fl	FL	A1	NOO	223,525
Santa Clara (City Of) Ca Electric Enterprise	CA	A1	STA	223,170
Denton (City Of) Tx Combined Utility Enterprise	TX	A1	NOO	209,885
Columbia (City Of) Mo Combined Utility Enterprise	MO	A1	NOO	192,364
Lafayette (City Of) La Combined Utilities Enterprise	LA	A1	STA	191,400
Virgin Islands Water & Power Authority	VI	Baa2	STA	190,270
Bryan Rural Electric System	TX	A2	NOO	181,890
Lansing Board Of Water & Light, Mi	MI	Aa3	STA	177,787
Bryan (City Of) Tx Electric Enterprise	TX	A1	NOO	175,835
Paducah (City Of) Ky Electric Enterprise	KY	A2	NEG	173,690
Hamilton (City Of) Oh Electric Enterprise	OH	A3	STA	168,775
Fayetteville Public Works Commission, Nc	NC	Aa3	POS	150,480
Owensboro (City Of) Ky Electric Enterprise	KY	A3	NEG	149,878
Cowlitz County Public Utility District 1	WA	A1	NOO	149,100
Ocala (City Of) Fl Combined Utility Enterprise	FL	A1	NOO	142,860
Pend Oreille County Public Utility District 1, Wa	WA	A3	NEG	140,534
Rock Hill (City Of) Sc Combined Utility Enterprise	SC	A2	NOO	124,857
Glendale (City Of) Ca Electric Enterprise	CA	Aa3	NOO	121,500
Burbank (City Of) Ca Combined Utility Enterprise	CA	A1	STA	113,055
Lakeview Light And Power	WA	Baa2	NEG	93,140
Rochester (City Of) Mn Electric Enterprise	MN	Aa2	STA	90,100
Merced Irrigation District, Ca	CA	Baa3	NOO	88,090
Lodi (City Of) Electric Public Power	CA	A2	STA	80,525
Key West Utility Board, Fl	FL	A2	STA	79,758
Manitowoc (City Of) Wi Electric Enterprise	WI	A1	STA	76,158
Greenville Utilities Commission, Nc	NC	A1	NOO	68,990
Griffin (City Of) Ga Combined Utility Enterprise	GA	A3	NOO	67,677
St. George (City Of) Ut Electric Enterprise	UT	A1	NOO	64,180
Vero Beach (City Of) Fl Electric Enterprise	FL	A1	NOO	57,155
Confederated Tribes Warm Springs Reservation	OR	A3	STA	57,130
Cedar Falls (City Of) Ia Electric Enterprise	IA	Aa3	NOO	56,310
Colton (City Of) Ca Electric Enterprise	CA	A2	NOO	56,029
Easley (City Of) Sc Combined Utility Enterprise	SC	A2	NOO	55,685
Monroe (City Of) Nc Combined Utility Enterprise	NC	A2	NOO	51,479
Los Alamos (County Of) Nm Combined Utility Enterprise	NM	A2	NOO	47,406
Princeton (City Of) Ky	KY	Baa1	NOO	45,258
Springfield (City Of) IL Electric Enterprise	IL	A1	NEG	42,311
Arizona Power Authority	AZ	Aa2	STA	41,750
Jacksonville Beach (City Of) Fl Combined Utility Enterprise	FL	A1	NOO	41,589

Rated Issuers Sorted by Debt Outstanding

Obligor Name	State	Actual Rating	Outlook	Debt Outstanding ($'000)
Holyoke Gas And Electric Department	MA	A1	STA	41,548
Hastings (City Of) Ne Electric Enterprise	NE	A2	STA	40,570
Leesburg (City Of) Fl Electric Enterprise	FL	A2	NOO	40,220
Marshall (City Of) Mn Combined Utility Enterprise	MN	A3	NOO	39,355
Newnan Water, Sewerage & Light Commission, Ga	GA	A2	NOO	36,642
Burlington (City Of) Vt Electric Enterprise	VT	Baa2	NEG	36,370
Greer Commission Of Public Works, Sc	SC	A2	NOO	35,209
Shelby (City Of) Nc Combined Utility Enterprise	NC	Baa1	NOO	33,734
Kaukauna (City Of) Wi Electric Enterprise	WI	A3	NOO	33,540
Grand Island (City Of) Ne Electric Enterprise	NE	A1	STA	29,915
Independence (City Of) Mo Combined Utility Enterprise	MO	A1	NOO	28,557
Farmington (City Of) Nm Combined Utility Enterprise	NM	A1	STA	27,916
Batavia (City Of) Il Electric Enterprise	IL	A1	STA	26,290
Plymouth (City Of) Wi Combined Utility Enterprise	WI	A2	NOO	24,770
Monroe (City Of) Ga Combined Utility Enterprise	GA	A2	NOO	24466
Greenville (City Of) Tx Electric Enterprise	TX	A2	NEG	23,610
Shakopee Public Utilities Commission, Mn	MN	A2	NOO	21,470
Murray City (City Of) Ut Electric Enterprise	UT	A2	NOO	21,190
Geneva (City Of) Il Electric Enterprise	IL	A1	STA	19,198
Green Island Power Authority, Ny	NY	Baa3	NEG	18,320
Moorhead (City Of) Mn Combined Utility Enterprise	MN	A1	NOO	17,044
Algona (City Of) Ia Electric Enterprise	IA	A2	NOO	16,100
Jonesboro (City Of) Ar Combined Utility Enterprise	AR	A1	NOO	16,035
Provo (City Of) Ut Electric Enterprise	UT	A1	NOO	15,411
Rochelle (City Of) Il Electric Enterprise	IL	A3	STA	14,245
Elberton (City Of) Ga Combined Utility Enterprise	GA	A3	NOO	13,913
Princeton (City Of) Mn Combined Utility Enterprise	MN	A3	NOO	13,739
Pella (City Of) Ia Electric Enterprise	IA	A2	NOO	13,220
Waupun (City Of) Wi Combined Utility Enterprise	WI	A3	NOO	12,790
Indianola (City Of) Ia Electric Enterprise	IA	A2	NOO	12,568
Spencer (City Of) Ia Electric Enterprise	IA	A1	NOO	12,325
Harlan Municipal Utilities, Ia	IA	A3	NOO	11,930
Gaffney (City Of) Sc Combined Utility Enterprise	SC	A3	NOO	11,150
St. Peter (City Of) Mn Electric Enterprise	MN	A3	NOO	10,110
Azusa (City Of) Electric (Light) Fund	CA	A3	NOO	9,525
Waunakee (Village Of) Wi Combined Utility Enterprise	WI	A2	NOO	8,590
Morgan City (City Of) La Combined Utility Enterprise	LA	A3	NOO	8,540
Owatonna Public Utilities Commission	MN	A1	NOO	8,500
Sun Prairie (City Of) Wi Combined Utility Enterprise	WI	A1	NOO	7,192

Rated Issuers Sorted by Debt Outstanding

Obligor Name	State	Actual Rating	Outlook	Debt Outstanding ($'000)
Coldwater (City Of) Mi Electric Enterprise	MI	A3	NOO	6,956
Atlantic (City Of) Ia Electric Enterprise	IA	A1	NOO	6,850
Waverly (City Of) Ia	IA	A1	NOO	6,736
Stoughton (City Of) Wi	WI	A2	NOO	6,630
Benson (City Of) Mn Electric Enterprise	MN	Baa2	NOO	6,442
Washington City (City Of) Ut Electric Enterprise	UT	Baa1	NOO	6,410
Clinton (City Of) Sc Combined Utility Enterprise	SC	Baa1	NOO	6,123
Oconomowoc (City Of) Wi Electric Utility Enterprise	WI	A2	NOO	5,480
Henderson Municipal Power & Light	KY	A3	STA	5,433
Santa Clara (City Of) Ut Electric Enterprise	UT	Ba1	NEG	5,302
Alexandria (City Of) Mn Electric Enterprise	MN	A2	NOO	5,130
Detroit Lakes (City Of) Mn Electric Enterprise	MN	Baa1	NOO	3,720
River Falls (City Of) Wi Electric Enterprise	WI	A2	NOO	3,575
Zeeland (City Of) Mi Electric Enterprise	MI	A1	NOO	3,330
New Richmond (City Of) Wi Electric Enterprise	WI	A2	NOO	2,305
Redwood Falls (City Of) Mn Electric Enterprise	MN	A3	STA	1,920
Jackson (City Of) Mo Electric Enterprise	MO	A1	NOO	1,835
Glenwood Springs (City Of) Co Electric Enterprise	CO	A3	NOO	310

Rated Issuers Sorted by State

Obligor Name	State	Actual Rating	Outlook	Debt Outstanding ($'000)
Jonesboro (City Of) Ar Combined Utility Enterprise	AR	A1	NOO	16,035
Arizona Power Authority	AZ	Aa2	STA	41,750
Salt River Agriculture Improvement & Power District, Az	AZ	Aa1	STA	4,558,734
Anaheim (City Of) Ca Electric Enterprise	CA	A1	STA	647,365
Azusa (City Of) Electric (Light) Fund	CA	A3	NOO	9,525
Burbank (City Of) Ca Combined Utility Enterprise	CA	A1	STA	113,055
Colton (City Of) Ca Electric Enterprise	CA	A2	NOO	56,029
Glendale (City Of) Ca Electric Enterprise	CA	Aa3	NOO	121,500
Imperial Irrigation District, Ca	CA	A1	STA	299,827
Lodi (City Of) Electric Public Power	CA	A2	STA	80,525
Los Angeles Department Of Water & Power, Ca Electric Enterprise	CA	Aa3	STA	5,711,209
Merced Irrigation District, Ca	CA	Baa3	NOO	88,090
Modesto Irrigation District, Ca	CA	A2	STA	860,199
Roseville (City Of) Ca Electric Enterprise	CA	A2	NEG	268,432
Sacramento Municipal Utility District, Ca	CA	A1	STA	2,811,850
Santa Clara (City Of) Ca Electric Enterprise	CA	A1	STA	223,170
Turlock Irrigation District, Ca	CA	A2	STA	966,700
Vernon (City Of) Ca Electric Enterprise	CA	A3	NEG	458,165
Colorado Springs (City Of) Co Combined Utility Enterprise	CO	Aa2	NEG	2,267,325
Glenwood Springs (City Of) Co Electric Enterprise	CO	A3	NOO	310
Gainesville (City Of) Fl Combined Utility Enterprise	FL	Aa2	STA	956,770
Jacksonville Beach (City Of) Fl Combined Utility Enterprise	FL	A1	NOO	41,589
Jea, Fl	FL	Aa2	STA	4,277,698
Key West Utility Board, Fl	FL	A2	STA	79,758
Kissimmee Utility Authority, Fl	FL	A1	NOO	223,525
Lakeland (City Of) Fl Electric Enterprise	FL	A1	NEG	520,399
Leesburg (City Of) Fl Electric Enterprise	FL	A2	NOO	40,220
Ocala (City Of) Fl Combined Utility Enterprise	FL	A1	NOO	142,860
Orlando Utilities Commission, Fl	FL	Aa1	NEG	1,823,711
Tallahassee (City Of) Fl Electric Enterprise	FL	Aa3	STA(m)	630,150
Vero Beach (City Of) Fl Electric Enterprise	FL	A1	NOO	57,155
Elberton (City Of) Ga Combined Utility Enterprise	GA	A3	NOO	13,913
Griffin (City Of) Ga Combined Utility Enterprise	GA	A3	NOO	67,677
Monroe (City Of) Ga Combined Utility Enterprise	GA	A2	NOO	24466

Rated Issuers Sorted by State

Obligor Name	State	Actual Rating	Outlook	Debt Outstanding ($'000)
Newnan Water, Sewerage & Light Commission, Ga	GA	A2	NOO	36,642
Guam Power Authority	GU	Ba1	STA	587,240
Algona (City Of) Ia Electric Enterprise	IA	A2	NOO	16,100
Atlantic (City Of) Ia Electric Enterprise	IA	A1	NOO	6,850
Cedar Falls (City Of) Ia Electric Enterprise	IA	Aa3	NOO	56,310
Harlan Municipal Utilities, Ia	IA	A3	NOO	11,930
Indianola (City Of) Ia Electric Enterprise	IA	A2	NOO	12,568
Pella (City Of) Ia Electric Enterprise	IA	A2	NOO	13,220
Spencer (City Of) Ia Electric Enterprise	IA	A1	NOO	12,325
Waverly (City Of) Ia	IA	A1	NOO	6,736
Batavia (City Of) Il Electric Enterprise	IL	A1	STA	26,290
Geneva (City Of) Il Electric Enterprise	IL	A1	STA	19,198
Rochelle (City Of) Il Electric Enterprise	IL	A3	STA	14,245
Springfield (City Of) IL Electric Enterprise	IL	A1	NEG	42,311
Unified Government Of Wyandotte County/Kansas City,Ks Combined Utility Enterprise	KS	A2	NEG	360,193
Henderson Municipal Power & Light	KY	A3	STA	5,433
Owensboro (City Of) Ky Electric Enterprise	KY	A3	NEG	149,878
Paducah (City Of) Ky Electric Enterprise	KY	A2	NEG	173,690
Princeton (City Of) Ky	KY	Baa1	NOO	45,258
Lafayette (City Of) La Combined Utilities Enterprise	LA	A1	STA	191,400
Morgan City (City Of) La Combined Utility Enterprise	LA	A3	NOO	8,540
Holyoke Gas And Electric Department	MA	A1	STA	41,548
Coldwater (City Of) Mi Electric Enterprise	MI	A3	NOO	6,956
Lansing Board Of Water & Light, Mi	MI	Aa3	STA	177,787
Zeeland (City Of) Mi Electric Enterprise	MI	A1	NOO	3,330
Alexandria (City Of) Mn Electric Enterprise	MN	A2	NOO	5,130
Benson (City Of) Mn Electric Enterprise	MN	Baa2	NOO	6,442
Detroit Lakes (City Of) Mn Electric Enterprise	MN	Baa1	NOO	3,720
Marshall (City Of) Mn Combined Utility Enterprise	MN	A3	NOO	39,355
Moorhead (City Of) Mn Combined Utility Enterprise	MN	A1	NOO	17,044

Rated Issuers Sorted by State

Obligor Name	State	Actual Rating	Outlook	Debt Outstanding ($'000)
Owatonna Public Utilities Commission	MN	A1	NOO	8,500
Princeton (City Of) Mn Combined Utility Enterprise	MN	A3	NOO	13,739
Redwood Falls (City Of) Mn Electric Enterprise	MN	A3	STA	1,920
Rochester (City Of) Mn Electric Enterprise	MN	Aa2	STA	90,100
Shakopee Public Utilities Commission, Mn	MN	A2	NOO	21,470
St. Peter (City Of) Mn Electric Enterprise	MN	A3	NOO	10,110
Columbia (City Of) Mo Combined Utility Enterprise	MO	A1	NOO	192,364
Independence (City Of) Mo Combined Utility Enterprise	MO	A1	NOO	28,557
Jackson (City Of) Mo Electric Enterprise	MO	A1	NOO	1,835
Springfield (City Of) Mo Combined Utility Enterprise	MO	Aa3	STA	773,571
Fayetteville Public Works Commission, Nc	NC	Aa3	POS	150,480
Greenville Utilities Commission, Nc	NC	A1	NOO	68,990
Monroe (City Of) Nc Combined Utility Enterprise	NC	A2	NOO	51,479
Shelby (City Of) Nc Combined Utility Enterprise	NC	Baa1	NOO	33,734
Grand Island (City Of) Ne Electric Enterprise	NE	A1	STA	29,915
Hastings (City Of) Ne Electric Enterprise	NE	A2	STA	40,570
Lincoln (City Of) Ne Electric Enterprise	NE	Aa2	STA	584,050
Nebraska Public Power District	NE	A1	STA	2,275,745
Omaha Public Power District, Ne	NE	Aa1	STA	2,011,969
Farmington (City Of) Nm Combined Utility Enterprise	NM	A1	STA	27,916
Los Alamos (County Of) Nm Combined Utility Enterprise	NM	A2	NOO	47,406
Green Island Power Authority, Ny	NY	Baa3	NEG	18,320
Long Island Power Authority, Ny	NY	A3	NEG	9,622,960
New York State Power Authority	NY	Aa2	STA	1,941,000
Cleveland (City Of) Oh Electric Enterprise	OH	A2	STA	266,313
Hamilton (City Of) Oh Electric Enterprise	OH	A3	STA	168,775
Grand River Dam Authority, Ok	OK	A2	STA	834,596
Confederated Tribes Warm Springs Reservation	OR	A3	STA	57,130
Puerto Rico Electric Power Authority	PR	A3	NEG	8,230,982

Rated Issuers Sorted by State

Obligor Name	State	Actual Rating	Outlook	Debt Outstanding ($'000)
Clinton (City Of) Sc Combined Utility Enterprise	SC	Baa1	NOO	6,123
Easley (City Of) Sc Combined Utility Enterprise	SC	A2	NOO	55,685
Gaffney (City Of) Sc Combined Utility Enterprise	SC	A3	NOO	11,150
Greer Commission Of Public Works, Sc	SC	A2	NOO	35,209
Rock Hill (City Of) Sc Combined Utility Enterprise	SC	A2	NOO	124,857
South Carolina Public Service Authority	SC	Aa3	STA	5,154,620
Memphis (City Of) Tn Electric Enterprise	TN	Aa2	STA	848,305
Austin (City Of) Tx Electric Enterprise	TX	A1	STA	1,412,630
Brownsville (City Of) Tx	TX	A2	STA	299,210
Bryan (City Of) Tx Electric Enterprise	TX	A1	NOO	175,835
Bryan Rural Electric System	TX	A2	NOO	181,890
Denton (City Of) Tx Combined Utility Enterprise	TX	A1	NOO	209,885
Greenville (City Of) Tx Electric Enterprise	TX	A2	NEG	23,610
Lower Colorado River Authority, Texas	TX	A1	STA	3,085,151
San Antonio (City Of) Tx Combined Utility Enterprise	TX	Aa1	STA	4,835,820
Murray City (City Of) Ut Electric Enterprise	UT	A2	NOO	21,190
Provo (City Of) Ut Electric Enterprise	UT	A1	NOO	15,411
Santa Clara (City Of) Ut Electric Enterprise	UT	Ba1	NEG	5,302
St. George (City Of) Ut Electric Enterprise	UT	A1	NOO	64,180
Washington City (City Of) Ut Electric Enterprise	UT	Baa1	NOO	6,410
Virgin Islands Water & Power Authority	VI	Baa2	STA	190,270
Burlington (City Of) Vt Electric Enterprise	VT	Baa2	NEG	36,370
Chelan County Public Utility District 1, Wa	WA	Aa2	NEG	1,027,620
Clark County Public Utility District 1, Wa	WA	A2	STA	407,215
Cowlitz County Public Utility District 1	WA	A1	NOO	149,100
Douglas County Public Utility District 1, Wa	WA	Aa3	STA	273,700
Grant County Public Utility District 2, Wa	WA	Aa3	STA	1,068,685
Lakeview Light And Power	WA	Baa2	NEG	93,140
Pend Oreille County Public Utility District 1, Wa	WA	A3	NEG	140,534
Seattle (City Of) Wa Electric Enterprise	WA	Aa2	STA	1,536,775
Snohomish County Public Utility District 1, Wa Electric Enterprise	WA	Aa3	STA	627,616
Tacoma (City Of) Wa Electric Enterprise	WA	Aa3	STA	612,615

Rated Issuers Sorted by State

Obligor Name	State	Actual Rating	Outlook	Debt Outstanding ($'000)
Kaukauna (City Of) Wi Electric Enterprise	WI	A3	NOO	33,540
Manitowoc (City Of) Wi Electric Enterprise	WI	A1	STA	76,158
New Richmond (City Of) Wi Electric Enterprise	WI	A2	NOO	2,305
Oconomowoc (City Of) Wi Electric Utility Enterprise	WI	A2	NOO	5,480
Plymouth (City Of) Wi Combined Utility Enterprise	WI	A2	NOO	24,770
River Falls (City Of) Wi Electric Enterprise	WI	A2	NOO	3,575
Stoughton (City Of) Wi	WI	A2	NOO	6,630
Sun Prairie (City Of) Wi Combined Utility Enterprise	WI	A1	NOO	7,192
Waunakee (Village Of) Wi Combined Utility Enterprise	WI	A2	NOO	8,590
Waupun (City Of) Wi Combined Utility Enterprise	WI	A3	NOO	12,790

Appendix B: Public Power Electric Utilities-Generators Methodology Factor Grid

Public Power Rating Methodology

Factor	Sub-Factor / Description	Weight	Aaa	Aa	A	Baa	Ba
Total Weight		**100%**					
1. Cost Recovery Framework Within Service Territory	-Monopoly with unregulated rate setting -Service area economic strength -Customer base stability	25%	Monopoly with unregulated rate setting; Very strong service area economy	Monopoly with unregulated rate setting; Strong service area credit economy	Monopoly with unregulated rate setting; Average service area economy	Regulation of rates by State; Weak service area economy	Regulation of rates by State; Very weak service area economy
2. Willingness and Ability to Recover Costs with Sound Financial Metrics	-Rate-setting record -Timeliness of recovery -Political risk -Local Government Supportiveness -General fund transfer policy	25%	Excellent rate-setting record; Rates, fuel, & purchased power cost adjustments less than 10 days; No political intervention in past or extremely high support from related government; Very limited General Fund transfers governed by policy	Strong rate-setting record; Rates, fuel, & purchased power cost adjustments 10 to 30 days; Limited political intervention in past or high support from related government; Conservative and well-defined General Fund transfers governed by policy	Adequate rate-setting record; Rates, fuel, & purchased power cost adjustments 31 to 60 days; Some political intervention in past or average support from related government; Moderate General Fund transfers	Below average rate-setting record; Rates, fuel, & purchased power cost adjustments 61 to 99 days; Persistent political intervention or below average support from related government; Large General Fund transfer not governed by policy	Consistent record of insufficiently setting rates; Rates, fuel, & purchased power cost adjustments 100 days or more; Highly political climate or no support from related government; Sizeable General Fund transfer not governed by policy
3. Management of Generation Risks	- Diversity of supply - Reliability and cost of supply & distribution	10%	Very strong management of generation risks; High degree of diversification of generation and/or fuel sources; Well insulated from commodity price changes; Single generation asset provides less than 20% of power; and/or up to 20% of energy from coal-fired generation with carbon mitigation strategy	Strong management of generation risks; Some diversification of generation and/or fuel sources; Minimally affected by commodity price changes; Single generation asset provides less than 40% of power; and/or 21% to 40% of energy from coal-fired generation with carbon mitigation strategy	Average management of generation risks; Some reliance in one type of generation or fuel source, but diversified with purchased power sources; Modest exposure to commodity price changes; Single generation asset may provide 40% to 55% of power; and/or 41% to 55% of energy from coal-fired generation with carbon mitigation strategy	Below average management of generation risks; Reliance on a single type of generation or fuel source, with limited diversification via purchased power; Moderate exposure to commodity prices; Single generation asset provides 56% to 75% of power; and/or 56% to 70% of of energy from coal-fired generation with no carbon mitigation strategy	Poor management of generation risks; High concentration in a single type of generation or highly reliant on a single fuel source, with minimal diversification via purchased power; Notably exposed to commodity price shocks; Single generation asset provides over 75% of power; and/or 71% to 100% of energy from coal-fired generation with no carbon mitigation strategy

Public Power Rating Methodology

Factor	Sub-Factor / Description	Weight	Aaa	Aa	A	Baa	Ba
4. Competitiveness	Rate Competitiveness (compared to state average)	10%	25% or more below average	25% to 7.51% below average	7.5% below average to 7.5% above average	7.51% to 25% above average	25% or more above average
5. Financial Strength							
(a) Liquidity	Adjusted days liquidity on hand (3-year avg) (days)	10%	≥ 250 days	≥ 150 days to 249 days	≥ 90 days to 149 days	≥ 30 days to 89 days	Less than 30 days
(b) Leverage	Debt ratio (3-year avg) (%)	10%	Less than 25%	≥ 25% less than 50%	≥ 50% less than 75%	≥ 75% less than 100%	≥ 100%
(c) Operating Resiliency	Adjusted Debt Service Coverage OR Fixed Obligation Charge Coverage (3-year avg) (x)	10%	≥ 2.50x	≥ 2.00x to 2.49x	≥ 1.50x to 1.99x	≥ 1.10x to 1.49x	Below 1.10x

Notching Factors

1. Operational – (i.e. Customer Concentration, additional borrowing needs, construction risk)
2. Financial – (i.e. Covenant or Derivative Risks, Financial Engineering, other liquidity related risks, DSRF funding levels below MADS)
3. Other – (i.e. factors not appropriately captured in the grid)

Appendix C: Definition of Ratios

Liquidity: Adjusted Days Liquidity on Hand (days)

(Available unrestricted cash and investments) (eligible unused bank line)) x 365 days / (utility's annual operating and maintenance expenses)

Leverage: Debt Ratio (%)

(Gross debt –debt service funds –interest payable and debt service reserve funds) / (Gross fixed plant assets –accumulated depreciated on plant plus net working capital (net current liquid assets unrelated to debt –net current liabilities unrelated to debt)

Financial Operating Resiliency: Adjusted Debt Service Coverage Ratio OR Fixed Obligation Charge Coverage Ratio (x)

Adjusted Debt Service Coverage Ratio: (Annual recurring revenues plus interest income)-(recurring annual operating expenses-depreciation expense plus General Fund transfers) /aggregate annual debt service or

Fixed Obligation Charge Coverage Ratio (Annual recurring revenues plus interest income)-(recurring annual operating expenses-depreciation expense and adjusted for other non-cash items plus General Fund transfer-JPA payment only the debt service portion of annual payment) /aggregate annual debt service plus the JPA payment only the debt service portion.

Appendix D: Industry Overview and Comparison to Investor Owned Utilities

Public power electric utilities serve about 12% of the total U.S. population, while investor-owned utilities (IOU) serve about 70% and the remainder are served by electric cooperatives. These shares of the industry have remained virtually unchanged over the past several decades as no public power electric utilities were privatized and only two new large municipal electric utilities have formed during this time period, including the Long Island Power Authority (rated A3 negative outlook) and Winter Park, Florida (rated Aa3). Electric industry deregulation did create numerous new entities including merchant transmission and generation companies, but most electricity customers are served by integrated utilities that provide electric generation, transmission and distribution services. Competition at the retail level has increased with some states opening up the industry to firms that market electricity as part of retail choice programs. That activity is concentrated in a few states, notably Texas, Pennsylvania, and Maryland, and public power electric utilities, with the exception of Cleveland Public Power, OH, do not participate.

The median rating of A1 for U.S. public power electric utilities that directly own generation and A2 for those who indirectly own generation through their JPA participation have higher median ratings than the rest of the electric industry. The median senior unsecured investor-owned utility rating is Baa1. The major credit factors that drive the strong credit quality of public power electric utilities is their monopoly role providing an essential service with unregulated rate setting. Also, there is a strong record of debt service repayment with a very limited default record. The following chart compares some characteristics that distinguish the risk profile of the public power electric utility and investor-owned utility sectors.

Investor-Owned Utilities	Public Power Electric Utilities-Generator
*Median rating of Baa1	*Median rating of A1
*Rate regulated	*Not rate regulated
*Profit seeking; operated for the benefit of shareholders with obligation to serve regulated ratepayers	*Operated for public benefit of the region served with obligation to serve customers
*Most are large and may have multiple subsidiaries	*Most are small relative to IOUs
*Subject to competition in the wholesale market, with some competition in retail market	*Little retail competition although subject to competition in wholesale market
*Some history of defaults, usually as a result of the need for large rate increases that regulators or customers do not approve or accept	*Defaults have been infrequent
*Can file Chapter 11 bankruptcy	*Cannot file Chapter 11 bankruptcy but can file under the more protective Chapter 9
*Tend to have higher rates compared to municipal or public power utilities	*Tend to have lower rates due to tax-exempt debt financing; preference power; lower salary structure; and lower earnings requirement
*Private shareholder equity; no government support	*No private equity; may have access to local government fiscal support in times of fiscal stress

Appendix: E: Key Rating Issues Over the Intermediate Term

Challenging Transition to Cleaner Fuels

As long as the slow economic growth in the U.S. prevails, we believe the U.S. Congress is unlikely to enact any major climate change initiative out of concern about such policies crippling the fragile economy. However, the transition to cleaner fuels and away from fossil fuels continues to take place as utilities balance capital investment for new generation with the uncertainty of environmental regulation. The Environmental Protection Agency (EPA) continues to establish timetables for compliance with existing Clean Air and Clean Water Act rules on various pollutants. Most utilities realize that at some point they will have to make investments to comply with EPA standards. While the public power electric utility sector has made advancements, particularly related to larger coal-fired units and shifting its resource mix to more natural gas, the challenge of mercury control and carbon capture remain.

Moody's believes the transition to cleaner fuels will remain a major financial and operational challenge for most electric utilities, especially since the options have become more problematic in recent years. The moratorium on new coal-fired generation facilities, the questionable capability of adequate natural gas infrastructure, the pall over new nuclear generation post the Japan disaster, and the high cost and variability of new renewable energy sources, collectively limit a utility's generation choices. While renewable energy development has been impressive, it is expected to remain a small portion of the U.S. energy mix without significant technological advancement, cost reduction and/or increased subsidization of the industry. Likewise, energy efficiency programs have potential but customer behavior limits the potential impact of this least expensive resource.

Economic and Financial Market Conditions

While public power electric utilities have demonstrated some resiliency to unsettled economic and financial market conditions due partly to the essential nature of the service provided, a protracted or severe recession could negatively affect credit profiles over the intermediate term in several ways. Falling demand for electricity could negatively impact debt service coverage margins and liquidity. Poor economic conditions, including high unemployment and low wage inflation, could make it harder for policymakers to establish the necessary rate increases needed to maintain sound financial metrics. In cases where the utility is owned by the municipal government and the city receives a General Fund transfer from the utility, there may be pressure placed on the utility to increase the transfer amount to help with the municipal government's budget.

Inflection Point

While public power electric utilities have rate flexibility and the unregulated ability to adjust rates, cost pressures could rise to a point that retail rates become a burden for some customers, resulting in political pressure for lower rates. Several public power electric utilities in 2010 and 2011 either delayed rate increases or were only able to raise their retail rates slightly, which then affected the margins available to meet debt service coverage. Moody's believes this is an inflection point that is a lingering risk for utilities as increased costs to comply with environmental regulations and the move to cleaner but potentially more expensive fuels takes place. This can be particularly acute when high unemployment and low wage inflation persist.

Appendix F: Generation Risks and Mitigation Table

Generation Risks	Mitigation Measure
Coal-Fired Generation Risks	
*Clean Air Act compliance	*Proactive and economic approach to meet NOX, SO2 and mercury standards including capital program for environmental compliance
*Clean Water Act compliance	*Proactive approach to water quality issues
*Fuel delivery disruption	*Coal inventory on site of 60 days or appropriate level to manage risk of transportation disruption
*Greenhouse gas emissions regulation	*Strategic planning effort to evaluate CO2 reduction options and future cost mitigation strategies
*Maintenance of strong availability and capacity factors	*Ongoing preventive maintenance program with management objectives to meet optimal levels for plant age and condition
Nuclear Generation Risks	
*Safe storage of radioactive waste	*Provide adequate on-site storage of waste to license expiration in the absence of other current alternatives
*Operating record within NRC safety and performance guidelines	*Manage compliance including improving low scores on Nuclear Regulatory Commission (NRC) review
*Decommissioning of retired plant	*Evidence of funding of decommissioning costs pursuant to NRC formula
*Maintenance of high plant capacity factors	*Preventive and ongoing maintenance to avoid forced outages and to minimize refueling outages
Hydro Generation Facilities Risks	
*Drought conditions and low or below average water	*Ensure that power supply and financial margins can withstand low water periods; plan for replacement power and liquidity
*Fish and wildlife protection	*Strong planning and implementation function to mitigate potential impacts on local wildlife so limited regulatory constraints on water flow
*Federal Energy Regulatory Commission relicensing risk	*Prudent management of hydro record; strong relicensing planning including participation from stakeholder groups
Natural Gas Fired Generation	
*Fuel availability and deliverability	*Optionality of delivery points, suppliers and contracts
*Natural gas price risk	*Natural gas prepayment bonds; derivative hedging products; storage facilities
*Clean Air Act compliance	*Preparation of engineering assessments and cost estimates of compliance with possible new emissions standards

Moody's Related Research

Industry Outlooks:

» Regulation Provides Stability as Risks Mount, January 2011 (129930)

» Outlook Update: U.S. Coal Industry: U.S. Coal Demand to Stay Flat Amid High Inventory and Low Natural Gas Prices, July 2011 (134639)

» Midstream Energy Sector is Stable, But Business Risk is Increasing, March 2010 (124030)

» U.S. Public Power Electric Utility Outlook-2010, June 2010 (125624)

» U.S. Public Power Utility Medians, 2011, April 2011 (131623)

Rating Methodologies:

» U.S. Municipal Joint Power Agencies, September 2006 (99024)

» U.S. Public Power Electric Utilities, April 2008 (106322)

» Regulated Electric and Gas Utilities, August 2009 (118481)

» Unregulated Utilities and Power Companies, August 2009 (118508)

» Natural Gas Pipelines, December 2009 (121678)

» U.S. Electric Generation & Transmission Cooperatives, December 2009 (121189)

Request For Comment:

» Moody's Considers Use Of New Financial Metrics In U.S. Public Power Electric Utility Rating Methodology , June 2011 (133787)

Rating Implementation Guidance:

» Recalibration of U.S. Municipal Ratings to its Global Rating Scale, March 2010 (123300)

Special Comments:

» Low Prices Pose Little Trouble for Midwest Natural Gas Companies, May 2011 (133445)

» Re-evaluating Creditworthiness for Global Nuclear Generators, April 2011 (131818)

» Exelon Looks to Acquire Constellation Energy: Long generation supply coupled with short retail load designed to balance position book, April 2011 (132850)

» U.S. Investor-Owned Utilities: Bonus Depreciation Provides Material Near-Term Benefit For The Sector But Raises Longer-Term Questions, February 2011 (131078)

» Oil Prices Signal Buoyant 2011 for Energy, But Natural Gas and Capacity Issues Pose Risks, January 2011 (129899)

» Investment-Grade, Unregulated Power: Not Immune to Rating Pressures, November 2010 (128985)

» U.S. Electric Utilities: Uncertain Times Ahead; Strengthening Balance Sheets Now Would Protect Credit, October 2010 (128462)

» Key Drivers for Utility and Power Sector Rating Actions in 2010, October 2010 (128381)

- » Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilities, June 2010 (125664)
- » Cost Recovery Provisions Key to Investor Owned Utility Ratings and Credit Quality, June 2010 (122304)
- » U.S. Wholesale Merchant Energy: Bigger is Better, April 2010 (124300)
- » Liquidity: A Key Component to Investor-Owned Utility Ratings and Credit Quality, September 2010 (127546)
- » Texas Regulated Utilities Well Positioned as Market Continues to Evolve, May 2010 (125113)
- » US Electric G&T Cooperatives Not Immune to Liquidity Concerns, February 2010 (123245)

Global Risk Perspectives:

- » Global Macro-Risk Scenarios 2011-2012: Oil Price Supply Shock Downside Scenario, April 2011 (132426)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

The credit ratings assigned in this sector are primarily determined by this credit rating methodology. Certain broad methodological considerations (described in one or more secondary or cross-sector credit rating methodologies) may also be relevant to the determination of credit ratings of issuers and instruments in this sector. Potentially related secondary 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.

» contacts continued from page 1

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INVESTORS SERVICE

Rating Update: Moody's affirms LIPA's ratings (1st lien revenue bonds Baa1); revises outlook to stable

Global Credit Research - 22 Sep 2014

Approximately $5 billion of rated debt affected

LONG ISLAND POWER AUTHORITY
Electric Distribution and Generation
NY

Opinion

NEW YORK, September 22, 2014 --Moody's Investors Service has affirmed the ratings of the Long Island Power Authority (LIPA or the Authority), including its first lien revenue bonds at Baa1 and its second lien revenue bonds at Baa2. LIPA's third lien NYSERDA notes were refunded in December 2013. Concurrent with the rating affirmation, the rating outlook was revised to stable from negative reflecting LIPA's smooth transition to operations under its contract with PSEG - Long Island, a stronger liquidity position, and our expectation that the upcoming budgetary and rate case filings will be handled in a manner that maintains or improves financial metrics.

SUMMARY RATING RATIONALE

The Baa1 rating for LIPA's senior revenue bonds and the Authority's stable outlook reflects its smooth transition to operations under PSEG - Long Island (PSEG-LI), and our assumption that this relationship will continue to bear fruit as PSEG-LI takes the lead in areas such as resource planning, fuel procurement, and rate case filings. The rating considers the challenges facing LIPA and PSEG-LI as they seek to implement what is currently an uncertain, but potentially large, capital program to improve the efficiency and reliability of the system and to achieve the clean energy objectives of the state of New York, but also recognizes the commitments LIPA has received at both federal and state levels, to assist with continuing storm hardening investment which helps to mitigate the potential rate impact.

The rating and outlook reflect the utility's improved liquidity position and our expectation that credit metrics will remain appropriate for the rating as LIPA and PSEG-LI prepare for their first rate case filing with the recently created Long Island office of the New York Department of Public Service (DPS). Our rating further assumes that the rate case filing and ultimate outcome will enable LIPA to maintain or improve its financial position. The economic strength of LIPA's service territories in the Long Island counties of Nassau and Suffolk continue to be a primary positive factor underpinning the rating.

Issuer Profile

LIPA was established in 1986 as a corporate municipal instrumentality of the State of New York under the Long Island Power Authority Act (the LIPA Act). In 1998, the Authority became the retail supplier of electric service in most of Nassau and Suffolk Counties and the Rockaway Peninsula of Queens by acquiring the Long Island Lighting Company (LILCO) as a wholly owned subsidiary which does business as LIPA. LIPA's assets currently consist of a transmission and distribution system that is used to serve approximately 1.1 million customers in an approximately 1,230 square mile service territory (911 miles in Suffolk, 287 in Nassau and 32 in Rockaway), as well as an 18% (234 MW) interest in the Nine Mile Point Unit 2 nuclear facility. Peak load in 2013 was reported at 5,602 MW versus available capacity, including purchased capacity, of 6,014 MW.

Strengths

Economic strength of the service territory

Ability to obtain federal funding for storm related expenditures

Potential for improved operating efficiency and customer service under operations by PSEG-LI

Challenges

Relatively weak liquidity and financial credit metrics

Required rate case filings with New York DPS

Need to implement system improvements while rates remain under political scrutiny

Outlook

The stable outlook incorporates our expectation that LIPA will successfully extend, and possibly expand, its credit facilities prior to their current 2015 termination dates, that customer satisfaction with PSEG-LI will continue to increase, that the company's 2016-2018 rate filing will look to maintain or improve financial metrics, that the DPS rate proceeding will be conducted in a timely fashion, and that investment decisions will be made in a manner that is supportive of credit quality.

What could change the rating - Up

The rating is not expected to move upward over the near-to-medium term. Longer term, upward pressure could develop if, following the results of the 2016-2018 rate filing, there is a sustainable improvement in credit metrics. If for example, LIPA's fixed obligation charge coverage were to remain above 1.25 and its days of liquidity on hand (including CP availability) were to be maintained at or over 120. The establishment of a meaningful debt service reserve for the revenue bonds could also put upward pressure on the rating.

What could change the rating - Down

Downward rating pressure could develop if there were to be an increase in operating costs or capital expenditures incurred or undertaken without a commensurate increase in revenue resulting in a weakening of credit metrics, for example if coverage of fixed obligation charges was expected to remain below 1.10 x there would likely be downward pressure on the rating. A board approved budget or rate case filing that is not consistent with maintaining or improving financial metrics, a protracted rate case process or the establishment of final rates that are not consistent with maintaining or improving financial metrics would likely put downward pressure on the rating. Liquidity strain, caused perhaps by delays in the receipt of anticipated state or federal grant income, a decline in cash receipts or a spike in operating costs such that days of liquidity on hand were to decline below 50 could put downward pressure on the rating.

DETAILED CREDIT DISCUSSION

Smooth transition to operations by PSEG- LI

As of January 2014, PSEG-LI, a subsidiary of New Jersey-based Public Service Enterprise Group (PSEG) took over the operations and maintenance of LIPA's T&D system under an amended operating services agreement which placed responsibility for customer relations and satisfaction, strategy, policy making, capital planning, budgets, emergency response, and rate case filings with PSEG-LI. The operational transition occurred without incident, even in the face of a major storm that hit Long Island in early January. The PSEG-LI logo and brand became effective on January 1st, making it clear to customers which entity is responsible for their service and satisfaction. Although the utility still scored the lowest of electric utilities included in J.D. Power's most recent survey (covering performance between July 2013 and May 2014), PSEG-LI reports substantial improvement for the period from January through May 2014 during which they were the operator. Under the terms of the operating agreement, PSEG-LI is required to achieve first quartile performance on specific components of this survey by year five of its operations; early results are reported to be ahead of baseline expectations.

Beginning in 2015, PSEG-LI will also assume responsibility for fuel and power procurement, and as discussed further below, the operator is already actively involved in resource planning, budgeting and rate case preparation, an arrangement that we view as supportive to credit quality, given the experience and track record of PSEG.

LIPA's board has been reconstituted with a full roster of nine members, six new and three from the prior board. The board and its committees have met regularly and are reported to be actively engaged and supportive of operations to date.

First rate review case to be filed in early 2015 - we expect credit metrics to be a factor

The 2013 LIPA Reform Act created a Long Island office of the New York Department of Public Service (DPS) to review LIPA's operations including its rates and budgets. In accordance with the act, LIPA must first file for review a rate plan for the 2016-2018 periods. Rates must also be reviewed in any year thereafter where proposed rates

would increase aggregate LIPA revenues by more than 2.5%. LIPA and PSEG-LI will begin preparing for their initial rate review case toward the end of this year with an expectation of a February 2015 filing. This should allow sufficient time for DPS review (required within 240 days) and resolution in the case of disagreement (notice and public hearings) prior to a final determination by the LIPA board and implementation of new rates in 2016.

The LIPA/PSEG-LI rate case filing will incorporate an update of traditional components such as sales forecasts, operating and capital budgets, taxes (or payments in lieu of tax) and financing costs as well as estimated income to be provided by federal and state grants. We understand that management is currently reviewing rate setting policies to achieve more traditional financial metrics for public power systems, such as fixed obligation coverage, debt ratio and liquidity measures, rather than the current practice of setting rates to achieve a net income target of $75 million (which was rarely attained). Assuming forecasted metrics are based on supportable assumptions with reasonable margins, we would view this approach as credit positive. In any event, we expect LIPA/PSEG-LI will seek to establish rates that are sufficient to recover expenses and capital investment while maintaining or improving its financial condition, and we note that DPS recommendations are required to be consistent with generating sufficient revenues to satisfy debt service. While an additional step, the new rate case filing process is viewed as a credit positive to the extent that it imposes greater transparency and discipline to LIPA's rate making process and serves to neutralize or minimize political issues that have arisen in the past.

Uncertain, potentially large, capital plan supplemented by anticipated government funding with additional mitigation from efficiency programs

LIPA's capital and resource plans are currently being reconsidered in conjunction with the transitioning of LIPA's power supply group to PSEG-LI and the preparation of multi-year forecasts. Most recently, as a result of a change in planning criteria, PSEG-LI recommended deferral of LIPA's planned contract with Caithness II, a 706 MW gas project to be constructed in Yaphank. LIPA's original capital plan included significant investment (over $900 million to be spent in 2015 and 2016) in conjunction with upgrades required to bring this facility on line by 2018. While this deferral should relieve some near term capital investment and upward rate pressure, longer term resource needs are still being evaluated. PSEG- LI is now in the process of completing an Integrated Resource Plan that is expected to be concluded by the end of 2015.

Resource planning and investment will also be impacted by evolving state goals regarding renewables, efficiency and distributed generation. PSEG-LI has proposed a plan termed "Utility 2.0" under which it will invest approximately $200 million during 2015-2018 to improve efficiency on the grid, reduce peak loads, reduce emissions and address emerging capacity needs. Although PSEG-LI is seeking to earn a return on this investment, they believe the cost to rate-payers would largely be offset by improvements in efficiency and the ability to displace currently planned generation. PSEG-LI believes the plan is consistent with the Reforming the Energy Vision plan of the New York Public Service Commission. The Utility 2.0 plan will be considered as part of LIPA's upcoming budgeting process, and if approved by the board, incorporated in the rates for the 2016 - 2018 periods that will be reviewed by the DPS staff.

As was the case with other utilities in the Tri-state area, following Superstorm Sandy, LIPA identified the potential for numerous upgrades to its system that could improve its ability to withstand future storms. However, unlike investor owned utilities, LIPA has the ability to request funding for these upgrades from the federal government through FEMA rather than increasing rates to its customers on Long Island. In February, LIPA signed a letter of undertaking (LOU) with FEMA and New York State under a new pilot program which committed $730 million to LIPA for storm hardening. These funds are in addition to the reimbursement of about $700 million for actual costs resulting from the storm. The improvements are to be made to assets that were damaged by the storm with a goal of reducing future losses to these assets by a minimum of 20%. The investments are to be made within four years and LIPA will have substantial flexibility in allocating the funds as needed. Although the FEMA funds will be received on a reimbursement basis, upfront coordination amongst LIPA, PSEG-LI and FEMA in the areas of accounting and procurement policies is expected to minimize delays. The ability for LIPA to make this level of investment in its systems, thereby improving reliability without the need for a rate increase, is a clear credit positive and has the potential to offset at least a portion of the cost of investment needed elsewhere in the system. We expect the authority to manage the process with a view to assuring payment delays remain within the bounds of available liquidity.

Liquidity has stabilized

We have historically highlighted LIPA's liquidity position as an area of credit weakness. The utility has generally ended its fiscal year (December) with less than 60 days of operating cash on hand, and available external liquidity was limited to $100 million of commercial paper availability (approximately 10 days), and although LIPA ultimately has been able to pass the cost of major storms on to the Federal Energy Management Agency (FEMA) and/or the

State of New York, reimbursement has been slow in coming. As of December 2012, the utility had only 37 days of cash on hand (48 including CP availability).

In March 2013, LIPA bolstered its liquidity by obtaining a $500 million multi-year (March 2016 maturity) credit facility intended primarily to fund accounts the Authority is required to maintain under the terms of its operating services agreement with PSEG-LI; specifically LIPA must maintain 90 days of anticipated transmission and distribution (T&D) operating and capital expenditures. As of December 2013, approximately $263 million had been funded into the PSEG-LI accounts. In addition, in December 2013, LIPA used a portion of the proceeds of its $2 billion debt securitization to repay commercial paper outstanding, bringing availability to $300 million. As a result, as of December 2013, LIPA had about $640 million of available cash (including the PSEG-LI accounts, but excluding about $10 million of reserves held for its securitization bonds) or over 80 days on hand (over 120 including CP availability) and approximately $237 million available under its revolving credit facility. In 2013 LIPA also arranged a financing vehicle for Consolidated Edison Energy, Inc. (Con Ed), its current fuel manager, under which Con Ed could sell up to $85 million of LIPA fuel receivables to a financial institution with LIPA paying the associated interest. The arrangement provides LIPA with more flexibility with regard to the timing of these payments. The agreement will terminate in December 2014 when PSEG-LI assumes responsibility for fuel management.

As of June 30, 2014, a traditional low point in LIPA's cash cycle, cash on hand (including the PSEG-LI accounts but excluding the securitization reserves) was about $560 million (approximately 70 days cash on hand), with no commercial paper availability, approximately $137 million available under its revolver and $43 million available under the $85 million fuel receivable facility. As of August 31st, after a relatively mild summer, available cash on hand was also about $560 million (70 days) with continued full use of the $300 million commercial paper program but revolver availability had increased to $162 million, and the full $85 million was available under the fuel facility. LIPA's revolving credit facility and fuel receivables agreement require a representation of no material adverse change for draws, and the utility's external sources comprise an unusually large percentage of its overall liquidity, as such, we do not include these sources directly in our calculation of adjusted days liquidity on hand. We do however recognize there is additional liquidity cushion created by these facilities. The rating recognizes the lack of a dedicated debt service reserve fund which is a comparative weakness.

We anticipate LIPA's liquidity position will continue to strengthen. Based on the positive market response we understand the Authority received on its request for proposals to renew its letter of credit facilities ($974 million expiring at various dates in 2015), LIPA is currently considering expanding its commercial paper facilities by $100-$200 million to further bolster its liquidity. In addition, as discussed below, receipt of up to $277 million in pending grant income is also expected in 2014. A bond transaction contemplated in the fourth quarter could also replenish some liquidity used during the year for capital projects.

Grant Income continues to trickle in

As of July 2014, LIPA had received approximately $444 million of the $579 million the Authority is currently expecting as reimbursement from the Federal Energy Management Agency (FEMA) for damage from Superstorm Sandy (90% of damage less insurance proceeds). The additional $134 million is expected by the end of September. State funding of approximately $143 million for the portion of storm costs not reimbursed by FEMA, related to Superstorm Sandy and Hurricane Irene, and other storm mitigation preventive measures (tree trimming), is also expected throughout 2014 and 2015.

Post securitization debt burden remains significant

In December 2013, LIPA completed an approximate $2 billion debt securitization. The securitization bonds, which are scheduled to mature in 2039, were issued through a special purpose vehicle, Utility Debt Securitization Authority (UDSA: Aaa (sf)) and used to refund higher cost LIPA debt with similar maturities. LIPA ratepayers will pay for the securitized debt via a special non-by passable charge included in their rates, and LIPA must set rates in a manner that assures recovery of all of costs, including debt service on the securitization bonds. The UDSA bonds are included on LIPA's consolidated financial statements and, notwithstanding their special legal protections and higher rating, we include them in our calculations of LIPA's debt and debt service obligations. As of December 2013 total debt outstanding, including the securitization debt ($2 billion), short term debt ($263 million) and capital leases (approximately $2.7 billion) was about $9.9 billion versus $9.7 billion at the end of 2012.

The average annual weighted yield of 4.22% on the securitization bonds resulted in net present value savings of approximately $132 million for LIPA ratepayers. Cash flow savings vis-à-vis the refunded debt is estimated to occur over the life of the transaction; but is most predominate in the near term (over 35% of the savings occurs in 2014 and 2015).

Going forward, we expect LIPA's absolute of level of debt will likely continue to grow as it funds needed capital investment. For example, LIPA's 2014 capital plan includes approximately $675 million of new money financing to fund its capital plan and other expenditures. As of December 2013, we calculated LIPA's debt ratio (debt/fixed assets plus working capital) at about 130%. The ratio has been improving steadily over the past few years (from 145% in 2009 and about 180% in 2006) but it remains above the maximum value of 100% indicated for the "Baa" scoring range in our rating methodology for U.S. Public Power Electric Utilities with Generation Ownership Exposure (Methodology). Although its absolute debt level is likely to remain elevated, in the future we expect a declining trend in the debt ratio will continue and anticipate that LIPA will attempt to set revenues at levels that can cover its debt service with margins that are comfortably within the Baa scoring range of 1.10-1.49 indicated in the Methodology for that factor.

Other Considerations

Moody's evaluates LIPA's financial performance relative to the U.S. Public Power Electric Utilities with Generation Ownership Exposure methodology and, as depicted below, the grid indicated rating for LIPA is Baa2, one notch below LIPA's current Baa1 rating. We note that the methodology scores for Factor 5 - Financial Strength, are based on three year historical averages. On a forward-looking basis we expect average financial metrics and other credit considerations to improve hence the one notch differential between the scorecard output and the assigned rating.

METHODOLOGY SCORECARD FACTORS

Factor 1 - Cost Recovery Framework within Service Territory: Aa

Factor 2 - Willingness to Recover Costs with Sound Financial Metrics: Baa

Factor 3 - Management of Generation Risks: A

Factor 4 - Competitiveness: A

Factor 5 Scores are assigned on the basis of a three year historical average

Factor 5 - Financial Strength - Debt Service Coverage (3 year average - 1.07x; 2013 - 1.18x): - Ba

Factor 5 - Financial Strength - Days liquidity on hand (3 year average - 79; 2013 - 122): days - Baa

Factor 5 - Financial Strength - Debt Ratio (3 year average - 131%; 2013 - 129%): - Ba

Notching Factors - Financial (Covenant/DSR): - 1

Scorecard Indicated Rating: Baa2

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RATING METHODOLOGY

The principal methodology used in this rating was U.S. Public Power Electric Utilities with Generation Ownership Exposure published in November 2011. Please see the Credit Policy page on www.moodys.com for a copy of this methodology.

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Electric Utility Ratings

*(**Editor's Note:** This criteria article was originally published on June 15, 2007, replacing criteria published on Sept. 28, 2006. We are republishing this article following our periodic review completed on May 31, 2013.)*

Standard & Poor's Ratings Services criteria reflect the challenges and risks of publicly owned utilities operating in a deregulated wholesale environment, and approaching retail competition. The criteria also reflect the dynamics of the energy industry and the credit implications for bondholders and lenders, and emphasize the qualitative and quantitative factors that indicate an electric utility's capacity to operate in a market in which it must work to retain, and gain customers.

Credit ratings for public power issuers embody the interplay between eight variables: management, operations, competitive position, markets, regulation, service area economy, finances and legal provisions. Standard & Poor's also assigns business profiles to all rated electric utilities, which includes the first five factors. These factors are incorporated in credit ratings, and enhance an investor's ability to differentiate between utility systems by complementing the credit ratings and outlooks.

Similarly, business profiles enable utilities to make comparative analyses and internal assessments to benchmark themselves against other utilities with which they may compete. Business profiles are ranked on a ten-point scale. A score of "1" reflects the strongest business profile.

Management

A competitive marketplace puts a premium on leadership skills. Management's decisions in all facets of utility rate setting, operations and finances, are critical to a public power system's long-term viability and strength. Standard & Poor's assessment of management includes an evaluation of the extent to which a utility's strategic plans are supported by local councils or boards of directors, and the extent to which the governing body's actions are supportive of credit quality. Management should demonstrate an understanding of, and be supportive of rate structures, customer service initiatives, and financial strategies that bolster credit quality. While Standard & Poor's evaluation of management consists of a qualitative assessment, our analysis employs specific criteria for measuring the effectiveness of management. The following elements are generally exhibited by well-run utilities:

- Institutionalized planning processes that are revised regularly to reflect changing conditions;
- Sound financial and operating policies that are supported, implemented and achieved;
- A deep and experienced executive team;
- A solid grasp of industry issues that extends beyond the local utility;
- Extensive knowledge of customers and their needs;
- Extensive knowledge of competitors; and
- A proactive and farsighted management approach that has the support of an informed board or council.

Management should also demonstrate an understanding of the risks and rewards associated with entering into

contracts with counterparties, and with entering into new lines of business beyond the scope of its core mission. Additionally, management will be assessed on their ability to operate within a given governance and oversight structure.

Operations

Standard & Poor's examines the full gamut of a utility's operations through a multi-pronged analysis that typically explores the following:

- Power and fuel resource mix, capacity, supply and demand;
- Operating efficiency and reliability; and
- Capital needs.

The strength of a utility's operational profile and cost competitiveness is rooted in its portfolio of power supply resources. Standard & Poor's evaluation also includes the analysis of the operating statistics of a utility's power transmission, distribution, and generating facilities. Efficiency measures, including frequency and duration of unplanned outages, plant heat rates, and availability and capacity factors, all are vital in determining facility efficiency and ultimately the competitive nature of an individual power plant, or the utility's overall cost profile.

Standard & Poor's examines the diversity or concentration of resources and assesses the fuels upon which a utility depends. This analysis explores resource availability, reliability and cost. Standard & Poor's does not have a bias toward owned or purchased resources, and the financial analysis of a purchased power agreement will equate fixed capacity payments with debt service incurred when financing directly owned or jointly owned generation assets in computing fixed charge coverage. Rather, resource diversity, flexibility, and cost competitiveness are the key determinants of operational health.

Issues associated with purchased resources include the level of demand charges, unique contract terms and duration of contracts, and the ability to take advantage of market opportunities. An important component of the power supply evaluation is an assessment of a utility's fuel mix, supply arrangements, fuel costs, and any financial or other hedging mechanisms designed to control fuel risk. Fuel contract terms, especially pricing conditions, duration, reopener options, and minimum take provisions will be examined. Standard & Poor's will look for a balance in the length and nature of these supply contracts, and for each utility will determine the degree of risk associated with its fuel purchasing practices.

Standard & Poor's will typically explore the degree of sophistication and the checks and balances used in conjunction with any hedging program. Crucial to the analysis of an issuer's fuel mix and purchased power mix is an assessment of counterparty risk. This includes an analysis of wholesale contracts with regard to duration, termination provisions, price, and the extent to which they add a fixed component to the financial profile. Coal, gas, and nuclear-fired generation at various times have fallen in and out of favor. As such, a diverse mix of fuel that enables a utility to employ cost efficient generation is viewed as a strong operational component.

Prepaid power purchase agreements typically offer the buyer favorable inducements such as discounts, and can be funded with tax-exempt debt issued by municipal issuers. For debt-financed, prepaid power contracts, the principal

and interest payments are treated similar to capacity payments of the more traditional purchased power agreements. Operational considerations include the source and nature of the contracted power supply, which may be unit specific or from a more diverse pool of generation assets; the amount of the commodity purchased relative to the issuer's total supply needs; contract duration; and creditworthiness of the power supplier. Contract terms are also scrutinized, and should provide bondholders with protection in the event the counterparty fails to perform its contractual obligations.

For prepaid natural gas transactions, the treatment of the debt issued to fund the prepayment is slightly different than that of prepaid power contracts, since pay-as-you go gas supply purchase agreements do not typically have a capacity component imputed, as with purchase power agreements. The annual amount of the debt service on the prepaid bonds is typically sized to approximate the cost of gas that would arise had the gas been purchased under a long-term gas purchase agreement, so the impact on cash flow under either scenario is minimal, as long as the supplier continues to perform.

For prepaid gas transactions involving directly issued debt or involving third party conduits such as joint action agencies, debt service is calculated or imputed to measure the transactions impact on debt ratios. However, the qualitative factors that mitigate potential pitfalls usually associated with debt leverage, such as the risks of load loss, supplier performance and remarketing, will be taken into consideration. Therefore, although evaluated on a case-by-case basis, debt-financed prepaid gas contracts, so long as their terms do not give rise to significant additional operating risks, and if structured so that counterparty risks and remarketing risks are mitigated, generally should have a neutral impact on credit quality when compared to a pay-as-you go gas purchase agreement

Costs of historical investments in generating plants continue to represent a significant challenge to utilities and frequently are a significant element underlying above-market rates. Investment is measured in terms of the amount of debt that has been incurred and the associated costs of servicing debt in relation to kWh sold, kWh of demand, kW of installed capacity, and the number of customers served by the system. Again, fixed capacity payments made under purchased power agreements will be factored into the analysis, equating such payments with principal and interest on generation-related debt. In the event that a municipal electric utility is faced with a deregulated retail environment, the elimination of stranded costs is critical to its viability. A utility whose fixed obligations cause rates to be above market levels is unlikely to be able to fully recover these costs in a competitive environment, which will have negative implications for both the utility's business profile and rating.

Transmission access is vital to a utility system's operations, and credit and business risk. In determining strength in this area, Standard & Poor's will generally look at the number of interconnections with which the utility in question has access, the cost profiles and supply and reserve characteristics of these other interconnected utilities, and the price paid for wheeling of power. Importantly, Standard & Poor's will evaluate the extent to which these interconnections and potential power diversity arrangements provide a utility with enhanced operating and competitive flexibility. The Federal Energy Regulatory Commission (FERC) is authorized to impose market rules regarding transmission operations, and the impact on a utility as such rules evolve will also be evaluated.

Operating efficiency and operational strength are measured with reference to the cost of producing a unit of energy. Historical and projected trends in average and marginal production costs on an absolute and relative basis are reviewed. A utility's generating costs relative to industry averages will indicate the economics of its power supply and

the potential for stranded costs.

The efficiency of a utility's services and operations is evaluated according to ratio analysis, including production cost per kWh, debt per kWh and debt per customer. A utility's efforts at managing its load curve—and therefore its costs—through demand side and resource management programs will be viewed positively to the extent that they are economically reasonable and practically achievable. Some utilities with below average load factors may be less able to control the associated inefficiencies and costs, but they also may be less susceptible to competitive forces.

Favorable operational characteristics include:

- Diverse supply sources;
- Favorable fuel supply arrangements coupled with cost containment strategies;
- Widespread transmission access that does not depend completely on a single entity to wheel power;
- Production costs that are competitive and reflect reasonable operating and maintenance costs; and
- Manageable environmental or regulatory exposures.

Some public power entities are active in, or planning to provide new services, such as telecommunications services, chilled water, and steam, in addition to their core businesses in order to diversify their revenue streams. Standard & Poor's will evaluate whether or not such additional ventures, which can increase financial risk, will be detrimental to the utility's core business. Important components of such analysis are the relative share of operating expenditures attributable to, and the amount increased leverage associated with such enterprises.

Competitive Position

Competitiveness is important to the retention of native load and the preservation of the revenue stream pledged to debt repayment, for both systems operating in open access environments or in those that are currently protected. Competitive positioning remains important, even for utilities in states that have yet to advance deregulation due to heightened awareness of retail choice among even captive electricity customers.

Overall system average rates, as well as rates on a customer class, are generally at the center of Standard & Poor's review of a utility's relative competitive position. The analysis is extended to include an assessment of the rates that a utility charges specific loads and rates levied on its largest customers relative to potential alternative suppliers. Standard & Poor's explores each utility's rate design, use of contract rates, and rate affordability. Affordability is measured relative to income levels and usage patterns. The commitment of policy makers to provide equitable rates that reflect the costs of providing service without subsidies is crucial in the changing environment. The presence of automatic power or fuel cost adjustments, which limit or avoid the political influence on timely rate adjustments geared to recapturing fluctuating commodity costs, is viewed favorably.

A discussion of rates also includes the issue of a utility's rate-setting process, whether by a third party or through self-regulation.

Strong competitive position characteristics generally include:

- A rate design that equitably apportions costs between and among system customers;

- Unit rates by customer classification that display a competitive advantage;
- Projections of rates that will continue to display a competitive advantage, preserve the revenue stream associated with native load, fund capital expenditures for system maintenance and growth and help attract new load;
- Ability to establish rates free from state regulatory bodies; and
- Flexibility to adjust rates quickly and frequently to match potentially volatile cost structures.

Service Area

An analysis of a utility's service area typically entails a review of its customer base and demographic characteristics.

Standard & Poor's considers each utility's customer base in terms of total number of customers and the number of customers by class. Revenues, kWh sales, margins and load factors are examined for each customer class and for the largest customers. The terms and time frames of any long-term contracts negotiated with industrial and commercial customers are also examined. Load factors and unit costs charged to key industrial customers are particularly important because they demonstrate the attractiveness of these customers to other suppliers or the opportunity for self-generation, and the potential for lost revenues. Large customers' supply options and cogeneration capabilities are important to ascertain potential system exposure. Also usually factored into the analysis of the customer base is an evaluation income levels to determine the relative affordability of rates.

The service areas of rural areas are sparsely populated with few customers per line mile, which reduces the risk that a competing utility will cherry pick its most attractive customers. Yet, these service areas also limit the opportunities for revenue growth, and tend to increase capital investment and service costs per unit of sales.

Historically, Standard & Poor's examined an electric utility's service area economy as a proxy for the stability of the revenue stream pledged to repay the utility's debt. While economic analysis remains a major focus, it can be tempered by the influence of competitive factors.

Favorable market characteristics include:

- Load factors for the system and leading customers that do not make the system particularly vulnerable to competitive factors;
- Stable or increasing population trends, in accordance with other forecasts for the utility; and
- High wealth indicators relative to cost-of-living indices and the level of electric rates.

Regulation

Standard & Poor's assessment of regulation encompasses several regulatory factors. These include the impact of federal, state, or local regulators with regard to ratemaking, competition, transmission, and the environment. The impact of the regulatory framework will come into play among several rating factors, particularly operational and financial factors.

In terms of restructuring of electric markets, Standard & Poor's believes that the movement toward a more openly competitive environment is possible over the long term, and would most likely occur on a state-by-state basis, as

opposed to via federal pre-emption. Standard & Poor's recognizes that many utilities will find that open markets will create opportunities, and also risks. Generally, however, public power utilities in regulatory environments that do not require them to face direct competitive threats from other power suppliers are subject to less credit risk.

Finances

A traditional analysis of a utility's financial performance generally incorporates a review of debt service coverage margins and liquidity, but also examines specific utility results and decisions. For example, some utilities are emphasizing competitiveness over the financial strength associated with excess coverage margins and debt service reserves, in an attempt to ensure long-term system viability. Standard & Poor's considers the effects of such policy changes and the potential diminution of financial cushions in its credit ratings. Standard & Poor's will typically assess the costs of achieving competitiveness and the impact of competitiveness upon financial integrity and system reliability. Reduced coverage and reserves may be appropriate for some utilities but not for others, depending upon the degree to which competitiveness can be enhanced and also the operational and competitive challenges that each utility faces.

Key financial ratios include debt service coverage, and fixed charge coverage; unrestricted cash as a percentage of total expenditures; and debt to equity, among others. While debt service coverage is a traditional financial metric for municipal utilities, it is more common for municipal electric systems to structure their operations using off-balance sheet debt for generation projects, and purchased power agreements that have debt-like characteristics. As such, fixed charge coverage, which imputes fixed payments associated with power and transmission purchases, whether through debt service or capacity payments tied to purchase contracts, is the more critical coverage ratio in the financial analysis of public power utilities. Transfers to other governments, while often expressly subordinate, are factored into the analysis as operating and maintenance expenses that reduce available net revenues, as transfers typically resemble property taxes, franchise fees, direct cost reimbursements, dividend, or return-on-equity type payments commonly paid by other enterprises such as investor-owned utilities.

The balance sheet has become a key tool for controlling costs and achieving competitiveness. Asset-to-liability management is particularly important for systems that have high debt due to their investments in high-cost generating assets and the extended use of capitalized interest to fund them. Popular options that are being pursued by public power include the restructuring of debt, extending the useful lives of plants, writing off uneconomic resources, accelerating the amortization of high-cost debt, and increasing the use of variable rate debt, interest rate swaps and other debt derivatives. It is quite likely that still other financial tools will be introduced in response to the pressure to bring down rates.

The use of each of these tools is evaluated relative to its appropriateness to the specific situation of a given utility. Generally, these mechanisms can be said to produce positive results to the extent that they reduce the upward pressure on rates. Utilities that maintain adequate cash balances to deal with the opportunities and challenges posed by a restructuring industry maintain important flexibility. For instance, ample funds will allow them to pay off high-cost debt, thereby improving their cost of capital and equity ratio. Some systems with strong business fundamentals could reduce their cash balances without impacting their credit ratings. This is particularly true for distribution systems that

do not have the same pressures and demands on liquidity as the more generation-dependent systems. The movement of the industry in this direction is evidenced by the revised bond resolutions and indentures that are designed to free up reserves that have been maintained under traditional financing documents.

Standard & Poor's monitors the use of synthetic financial instruments. These instruments present benefits, but also can increase risk, particularly as operating margins and reserves are trimmed to achieve competitiveness. Because risks associated with financial derivatives are borne by ratepayers and are not shared with owners, as is the case with investor owned utilities, it is imperative that a very high degree of oversight and control be employed.

Legal Provisions Of Retail Electric Systems

Standard & Poor's views an electric revenue bond transaction's legal provisions in conjunction with the system's overall financial profile. For electric utilities that are able to generate system surplus well above minimum levels required by bond covenants, legal provisions will be of less importance in the rating analysis. For electric utilities that demonstrate relatively weaker financial profiles, the analysis of legal provisions remains a critical factor. As defined in a bond indenture or resolution, the legal provisions make clear the issuer's capabilities, responsibilities, and the bondholder's recourse in the event of the issuer's noncompliance.

For an electric utility with a strong financial profile, strong or weak legal covenants will not correlate with a higher or lower rating. For a weaker electric utility, liberal legal covenants will continue to be viewed as a weakness and could serve as the basis for the assignment of a lower rating to systems with modest credit quality.

The most important legal provisions reviewed are the security pledge, rate covenant, flow of funds, additional bonds test, and debt service reserve. Also, a growing number of issuers are incorporating swaps or other derivatives into bond transactions, to supplement the traditional legal structure. Please refer to the Debt Derivative Profile section for additional information.

Security

The most common form of bond security for utility bonds is system net revenue. Some issuers elect to secure bonds on a gross revenue basis. However, Standard & Poor's believes that pledged system revenues should always be sufficient to cover debt service and operating expenses and, therefore, does not differentiate between net and gross revenue pledges. Similarly, off-balance sheet debt obligations of retail utilities that are usually secured by system operating expenses are treated as senior lien debt. Typically, these payments are take-or-pay obligations with wholesale agencies.

Rate Covenant

The rate covenant establishes the minimum level of debt service coverage that a system must provide on a fiscal-year basis. Standard & Poor's analyzes the rate covenant in relation to the overall operational and financial performance of the individual system. Generally, a mature system with stable operational and financial performance will not need as

strong a covenant as a system that can be subject to volatile financial margins or anticipates a large capital program.

A rate covenant addresses all obligations--senior and subordinate debt, as well as other system fund requirements. Typically, rate covenants for retail systems range from 1.10x- 1.25x the annual principal and interest requirements of senior lien debt. This extra margin provides bondholders with financial protection. Sufficiency-only rate covenants of senior lien debt are of less concern for issuer's that consistently set and achieve internal coverage policies well in excess of coverage levels required by the rate covenants.

For issuers that operate at less substantial margins, weak or sufficiency-only rate covenants will play a greater role in determining the rating. For these issuers, a covenant that allows the issuer to use existing cash reserves, otherwise known as "carryover coverage", or one-time revenue sources would likewise have negative rating consequences, especially if such funds are forecast to be necessary for coverage compliance.

Flow Of Funds

The flow of funds specifies the order and timing in which system revenues are used to meet the obligations created by the indenture. Of critical importance to the rating is the lien position of debt service payments in relation to other system obligations created by the indenture. The flow of funds defines the issuer's ability to transfer surplus funds out of the system. Such transfers can drain the utility's cash position or restrict capital improvements otherwise financed from earnings. Transfer payments that are limited to a reasonable amount and limited to a specific formula, such as a percentage of revenues, partially offset this concern. However, Standard & Poor's will calculate coverage both with and without transfers for comparative purposes. Frequency of payments to the debt service fund range from monthly to semiannual deposits. From a financial perspective, monthly deposits are preferred, since this approach allows a smooth buildup of the debt service fund and an early indication of any shortfalls.

Additional Bonds Test

As with the rate covenant, the additional bonds test is viewed in conjunction with the financial and debt profile of the system. The purpose of the additional bonds test is to protect existing bondholders from dilution of their security position. Standard & Poor's focuses on whether the issuer's right to and likelihood of issuing parity bonds at a later time would result in a decline in coverage. Attributes of a strong additional bonds test for parity debt include a test based on historical net revenues that preserve sound coverage of existing and proposed obligations. A test that measures historical earnings is preferred, since it is less speculative than those based on revenue projections. Often, projected tests rely on assumptions that might not be realized, such as future rate increases or revenues generated by new facilities.

Likewise, adjustments to historical net revenues to reflect new customers, system acquisitions, rate increases, or contracts for additional services can weaken an otherwise strong historical earnings test.

Reserves

Standard & Poor's looks for established reserve funds, such as debt service reserve accounts maintained at specific funding level, to provide additional cushion for debt service payments and system maintenance within a given budget year. For issuers with thinner margins, a fully funded debt service reserve is important, since it provides an additional layer of protection for bondholders.

Typically, a debt service reserve requirement is equal to the lesser of 125% of average annual debt service, 10% of bond proceeds, or maximum annual debt service thresholds, which are derived from IRS regulations. This restricted reserve is expected to be funded from bond proceeds, or built up from pledged revenues, usually over no more than five years. The former approach adds more credit strength. Substitution of cash-funded reserve by a surety bond and/or LOC obtained from a creditworthy entity also is acceptable. If the reserve fund is tapped to meet debt service payments, a reasonable replenishment schedule should follow. Renewal and replacement accounts and rate stabilization fund accounts are also common, and provide additional financial cushion, but are not considered necessary from a credit standpoint.

Typically, a system with stable operations and strong financial margins can carry diminished debt service reserve provisions, including the use of springing covenants, without credit implications. Alternatively, absence of fully funded reserve for systems that generate thinner margins, exhibit asset or customer base concentration, a shallow service area economy, or cash flow constraints, the may result in a lower rating.

Suggested Documentation

Financial Documents

- Official statement
- Indenture/resolution (including supplemental resolution and indenture)
- Other legal documents
- Debt service schedule (with and without current financing)
- Five years of audited financial information
- Capital improvement plan
- Current year budget
- Projections
- Contracts for purchased power (including participation agreements)
- Contracts for fuel (applicable)
- Contracts with leading customers
- Details on power and interest rate swaps.

System Information

- Type of unit (base, intermediate, peaking), fuel type, availability, capacity, load factors and installation date for individual generation units
- Peak data (historical)
- Load factors for leading customers
- Leading customers as a % of revenue
- Revenue by customer class (residential, commercial, industrial, other), historical
- Customers by class (residential, commercial, industrial, other) historical
- % power purchased, % power generated, historical & projected
- % of purchased power under contract, % of purchased power brought on spot market
- Fuel mix, historical and projected (for generators)
- Rates historical, projected
- Fixed charges for off-balance-sheet obligations, historical and projected
- Debt service schedule for off-balance-sheet projects, and participation percentages.
- Transfers historical and projected
- Rate stabilization funds (historical/projected) held at the issuer level
- Transfer policy and methodology if available
- Debt and hedge policies if available
- Policies related to entering into non-traditional ventures, if available
- Summary of power supply, transmission and fuel purchase contracts, including term, price, amounts, fixed and for capacity payments, and other key facets.

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Long Island Power Authority; Retail Electric

Credit Profile		
US$450.0 mil elec sys gen rev bnds ser 2014A due 09/01/2044		
Long Term Rating	A-/Negative	New
US$250.0 mil elec sys gen rev bnds ser 2014B due 09/01/2034		
Long Term Rating	A-/Negative	New
US$99.0 mil elec sys gen rev bnds ser 2014C due 09/01/2033		
Long Term Rating	A-/Negative	New
Long Island Pwr Auth elec sys gen rev		
Long Term Rating	A-/Negative	Affirmed

Rationale

Standard & Poor's Ratings Services has assigned its 'A-' rating, with a negative outlook, on the following Long Island Power Authority (LIPA), N.Y.'s proposed bonds:

- $450 million electric system general revenue bonds, series 2014A
- $250 million electric system general revenue bonds, series 2014B (federally taxable)
- $99 million electric system general revenue bonds, series 2014C (LIBOR floating rate tender notes)

At the same time, Standard & Poor's affirmed its 'A-' rating on the authority's $5.2 billion of unsecuritized revenue bonds. The outlook is negative.

LIPA will principally apply the 2014A and 2014B bonds' proceeds toward converting short-term obligations to long-term instruments by retiring commercial paper (CP)_and credit facility draws. The utility will also apply a portion of those bond proceeds to capital projects. The 2014C bonds' $99 million of proceeds will refund variable-rate demand obligations with floating rate notes.

LIPA's net revenues pay debt service on direct debt. As of September 30, 2014, the utility had $5.85 billion of debt, excluding the $2 billion of securitization debt the Utility Debt Securitization Authority issued in December 2013 to refinance a portion of the utility's debt. September's debt balance, net of securitization debt was 12% higher than Dec. 31, 2013's $5.2 billion, net of securitization debt.

The ratings reflect our opinion of the benefits of a stable revenue stream and prospects for stronger fixed charge coverage following the securitization of nearly 30% of its debt. LIPA serves the transmission and distribution needs of a broad and affluent customer base whose residential customers account for slightly more than half of operating revenues.

We believe these concerns temper the authority's credit strengths:

- Although ostensibly a transmission and distribution utility, LIPA secures its customers' energy and capacity needs under contracts that created substantial fixed financial obligations.

- Notwithstanding that LIPA's December 2013 $2.0 billion securitization reduced direct debt obligations and created the potential for stronger debt service coverage (DSC) of unsecuritized debt and improved leverage ratios, our analysis focuses on fixed charge coverage. That ratio treats capacity payments LIPA makes to energy suppliers to fund their recovery of capital investments in generating assets as debt service, rather than as expenses. We also treat the utility's recurring payments in lieu of taxes (PILOT) as operating expenses. The capacity and PILOT payments dilute debt service coverage ratios. Fixed charge coverage was 1.1x in 2008-2011, 1.0x in 2012, and 1.2x in 2013. Although we view pre-2013 coverage levels as thin for the rating, we consider the transition to stronger coverage in 2013 as favorable, if sustainable. Direct debt service coverage before Standard & Poor's adjustments for PILOT and capacity payments, was 2.0x in 2013.
- The utility has voluntarily submitted to the state's request that it freeze base rates in 2014 and management expects to extend the freeze through 2015. Although LIPA benefits from pass-through mechanisms for recovering changes in several components of its variable operating costs, we believe that freezing base rates could reduce the financial flexibility that we consider important to responding to changing costs and preserving credit quality, particularly as the utility adds debt that offsets some of the securitization's debt reductions.
- Legislation directs LIPA to submit a rate filing in 2015 to the New York Department of Public Service (DPS). The rate case will entail full evidentiary hearings. This requirement distinguishes the authority from most public power utilities that have autonomous ratemaking authority and the capacity to expeditiously respond to changes in their business climate.
- The 2015 rate filing is to cover the three years beginning Jan. 1, 2016. The three-year tenor of the rate case's scope might limit financial flexibility if circumstances change during the years the rate case covers and the utility is reluctant to file or the regulator opposes entertaining another rate case during those years.
- Because LIPA has never filed any rate cases, the introduction of regulatory oversight adds uncertainty to the assessment of its credit quality. Regulatory oversight of the utility's rates will not be tested until the DPS reviews the 2015 rate filing, adding uncertainty to projections of financial performance.
- Although the recent $2 billion securitization financing reduced direct debt, LIPA projected that it would not lower customer bills because they include the securitization bonds' debt service charges. Before adding short-term debt in 2014, the utility projected that combined securitization and unsecuritized debt service would closely parallel pre-securitization debt service, which could perpetuate customers' and politicians' rancor regarding the utility's rates and potentially constrain financial flexibility. This year's debt additions could place upward pressure on rates or erode financial margins.
- The authority does not prepare financial forecasts beyond annual budgets, which makes it difficult to gauge future debt service metrics and leverage. The uncertain inaugural rate case's outcome compounds this exposure.

LIPA is among the three largest public power utilities in the U.S. by customers and revenues. It serves about 1.1 million retail customers. Unlike similar-size peers, the authority relies on others to supply its customers' electricity needs. The utility purchases all but a small portion of its electricity from third parties. LIPA's owned generation capacity consists of a 233-megawatt, 18% interest in the Nine Mile Point 2 (NM2) nuclear plant, which equals less than 4% of peak demand. The plant is co-owned with and operated by Constellation Energy Nuclear Group, LLC. Contractual agreements with National Grid USA and other energy providers, as well as market purchases, serve all needs beyond NM2. The authority's contractual agreements with National Grid extend to 2028 and allow LIPA to purchase energy from resources other than National Grid's if they have lower costs, which is important because National Grid's resources have high production costs.

Two underwater transmission cables provide access to the PJM and New England independent system operator

markets. Although these cables help reduce LIPA's exposure to National Grid's high production costs, the cost of reserving National Grid capacity does not abate when LIPA purchases power from others.

Outlook

The negative outlook reflects our view that although the securitization has reduced direct debt obligations and should contribute to improvements in debt service coverage and leverage ratios for unsecuritized debt, the agreement to submit to a rate freeze, the absence of postsecuritization bill reductions, and the uncertainties associated with untested regulatory oversight of rates could limit LIPA's financial flexibility and erode credit metrics for unsecuritized debt. Moreover, debt added in 2014 could dilute some of the securitization's debt-reduction benefits. We will monitor the upcoming rate proceedings, capital spending, and financing needs to assess their implications for financial performance and the ratings.

The 2014C Floating Rate Notes

The series 2014C bonds will initially be offered in the floating rate note mode, which LIPA expects to be 70% of one month U.S.-dollar-denominated LIBOR, plus an adder to be determined. The utility will pay monthly interest on the bonds.

LIPA plans to issue a mandatory tender for the 2014C bonds on their fourth anniversary. If the bonds cannot be remarketed in conjunction with the mandatory tender, bondholders will retain the bonds until they can be remarketed. However, the bonds' interest rate can rise to 10% pending remarketing. Nevertheless, the structure's mechanics for a failed remarketing help shield the utility from contingent liquidity risks. Because the 2014C bonds represent less than 2% of the utility's debt portfolio, we view the potential spike in interest rates as a moderate exposure.

December 2013's Securitization Financing Will Not Reduce Customers' Bills

In December 2013, LIPA refunded more than one-quarter of its debt through a legislatively directed securitization. The Utility Debt Securitization Authority (UDSA), a special-purpose entity created for the transaction, sold $2.0 billion of bonds that retired a portion of the $7 billion of debt LIPA reported as of Dec. 31, 2012. The enabling legislation's stated rationale for a securitization cited the potential for reducing borrowing costs and creating customer savings.

The securitization bonds are not LIPA obligations. Securitization bondholders do not have a claim on the authority's revenues and the unsecuritized revenue bonds' holders do not have a claim on the funds pledged to the securitization bonds. The securitization bonds are secured by irrevocable consumption-based charges that cannot be bypassed.

UDSA's debt service requirements will be collected on LIPA's customer bills. At the time of the securitization and before adding short-term debt in 2014, the utility projected that aggregating securitization charges with its other charges would maintain bills at presecuritization levels and customers would not see savings compared with presecuritization bills.

Average consumer rates are about 20 cents per kilowatt-hour, which we believe is high in absolute terms. Also, Energy Information Administration data show that LIPA's 2012 residential rates were about 8% above the state's average and its commercial rates about 14% higher.

Because customers and politicians already perceived the authority's bills to be high before the securitization, we view the absence of a postsecuritization rate reduction as potentially perpetuating customers' and politicians' negative views of the utility, which could limit financial flexibility if rate increases are needed.

Legislatively Imposed Rate Oversight And A Rate Freeze Could Reduce Financial Flexibility

Legislative provisions enacted in 2013 impose regulatory oversight of LIPA's ratemaking that, in our view, has the potential to reduce the utility's financial flexibility and could impair the ratings.

The legislation directs LIPA to make a rate filing in 2015 for review by the DPS in full evidentiary hearings. The rate filing is to cover the three years beginning Jan. 1, 2016. In addition, the legislation requires full evidentiary hearings for "any [subsequent] rate proposal that would increase ... the aggregate revenues of the authority by more than two and one-half percent ... on an annual basis." LIPA's board can challenge a DPS rate recommendation, but the legislation requires that it do so only through adversarial hearings in which the board "present[s] the basis for its determination." The board's rejection of a DPS rate recommendation can be judicially challenged on the grounds of arbitrariness and capriciousness.

Although the utility believes it retains ratemaking authority pending the transition to DPS rate oversight, it acquiesced to the state's request that it agree to submit to a base rate freeze through 2014. Management projects that the rate freeze will likely be extended through 2015.

The authority continues to adjust the power supply charge component of its rates monthly, which we view as preserving an important element of its financial flexibility. During the rate freeze, the question remains open as to whether the utility possesses sufficient financial flexibility to address capital spending needs, additional debt, and inflationary pressures on wages and other costs that are recovered in base rates and that are outside the power cost adjustment mechanism, without eroding financial metrics. Expectations that the Federal Emergency Management Agency (FEMA) will provide funds for storm hardening could temper some of these concerns, but adding debt through the series 2014A-C financings and other financings could dilute securitization's benefits.

It is unclear whether the legislation's language specifying that changes in "aggregate revenues ... by more than two and one-half percent ... on an annual basis," as the trigger for DPS rate review, applies exclusively to changes in base rates, as the authority maintains, or covers cumulative changes in base rates and energy pass-through charges. In support of its position that the trigger applies only to base rates, LIPA cites the Public Service Commission's differentiation between required reviews of investor-owned utilities' base rate adjustments, compared to those utilities' use of pass-through mechanisms to capture changes in fuel and power procurement costs without rate hearings. Historically, the authority made unfettered adjustments, as needed, through its power supply charge. These adjustments led to disputes, some of which were litigated, but resolved in its favor.

On a positive note for LIPA, the legislation limits the annual increases in PILOTs it makes to municipalities to 2%. PILOTs rose 43% from 2008-2013, reaching $342 million. However, the legislation provides for the utility and its ratepayers to shoulder the costs of DPS oversight, which could dilute the PILOT relief.

The Securitization Improves Financial Metrics Marginally, But Not Enough To Overcome Other Credit Exposures

We believe that financial metrics have historically been only adequate for the rating, with debt to capitalization ratios of about 97% in 2010-2012, before the securitization, and fixed charge coverage of 1.1x in 2010-2011, and 1.0x in 2012, but 1.2x in 2013. The authority's financing documents provide that PILOTs are post-debt service obligations. However, we view recurring PILOTs as having the attributes of operating expenses. In addition, our debt service coverage analysis treats fixed capacity payments to generation suppliers as debt service, rather than operating expenses.

We have viewed the utility's use of monthly adjustment mechanisms that allowed timely recovery of changes in some variable costs and the service area's demographics as having compensated for thin fixed charge debt service coverage and high leverage. Although the securitization could contribute to stronger fixed charge coverage, compared to pre-2013 levels, we will monitor whether rate oversight and additional debt bears this out.

Standard & Poor's generally excludes nonrecurring grant income from its debt service coverage ratio calculation's numerator. However, part of the grant income that LIPA reported on its income statement in recent years principally represented FEMA reimbursements for storm damage repairs that the authority expensed and U.S. Treasury reimbursements for a portion of gross interest on Build America Bonds. Therefore, we included the grants in the coverage ratio's numerator. We also added the income statement's recovery of carrying charges on regulatory assets to the numerator. This money represents collections of debt service on bonds issued to finance a bill credit that coincided with the authority's inception.

The utility maintains what we view as sound liquidity, with unrestricted cash and investments of $292 million as of Sept. 30, 2014. It also had prefunded about $119 million of the system operator's operating expenses.

Although the authority has exhausted all $300 million of its CP program's capacity, its liquidity also benefits from $162 million available under a credit facility that can be used for general corporate purposes and $85 million of capacity in its fuel credit facility, which will expire by the end of the year. LIPA plans to more-than-double the size of its CP program to $625 million in December. About $100 million in a construction fund also represents available liquidity.

In addition to direct debt, the utility reported $2.6 billion of capital lease obligations on its balance sheet as of Dec. 31, 2013. These obligations represent the present value of capacity payment commitments to energy suppliers. Based on 2012's fiscal year-end results, we calculated a debt-to-capitalization ratio of 97%, which we believe is especially high for a distribution utility.

Whether The Transfer Of Day-To-Day Operations To A New Company Will Improve Performance Is Uncertain

The 2013 LIPA legislation transferred much of the day-to-day oversight of operations to PSEG Long Island, a subsidiary of New Jersey's Public Service Enterprise Group (PSEG). It remains uncertain whether the transition from National Grid USA's operational oversight will improve politicians' and ratepayers' negative perceptions of high rates. Both National Grid and PSEG are investor-owned companies.

The legislation sets three days as the baseline for restoring service following emergency or storm events. If the system operator, PSEG, does not meet this goal, it must provide the DPS with an assessment of its pre-event preparedness and post-event restoration efforts. As the LIPA pursues the storm-hardening measures that the governor and legislators called for in the wake of 2012's lengthy storm outages, the availability of ratemaking flexibility could be critical to supporting capital investments and preserving financial metrics. FEMA funding should temper this exposure.

Related Criteria And Research

Related Criteria

USPF Criteria: Electric Utility Ratings, June 15, 2007

Ratings Detail (As Of November 24, 2014)		
Long Island Pwr Auth elec sys (MBIA) (ASSURED GTY)		
Unenhanced Rating	A-(SPUR)/Negative	Affirmed
Long Island Pwr Auth elec (wrap of insured) (AMBAC & AGM) (SEC MKT)		
Unenhanced Rating	A-(SPUR)/Negative	Affirmed
Long Island Pwr Auth elec (wrap of insured) (AMBAC, AGM & BHAC) (SEC MKT)		
Unenhanced Rating	A-(SPUR)/Negative	Affirmed
Long Island Pwr Auth elec (wrap of insured) (FGIC & AGM) (SEC MKT)		
Unenhanced Rating	A-(SPUR)/Negative	Affirmed
Long Island Pwr Auth elec (wrap of insured) (FGIC & ASSURED GTY) (SEC MKT)		
Unenhanced Rating	A-(SPUR)/Negative	Affirmed
Long Island Pwr Auth elec (wrap of insured) (FGIC & BHAC) (SEC MKT)		
Unenhanced Rating	A-(SPUR)/Negative	Affirmed
Long Island Pwr Auth elec (wrap of insured) (MBIA/National) (AGM) (SEC MKT)		
Unenhanced Rating	A-(SPUR)/Negative	Affirmed
Long Island Pwr Auth elec (wrap of insured) (SYNCORA GTY) (ASSURED GTY) (BHAC) (SEC MKT)		
Unenhanced Rating	A-(SPUR)/Negative	Affirmed
Long Island Pwr Auth elec (wrap of insured) (SYNCORA GTY) (ASSURED GTY) (SEC MKT)		
Unenhanced Rating	A-(SPUR)/Negative	Affirmed
Long Island Pwr Auth elec (wrap of insured) (SYNCORA) (MBIA) (National) (SEC MKT)		
Unenhanced Rating	A-(SPUR)/Negative	Affirmed

Ratings Detail (As Of November 24, 2014) (cont.)		
Long Island Pwr Auth elec (ASSURED GTY)		
Unenhanced Rating	A-(SPUR)/Negative	Affirmed
Long Island Pwr Auth elec (BHAC)		
Unenhanced Rating	A-(SPUR)/Negative	Affirmed
Long Island Pwr Auth elec (BHAC) (SEC MKT)		
Unenhanced Rating	A-(SPUR)/Negative	Affirmed
Long Island Pwr Auth elec		
Unenhanced Rating	A-(SPUR)/Negative	Affirmed
New York St Energy Research & Dev Auth, New York		
Long Island Pwr Auth, New York		
New York St Energy Research & Dev Auth (Long Island Pwr Auth)		
Long Term Rating	A-/Negative	Affirmed
New York St Energy Research & Dev Auth (Long Island Pwr Auth) (MBIA) (National)		
Unenhanced Rating	A-(SPUR)/Negative	Affirmed
New York St Energy Research & Dev Auth (Long Island Lighting Co Proj) elec		
Unenhanced Rating	A-(SPUR)/Negative	Affirmed

Many issues are enhanced by bond insurance.

U.S. Public Power Rating Criteria

Sector-Specific Criteria

Inside This Report

This criteria report replaces the prior version of the same title, dated Jan. 11, 2012. There have been no substantial changes to the criterion.

Related Research

2013 Outlook: U.S. Public Power and Electric Cooperative Sector — Nothing Shocking (December 2012)

U.S. Public Power Peer Study — June 2012 (June 2012)

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Scope

This criteria report details Fitch Ratings' approach to rating U.S. public power systems. It is a sector-specific extension of Fitch's global master criteria report, "Revenue-Supported Rating Criteria." More specifically, the report elaborates on five key areas of operational and financial importance to the credit quality of municipal and cooperative power entities: governance and management strategy; assets and operations; cost structure; financial performance and legal provisions; and customer profile and service area.

These key elements of Fitch's public power rating criteria remain largely consistent with its prior criteria reports. However, the weighting of individual credit factors changes as the industry evolves, particularly in response to new regulatory initiatives or as new market dynamics emerge. In addition, not all rating factors outlined in this report apply to each individual rating or rating action. Each specific rating action commentary or rating report discusses those factors most relevant to the individual rating decisions.

Key Rating Drivers

Rate Sufficiency and Flexibility: A public power utility's ability and willingness to maintain rates sufficient to meet all of its financial obligations is of paramount importance. Fitch considers how a utility's rate structure affects its capacity for the full and timely recovery of costs, as well as its flexibility to raise additional revenue. Ratemaking autonomy and the process for adjusting rates factor into this analysis.

Comprehensive Strategic Planning and Risk Management: The extent of strategic planning and risk management performed by a utility is a key indicator of management's preparedness and sophistication, and an important rating factor. Fitch typically reviews prior strategic and financial plans versus actual outcomes, as well as newly adopted strategies, to gauge management effectiveness.

Resource Adequacy and Performance: Ensuring the adequacy of power supply resources to meet current and projected demand is a fundamental planning requirement of public power utilities. Together with demonstrated operating efficiency, it is an important factor in providing a low-cost, reliable energy supply. Fitch measures resource adequacy and performance against industry standards for cost and reliability.

Financial Strength and Forecasting: The strength and stability of a utility's financial metrics reveal its ability to meet all financial obligations, and detailed financial forecasting provides an indication of future performance. Fitch reviews a broad array of historical and projected financial metrics in an assessment of a utility's financial strength, as well as a utility's adherence to adopted financial policies. Financial metrics focus principally on three core areas: cash flow, liquidity, and capital structure.

Service Area Composition and Depth: Service area characteristics demonstrate the breadth, depth, and stability of a utility's constituents, as well as their financial wherewithal. Fitch considers customer composition and concentration; income levels; and employment, population, and sales growth trends in this assessment.

Public Power Ratings in Context

U.S. public power utilities are effectively owned by their customers and operate with a mission to provide essential, reliable, and relatively low-cost electric service. Fitch's average rating for retail systems in the sector is 'A+', compared with an Issuer Default Rating of 'BBB+' for investor-owned utilities.

Key credit characteristics supporting higher ratings for public power utilities include their self-regulating authority, predominantly residential customer bases, and lower consolidated enterprise risk. Self-regulating authority allows for the more timely recovery of costs through electric rates, while higher proportions of residential customers provide for more stable energy sales and, in turn, more predictable financial operations. Efforts to diversify operations in the public power sector are extremely rare.

Governance and Management Strategy

The strength of a utility's senior management and governing body — usually an independent board of directors or elected city council — is a key credit consideration in Fitch's analytical process. Management's experience and ability to design and implement a comprehensive strategic plan is important to an issuer's rating, as is its ability to respond to unforeseen circumstances. A high degree of board or city council understanding and support of a utility's business strategy and the issues facing the utility is also important.

Achieving Strategic Goals

Fitch typically reviews prior strategic and financial plans versus actual outcomes in an assessment of management and governance effectiveness. A stronger management team consistently meets or exceeds financial projections, and deals well with unexpected developments. Moreover, Fitch takes into account the reasonableness of key financial and operational planning assumptions in its assessment.

Major Components of a Comprehensive Strategic Plan

Forecasts of customer and load growth.
New generation, transmission, or distribution requirements.
Plans to meet capital needs, including financing schedules.
Plans for rate increases.
Financial projections, including stress scenarios.
Risk-management procedures and analysis.

Comprehensive Resource Planning

Fitch analyzes a utility's integrated resource plan and its long-term strategies to provide reliable, high-quality, and low-cost service to its customers to determine if they are adequate and reasonable. Fitch monitors the implementation of those strategies and a utility's financial flexibility for responding to changing market conditions.

Fitch discusses with management the purpose, amount, and structure of planned debt issuances, and any debt-management policies in assessing a utility's capital needs and their effect on its future debt profile and financial performance. Fitch assesses the willingness and

Related Criteria

Criteria for Rating Prepaid Energy Transactions (August 2012)

Criteria for Assigning Short-Term Ratings Based on Internal Liquidity (June 2012)

Revenue-Supported Rating Criteria (June 2012)

Attributes: Governance and Management

Stronger
Management and board of directors with extensive experience.
An objective, engaged board of directors.
Transparency and strong communication between management, the board of directors, and customers.
In the case of wholesale power systems, coordinated efforts among member utility systems and the governing body.
Frequent analysis and updating of financial forecasts and resource management plans.
Well-developed and documented risk-management policies and procedures.
Documented succession planning.
Midrange
Generally stable management team and board of directors with modest turnover.
Comprehensive strategic and resource plans, forecasts of demand, and risk-management policies that generally reflect current economic, system, and political conditions.
Weaker
A detached, politically-appointed board of directors.
Lack of experience or frequent turnover of management.
Significant political pressure in the underlying municipality or in the members' service area.
Failure to maintain open communication between the utility and the board of directors, which may reveal itself in unexpected, significant rate increases.
Limited financial forecasting and rate planning.
Lack of adequate risk-management policies and procedures.

ability of an issuer's management and governing body to increase rates to ensure the measured, timely, and adequate recovery of total costs. Fitch also evaluates the likely effect of rate increases on a utility's financial performance relative to its peer group.

Preparing for Uncertainties

The extent of risk management performed by a utility is a key indicator of management's sophistication. Fitch believes that the ability to manage unforeseen circumstances without causing material changes to the utility's financial or operating position is a good indication of management planning and preparedness. Fitch views favorably a management team that is able to recognize and discuss risks (and mitigating factors) that could affect a system, and in turn, bondholder security. Such risks include participation in the fuel and energy commodity markets; plans for managing a large generation unit or transmission outage; reliance on off-system counterparty credit quality; and the effect of regulatory or legislative changes.

Assets and Operations

Fitch analyzes the generation, transmission, and distribution assets of wholesale and retail power systems to determine if a utility's power supply mix and asset operating performance adequately meet existing and future demand requirements. Fitch also analyzes how a utility's power supply mix and performance compare to similar systems.

Generation Benchmarking

Fitch benchmarks a utility's generation mix to that of industry standards, the regional market in which the utility operates, and other utilities in the rating category. This allows for a comparative analysis of a utility's relative strengths and weaknesses. Fitch considers the following areas in its assessment of generation:

- Fuel mix;
- Plant availability and capacity factors;
- Load factor;

- Heat rate; and
- Environmental mandates or goals.

Fitch looks through the wholesale provider and performs a similar assessment for distribution systems that purchase power under bilateral contractual agreements from a joint-action agency or cooperative.

New Power Resources

Fitch analyzes how a utility's customer or load growth, expiring purchase power contracts, aging generation fleet, and renewable mandates influence the demand for future power resources. Fitch considers the following areas in its assessment of a utility's integrated resource plan:

- The type of generation chosen and alternatives considered;
- The size and cost of the unit;
- The effect of the unit on the utility's existing portfolio resource mix (baseload, intermediate, or peaking);
- The availability of transmission and distribution resources; and
- Environmental factors.

Building and owning assets provides many benefits, such as:

- Control of asset operation;
- Limited counterparty risk and collateral-posting (requirements associated with power purchases); and
- Equity associated with owning a long-term asset.

However, there are also benefits to being a power purchaser in periods when market power supply is ample and electric transmission access is available. Some small- to medium-sized systems can benefit from avoiding large, costly capital programs and operating obligations that come with owned generation.

Attributes: Assets and Operations

Stronger
A stable, diverse, and regionally cost-effective power resource mix.
Adequate fuel supply contracts and a well-constructed fuel-hedging strategy.
Sound operating performance that is in line with or better than industry standards.
Adequate reliability and redundancy.
A power supply plan to maintain load balance.
Sufficient transmission access.

Midrange
A power supply mix in line with the region.
Fuel-hedging strategy that strives to minimize fuel price volatility at competitive prices.
Sound asset operations, comparable to industry standards.
Limited outages that cause resources to perform below industry standards.
Evolving power supply plan that might have an open position.

Weaker
A generation portfolio that is uneconomic or might ultimately pose unusual environmental concerns.
Dependency on a single fuel or generation site.
Below-average reliability levels stemming from frequent outages, high line losses, theft, or customer dissatisfaction.
Excessive dependence on the open market for either spot power purchases or sales of surplus power.
Lack of a comprehensive power supply plan.

Fitch does not typically evaluate the merits of owning generation versus purchasing power. On the contrary, Fitch's analysis considers the costs and benefits to individual utilities of both scenarios.

Renewable Resources

Fitch reviews a utility's strategy for developing renewable or alternative power generation to gauge how a utility's generation mix will change, particularly when it must comply with a state renewable portfolio standard. Fitch also evaluates the capital and operational costs of the projects, and how they will ultimately affect customer rates.

Renewable energy projects are expected to have long-term environmental benefits. However, the intermittent nature of their generation and higher operating costs relative to traditional generating resources can pressure a utility's financial operations without adequate cost recovery. The availability and types of these resources and the transmission capability vary by region.

Environmental Considerations

Fitch conducts a review of a utility's compliance with current and proposed environmental standards to fully understand a system's future capital needs and operating expenses. Environmental retrofits can be costly on a capital basis and from an operating perspective, as increased captive consumption often results in lower plant output. The cost to retrofit may be high for older, coal-fired generating facilities, rendering the generating facility uneconomic and subject to retirement. As such, the effect of more restrictive federal and state environmental policies can have significant operating and financial repercussions for a utility.

Fuel-Supply Management

Fitch reviews a utility's hedging techniques as part of its risk-management assessment. The ability to manage fuel costs is a key credit factor, because fuel is often a utility's largest budgetary expense. Hedging can be critical to the financial stability of, for example, a retail distribution system that purchases a portion of its power in the spot market.

The use of financial markets and power derivatives can help mitigate the risk of price volatility or a longer term trend of increasing prices. However, these instruments can leave a utility exposed to a drop in fuel prices, which can render certain hedges uneconomic, or "out of the money." This might require a collateral posting by the utility that, if coupled with declines in operating performance, could tighten liquidity and result in negative credit pressures.

Other factors of the fuel supply that Fitch considers include:

- Diversity of fuel mix;
- Flexibility of fuel agreements;
- Fuel transportation arrangements; and
- Alternative fuels, if primary sources are not available.

The optimal fuel-supply strategy varies by utility. It is driven by the diversity of generating resources, sufficiency of fuel sources, and the ability to mitigate associated risks.

Off-System Sales and Purchases

Heavy reliance on off-system sales is viewed as a negative credit factor as revenues tend to be more volatile, reflecting inherently variable power market prices. However, a power generator's off-system sales to non-native load can reduce existing customers' costs or provide surplus funds for reinvestment in system facilities, depending on market conditions.

Conversely, spot purchases can increase overall cost efficiency if power generators can purchase power in the open market when the cost is beneficial (the market cost of power is lower than the cost of a system's own generation). However, short-term purchases will also expose issuers to greater cost volatility.

Distribution and Transmission

Fitch's review of a distribution system includes an assessment of its reliability, as measured by the frequency of outages, line losses, etc., and the extent and timeliness of necessary capital improvements for its traditionally "wires only" infrastructure. Fitch views the distribution function largely as a monopoly-type, stable business with limited business risk.

Fitch evaluates the level of historical and planned system investment to determine if customer growth will affect the operations of the existing system relative to a peer group. Fitch also reviews a utility's business strategy regarding its transmission connection with a regional operator or other transmission system that can provide it with reliable access to market power, if needed.

Cost Structure

Fitch analyzes a utility's cost structure and methods of adjusting rates to determine its rate-raising flexibility for the timely funding of financial operations and capital needs. The analysis is conducted "bottom up," by looking at the costs to generate (or purchase) and supply electricity to customers, and "top down," by examining the structure of retail rates charged to different customer classes. A utility with overall rates that are below neighboring systems or systems with similar fuel mixes is generally viewed as having greater flexibility to use rates as a tool for funding, and strong service territory income measures typically enhance this flexibility.

Local Rate-Setting Authority

Fitch views the flexibility most municipal systems and electric cooperatives have to independently adjust rates as a positive credit factor and distinguishing characteristic from comparable investor-owned utilities. Most public power systems are not subject to regulation by state public service commissions. Instead, public power systems typically maintain local authority to adjust rates as needed, which contributes to the timely recovery of costs. This provides management with the ability to raise rates to maintain financial stability, build liquidity, or pay for portions of a capital improvement plan.

Fitch also considers the use of automatic or interim rate adjustments, which further ensure timely cost recovery, in its assessment of a utility's rate structure. Interim adjustments that may be implemented by a utility's management team — without the involvement of a governing board — can help ensure the overall stability of financial operations.

Attributes: Cost Structure

Stronger
Sole authority to set appropriate customer or member rates and a demonstrated willingness to do so.
Retail/wholesale rates are typically below those of neighboring utilities and frequently more competitive nationally.
Competitive “all-in” production costs.
Use of an automatic monthly fuel or purchased power adjustment surcharge for timely recovery of variable energy and fuel costs.
Timely and measured rate increases in anticipation of multiyear capital spending.
Midrange
Authority to set customer or member rates, subject to the approval of an elected city council.
Comparable rates to neighboring utilities, and within range of regional averages.
Use of a fuel or purchased power adjustment surcharge typically adjusted less frequently than monthly.
Well documented rate strategy for servicing capital spending and related debt obligations.
Weaker
Outside regulatory approval required for rate increases.
Political pressure that might limit or postpone needed rate increases, which could ultimately affect a utility’s financial metrics.
Above-average rates relative to a peer group, which reduces flexibility for managing unforeseen operating or other capital expenses.
Lack of any fuel or purchased power adjustment factor.

The rates of wholesale power suppliers, including joint-action agencies and generation and transmission cooperatives, and their distribution members are compared at the wholesale and retail levels, respectively.

Rate Competitiveness and Affordability

Fitch analyzes rate affordability with a mixture of qualitative and quantitative factors. While this area typically does not have a significant impact on rating outcomes, Fitch’s perception of high or volatile rates, lack of future rate flexibility, or difficulty in obtaining timely rate relief may influence a utility’s rating. Fitch believes credit is due to those systems that consistently raise rates to preserve financial strength. However, Fitch believes these activities will be more sustainable when rate affordability is a focus of policymakers and cost containment is regularly employed. Fitch reviews a utility’s rates relative to neighboring systems and against service area income levels to gauge rate competitiveness and affordability.

Financial Performance and Legal Provisions

The assessment of a utility’s financial performance and policies, and the legal provisions underpinning specific debt issuances, are important considerations in Fitch’s rating process. Fitch reviews five years of audited financial statements for an established utility to understand its historical trends and competitive position relative to a peer group. A utility’s operating results, liquidity levels, and capital structure are evaluated. Financial projections, including planning assumptions for load growth, rate increases, and expenses, are likewise critical to the rating process. Fitch also examines the financial profiles of a wholesale power provider’s members as necessary, to the extent that information is available.

Financial Performance

Fitch's analysis of financial metrics focuses principally on three core areas: cash flow, liquidity, and capital structure. No single financial ratio stands apart from the rest. On the contrary, the ratios are examined together, providing a context for a utility's financial position that informs a complete analysis.

Cash Flow

Cash flow indicators, particularly as they pertain to debt service coverage, provide a measure of financial cushion to meet obligations to bondholders. Fitch primarily considers two measures of debt service coverage to compare utilities that own generation versus purchase power. The standard debt service coverage ratio measuring funds available for debt service to total debt service applies to all utilities. An adjusted measure of debt service coverage, primarily for retail systems that own little or no generation, treats a percentage (30%) of purchased power costs as a debt-like obligation. Thirty percent is an approximation based on historical experience for that portion of off-balance sheet obligations that might otherwise be a fixed expense. The ratio provides a more conservative estimate of financial margin and facilitates comparison with systems that own generation.

Key Financial Ratios

Ratio	Calculation	Significance
Cash Flow		
FADS ($)	Operating Revenues–Operating Expenses+Depreciation+Interest Income[a]	Provides a measure of cash flow from operations.
Debt Service Coverage (x)	FADS/Total Annual Debt Service	Indicates the margin available to meet current debt service requirements.
Coverage of Full Obligations (x)	(FADS+Fixed Charge–General Fund Transfer and/or PILOT)/(Total Annual Debt Service+Fixed Charge)[b]	Indicates the margin available to meet all debt service and other fixed obligations.
Debt/FADS (x)	Total Debt/FADS	Indicates the size of debt compared to the margin available for debt service.
Liquidity		
Days Cash on Hand	Unrestricted Cash and Cash Equivalents/(Operating Expenses–Depreciation)x365	Indicates financial flexibility, specifically cash and cash equivalents, relative to expenses.
Days Liquidity on Hand	(Unrestricted Cash and Cash Equivalents+Available Lines of Credit and Commercial Paper Capacity)/(Operating Expenses-Depreciation)x365	Indicates financial flexibility, including all available sources of cash and liquidity, relative to expenses.
Capital Structure		
Equity/Capitalization (%)	Total Equity/Capitalization	Provides a measure of cost recovery, leverage, and additional debt capacity.
Debt Service/Cash Operating Expenses (%)	Total Annual Debt Service/(Operating Expenses+Total Annual Debt Service–Depreciation)	Provides an indication of debt burden relative to cash operating expenses.
Debt/Customer ($)	Total Debt/Total Customers	Provides a measure for relative comparison of leverage.
Variable-Rate Debt/Total Debt (%)	Variable-Rate Debt/Total Debt	Provides context for an issuer's short-term obligations.
Other		
Operating Margin (%)	Operating Margin/Operating Revenues	Provides a measure of operating stability and capacity to manage an increase in debt levels.
Capex/Depreciation and Amortization (%)	Capex/(Depreciation+Amortization)	Indicates whether annual capital spending keeps pace with depreciation.
Free Cash Flow/Capex ($)	(FADS–Total Annual Debt Service–General Fund Transfer and/or PILOT)/Capex	Indicates a utility's ability to internally fund capex.
Net Debt/Net Capital Assets (x)	(Total Debt–Cash and Reserve Funds)/Net Utility Plant	Provides a measure of leverage relative to the book value of physical assets.
General Fund Transfer/Operating Revenues (%)	(General Fund Transfer+PILOT)/Operating Revenues	Indicates the degree to which a utility provides city or county general fund support.

[a]Operating revenues exclude deferrals to and transfers from a rate stabilization fund. [b]Fixed charge – 30% of purchased power expense, which is an approximation of the associated fixed expense. FADS – Funds available for debt service. PILOT – Payment in lieu of taxes.

Wholesale power suppliers often have lower coverage levels than retail systems, as total wholesale costs are passed through to their members on a monthly basis. Fitch reviews a wholesale system's cost structure, rate adjustment, and billing processes to assess the timeliness of cost recovery, given their lower financial coverage metrics.

Liquidity

Liquidity measures, such as days cash on hand and days liquidity on hand, provide an estimate of an issuer's ability to meet uncertain operating or other capital expenses. Public power entities typically carry less cash on the balance sheet than water and wastewater utilities. As such, days liquidity on hand, reflecting any undrawn bank facilities, is an important measure of financial flexibility.

Certain utilities, typically cooperatives, rely heavily on third-party liquidity providers for bank revolvers or lines of credit. Fitch assesses the diversity and credit quality of the liquidity providers, the ability to extend and replace such agreements, and the adequacy and terms of the liquidity support when reviewing these utilities.

Fitch reviews transfers by a utility to the corresponding municipality's general fund to determine if they are formulaic or subject to limitation. Subjective, open-ended transfer policies that allow a local government to affect the liquidity levels of a utility generally increase credit risk. For electric cooperatives, the amount of patronage capital repatriated has similar importance.

Capital Structure

A utility's capital structure, which encompasses the strength of its balance sheet, presents another indication of financial flexibility. More specifically, the equity-to-capitalization ratio measures a utility's ability to grow equity over time.

A rising equity ratio is favorable, as it suggests adequate cost recovery in rates or load growth. A high level of system equity indicates capacity for issuing additional debt to fund future capital needs. Wholesale power providers with equity levels below 10% are likely to be considered financially disadvantaged.

Attributes: Select Financial Metrics (Retail Systems)

Debt Service Coverage (x)	Debt/FADS (x)	Days Cash on Hand	Equity/Capitalization (%)
Stronger			
Coverage of consistently more than 2.0x provides solid cash flow and bondholder protection.	Less than 6x debt to FADS indicates a favorable level of leverage relative to cash flow.	More than 120 days cash on hand indicates solid financial flexibility to meet unforeseen spending needs.	Strong equity levels of more than 40% indicate adequate cost recovery and ample debt capacity for future capital needs.
Midrange			
Many utilities target coverage in the 1.5x–2.0x range.	Ratios in the 6x–9x range indicate a generally balanced level of debt relative to cash flow.	Many utilities target approximately 60–90 days operating cash.	Many utilities maintain 20%–40% equity levels.
Weaker			
Consistently less than 1.5x coverage provides limited cushion for unexpected revenue shortfalls.	Greater than 9x debt without a suitable rationale can indicate a deficient rate structure.	Less than 60 days cash indicates less financial flexibility, but can be adequate if a utility is subject to less cash flow volatility.	Less than 15% and 10% equity is relatively low for retail electric and wholesale systems, respectively.

FADS – Funds available for debt service. Note: The debt and equity ratios above do not reflect off-balance sheet obligations, which apply to retail systems that are participants in joint-action agencies or are part-owners of generation facilities. Fitch reviews adjusted financial ratios to take into account such obligations.

Debt Profile

Fitch's assessment of a utility's debt profile considers the purpose, amount, and structure of its existing debt. Fitch also considers any off-balance sheet obligations such as take-or-pay contracts or interest rate swap agreements for a complete assessment of fixed expense obligations. Future financing plans, including the funding of a long-term capital program, and the renewal and replacement of any bank liquidity facilities, are also important considerations, particularly as they will affect financial metrics.

The amount of hedged or unhedged variable-rate debt an issuer can manage is a function of its operating risk profile; the strength, predictability, and amount of its cash flows; the level of available funds; and its management of interest rate exposure and maturities. Fitch will assess the resiliency of an issuer's financial metrics relative to a peer group when evaluating its ability to manage variable-rate and short-term debt exposure. Higher rated issuers are typically better able to take on a greater percentage of variable-rate debt, as compared with lower rated issuers.

Legal Provisions

Aspects of the Bond Indenture

The legal provisions of a bond indenture or resolution provide a framework for the establishment of funds and, ultimately, the repayment of a debt obligation. Consequently, Fitch analyzes indenture provisions, such as the pledge of revenues, rate covenant, additional bonds test, debt service reserve fund, and flow of funds to determine the relative strength of the security.

Bond covenants are important to overall bondholder protection, though the degree to which they influence a rating varies. The legal provisions take on greater importance the weaker the credit quality, as they are more likely to be tested.

Pledge of Revenues

Fitch does not distinguish between a pledge of gross and net revenues for public power systems, as all systems must fully cover annual operating expenses and debt service from total revenues. A weaker revenue pledge may allow for the inclusion of other available funds as revenues.

Separately, a mortgage interest provides bondholder support via a lien on physical assets, as is typical of cooperatives.

Rate Covenant

The rate covenant provides a minimum level of protection and ensures that a system reliably covers debt service by a certain margin. Fitch views it as an element of financial cushion. Rate covenants with only a 1.0x (sum sufficient) debt service coverage requirement, or those that allow inclusion of other funds in the calculation, are viewed as being weaker.

Additional Bonds Test

The terms of the additional bonds test often mimic the rate covenant. The strongest tests include both a historical and projected debt service coverage test and limit the period for calculating net revenues to the 12 months immediately preceding the issuance of additional debt.

Debt Service Reserve Fund

The incidence of relying on a debt service reserve fund to pay debt obligations is low, given the limited number of public power entities that Fitch rates below investment grade. However, maintaining additional legally restricted, cash-funded reserves is looked upon favorably, particularly for weaker credits. Fitch evaluates those instances where reserve funds have been funded with a surety from a financial guarantor on a case-by-case basis.

Flow of Funds

The flow of funds is fairly standardized, providing for regular deposits to the debt service fund after the payment of operations and maintenance. As such, the flow of funds has little bearing on the rating, except in the uncommon instances when it deviates from the typical arrangement.

Attributes: Select Indenture Provisions

Rate Covenant	Additional Bonds Test
Stronger	
Greater than 1.25x coverage of ADS by net revenues alone.	More than 1.25x coverage of MADS from net revenues. Typically, the test includes both a historical and projected revenue period; the test will have to be met over a consecutive number of months.
Midrange	
Coverage of ADS between 1.10x and 1.25x by net revenues alone.	Coverage of MADS from net revenues of between 1.10x and 1.25x. Might only include a historical or projected net revenue coverage test; might allow inclusion of other available fund balances to meet the test.
Weaker	
Less than 1.10x coverage of ADS by net revenues plus available funds.	Less than 1.10x coverage of ADS from net revenues. Typically, a historical or projected test, with a looser interpretation of the revenue period (i.e. 12 consecutive months of the 24 months preceding the issuance of additional bonds).

ADS – Annual debt service. MADS – Maximum annual debt service.

Wholesale Power Contracts

The power sales contracts between a wholesale power supplier and its distribution customers are among the most important factors supporting the credit rating of a wholesale power system (joint-action agency or cooperative), as the credit strength of a wholesale provider is intrinsically linked to that of its purchasers. A wholesale power supplier would be unlikely to obtain an investment-grade rating absent these long-term agreements, many of which are court validated to provide assurances that they are enforceable.

In particular, Fitch evaluates the nature of the contractual obligation (take-or-pay, take-and-pay, all requirements, etc.) and the expiration and renewal terms of these contracts relative to the final maturity of an issuer's outstanding bonds. Debt maturities beyond the terms of the agreements are considered a negative rating factor, as issuers could be forced to sell power in the open market on a merchant basis to support debt service.

Take-Or-Pay Contracts

Strengths

Long-term commitment of participants to purchase 100% of project output.

Participants are required to make payments regardless of unit operation; many such contracts have been deemed by the state courts as legally binding to the participants.

Contracts can mitigate price volatility risk (for the power purchaser) inherent in short-term purchase power contracts, as the contracts are often for a fixed price plus a modest escalator.

Step-up requirements can mitigate the default risk of the weakest and smallest participants (e.g. with a 25% step up, a default by 25% of participants [by participation] would be borne by the other participants rather than by bondholders).

Weaknesses

Depending on the transaction's structure, the step-up provision can be insufficient to mitigate a default of the weakest participants.

Take-And-Pay Contracts

Strengths

Long-term commitment of participants to purchase 100% of agency output.

Participants are obligated to pay for power that is delivered, whether generated or purchased.

The risk of an individual participant defaulting is, in effect, borne by membership rather than bondholders in the form of higher average wholesale rates set by the agency (e.g. an unlimited step-up provision when "take-and-pay" is coupled with an "all-requirements" power supply contract).

Weaknesses

Participants are only obligated to pay for power that is available. Hence, an agency would lose revenues if it did not deliver power.

Effects of Litigation

Fitch considers any litigation that might result in financial payments in its review of an issuer's legal framework. Any such payments that materially affect an issuer's balance sheet could result in a negative rating action.

Customer Profile and Service Area

Service area characteristics provide an indication of the stability of a constituency's load, and ultimately its ability to pay electric bills. Stronger electric systems typically serve growing, well-

Key Service Area Metrics

Indicator	Source	Significance
Economic Factors	U.S. Bureau of Labor Statistics and U.S. Bureau of Economic Analysis.	A diversified economy is typically better positioned to absorb cyclical changes than an economy concentrated in a certain sector, providing for greater stability of revenues.
Customer Profile (breakdown of residential, commercial, and industrial customers)	Utility or consultant.	A higher percentage of residential energy sales (more than 40%) typically provides for greater financial stability. Residential customers each account for very small percentages of total sales. As such, the loss of any single customer does not disrupt a utility's revenue stream.
Top 10 Customers	Utility or consultant.	As a percentage of the total, 5% of sales to the largest customer or 25% of sales to the 10 largest customers reveals concentration in the revenue base, which can be disruptive if a large customer(s) leaves the area.
Population	U.S. Census.	A growing service area typically leads to additional energy sales, in support of revenues.
kWh Sales (breakdown of residential, commercial, and industrial sales)	Utility or consultant.	The trend of kWh sales provides an indication of the health of the local economy, with steady annual increases demonstrating sound economic and population growth.
Unemployment Rate	U.S. Bureau of Labor Statistics.	Provides an indication of the relative depth of a local employment base.
Income Levels	U.S. Census and U.S. Bureau of Economic Analysis.	Provides an indication of the relative ability to pay.

diversified areas. However, the essential nature of electric service and the remedies available to most public power providers (e.g. shutoffs and liens) make payment delinquencies in the sector extremely low, regardless of wealth and other economic indicators.

Service Area Considerations

A utility's ability to maintain a sound operating position, despite changing service area characteristics, is an important rating consideration. Some of the factors Fitch considers in its assessment of a service area are shown in the Key Service Area Metrics table on page 12.

Fitch performs a more detailed analysis of an electric system's customer base to further evaluate the stability of the revenue source when there is industry or customer concentration. The latter is defined as one or a few large customers accounting for a material proportion of revenues (e.g. an individual customer accounting for more than 5%, or the top 10 accounting for more than 25% of the system's operating revenues). Fitch also conducts an analysis of all relevant member information when reviewing joint-action agencies and cooperatives as necessary, to the extent that information is available.

Key Rating Considerations

Governance and Management Strategy

- Type of governing body
- Management's relationship with governing body
- Management's experience and depth of industry knowledge
- Business strategy and planning
- Management's track record at achieving financial and strategic goals
- The relationship among the members, for joint-action agencies and cooperatives

Assets and Operations

- Review of generation mix and comparison to the region
- Historical operating performance of generation facilities
- Relative load balance or shortfall, and plans for meeting additional power needs
- Environmental concerns and compliance
- Fuel supply and hedging contracts
- Off-system power sales/purchases
- Distribution and transmission issues

Cost Structure

- State or federal regulatory oversight
- Rate-raising flexibility and competitiveness
- Process of adjusting rates to ensure timely and adequate cost recovery
- Structure and use of fuel or purchased power adjustment mechanism
- Generating plant production costs relative to similar plants in the region
- Average total power supply cost relative to a peer group
- Average wholesale cost of power, for joint-action agencies and cooperatives
- Average retail rates by customer classification and comparison to peers

Financial Performance and Legal Provisions

- Management's financial policies
- Historical five-year analysis of key cash flow, liquidity, and leverage ratios
- Financial projections and reasonableness of key assumptions
- Existing debt characteristics and future financing needs
- Financial analyses of the largest member distribution systems, for joint-action agencies and cooperatives
- Review of indenture provisions and bond security features
- Type, length, and renewal terms of wholesale power contracts
- Any material pending litigation

Customer Profile and Service Area

- Economic and demographic makeup and trends
- Customer composition, including a breakout of kWh sales and revenues
- Customer revenue or business sector concentration
- Service area profiles of member systems, for joint-action agencies and cooperatives

Long Island Power Authority
Selected Financial Statistics

DR-278
3/15/15

Item	Financial Ratio	Reference	2016	2017	2018	3 Year Average
i	Adjusted Days of Liquidity	detailed below	123	124	125	124
ii	Unrestricted Cash as Percent of Total Expenditures	detailed below	34%	34%	34%	42%
iii	Debt Ratio - Debt as % of Capitalization	(a+b)/(a+b+c)	96%	96%	96%	96%
iv	Debt Ratio - Debt as a % of Capital Assets	(a+b)/(b+h)	152%	146%	140%	146%
v	Debt Ratio - Debt as a % of Capital Assets Plus Working Capital	(a+b)/(b+h+i)	143%	138%	132%	138%
vi	Debt Service and Fixed Obligation Coverage - LIPA + UDSA	(e:h)/(e:g)	1.15 x	1.20 x	1.25 x	1.20 x
vii	Debt Service and Fixed Obligation Coverage - LIPA only	(f:h)/(f:g)	1.20 x	1.30 x	1.40 x	1.30 x

Source	Financial Statistic	Reference	2016	2017	2018
KK-2	Total Debt (LIPA + UDSA)	a	8,230,222	8,285,076	8,264,646
KK-2	Capital Lease Obligations	b	2,188,296	1,997,341	1,824,665
KK-2	Total Equity	c	458,282	441,964	460,346
RRP-2, A-11	UDSA Debt Service	d	204,748	270,340	301,698
RRP-2, A-11	LIPA Debt Service Payments	e	297,426	248,005	235,924
RRP-2, A-11	Capital Lease Obligation Payments	f	312,944	302,529	277,338
RRP-2, A-11	Total Coverage	g	121,395	162,897	204,772
DR-135	Net Plant Assets	h	4,668,852	5,025,430	5,371,249
Below	Working Capital	i	425,000	425,000	425,000

Days Cash on Hand Calculation

	12/31/2014	2016	2017	2018
Unrestricted Cash and Cash Equivalents				
Operating Account and Rate Stabilization Fund	277,680	275,000	275,000	275,000
Construction Fund (Prefunding from December 2014 Bond Proceeds)	332,481	-	-	-
Total	610,161	275,000	275,000	275,000
Restricted Funds for PSEG-LI Operating and Storms Accounts	148,050	150,000	150,000	150,000
Total Unrestricted Funds and Restricted Funds for PSEG-LI Operations	758,211	425,000	425,000	425,000

	$375MM Revolving Credit Agreement - Avg. Available	435,000	375,000	375,000	375,000
	$325MM General Revenue Notes Commercial Paper Program - Avg. Available	-	-	1,200	21,189
	$300MM Subordinate Lien Commercial Paper Program - Avg. Available	85,000	277,888	300,000	300,000
	Total Available Credit	520,000	652,888	676,200	696,189
	Total Cash and Available Credit	1,278,211	1,077,888	1,101,200	1,121,189
RRP-1, pg 5	Fuel and Purchased Power Expense	1,659,272	1,681,830	1,701,494	1,714,252
RRP-1, pg 6	O&M Expense	1,084,061	1,150,793	1,168,476	1,173,642
RRP-1, pg 6	Storm Restoration	30,462	48,169	49,077	50,199
RRP-1, pg 6	General and Administrative	29,053	26,825	26,967	27,784
RRP-1, pg 3	Payments in Lieu of Taxes	332,621	341,553	347,604	353,843
RRP-1, pg 3	Grant Income	-114,521	(40,570)	(45,099)	(49,572)
	Total Operating Expenses	3,020,948	3,208,600	3,248,519	3,270,148
	Days Cash Available	154	123	124	125
	Available Cash as Percent of Operating Expenses	42%	34%	34%	34%

Total Impact Under No Downgrade Scenario (x1000) Using Staff Estimates			
Consolidated Debt Service	$607,633	$639,550	$687,189
LIPA Debt Service	$288,660	$228,149	$207,300
UDSA Debt Service	$199,322	$254,390	$286,543
Coverage Requirement	$119,652	$157,011	$193,347
Moody's, S&P, and Fitch Current Ratings	Baa1/A-/A-	Baa1/A-/A-	Baa1/A-/A-
Estimated cost of long term debt under no downgrade scenario[1]	4.12%	4.12%	4.12%

Total Minimum Impact Under 1 Notch Downgrade Scenario (x1000) based on Changes in LTD fixed rate cost			
Consolidated Debt Service	$607,939	$641,106	$690,432
LIPA Debt Service	$288,914	$229,349	$209,617
UDSA Debt Service	$199,322	$254,390	$286,543
Coverage Requirement	$119,703	$157,367	$194,271
Moody's, S&P, and Fitch Downgrade Ratings	Baa2/BBB+/BBB+	Baa2/BBB+/BBB+	Baa2/BBB+/BBB+
Estimated cost of long-term debt under a 1 notch downgrade scenario[2]	4.43%	4.43%	4.43%

	DELTA		
Consolidated Debt Service	$305	$1,555	$3,242
LIPA Debt Service	$255	$1,200	$2,318
UDSA Debt Service	$0	$0	$0
Coverage Requirement	$51	$355	$925

Comment

[1]Estimated cost of Long-term debt used to determine Staff Finance Panel's recommended debt service requirement

[1]Mergent Bond Record average bond yield of 4.39% for "Baa2/BBB+/BBB+" as of March 2015 plus LIPA's historical average bond yield spread of 0.04%

LIPA's Long term debt Yields(20-Year term Minimum)

	Offering Date	Series	Offering Amount	Coupon	YTM	Term
1	Sep-28-2011	Series 2011A	$63,360,000	5.00	4.812	25
2	Sep-28-2011	Series 2011A	$62,200,000	5.00	4.889	26
3	Sep-28-2011	Series 2011A	$70,030,000	5.00	4.892	27
4	Jul-16-2012	Series 2012A	$44,295,000	5.00	4.419	24
5	Jul-16-2012	Series 2012A	$46,505,000	5.00	4.432	25
6	Dec-16-2014	Series 2014A	$48,215,000	5.00	4.084	20
7	Dec-16-2014	Series 2014A	$29,360,000	5.00	4.163	21
8	Dec-16-2014	Series 2014A	$16,910,000	5.00	4.249	22
9	Dec-16-2014	Series 2014A	$17,610,000	5.00	4.268	23
10	Dec-16-2014	Series 2014A	$18,350,000	5.00	4.285	24
11	Dec-16-2014	Series 2014A	$19,120,000	5.00	4.301	25
12	Dec-16-2014	Series 2014A	$13,920,000	4.00	3.989	22
13	Dec-16-2014	Series 2014A	$14,620,000	4.00	3.990	23
14	Dec-16-2014	Series 2014A	$15,350,000	4.00	3.990	24
15	Dec-16-2014	Series 2014A	$16,110,000	4.00	3.990	25
16	Dec-16-2014	Series 2014A	$36,830,000	5.00	4.347	26
17	Dec-16-2014	Series 2014A	$38,670,000	5.00	4.359	27
18	Dec-16-2014	Series 2014A	$40,605,000	5.00	4.371	28
19	Dec-16-2014	Series 2014A	$42,635,000	5.00	4.381	29
20	Dec-16-2014	Series 2014A	$44,765,000	5.00	4.391	30
	Average (%)		**$34,973,000**	**4.80**	**4.33**	**25**
	Median (%)		**$37,750,000**	**5.00**	**4.32**	**25**

Public Utility Bond Yield By Ratings Categories (from Mergent Bond Record)

	Date	AA	AA-	A+	A	A-	BBB+	BBB
1	Sep-28-2011	**4.3**	4.38	4.44	**4.55**	4.78	4.93	**5.24**
2	Sep-28-2011	**4.3**	4.38	4.44	**4.55**	4.78	4.93	**5.24**
3	Sep-28-2011	**4.3**	4.38	4.44	**4.55**	4.78	4.93	**5.24**
4	Jul-16-2012	**3.54**	3.66	3.73	**3.89**	4.20	4.41	**4.83**
5	Jul-16-2012	**3.54**	3.66	3.73	**3.89**	4.20	4.41	**4.83**
6	Dec-16-2014	**3.78**	3.79	3.80	**3.82**	4.09	4.27	**4.63**
7	Dec-16-2014	**3.78**	3.79	3.80	**3.82**	4.09	4.27	**4.63**
8	Dec-16-2014	**3.78**	3.79	3.80	**3.82**	4.09	4.27	**4.63**
9	Dec-16-2014	**3.78**	3.79	3.80	**3.82**	4.09	4.27	**4.63**
10	Dec-16-2014	**3.78**	3.79	3.80	**3.82**	4.09	4.27	**4.63**
11	Dec-16-2014	**3.78**	3.79	3.80	**3.82**	4.09	4.27	**4.63**
12	Dec-16-2014	**3.78**	3.79	3.80	**3.82**	4.09	4.27	**4.63**
13	Dec-16-2014	**3.78**	3.79	3.80	**3.82**	4.09	4.27	**4.63**
14	Dec-16-2014	**3.78**	3.79	3.80	**3.82**	4.09	4.27	**4.63**
15	Dec-16-2014	**3.78**	3.79	3.80	**3.82**	4.09	4.27	**4.63**
16	Dec-16-2014	**3.78**	3.79	3.80	**3.82**	4.09	4.27	**4.63**
17	Dec-16-2014	**3.78**	3.79	3.80	**3.82**	4.09	4.27	**4.63**
18	Dec-16-2014	**3.78**	3.79	3.80	**3.82**	4.09	4.27	**4.63**
19	Dec-16-2014	**3.78**	3.79	3.80	**3.82**	4.09	4.27	**4.63**
20	Dec-16-2014	**3.78**	3.79	3.80	**3.82**	4.09	4.27	**4.63**
	Average (%)	**3.83**	**3.87**	**3.89**	**3.94**	**4.20**	**4.38**	**4.74**
	Median (%)	**3.78**	**3.79**	**3.80**	**3.82**	**4.09**	**4.27**	**4.63**

Spread (Mergent Bond Record data over LIPA's Debt)

	Date	AA	AA-	A+	A	A-	BBB+	BBB
1	Sep-28-2011	(0.512)	-0.43	-0.37	-0.26	-0.03	0.12	0.43
2	Sep-28-2011	(0.589)	-0.51	-0.45	-0.34	-0.11	0.04	0.35
3	Sep-28-2011	(0.592)	-0.51	-0.45	-0.34	-0.11	0.04	0.35
4	Jul-16-2012	(0.879)	-0.76	-0.68	-0.53	-0.22	-0.01	0.41
5	Jul-16-2012	(0.892)	-0.78	-0.70	-0.54	-0.23	-0.02	0.40
6	Dec-16-2014	(0.304)	-0.29	-0.28	-0.26	0.01	0.19	0.55
7	Dec-16-2014	(0.383)	-0.37	-0.36	-0.34	-0.07	0.11	0.47
8	Dec-16-2014	(0.469)	-0.46	-0.45	-0.43	-0.16	0.02	0.38
9	Dec-16-2014	(0.488)	-0.47	-0.47	-0.45	-0.18	0.00	0.36
10	Dec-16-2014	(0.505)	-0.49	-0.48	-0.47	-0.20	-0.02	0.34
11	Dec-16-2014	(0.521)	-0.51	-0.50	-0.48	-0.21	-0.03	0.33
12	Dec-16-2014	(0.209)	-0.20	-0.19	-0.17	0.10	0.28	0.64
13	Dec-16-2014	(0.210)	-0.20	-0.19	-0.17	0.10	0.28	0.64
14	Dec-16-2014	(0.210)	-0.20	-0.19	-0.17	0.10	0.28	0.64
15	Dec-16-2014	(0.210)	-0.20	-0.19	-0.17	0.10	0.28	0.64
16	Dec-16-2014	(0.567)	-0.55	-0.54	-0.53	-0.26	-0.08	0.28
17	Dec-16-2014	(0.579)	-0.57	-0.56	-0.54	-0.27	-0.09	0.27
18	Dec-16-2014	(0.591)	-0.58	-0.57	-0.55	-0.28	-0.10	0.26
19	Dec-16-2014	(0.601)	-0.59	-0.58	-0.56	-0.29	-0.11	0.25
20	Dec-16-2014	(0.611)	-0.60	-0.59	-0.57	-0.30	-0.12	0.24
	Average (%)	**-0.50**	**-0.46**	**-0.44**	**-0.39**	**-0.13**	**0.05**	**0.41**
	Median (%)	**-0.52**	**-0.50**	**-0.46**	**-0.44**	**-0.17**	**0.01**	**0.37**

Public Utility Bond Yield Averages By Ratings Categories (from Mergent Bond Record)

Date		S&P	AA	AA-	A+	A	A-	BBB+	BBB
From	To	Moody's	Aa2	Aa3	A1	A2	A3	Baa1	Baa2
1/1/2015	1/31/2015		**3.53**	3.54	3.56	**3.58**	3.85	4.03	**4.40**
2/1/2015	2/28/2015		**3.62**	3.64	3.65	**3.67**	3.93	4.10	**4.44**
3/1/2015	3/31/2015		**3.67**	3.70	3.72	**3.75**	4.00	4.16	**4.49**

LIPA split rating	BBB+/A-
Average of BBB+/A- (As of March 2015)	4.08%
Add Average spread for BBB+/A-	0.04%
LIPA Estimated Rate	**4.12%**

PATRICK PISCITELLI

PROFESSIONAL EXPERIENCE

New York State Department of Public Service, Albany, NY
Principal Financial Analyst
December 2003 – Present

Provide analysis and recommendations to Senior Management and other members of the Department of Public Service regarding financial and accounting issues for New York State utilities. Also, provides rate of return, financial, and accounting testimony in electric, telephone, and water company rate proceedings.

National Grid USA, Westborough, MA
Principal Financial Analyst
November 2002 – December 2003

Responsible for the development and implementation of the National Grid USA Risk Management Policy for the management of the Company's energy procurement market and credit risks. Also, responsible for establishing the procedures for evaluating, reporting, and monitoring the risk exposures and for the operating Companies adherence to the Corporate Policies and Procedures.

Niagara Mohawk Power Corporation, Syracuse, NY
Corporate Financial Risk Manager
October 1996 – November 2002

Responsible for the development and implementation of a Corporate Financial Risk Management Program to manage the financial risks of commodity and foreign currency transactions, and the corporate loan portfolio. Interact and make presentations to Senior Management regarding Financial Risk Management strategies and results. Developed and implemented Financial Risk Management Plans, Policies, and Procedures and developed Value-at-Risk and Credit-at-Risk Models to quantify the Capital-at-Risk resulting from the Energy and Gas Supply Portfolios.

Associate Director of Finance and Investments
May 1991 - October 1996

Analyzed and presented recommendations to Senior Management regarding the financing options available to the Company. Co-managed the Pension Fund and managed all investment aspects of the Nuclear Decommissioning Trust Fund, the Supplemental Executive Retirement Plan, and charitable foundation. Responsible for interacting with the Investment Community to carry out the plans and policies of Niagara Mohawk.

First Albany Corporation, Albany, NY
Assistant Vice President
October 1987 - May 1991

Responsibilities included investment banking, consulting, and conducting financial and economic analysis. As an Investment Banker and consultant, I was responsible for analyzing investment opportunities for institutional clients and authoring investment research reports. Served as the financial analyst to the United States Bankruptcy Court during the Public Service of New Hampshire Bankruptcy Proceeding.

New York State Department of Public Service, Albany, NY
Senior Utility Financial Analyst
July 1981 – May 1983
Associate Utility Financial Analyst
May 1983 –June 1985
Principal Financial Analyst
June 1985 – October 1987

In positions of increasing responsibility provided analysis and recommendations to Senior Management and other members of the Department of Public Service regarding financial and accounting issues for New York State utilities. Provided rate of return, financial, and accounting testimony in electric, telephone, and water company rate proceedings. Also negotiated and testified in various rate case settlements.

Russell Sage Graduate School, Albany, NY
Adjunct Professor, MBA Program
Fall 1996

EDUCATION

Union University, Schenectady, NY
Master of Business Administration
Concentration - Management Information Systems

State University College at Potsdam, New York
Bachelor of Arts
Major - Economics

VOLUNTEER ACTIVITIES

Empower Federal Credit Union,
Member of the Board of Directors
Chair, Empower Affiliated Services
Finance Committee
September 1999 – present

Onondaga Community College Housing Development Corporation,
President of the Board of Directors

Finance and Audit and Executive Committee
September 2006 – present