Fitch Rates Commonwealth Edison's $350MM FMBs 'BBB+'

Ratings Endorsement Policy

25 Sep 2012 3:54 PM (EDT)

Fitch Ratings-New York-25 September 2012: Fitch Ratings has assigned a 'BBB+' rating to Commonwealth Edison Co.'s (Comed) $350 million 3.8% first mortgage bonds (FMBs) due Oct. 1, 2042. Net proceeds will be used to repay outstanding commercial paper and for general corporate purposes. The Rating Outlook is Stable.

Key Rating Drivers

Credit Metrics: Comed's credit quality measures will be adversely affected for the remainder of 2012 by a recently implemented rate reduction but should remain supportive of the current ratings. Fitch estimates the 2012 ratios of EBITDA/interest and Debt/EBITDA will approximate 4.0 times (x) and FFO/debt 20%. Current ratings assume a portion of the rate reduction will be restored following the resolution of a rehearing and that higher rates are implemented in 2013.

Regulatory Uncertainty: The positions taken by the Illinois Commerce Commission (ICC) in Comed's initial Formula Rate Plan (FRP) filing heightened regulatory risk for utilities in Illinois. In ordering a $168.6 million rate reduction, the ICC disallowed a return on Comed's pension asset and relied on an average rate base and capital structure, all of which appears to be inconsistent with the FRP legislation. The company supported a $59.1 million rate reduction, largely reflecting a lower return on equity (ROE) as per the rate formula.

FRP Appeal: Fitch expects at least $35 million of the FRP rate reduction will be restored, consistent with the recommendation of the Administrative Law Judge (ALJ) hearing Comed's appeal. The ALJ's position reflects a reversal of the ICC's treatment of the pension asset but maintains the use of an average rate base and capital structure. The Illinois House of Representatives passed a non-binding resolution supporting Comed's position. A final order on rehearing is due by Nov. 19, 2012.

Pending Rate Case: Current ratings anticipate higher rates and stronger credit quality measures in 2013 following a decision in the second FRP proceeding. In its April 2012 filing, Comed proposed a $106.2 million rate increase to be effective Jan. 1, 2013. The proposed increase reflects actual 2011 results and estimated plant additions through 2012 as per the FRP legislation. The ICC staff is recommending a net reduction of $$69.4 million including a $37.3 million base rate increase offset by a $106.7 million reconciliation adjustment. Prospectively, Comed will file an annual FRP each May with new rates effective the following January.

Rising Capex: Capital expenditures are forecasted to rise to $4.5 billion over the three-year period 2012-2014, including $1.6 billion in 2013 and 2014, compared to $2.8 billion in the prior three-year period. The higher outlays are primarily driven by the Illinois Energy Infrastructure Modernization Act (EIMA), which requires Comed to invest an incremental $1.3 billion on electric system upgrades over five years and an additional $1.3 billion for smart grid deployment over 10 years. The legislation provides for recovery through the FRP filings.

Commodity Price Exposure: Ratings benefit from the absence of commodity price exposure and the associated cash flow volatility. Legislation that provides Illinois utilities the ability to adjust tariffs annually to reflect changes in uncollectible accounts is also credit positive.

Liquidity: A $1 billion unsecured credit facility and ready access to capital markets provide adequate liquidity. Debt maturities are well laddered and relatively modest over the next several years.

What would lead to consideration of a negative rating action?
An unfavorable ruling in Comed's second FRP filing is the primary credit risk and could adversely affect ratings.

What would lead to consideration of a positive rating action?
Adherence to the principles in the EIMA would lower regulatory risk, provide a timely return of and on invested capital and could lead to improved ratings.

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Applicable Criteria and Related Research:
--'Corporate Rating Methodology' (Aug. 12, 2011);
--'Parent and Subsidiary Rating Linkage' (Aug. 12, 2011);
--'Recovery Ratings and Notching Criteria for Utilities' (May 3, 2012);
--'Rating North American Utilities, Power, Gas and Water Companies' (May 12, 2011).

Applicable Criteria and Related Research:
Corporate Rating Methodology
Parent and Subsidiary Rating Linkage
Recovery Ratings and Notching Criteria for Utilities
Rating North American Utilities, Power, Gas, and Water Companies

Fitch Affirms Exelon Corp's and Subsidiaries Ratings Ratings Endorsement Policy
08 Feb 2013 12:34 PM (EST)

Fitch Ratings-New York-08 February 2013: Fitch Ratings has affirmed the Issuer Default Ratings (IDR) and instrument ratings of Exelon Corp. (EXC) and each of its existing operating subsidiaries, including Exelon Generation Company (Exgen), Commonwealth Edison Company (Comed), PECO Energy Company (PECO) and Baltimore Gas and Electric Co. (BG&E). The Rating Outlook for Comed has been revised to Positive from Stable. The Rating Outlook for all other entities remains Stable.

The ratings of EXC and Exgen reflect recent steps taken by management to solidify their credit quality and ratings in the face of a persistently low power price environment that is pressuring wholesale and retail profit margins. The positive actions include substantial reductions in both capex and the common stock dividend. Consequently, credit protection measures are expected by Fitch to remain strong during a low point in the commodity cycle and compare favorably to Fitch's target ratios and their respective peer groups.

The EXC and Exgen ratings also reflect ample liquidity, and a competitive nuclear fleet that is low on the dispatch curve and stands to benefit from new and existing environmental regulations that impose additional costs on coal plants. The consolidated rating also benefits from the earnings contribution of three regulated utilities, which account for about 50% of earnings and cash flow.

KEY RATING DRIVERS

EXC and Exgen

Dividend Reduction: EXC's dividend was reduced 40%, saving approximately $700 million annually. Fitch expects Exgen will be the primary beneficiary of the dividend reduction and to apply a significant portion of the savings to debt reduction. The new dividend takes effect in the second quarter of 2013.

Reduced Capex: In November 2012, management lowered Exgen's capex budget by $2.3 billion over the five year period 2013 - 2017. The capex reduction includes approximately $1.025 billion from the deferral of planned nuclear uprates and $1.25 billion from eliminating unidentified wind and solar investments. The reductions meaningfully reduced pressure on credit quality measures.

Financial Position: The combined reductions of the common stock dividend and capex have strengthened the financial positions of both EXC and Exgen. Cash flow measures are particularly strong. Fitch estimates EXC's adjusted ratio of FFO/interest to be in excess of 6.0x over the next several years and FFO/debt approximately 30%. Fitch estimates Exgen's adjusted ratio of FFO/interest to be in excess of 7.0x over the next several years and FFO/debt in excess of 40%.

Liquidity: Liquidity is ample and debt maturities should be manageable. On a consolidated basis committed credit facilities aggregate $8.4 billion, including $5.7 billion at Exgen and $500 million at EXC, and extend to 2017. Moreover, Fitch expects Exgen to be free cash flow positive over the next several years.

Low Commodity Price Environment: Low power prices, weak demand and aggressive competitive pricing behavior have adversely affected Exgen's wholesale and retail margins and are expected by Fitch to persist for several more years. It does appear however, that we are in the low point of the commodity cycle with limited downside risk. Moreover, the lower dividend and spending plan have positioned both EXC and Exgen to withstand further stresses.
Comed

Credit Metrics: Over the next several years, Fitch expects Comed to sustain the improvement in credit metrics achieved in 2012, largely due to a rate increase implemented Jan. 1, 2013 and a new regulatory paradigm in Illinois that allows for annual rate adjustments to earn a return on new investments and recover changes in the cost of service. Fitch estimates the ratio of EBITDA/interest will average about 5.0x and FFO/interest about 4.5x over the next several years. Over the same period FFO/debt is expected by Fitch to average about 18% and Debt/EBITDA about 3.9x.

Regulatory Environment: Illinois implemented a formula based rate plan (FRP) in October 2011 that fundamentally changed regulation of electric delivery service in Illinois. While the FRP remains less favorable than initially expected by Fitch, it does provide for annual rate adjustments, recognizes planned capital additions and includes a true-up mechanism that combine to reduce, albeit not eliminate, rate lag. The primary negatives are a relatively low formula based return on equity (ROE) and reliance on an average, rather than year-end rate base, which reduces the revenue requirement.

FRP Appeal: Following its initial FRP decision, Comed filed an appeal with the Illinois Commerce Commission (ICC) and in October 2012 the ICC reversed its position on the treatment of the Comed's pension asset. The reversal restored about $135 million of revenue in 2012. The ICC maintained its position on the use of an average, rather than year-end, rate base and capital. Following the rehearing order, Comed filed an appeal in state court regarding the use of an average rate base and the interest rate used to calculate the carrying cost on reconciliation adjusted balances.

Recent Comed Rate Case: On Dec. 19, 2012, the ICC issued an order in Comed's second FRP filing. The decision was more constructive than the previous order, but continues to rely on an average rate base and capital structure. The ICC granted Comed a $72.6 million rate increase compared to $74.2 million supported by the company. The allowed ROE was 9.71% based on the pre-established formula (3.91% Treasury yield plus 580 basis points), compared to 10.05% in the prior case. Prospectively, Comed will file an annual FRP each May with new rates effective the following January. Since Treasury rates are unlikely to fall there is limited downside on the ROE.

Rising Capex: Capital expenditures are forecasted to rise to approximately $4.3 billion over the three-year period 2013-2015, compared to $3.3 billion in the prior three-year period. The higher outlays are primarily driven by the Illinois Energy Infrastructure Modernization Act (EIMA), which requires Comed to invest an incremental $1.3 billion on electric system upgrades over five years and an additional $1.3 billion for smart grid deployment over 10 years. The legislation provides for recovery through the FRP filings.

Commodity Price Exposure: Ratings benefit from the absence of commodity price exposure and the associated cash flow volatility.

Liquidity: A $1 billion unsecured credit facility provides ample liquidity. Annual debt maturities will require on-going capital market access.

Like-Kind-Exchange: Comed's exposure to the IRS's disallowance of the tax benefits associated with a like-kind-exchange is a credit concern, however the issue is not likely to be resolved for several years and was not factored into the rating decision. As of Jan. 28, 2013, EXC's potential tax and after-tax interest that could become payable, excluding penalties, is $860 million, of which $260 million would be paid by Comed.

PECO

Financial Position: Historical and projected credit measures are well in excess of Fitch's target ratios for the current rating category and the companies' peer group of 'BBB+' distribution utilities. In 2013, Fitch estimates EBITDA/interest of approximately 7.0x, FFO/interest 5.0x and FFO/Debt about 20%.
Regulatory Environment: In February 2012, HB 1294 was signed into law. The legislation is intended to encourage utilities to invest in infrastructure by providing cost recovery through an automatic adjustment mechanism. Under the law, utilities will file a long-term infrastructure improvement plan starting in 2013 and the Pennsylvania Public Utility Commission (PUC) will establish a distribution system investment charge (DSIC) to recover the invested capital. The DSIC will be updated quarterly. The new legislation also allows rate filings to include fully forecasted test years, significantly reducing regulatory lag.

Commodity Price Exposure: Ratings benefit from the absence of commodity price exposure and the associated cash flow volatility.

BG&E

Financial Position: The BG&E rating reflects historical and projected credit measures that are consistent with the rating category. In 2013, Fitch estimates EBITDA/interest of approximately 5.5x, FFO/interest 4.5x and FFO/Debt about 20%.

Regulatory Recovery Mechanisms: Rate adjustment mechanisms outside of base rate cases tend to stabilize BG&E's on-going cash flow. These include decoupling for both residential and certain commercial gas and electricity deliveries and purchased gas and purchased power recovery mechanisms.

Regulatory Environment: The regulatory environment in Maryland remains challenging largely due to regulatory lag and the authorization of equity returns that are among the lowest in the industry. The MPSC has been resistant to adopting forward looking test years or other approaches to shorten regulatory lag.

Rate Filing: On July 27, 2012, BG&E filed a request with the MPSC for electric and gas distribution rate increases. Including updates during the rate proceedings the electric and gas rate requests were $130.1 million and $45.6 million, respectively. The increases are premised on a 10.5% return on equity (ROE). A decision is required in February 2013.

RATING SENSITIVITIES

What could trigger a negative rating action:

--Lack of rate support for utility infrastructure investments or changes in the commodity cost recovery provisions in Illinois, Pennsylvania or Baltimore.
--More aggressive growth strategy that increased business risk and/or leverage.
--Sustained nuclear outage.
--Increase in risk appetite as evidenced by change in hedging strategy at Exgen.

What could trigger a positive rating action:

--Other than an unexpected change in business strategy (i.e. additional sources of regulated earnings and cash flow), positive rating action at parent is unlikely at the present rating level.
--For Comed, a constructive decision in Comed's next FRP proceeding that supports infrastructure investments and strengthens cash flow could lead to a one-notch upgrade.

Fitch has affirmed the following ratings with a Stable Outlook:

Exelon Corp.
--Issuer Default Rating (IDR) at 'BBB+';
--Senior unsecured debt at 'BBB+';
--Junior Subordinated Notes at 'BBB-'
--Commercial paper at 'F2';
--Short-term IDR at 'F2'.

Exelon Generation Co., LLC
--Issuer Default Rating (IDR) at 'BBB+';
--Senior unsecured debt at 'BBB+';
--Commercial paper at 'F2';
--Short-term IDR at 'F2'.

PECO Energy Co.
--Issuer Default Rating (IDR) at 'BBB+';
--First mortgage bonds at 'A';
--Senior unsecured debt at 'A-';
--Preferred stock at 'BBB';

--Commercial paper at 'F2';
--Short-term IDR at 'F2'.

PECO Energy Capital Trust III
--Preferred stock at 'BBB'.

PECO Energy Capital Trust IV
--Preferred stock at 'BBB'.

Baltimore Gas and Electric Company
--Issuer Default Rating (IDR) at 'BBB;
--First mortgage bonds at 'A-';
--Senior unsecured debt at 'BBB+';
--Pollution Control Bonds at 'BBB+'
--Preferred stock to at 'BBB-';
--Short-term IDR at 'F2';
--Commercial paper at 'F2'.

BGE Capital Trust II
--Preferrred stock at 'BBB-'.

Fitch has affirmed the following ratings with a Positive Outlook:

Commonwealth Edison Company
--Issuer Default Rating (IDR) at 'BBB-;
--First mortgage bonds at 'BBB+';
--Senior unsecured debt at 'BBB';
--Preferred stock at 'BB+';
--Short-term IDR at 'F3';
--Commercial paper at 'F3'.

ComEd Financing Trust III
--Preferred stock at 'BB+'.

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Applicable Criteria and Related Research
--'Corporate Rating Methodology' (Aug. 8, 2012);
--'Parent and Subsidiary Rating Linkage' (Aug. 12, 2011)
--'Recovery Ratings and Notching Criteria for Utilities' (Nov. 12, 2012).

Applicable Criteria and Related Research
Corporate Rating Methodology
Parent and Subsidiary Rating Linkage
Recovery Ratings and Notching Criteria for Utilities

FitchRatings

Corporates

Electric-Corporate / U.S.A.

Commonwealth Edison Company

Subsidiary of Exelon Corp.
Full Rating Report

Ratings

Foreign Currency

Long-Term IDR	BBB–
Short-Term IDR	F3
Secured	BBB+
Senior Unsecured	BBB
Preferred Stock	BB+
Commercial Paper	F3

IDR – Issuer Default Rating.

Rating Outlook

Long-Term Foreign-Currency IDR	Positive

Financial Data

Commonwealth Edison Company

($ Mil.)	12/31/12	12/31/11
Revenue	5,443	6,056
Gross Margins	3,136	3,021
Operating EBITDA	1,509	1,542
Net Income	379	416
CFFO	1,334	836
Total Debt	5,736	5,860
Total Capitalization	13,162	13,000
Capex/Depreciation	201.29	185.56

Related Research

Baltimore Gas and Electric Company (April 2013)

Exelon Corp. (April 2013)

Exelon Generation Company, LLC (April 2013)

PECO Energy Company (April 2013)

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Key Rating Drivers

Credit Metrics: Higher rates effective Jan. 1, 2013, and a formula rate plan that allows for annual rate adjustments should allow Commonwealth Edison Co. (Comed) to sustain its currently sound financial position over the next few years. Offsetting factors are rising pension costs and reduced tax benefits from bonus depreciation. Fitch Ratings estimates EBITDA/interest will average about 5.0x, FFO/interest 4.5x, and FFO/debt 18%. Each measure is strong for the current rating. One lagging measure is debt/EBITDA, which Fitch expects to average about 4.0x over the next several years.

Regulatory Environment: A formula based rate plan (FRP) implemented in October 2011 provides increased regulatory predictability in Illinois. While the FRP remains less favorable than initially expected by Fitch, it does provide for annual rate adjustments, recognizes forward-looking capital additions and includes a true-up mechanism reducing, albeit not eliminating, rate lag. In Fitch's view, the primary deficiencies are a relatively low formula-based return on equity (ROE) and reliance on an average, rather than year-end rate base, which reduces the revenue requirement.

Rising Capex: Capex is forecast to rise to approximately $4.4 billion over the three-year period from 2013 to 2015, compared with $3.3 billion in the prior three-year period. The higher outlays are primarily driven by the Illinois Energy Infrastructure Modernization Act (EIMA), which requires Comed to invest an incremental $1.3 billion on electric system upgrades over five years and an additional $1.3 billion for smart grid deployment over 10 years. The legislation provides for recovery through the FRP filings.

Commodity Price Exposure: Ratings and credit quality benefit from the absence of commodity price exposure, which limits cash flow volatility and reduces business risk. Comed's energy supply costs are recovered from customers through a monthly fuel adjustment mechanism. The company has no volumetric or price risk on energy supply costs.

Like-Kind Exchange: Comed's exposure to the IRS's disallowance of the tax benefits associated with a like-kind exchange is a credit concern. However, the issue is not likely to be resolved for several years and was not factored into the current rating. Comed's potential tax and after-tax interest that could become payable, excluding penalties, is $260 million as of Jan. 28, 2013.

Rating Outlook: The Positive Rating Outlook reflects credit metrics that Fitch expects to remain consistent with 'BBB' target credit ratios and the predictability of future rate recovery due to the evolution of the formula rate plan in Illinois.

Rating Sensitivities

Positive Action: A constructive outcome in Comed's next FRP filing could lead to a one-notch upgrade. In particular, adherence by the Illinois Commerce Commission (ICC) to the principles applied in the most recent rate decision. A successful court challenge regarding the use of an average rather than year-end rate base and the interest rate used to calculate the carrying cost on true-up revenue in FRP filings, or the enactment of Senate Bill 9 would also have a beneficial impact on credit quality.

Negative Action: Lack of rate support for utility infrastructure investments or an over-reliance on Comed to fund the parent common stock dividend pose the greatest threats to ratings.

FitchRatings

Corporates

Financial Overview

Liquidity and Debt Structure

A $1 billion committed credit facility provides ample liquidity. The credit facility supports a commercial paper program of equal size and provides for direct borrowings. The credit facility extends to March 2018 and allows for an additional one-year extension. Available cash at Dec. 31, 2012 was $144 million.

Long-term debt as of Dec. 31, 2012 aggregated $5.8 billion, including $206 million of subordinated debentures that qualify for 50% equity credit under Fitch's methodology. Approximately 95% of the outstanding long-term debt is first mortgage bonds. Annual debt maturities in each of the next five years ranging between $250 million and $665 million should be manageable, but will require capital market access.

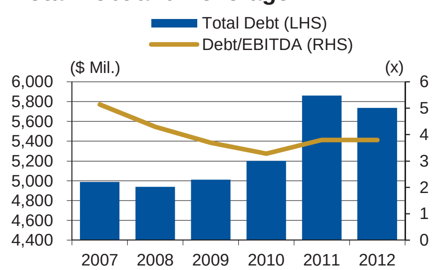
Debt Maturities

($ Mil.)

2013	252
2014	617
2015	260
2016	665
After 2016	3,999
Cash and Cash Equivalents	144
Undrawn Committed Facilities	1,000

Source: Company data, Fitch.

Total Debt and Leverage

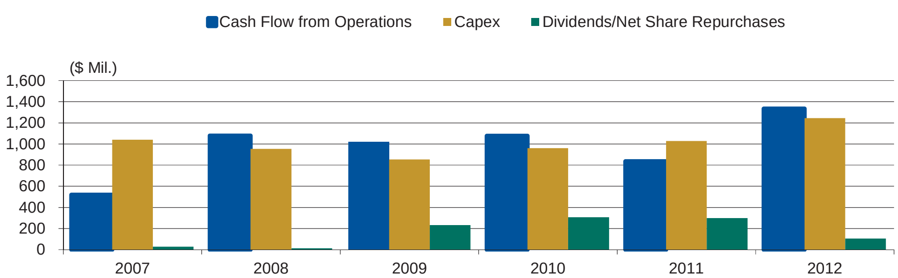


Source: Company data, Fitch.

Cash Flow Analysis

Fitch expects capex to rise to approximately $4.4 billion over the three-year period from 2013 to 2015, or about 2.5x depreciation. Fitch expects internal cash generation after dividends to provide 65%–75% of capex. The recent action by parent EXC to reduce its common stock dividend by 40%, or nearly $750 million annually, is expected to have limited impact on Comed. Affiliate Exelon Generation Co., LLC will be the primary beneficiary, with Comed expected to upstream about 70% of earnings.

CFO and Cash Use



Source: Company data, Fitch.

Related Criteria

Recovery Ratings and Notching Criteria for Utilities (November 2012)

Corporate Rating Methodology (August 2012)

Parent and Subsidiary Rating Linkage (August 2012)

Peer and Sector Analysis

Peer Group

Issuer	Country
BBB	—
Baltimore Gas and Electric Company	—
PPL Electric Utilities	—
BBB+	
PECO Energy Co.	—

Source: Fitch.

Issuer Rating History

Date	LT IDR (FC)	Outlook/ Watch
Feb. 8, 2013	BBB–	Positive
March 12, 2012	BBB–	Stable
April 28, 2011	BBB–	Stable
Jan. 24, 2011	BBB–	Stable
Jan. 25, 2010	BBB–	Stable
May 30, 2008	BB+	Stable
Aug. 29, 2007	BB+	Stable
Aug. 1, 2007	BB	RWP
March 9, 2007	BB	RWN
Nov. 17, 2006	BBB–	RWN
July 31, 2006	BBB–	Negative
Jan. 9, 2006	BBB+	Negative
Dec. 6, 2005	BBB+	Stable
Dec. 20, 2004	BBB+	Stable
May 2, 2001	BBB+	Stable
Oct. 20, 2000	BBB+	—
Dec. 17, 1999	BBB+	—
July 26, 1999	BBB	—
Jan. 8, 1997	BBB–	—

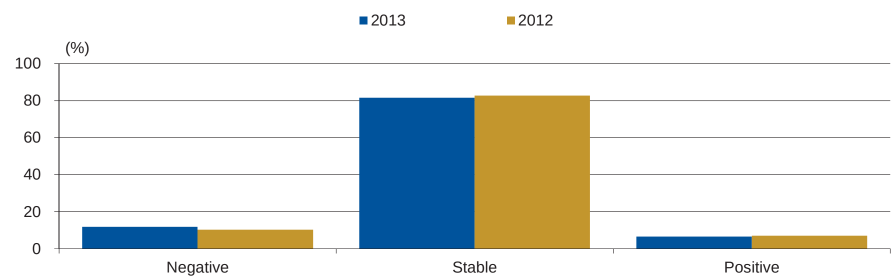
LT IDR (FC) – Long-term Issuer Default Rating (foreign currency).
RWP – Rating Watch Positive.
RWN – Rating Watch Negative.
Source: Company data, Fitch.

Peer and Sector Analysis

	Commonwealth Edison Co.	Baltimore Gas and Electric Company	PPL Electric Utilities	PECO Energy Co.
LTM as of	12/31/12	12/31/12	12/31/12	12/31/12
Long-Term IDR	BBB–	BBB	BBB	BBB+
Outlook	Positive	Stable	Stable	Stable
Financial Statistics ($ Mil.)				
Revenue	5,443	2,653	1,763	3,186
EBITDA	1,509	348	454	860
FCF	(17)	(173)	(331)	109
Total Adjusted Debt	5,736	1,975	1,967	2,312
Funds Flow from Operations	1,231	536	387	731
Capex	(1,246)	(582)	(624)	(422)
Credit Metrics (x)				
EBITDA/Gross Interest Coverage	4.72	2.78	4.59	6.56
Debt/FFO	4.66	3.68	5.08	3.16
Debt/EBITDA	3.80	5.68	4.33	2.69
FFO Interest Coverage	4.85	5.29	4.91	6.58
Capex/Depreciation (%)	201.29	247.66	390.00	179.57

IDR – Issuer Default Rating.
Source: Company data, Fitch.

Sector Outlook Distribution



Source: Fitch.

Key Rating Issues

FRP Appeal

Following a rehearing on its initial FRP decision, the ICC reversed its original position and allowed Comed to earn a debt return on its pension asset. The after-tax return on the $1.1 billion pension asset is about $65 million annually. However, the ICC maintained its position on using an average (rather than year-end) rate base and capital structure to determine the revenue requirement and a short-term debt rate (rather than the weighted cost of capital) to calculate the carrying charges on reconciliation (true-up) balances related to under- or over-recoveries. Following the rehearing order, Comed filed an appeal in state court on the issues that were not reversed by the ICC. Fitch believes the ICC's position is inconsistent with language in the legislation.

Recent Comed Rate Case

The ICC issued an order in Comed's second FRP filing on Dec. 29, 2012. The decision was more constructive than the previous order, but continues to rely on an average rate base and capital structure and short-term interest rates to calculate the carrying charges on reconciliation balances. The ICC granted Comed a $72.6 million rate increase, compared with the $74.2 million supported by the company. The allowed ROE was 9.71% based on the pre-established formula (3.91% Treasury yield plus 580 bps), compared with 10.05% in the prior case. Prospectively, Comed will file an annual FRP each May with new rates effective the following January. There is limited downside on the ROE since Treasury rates are unlikely to fall.

Load Trends

Weather-normalized electric load is expected to be flat in 2013, with moderate improvement thereafter. The 2013 outlook includes a decline in sales to the higher margin residential and small commercial and industrial customers, offset by an increase in sales to lower margin large commercial and industrial customers.

Energy Infrastructure Modernization Act

Since 2011, Comed's distribution rates have been established through a performance-based FRP, as established by the EIMA. The legislation requires participating utilities to invest certain amounts in their distribution systems, with cost recovery provided through annual FRP filings. Instead of periodic rate filings, delivery service rates are reset annually based on the actual cost of service, subject to a prudence review by the ICC. The FRP dictates the allowed equity return and requires use of the actual rate base and capital structure. The legislatively set ROE is equal to the 12-month average of the 30-year Treasury bond yield during the test year, plus a risk premium of 580 bps.

Although the FRP relies on a historical test year, defined as data in the most recently filed Federal Energy Regulatory Commission (FERC) Form 1, there are two adjustments that limit regulatory lag. The annual rate filings include post-test year net plant additions for the ensuing 12-month period, and an annual reconciliation (with interest) of the previously allowed revenue requirement based on actual costs during the prior rate year. The FRP also sets protocols for several items that have been contentious in past rate cases, including the treatment of incentive compensation, pension and other post-employment benefits, severance costs, and the investment return on Comed's pension asset.

If the earned ROE is more than 50 bps above or below the authorized ROE, the companies are required to refund/collect any amounts outside of the dead band. The FRP will be terminated if the average annual rate increase for the years 2012–2014 were to exceed 2.5%. Otherwise, the FRP will terminate Dec. 31, 2017, unless extended by the legislature.

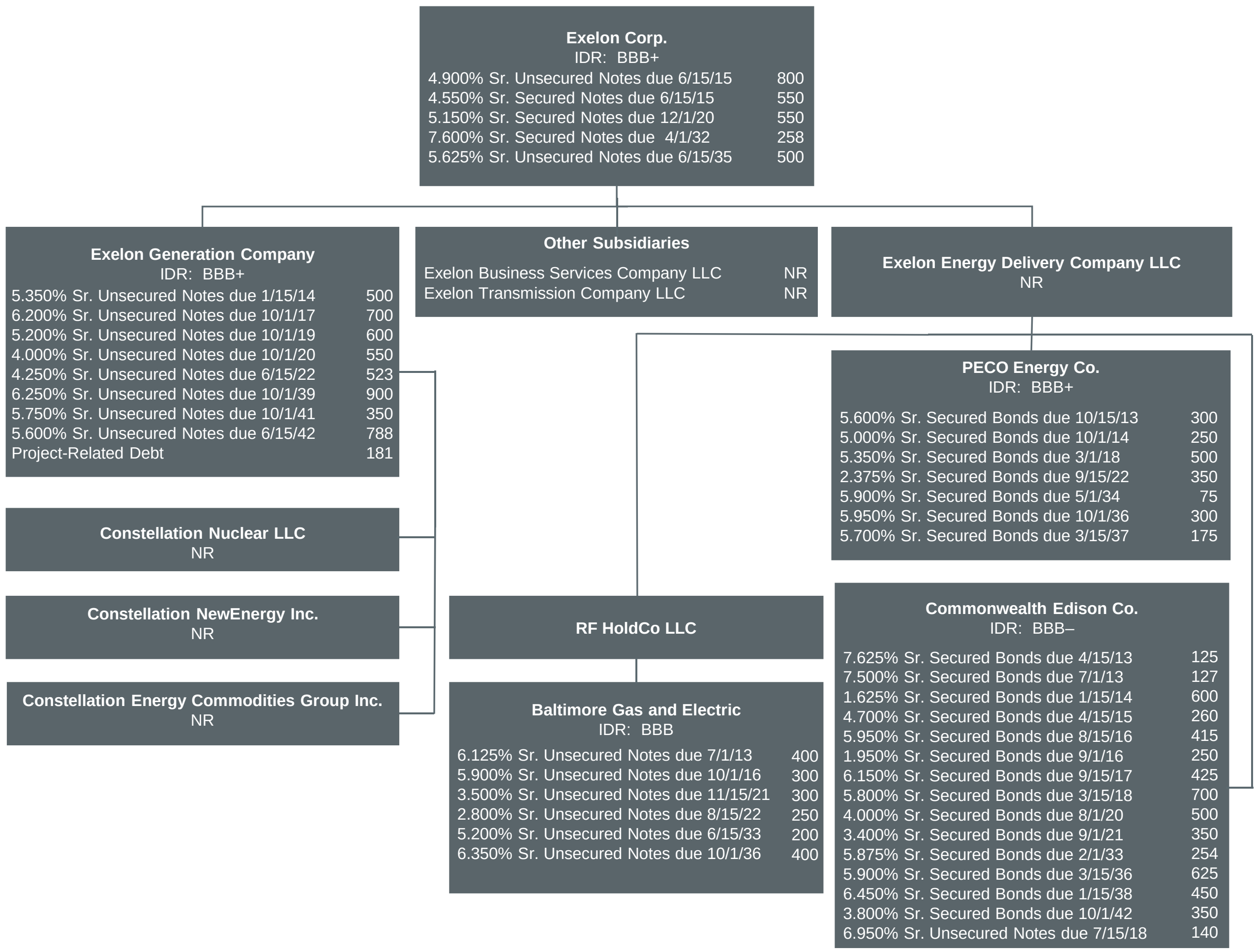
Pending Legislation

The Illinois Senate Executive Committee voted to pass Senate Bill (S.B.) 9 on Feb. 13, 2013, which if enacted, would clarify certain provision in the FRP and allow utilities to recover amounts not allowed in previous FRP proceedings. The legislation includes language indicating the ICC should use the utilities' year-end rate base and capital structure, and specifies that any reconciliation amounts should accrue interest using the utilities' weighted average cost of capital.

FitchRatings **Corporates**

Organizational Structure

Organizational Structure — Exelon Corp.
($ Mil., As of Dec. 31, 2012)



IDR – Issuer Default Rating. NR – Not rated.
Source: Company filings, Bloomberg, and Fitch Ratings.

Definitions

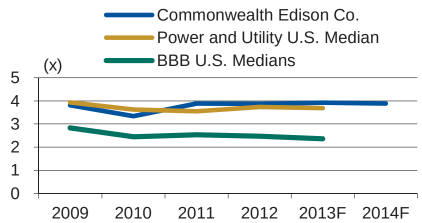
- Leverage: Gross debt plus lease adjustment minus equity credit for hybrid instruments plus preferred stock divided by FFO plus gross interest paid plus preferred dividends plus rental expense.
- Interest Cover: FFO plus gross interest paid plus preferred dividends divided by gross interest paid plus preferred dividends.
- FCF/Revenue: FCF after dividends divided by revenue.
- FFO/Debt: FFO divided by gross debt plus lease adjustment minus equity credit for hybrid instruments plus preferred stock.

Fitch's expectations are based on the agency's internally produced, conservative rating case forecasts. They do not represent the forecasts of rated issuers individually or in aggregate. Key Fitch forecasts assumptions include:

- Retail sales growth of less than 1% annually.
- Annual rate increases through FRP proceedings.
- No resolution of Like Kind Exchange issue in forecast period.
- Dividend payout ratio of no more than 70%.

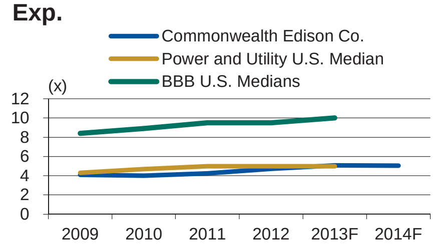
Key Metrics

Leverage: Total Adj. Debt/Op. EBITDAR



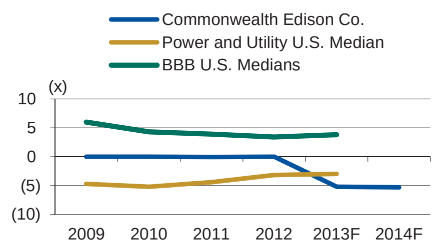
F – Forecast.
Source: Company data, Fitch.

Int. Coverage: Op EBITDA/Gross Int. Exp.



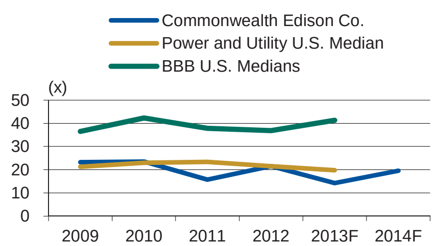
F – Forecast.
Source: Company data, Fitch.

FCF/Revenues



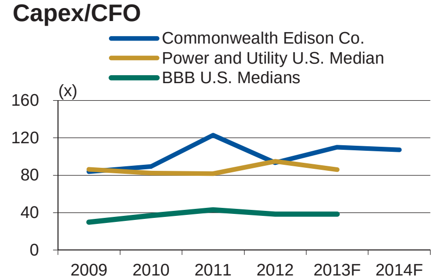
F – Forecast.
Source: Company data, Fitch.

FFO/Debt



F – Forecast.
Source: Company data, Fitch.

Capex/CFO



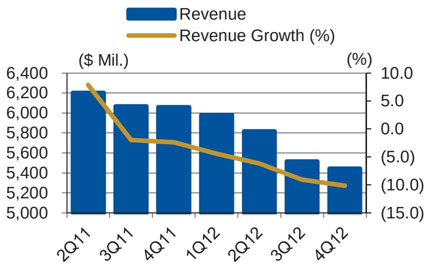
F – Forecast.
Source: Company data, Fitch.

Company Profile

Comed, a wholly owned subsidiary of EXC, is a regulated electric distribution and transmission utility serving approximately 3.8 million customers in northern Illinois, including the city of Chicago. The company supplies electricity to customers as the provider of last resort (POLR), but bears no commodity price risk. POLR supply costs are recovered from customers and adjusted monthly.

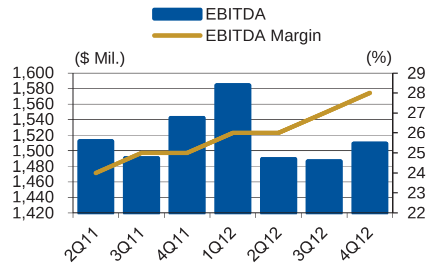
Business Trends

Revenue Dynamics



Source: Company data, Fitch.

EBITDA Dynamics



Source: Company data, Fitch.

Financial Summary — Commonwealth Edison Co.

($ Mil., Fiscal Years Ended Dec. 31)	2008	2009	2010	2011	LTM Ended 12/31/12
Fundamental Ratios (x)					
FFO/Interest Expense	4.23	4.50	4.08	3.54	4.85
CFO/Interest Expense	4.05	4.06	3.71	3.30	5.17
FFO/Debt (%)	23.13	23.28	23.53	15.73	21.46
Operating EBIT/Interest Expense	1.90	2.55	2.68	2.72	2.78
Operating EBITDA/Interest Expense	3.25	4.08	4.00	4.25	4.72
Operating EBITDAR/(Interest Expense + Rent)	3.07	3.84	3.84	4.05	4.53
Debt/Operating EBITDA	4.29	3.69	3.28	3.80	3.80
Common Dividend Payout (%)	—	64.17	91.99	72.11	27.70
Internal Cash/Capital Expenditures (%)	113.22	91.34	79.73	52.14	98.64
Capital Expenditures/Depreciation (%)	198.96	168.11	182.89	185.56	201.29
Profitability					
Adjusted Revenues	6,136	5,774	6,204	6,056	5,443
Net Revenues	2,554	2,709	2,897	3,021	3,136
Operating and Maintenance Expense	1,125	1,091	1,069	1,201	1,345
Operating EBITDA	1,152	1,357	1,588	1,542	1,509
Depreciation and Amortization Expense	479	508	526	554	619
Operating EBIT	673	849	1,062	988	890
Gross Interest Expense	354	333	397	363	320
Net Income for Common	201	374	337	416	379
Operating and Maintenance Expense % of Net Revenues	44.05	40.27	36.90	39.76	42.89
Operating EBIT % of Net Revenues	26.35	31.34	36.66	32.70	28.38
Cash Flow					
Cash Flow from Operations	1,079	1,020	1,077	836	1,334
Change in Working Capital	(63)	(147)	(147)	(86)	103
Funds from Operations	1,142	1,167	1,224	922	1,231
Dividends	—	(240)	(310)	(300)	(105)
Capital Expenditures	(953)	(854)	(962)	(1,028)	(1,246)
FCF	126	(74)	(195)	(492)	(17)
Net Other Investment Cash Flow	(5)	20	23	15	6
Net Change in Debt	(175)	78	132	662	(100)
Net Equity Proceeds	14	8	2	—	—
Capital Structure					
Short-Term Debt	60	155	—	—	—
Long-Term Debt	4,878	4,857	5,201	5,860	5,736
Total Debt	**4,938**	**5,012**	**5,201**	**5,860**	5,736
Total Hybrid Equity and Minority Interest	155	155	103	103	103
Common Equity	6,735	6,882	6,910	7,037	7,323
Total Capital	**11,828**	**12,049**	**12,214**	**13,000**	**13,162**
Total Debt/Total Capital (%)	41.75	41.60	42.58	45.08	43.58
Total Hybrid Equity and Minority Interest/Total Capital (%)	1.31	1.29	0.84	0.79	0.78
Common Equity/Total Capital (%)	56.94	57.12	56.57	54.13	55.64

Source: Company reports.

The ratings above were solicited by, or on behalf of, the issuer, and therefore, Fitch has been compensated for the provision of the ratings.

FitchRatings

Corporates

Electric-Corporate / U.S.A.

Exelon Corp.

Full Rating Report

Ratings

Foreign Currency

Long-Term IDR	BBB+
Short-Term IDR	F2
Senior Unsecured	BBB+
Subordinated	BBB–
Commercial Paper	F2

IDR – Issuer Default Rating.

Rating Outlook

Long-Term Foreign-Currency IDR	Stable

Financial Data

Exelon Corp.

($ Mil.)	12/31/12	12/31/11
Revenue	23,407	18,924
Gross Margin	13,250	11,796
Operating EBITDA	4,358	5,890
Net Income	1,160	2,495
CFFO	6,068	4,853
Total Debt	18,518	13,625
Total Capitalization	40,841	28,252
Capex/Depreciation	321.92	306.22

Related Research

Baltimore Gas and Electric Company (April 2013)

Commonwealth Edison Company (April 2013)

Exelon Generation Company, LLC (April 2013)

PECO Energy Company (April 2013)

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Key Rating Drivers

Proactive Management Actions: Exelon Corp.'s (EXC) ratings are supported by recent steps taken by management to reduce financial commitments and solidify credit quality in the face of persistently low power prices that are pressuring wholesale and retail profit margins at its merchant generation subsidiary. The positive actions include reductions in both capex and the common dividend. Fitch Ratings consequently expects financial metrics to remain strong during a low point in the commodity cycle, and to compare favorably to Fitch's target ratios and their respective peer groups.

Dividend Reduction: EXC reduced its dividend 40%, saving nearly $750 million annually. Fitch expects EXC's merchant generation subsidiary Exelon Generation Company, LLC (Exgen) to be the primary beneficiary of the dividend reduction, and for Exgen to apply available cash to retire maturing debt. The new dividend takes effect in the second quarter of 2013.

Reduced Capex: In November 2012, management lowered Exgen's capex budget by $2.3 billion over the 2013–2017 period. The reductions include approximately $1.025 billion from deferring planned nuclear uprates and $1.25 billion from eliminating unidentified wind and solar investments. The reductions meaningfully reduced pressure on credit quality measures. Any incremental investments are expected to be contracted renewables, regulated utilities, or distressed merchant assets in regions with a well-functioning capacity market and/or tight reserve position.

Low Commodity Price Environment: Low power prices, weak demand, and aggressive competitive pricing behavior have adversely affected wholesale and retail margins, and Fitch expects them to persist for several more years, keeping pressure on credit quality measures. The situation is exacerbated by rising nuclear operating, fuel, and maintenance costs.

Utility Earnings Contribution: The consolidated ratings also consider the contributions of EXC's three regulated utilities, which account for about 50% of consolidated earnings and cash flow. The utilities have limited commodity price risk and a relatively predictable earnings stream, balancing the more volatile earnings and cash flow of the commodity-sensitive merchant business. Each of the utilities has large capex programs that will require ongoing rate support and external financings.

Financial Position: The combined reductions of the common stock dividend and capex have solidified EXC's consolidated financial position. Fitch estimates EXC's adjusted ratio of FFO/interest to be in excess of 6.0x over the next several years and FFO/debt to be approximately 30%.

Rating Sensitivities

Positive Action: A positive rating action is unlikely in the current power price environment.

Negative Action: Lack of rate support for utility infrastructure investments or changes in the commodity cost recovery provisions in Illinois, Pennsylvania, or Maryland could weaken credit metrics of the individual utilities and the parent. A more aggressive growth strategy that increases business risk and/or leverage, a sustained nuclear outage, or a change in hedging strategy at Exgen could also be triggers for a downward rating action.

FitchRatings **Corporates**

Financial Overview

Liquidity and Debt Structure

Cash flow from operations, commercial paper borrowings, committed bank credit facilities, and capital market access provide ample liquidity. EXC and each of its operating subsidiaries maintain separate credit facilities that aggregate $8.4 billion, including $500 million at EXC and $5.7 billion at Exgen. Credit facilities at the utilities total $2.2 billion, including $1 billion at Commonwealth Edison Co. (Comed) and $600 million at both PECO Energy Co. (PECO) and Baltimore Gas & Electric Co. (BGE). All revolving credit facilities extend to 2017, except for Comed's, which has been extended to 2018. Subsidiaries Exgen and PECO also participate in a corporate money pool. Comed and BGE are excluded from the money pool due to ring-fencing measures. Available cash at Dec. 31, 2012 was $1.5 billion, mostly housed at Exgen, which should provide opportunities to retire maturing debt. Annual debt maturities are expected to be manageable, but will require capital market access, particularly at the utilities.

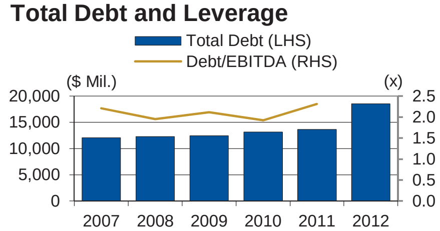
Debt Maturities and Liquidity

($ Mil., At Dec. 31, 2012)

2013	979
2014	1,483
2015	1,613
2016	1,041
After 2016	13,829
Cash and Cash Equivalents	1,486
Undrawn Committed Facilities	6,479

Source: Company data, Fitch.

Total Debt and Leverage

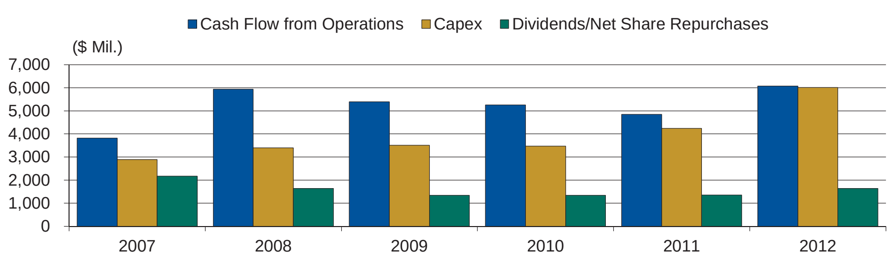


Source: Company data, Fitch.

Cash Flow Analysis

EXC's cash flow position has been strengthened considerably by the recently announced reduction in the common stock dividend and cutbacks in growth capex within the merchant business. Forecast capex of $15.6 billion over the three year period from 2013 to 2015 reflects increasing utility investments and declining investment in the merchant business. The three utilities account for approximately $8 billion, or 51%, of capex, and the merchant business accounts for the remaining $7.6 billion. Fitch expects internally generated funds, after dividends, to supply approximately 90% of consolidated capex over the next three years, with the merchant business being FCF positive.

CFO and Cash Use



Source: Company data, Fitch.

Related Criteria

Recovery Ratings and Notching Criteria for Utilities (November 2012)

Corporate Rating Methodology (August 2012)

Parent and Subsidiary Rating Linkage (August 2012)

Peer and Sector Analysis

Peer Group

Issuer	Country
BBB+	
Exelon Corp.	United States
Public Service Enterprise Group Incorporated	United States
BBB	
PPL Corporation	United States
BBB–	
FirstEnergy Corporation	United States

Source: Fitch.

Issuer Rating History

Date	LT IDR (FC)	Outlook/ Watch
Feb. 8, 2013	BBB+	Stable
March 12, 2012	BBB+	Stable
April 28, 2011	BBB+	Stable
Jan. 24, 2011	BBB+	Stable
Jan. 25, 2010	BBB+	Stable
July 21, 2009	BBB+	Stable
Oct. 20, 2008	BBB+	RWN
May 30, 2008	BBB+	Stable
Aug. 29, 2007	BBB+	Stable
Jan. 18, 2007	BBB+	Stable
Nov. 17, 2006	BBB+	Stable
Dec. 6, 2005	BBB+	Stable
Dec. 20, 2004	BBB+	Stable
May 2, 2001	BBB+	Stable
Oct. 20, 2000	BBB	—

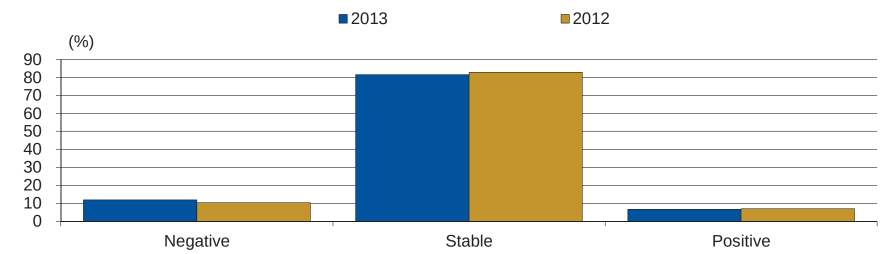
LT IDR (FC) – Long-term Issuer Default Rating (foreign currency).
RWN – Rating Watch Negative.
Source: Fitch.

Peer and Sector Analysis

	Exelon Corp.	Public Service Enterprise Group Incorporated	PPL Corporation	FirstEnergy Corporation
LTM as of	12/31/12	12/31/12	12/31/12	12/31/12
Long-Term IDR	BBB+	BBB+	BBB	BBB–
Outlook	Stable	Stable	Stable	Stable
Financial Statistics ($ Mil.)				
Revenue	23,407	9,517	12,286	15,213
EBITDA	4,358	3,068	4,209	3,720
FCF	(1,655)	(781)	(1,191)	(1,655)
Total Adjusted Debt	18,518	7,437	17,760	19,391
Funds Flow from Operations	5,866	2,625	3,057	2,236
Capex	(6,007)	(2,574)	(3,120)	(3,004)
Credit Metrics (x)				
EBITDA/Gross Interest Coverage	4.19	7.19	4.15	3.54
FFO/Debt	31.68	35.3	17.21	11.53
Debt/EBITDA	4.25	2.42	4.22	5.21
FFO Interest Coverage	6.64	7.15	4.02	3.13
Capex/Depreciation (%)	321.92	307.16	283.64	201.07

IDR – Issuer Default Rating.
Source: Company data, Fitch.

Sector Outlook Distribution



Source: Fitch.

Key Rating Issues

Merchant Operations

The operating environment for EXC's merchant generation business is expected to remain challenging, with sluggish demand and low natural gas and power prices likely to persist for several years. Favorably, the recently announced reductions in the common stock dividend and merchant capital investments will reduce cash outflows by more than $5 billion over the next five years, easing the pressure on cash flow and credit quality measures during a low point in the commodity cycle. Moreover, the largely nuclear-fueled generating fleet is well positioned to benefit from any uplift in power prices from higher environmental costs on fossil units and plant retirements.

Regulated Operations

EXC's three regulated transmission and distribution utilities provide predictable cash flows from relatively low-risk operations. The three utilities are expected to provide roughly 50% of earnings and 45%–50% of cash flow over the next several years. Each of the utilities operates with fuel recovery mechanisms that limit commodity price risk, balancing the more volatile commodity exposure of the merchant generation business. Each of the utilities is in the midst of a large capex program designed to enhance reliability and install smart meters that will require ongoing rate support.

Both Illinois and Pennsylvania have implemented formula-based rate plans that should reduce regulatory lag. Illinois implemented a formula-based rate plan (FRP) in October 2011 that fundamentally changed regulation of electric delivery service. While the FRP remains less favorable than initially expected by Fitch, it provides for annual rate adjustments, recognizes planned capital additions, and includes a true-up mechanism that combine to reduce, albeit not eliminate, rate lag. The primary negatives are a relatively low formula-based return on equity (ROE) and reliance on an average, rather than year-end, rate base, which reduces the revenue requirement.

In Pennsylvania, HB 1294 was signed into law in February 2012. The legislation is intended to encourage utilities to invest in infrastructure by providing cost recovery through an automatic adjustment mechanism. Under the law, utilities will file a long-term infrastructure improvement plan starting in 2013, and the Pennsylvania Public Utility Commission (PUC) will establish a distribution system investment charge (DSIC) to recover the invested capital. The DSIC will be updated quarterly. The new legislation also allows rate filings to include fully forecast test years, significantly reducing regulatory lag.

Rate Adjustments

Comed implemented a $72.6 million rate increase effective Jan. 1, 2013. The rate decision was the second under the FRP process and was more constructive than the previous FRP order, but continues to rely on an average, rather than year-end, rate base and capital structure. The allowed ROE was 9.71% based on the pre-established formula (3.91% 30-year Treasury yield plus 580 bps), compared with 10.05% in the prior case. Prospectively, Comed will file an annual FRP each May, with new rates effective the following January. There is limited downside on the ROE since Treasury rates are unlikely to fall.

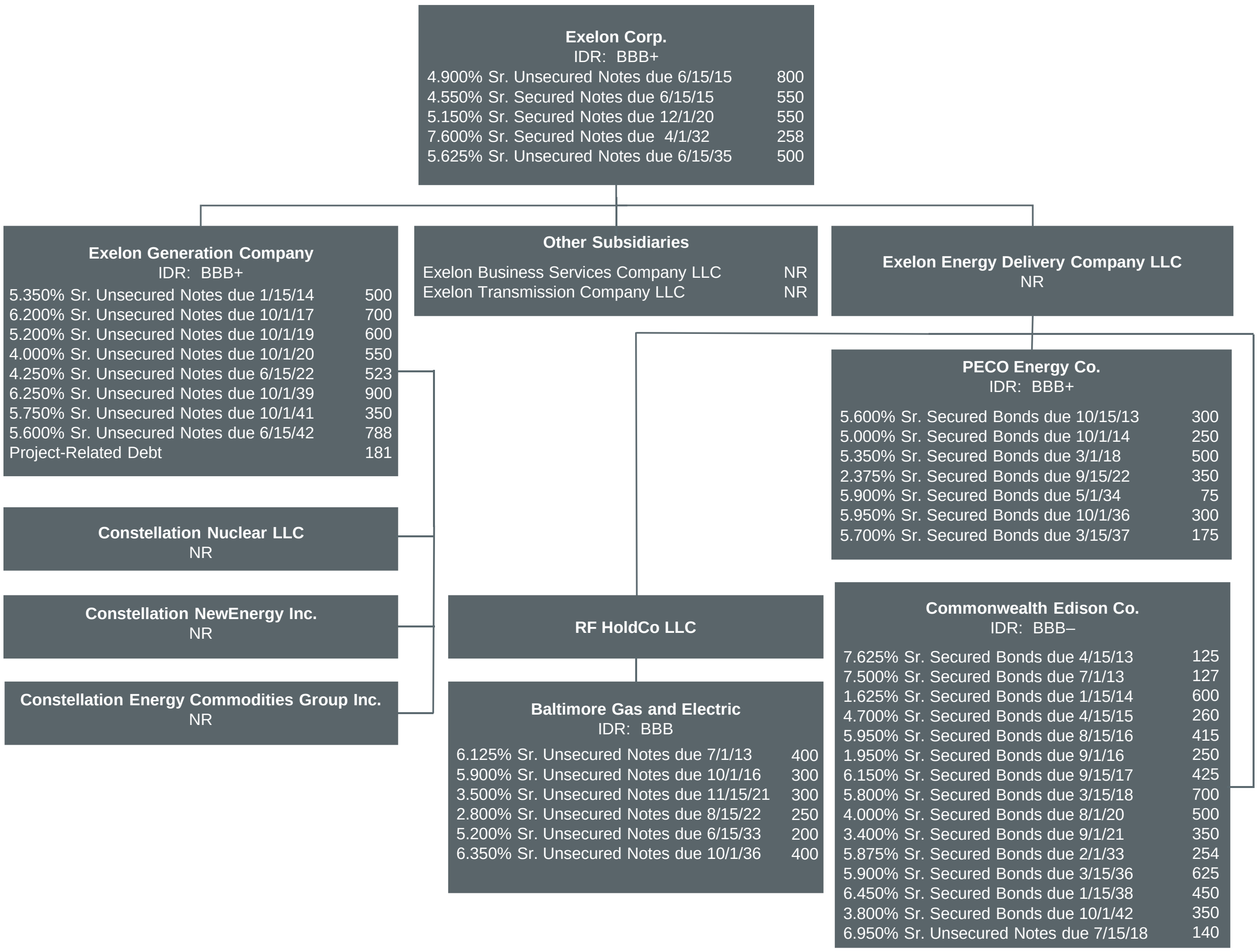
BGE was authorized electric and gas rate increases of $80.6 million and $32.4 million, respectively, effective Feb. 23, 2013. The tariff adjustments were the first change in electric and gas distribution rates since December 2010. Overall, Fitch considers the rate decision to be relatively balanced, but rate lag remains an issue, particularly during this period of rising costs and infrastructure investments and flat sales growth. In particular, the decision relied on a historical test year with limited forward adjustments that will likely preclude BGE from earning its allowed ROE.

Like-Kind Exchange

EXC's exposure to the IRS's disallowance of the tax benefits associated with a like-kind-exchange transaction is a credit concern. However, the issue is not likely to be resolved for several years and was not factored into the current rating, as the company plans to litigate. The IRS has asserted the transaction is substantially similar to a sale-in, lease-out (SILO) leasing transaction and does not qualify for a tax deduction. Recently, the U.S. Court of Appeals for the Federal Circuit disallowed Consolidated Edison Co.'s deductions stemming from a lease-in, lease-out (LILO) transaction similar to a SILO. As of Jan. 28, 2013, EXC's potential tax and after-tax interest that could become payable, excluding penalties, is $860 million, of which $260 million would be paid by Comed.

Organizational Structure

Organizational Structure — Exelon Corp.
($ Mil., As of Dec. 31, 2012)



IDR – Issuer Default Rating. NR – Not rated.
Source: Company filings, Bloomberg, and Fitch Ratings.

FitchRatings **Corporates**

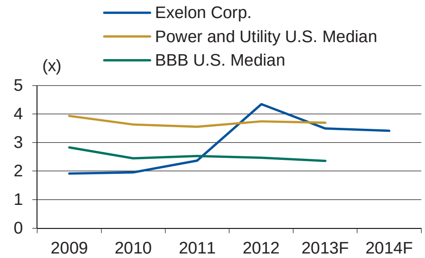
Definitions

- Leverage: Gross debt plus lease adjustment minus equity credit for hybrid instruments plus preferred stock divided by FFO plus gross interest paid plus preferred dividends plus rental expense.
- Interest Cover: FFO plus gross interest paid plus preferred dividends divided by gross interest paid plus preferred dividends.
- FCF/Revenue: FCF after dividends divided by revenue.
- FFO/Debt: FFO divided by gross debt plus lease adjustment minus equity credit for hybrid instruments plus preferred stock.

Fitch's expectations are based on the agency's internally produced, conservative rating case forecasts. They do not represent the forecasts of rated issuers individually or in aggregate. Key Fitch forecasts assumptions include:

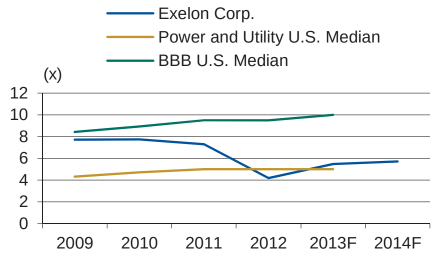
- Gas and power prices in line with current forwards.
- Utility sales growth of less than 1% annually.
- Annual rate increases for Comed and BGE.
- Discretionary renewable investments, if any, are funded with non-recourse debt.
- Continuation of all existing cost recovery clauses.

Leverage: Total Adjusted Debt/ Operating EBITDAR



F – Forecast.
Source: Company data, Fitch.

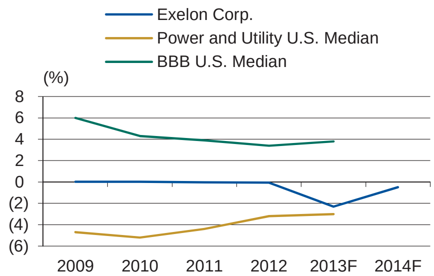
Interest Coverage: Operating EBITDA/ Gross Interest Expense



F – Forecast.
Source: Company data, Fitch.

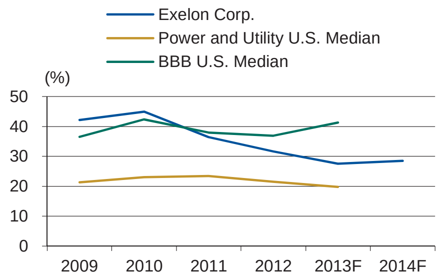
Key Metrics

FCF/Revenues



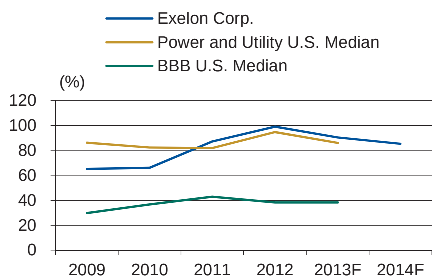
F – Forecast.
Source: Company data, Fitch.

FFO/Debt



F – Forecast.
Source: Company data, Fitch.

Capex/CFO



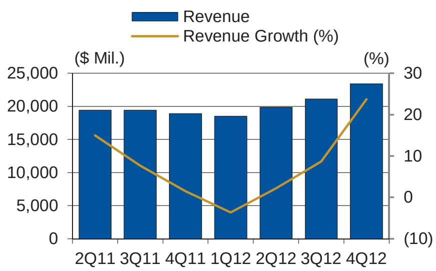
F – Forecast.
Source: Company data, Fitch.

Company Profile

Exelon Corp. is an energy holding company engaged through its primary subsidiaries in wholesale power generation, retail energy marketing, and regulated electric and natural gas delivery operations. EXC completed its merger with Constellation Energy Group on March 12, 2012, with EXC continuing as the surviving entity. The merger added a third regulated transmission and distribution utility (BGE) and a large retail customer supply business that is complementary and synergistic to EXC's merchant generation business. After the merger, the regulated and competitive businesses are each expected to provide roughly 50% of EBITDA, which is not meaningfully different than the premerger contributions. The regulated subsidiaries operate in Illinois, Pennsylvania, and Maryland.

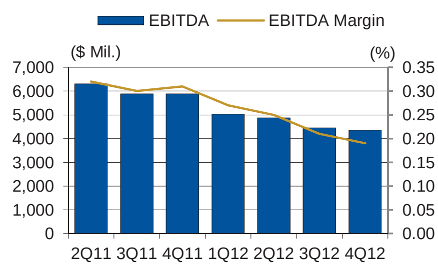
Business Trends

Revenue Dynamics



Source: Company data, Fitch.

EBITDA Dynamics



Source: Company data, Fitch.

Pension Analysis

Pension Analysis — Exelon Corp.

(Years Ended Dec. 31)	2010	2011	2012
PBO (Under)/Over Funded Status (Global, $ Mil.)	(3,665)	(2,236)	(3,443)
Pension Funded Status (U.S. Only, %)	71	83	80
Estimated Pension Outflows (U.S.)/(FFO + Pension Contribution) (%)	10.71	7.52	12.84

Company data, Fitch.

FitchRatings **Corporates**

Financial Summary — Exelon Corp.

($ Mil., Fiscal Years Ended Dec. 31)	2008	2009	2010	2011	LTM Ended 12/31/12
Fundamental Ratios (x)					
FFO/Interest Expense	7.19	7.84	7.64	7.13	6.64
CFO/Interest Expense	8.47	8.04	6.92	6.99	6.83
FFO/Debt (%)	40.08	42.12	44.88	36.43	31.68
Operating EBIT/Interest Expense	6.58	6.18	5.35	5.56	2.39
Operating EBITDA/Interest Expense	7.91	7.69	7.73	7.27	4.19
Operating EBITDAR/(Interest Expense + Rent)	7.28	7.06	7.21	6.66	3.86
Debt/Operating EBITDA	1.95	2.11	1.92	2.31	4.25
Common Dividend Payout (%)	48.78	50.99	53.96	55.83	146.54
Internal Cash/Capital Expenditures (%)	135.42	114.15	111.44	81.7	72.45
Capital Expenditures/Depreciation (%)	320.04	302.24	164.33	306.22	321.92
Profitability					
Adjusted Revenues	18,149	16,558	18,644	18,924	23,407
Net Revenues	11,567	11,277	12,209	11,796	13,250
Operating and Maintenance Expense	4,566	4,675	4,600	5,196	7,961
Operating EBITDA	6,292	5,892	6,865	5,890	4,358
Depreciation and Amortization Expense	1,063	1,162	2,111	1,383	1,866
Operating EBIT	5,229	4,730	4,754	4,507	2,492
Gross Interest Expense	795	766	888	810	1,041
Net Income for Common	2,737	2,716	2,574	2,495	1,160
Operating and Maintenance Expense % of Net Revenues	39.47	41.46	37.68	44.05	60.08
Operating EBIT % of Net Revenues	45.21	41.94	38.94	38.21	18.81
Cash Flow					
Cash Flow from Operations	5,942	5,394	5,255	4,853	6,068
Change in Working Capital	1,023	158	(644)	(110)	202
Funds From Operations	4,919	5,236	5,899	4,963	5,866
Dividends	(1,335)	(1,385)	(1,389)	(1,393)	(1,716)
Capital Expenditures	(3,402)	(3,512)	(3,469)	(4,235)	(6,007)
FCF	1,205	497	397	(775)	(1,655)
Net Other Investment Cash Flow	24	41	468	19	1,081
Net Change in Debt	(576)	(551)	(391)	571	685
Net Equity Proceeds	(306)	42	48	38	72
Capital Structure					
Short-Term Debt	211	155	225	388	210
Long-Term Debt	12,060	12,273	12,919	13,237	18,308
Total Debt	**12,271**	**12,428**	**13,144**	**13,625**	**18,518**
Total Hybrid Equity and Minority Interest	358	358	243	242	892
Common Equity	11,047	12,640	13,560	14,385	21,431
Total Capital	**23,676**	**25,426**	**26,947**	**28,252**	**40,841**
Total Debt/Total Capital (%)	51.83	48.88	48.78	48.23	45.34
Total Hybrid Equity and Minority Interest/Total Capital (%)	1.51	1.41	0.90	0.86	2.18
Common Equity/Total Capital (%)	46.66	49.71	50.32	50.92	52.47

Source: Company reports.

The ratings above were solicited by, or on behalf of, the issuer, and therefore, Fitch has been compensated for the provision of the ratings.

MOODY'S INVESTORS SERVICE

Credit Opinion: Commonwealth Edison Company

Global Credit Research - 05 Mar 2012

Chicago, Illinois, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	Baa2
First Mortgage Bonds	A3
Senior Secured Shelf	(P)A3
Senior Unsecured	Baa2
Commercial Paper	P-2
Parent: Exelon Corporation	
Outlook	Rating(s) Under Review
Issuer Rating	*Baa1
Senior Unsecured	*Baa1
Subordinate Shelf	*(P)Baa2
Pref. Shelf	*(P)Baa3
Commercial Paper	P-2
ComEd Financing III	
Outlook	Stable
BACKED Pref. Stock	Baa3

* Placed under review for possible downgrade on April 28, 2011

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Key Indicators

[1]**Commonwealth Edison Company**

	2011	2010	2009	2008
(CFO Pre-W/C + Interest) / Interest Expense	5.2x	3.9x	4.0x	3.9x
(CFO Pre-W/C) / Debt	25%	20%	20%	18%
(CFO Pre-W/C - Dividends) / Debt	21%	15%	16%	18%
Debt / Book Capitalization	38%	39%	40%	42%

[1] All ratios calculated in accordance with the Global Regulated Electric Utilities Rating Methodology using Moody's standard adjustments.

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Regulatory environment shows improvement but possibility of unpredictable outcomes remain

Improved ability to recover costs under new legislation

Strong credit metrics for rating category

Sizeable capital program

Dispute with IRS remains an overhang credit issue

Corporate Profile

Commonwealth Edison Company (ComEd) is a regulated electric transmission and distribution company and a subsidiary of Exelon Corporation (Exelon: Baa2 senior unsecured; stable). ComEd provides energy delivery services to retail and wholesale customers in northern Illinois, including the city of Chicago. ComEd is regulated by the Illinois Commerce Commission (ICC) and the Federal Energy Regulatory Commission (FERC). At December 31, 2011, ComEd had total assets of $22.65 billion.

SUMMARY RATING RATIONALE

ComEd's Baa2 senior unsecured rating primarily reflects an improved but still less predictable state regulatory environment in which the company operates, strong credit metrics for the rating category, and an improved cost recovery mechanism following last year's passage of legislation. The rating recognizes the company's good liquidity management, the diversity of its regional economy which helps mitigate the financial impact from the still weak economic recovery, as well as the overhang of the company's ongoing exposure to litigation with the IRS.

DETAILED RATING CONSIDERATIONS

Regulatory environment improved but possibility of unpredictable outcomes remain

An important factor in the rating methodology for Regulated Electric and Gas Utilities is the credit supportiveness of the regulatory framework.

ComEd's rating recognizes an improved, but still challenging regulatory environment that continues to persist for electric utilities in Illinois leading to lingering concerns about the framework's predictability. Intervention risk from key and influential stakeholders have occurred in past rate case decisions and regulatory actions involving ComEd making the framework less reliable. Specifically, actions by consumer groups, the Illinois Attorney General, and various legislators have had negative implications for regulatory decisions involving ComEd and other IOUs in the state.

On Dec. 30, 2011, the Energy Infrastructure Modernization Act (EIMA) became law. The EIMA establishes a new distribution formula-rate-plan (FRP) ratemaking paradigm for the state's largest electric utilities and is intended to spur utility infrastructure investment. Specifically, EIMA requires electric utilities that serve at least one million customers, ComEd and Ameren subsidiary Ameren Illinois (AI) , to invest specific amounts in their transmission and distribution (T&D) systems, with recovery of these investments to occur in the context of annual FRP proceedings, subject to ICC approval.

The legislation requires ComEd to invest $1.3 billion over a five-year period in electric system upgrades, modernization projects, and training facilities, and at least $1.3 billion over a 10-year period in transmission & distribution assets and smart-grid system upgrades. Key aspects of the FRP calculation include cost recovery of the utility's actual capital structure, excluding goodwill; a legislatively-set formula for purposes of calculating the allowed return on equity (ROE) equivalent to a 580 basis-point premium above the 12-month average 30-year Treasury Bond yield; recovery of pension-related costs, as well as recovery of certain incentive compensation expenses. If the utility's actual ROE in a given period is more than 50 basis points above or below its authorized ROE, the company is required to refund to/collect from ratepayers any amounts outside of this deadband. Also, the utility's allowed ROE can be reduced if it fails to meet certain performance metrics. Moreover, the new law requires the utility's FRP to be terminated if the average annual rate increase for the years 2012 through 2014 exceeds 2.5%. All FRPs are to terminate at year-end 2017 (unless legislation is enacted permitting the continued use of these rate plans), and unrecovered costs associated with the investment programs would presumably be addressed in traditional base rate proceedings.

Although the passage of EIMA helps to offset lingering concerns about the predictability of the regulatory framework, the legislation remains untested. Moreover, we understand that the ICC and other stakeholders were opposed to the law's passage since, in their opinion, EIMA limits the oversight ability of the commission. We continue to view the state's regulatory framework for electric utilities as having the potential to be unpredictable and unreliable. Therefore, the regulatory framework (Factor 1 in the Methodology) for ComEd continues to be scored below investment grade or at Ba. Our future assessment of this Factor will be influenced by the manner in which the new regulatory framework is implemented and whether it is accepted as a workable regulatory model by key constituents.

Ability to recover costs and earn returns is acceptable

In light of the passage of EIMA, we believe ComEd's ability to recover costs and earn reasonable returns (Factor 2) has improved and is consistent with an mid-Baa score for this rating factor. Specifically, we believe that passage of EIMA will enhance cost recovery and reduce regulatory lag. From a timing perspective, ComEd implemented into 2011 rates amounts due under the true-up mechanism in EIMA and made its initial filing with the ICC in November 2011 to implement a $44 million refund to customers during the period June 1, 2012 through Dec. 31, 2012. The November 2011 filing reflects a 2010 test year and 2011 plant additions. ComEd plans to file its 2011-test-year FRP case during May 2012, reflecting 2012 net plant additions. New rates associated with that proceeding would take effect in January 2013. Thereafter, ComEd would submit an annual FRP filing each May, with new rates to take effect the following January.

Material Capital Investment

Over the past several years, ComEd's capital expenditure program has approximated around $950 million each year to maintain and strengthen the transmission and distribution network in and around its service territory, and to improve overall reliability for customers. Prospectively, we anticipate that capital spending for smart grid deployment, infrastructure, and maintenance to be approximately $1.5 billion each year. We expect a large portion of these costs to be recovered through the annual FRP filings with the ICC. Like most distribution and transmission systems that serve large metropolitan areas, continued capital investment is important for maintaining system reliability, given the age of these systems.

Strong Credit Metrics for the Current Rating

For the past three years, ComEd has produced very strong credit metrics for the Baa rating category. Reported 2011 results for ComEd included net income of $416 million, representing a 23% increase over 2010 results. The improvement is largely a function of receipt of the distribution rate case during mid 2011 and revenue from recently enacted legislation addressing the recovery of infrastructure investments. Cash flow (CFO pre W/C) to debt has averaged around 21.6%, cash flow coverage of interest expense has averaged 4.3x and retained cash flow to cash has averaged 16.6% for the past three years, all of which are reflective of a higher Baa rating. Some of this financial performance can be attributed to the positive impact of tax treatment, including the receipt of bonus depreciation, which is not a sustainable source of cash flow. We view Exelon's decision to utilize the receipt of bonus depreciation to voluntarily make a sizable contribution to ComEd's pension plan as a conservative and credit supportive action. Prospectively, and factoring in the benefits of loss of bonus depreciation in the near-term financial results, we believe that ComEd will produce credit metrics that will strongly position the company within the Baa2 rating category.

IRS dispute remains an overhang credit issue

Exelon, through ComEd, is involved in a tax dispute with the IRS relating to the $2.8 billion tax gain associated with the 1999 sale of ComEd's fossil generating assets, and the subsequent transition to market rates for generation that occurred among ComEd's and PECO's customers. Exelon believes that it was economically compelled to dispose of ComEd's fossil generating plants and that the proceeds from the sale of the fossil plants were properly reinvested in qualifying replacement property such that $1.6 billion of the gain could be deferred over the lives of the replacement property under the involuntary conversion provisions. The remaining approximately $1.2 billion of the gain was deferred by reinvesting the proceeds from the sale in qualifying replacement property under the like-kind exchange provisions. The like-kind exchange replacement property purchased by Exelon included interests in three municipal-owned electric generation facilities which were properly leased back to the municipalities.

In the third quarter 2010, Exelon and the IRS reached a nonbinding, preliminary agreement to settle Exelon's involuntary conversion and competitive transition charge positions. Under the terms of the agreement, Exelon estimates that the IRS will assess tax and interest of approximately $300 million in 2012, and that Exelon will receive additional tax refunds of approximately $365 million between 2012 and 2014, of which $335 million would be received by ComEd, $55 million would be received by ExGen and the remainder paid by Exelon.

During 2010, Exelon and IRS failed to reach a settlement with respect to the like-kind exchange position. As year-end 2011, assuming Exelon's preliminary settlement of the involuntary conversion position is finalized, the potential tax and interest, exclusive of penalties, that could become currently payable in the event of a fully successful IRS challenge to Exelon's like-kind exchange position could be as much as $860 million, of which $550 million would be paid by ComEd and the remainder by Exelon.

Liquidity

ComEd's Prime-2 short-term rating for commercial paper reflects our view that the company will maintain adequate liquidity for the next 4 quarters.

ComEd has a $1 billion unsecured revolving credit facility that expires on March 25, 2013. This credit facility is used primarily to provide liquidity support and for the issuance of letters of credit. As of December 31, 2011, there were no borrowings under the facility; however, $1 million of the facility is used for letters of credit, leaving $999 million of availability. While the credit agreement does not contain any rating triggers that would affect borrowing access to the commitment and does not require any material adverse change (MAC) representation for borrowings, there is a requirement to maintain a ratio of net cash flow from operations to net interest expense at a minimum level of at least 2.0 times. At December 31, 2011 ComEd's ratio of net cash flow from operations to net interest expense was 6.39x. Cash on hand at December 31, 2011 was $233 million. We understand that the company is currently in the market replacing and extending the $1 billion revolver due March 2013 to a March 2017 expiry date at the same $1 billion level.

In light of the ample capital investment program anticipated at the utility, the company is expected to be free cash flow negative for the next few years. During 2011, ComEd paid out about 70% of its earnings to Exelon in the form of a dividend. In light of the capital needs at the utility, we do not believe that the ComEd dividend will reach the 70% payout level over the next several years. ComEd has approximately $450 million of debt maturing in 2012, $252 million in 2013, and $600 million in 2014. We would anticipate the company seeking to access the capital markets to refinance a substantial portion of this debt given the planned capital requirements of the utility.

As of December 31, 2011, we observe that if ComEd lost its investment grade credit rating, it could be required to provide $227 million of incremental collateral.

For more information on Exelon's liquidity, please see the Exelon Credit Opinion on www.moodys.com.

Rating Outlook

ComEd's rating outlook is stable reflecting an expectation that financial results will remain strong for the rating category, particularly with the passage of EIMA, which helps to offset lingering concerns about the regulatory framework, which has historically been less predictable. ComEd's stable outlook further incorporates our belief the company's dividend policy will remain sensible in light of the utility's increased capital spending requirements.

What Could Change the Rating - Up

In light of the March 2nd one notch upgrade by Moody's, the newness of ratemaking under EIMA, and the increased capital spending anticipated at ComEd, limited prospects exist for the utility's ratings to be upgraded in the near-term. However, upward rating pressure can surface if the new regulatory framework is seamlessly implemented, accepted as a workable model by key constituents in the state, and results in better financial results for the state's utilities. Specifically, consideration of a higher rating could emerge if ComEd's the ratio of cash flow to debt exceeds 20% and its cash flow interest coverage exceeds 5.0x on a sustainable basis.

What Could Change the Rating - Down

The rating could be downgraded if the implementation of EIMA ratemaking is altered dramatically or terminated, if the company's cash flow to debt declines to below 16.0% or cash flow to interest expense falls below 3.5x for an extended period. Additionally, negative rating pressure could materialize if the outcome of a continuing IRS challenge concerning certain sale/leaseback transactions affecting Exelon and ComEd leads to substantial payments for the utility.

Other Considerations

As depicted below, ComEd's indicated rating under the grid on a historical and projected basis is Baa2 on par with the current senior unsecured rating.

Rating Factors

Commonwealth Edison Company

Regulated Electric and Gas Utilities Industry [1][2]	**Current 12/31/2011**		**Moody's 12-18 month Forward View* As of February 2012**	
Factor 1: Regulatory Framework (25%)	Measure	Score	Measure	Score
a) Regulatory Framework				
Factor 2: Ability To Recover Costs And Earn Returns (25%)		Ba		Ba
a) Ability To Recover Costs And Earn Returns		Baa		Baa
Factor 3: Diversification (10%)				
a) Market Position (10%)		Baa		Baa
b) Generation and Fuel Diversity (na)		na		na
Factor 4: Financial Strength, Liquidity And Key Financial Metrics (40%)				

a) Liquidity (10%)		Baa		Baa
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	4.3x	Baa	4.8 - 5.3x	A
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	21.6%	Baa	18 - 21%	Baa
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	17.3%	A	16 - 17%	Baa
e) Debt/Capitalization (3 Year Avg) (7.5%)	39.1%	A	35 - 36%	A
Rating:				
a) Indicated Rating from Grid		Baa2		Baa2
b) Actual Rating Assigned		Baa2		Baa2

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of 12/31/2011(L); Source: Moody's Financial Metrics

MOODY'S
INVESTORS SERVICE

Announcement: Moody's Disclosures on Credit Ratings of Exelon Corporation.

Global Credit Research - 09 Mar 2012

New York, March 09, 2012 -- The following release represents Moody's Investors Service's summary credit opinion on Exelon Corporation and includes certain regulatory disclosures regarding its ratings. This release does not constitute any change in Moody's ratings or rating rationale for Exelon Corporation and its affiliates.

Moody's current ratings on Exelon Corporation and its affiliates are:

Senior Unsecured domestic currency ratings of Baa1, on review for possible downgrade

LT Issuer Rating ratings of Baa1, on review for possible downgrade

Senior Unsec. Shelf domestic currency ratings of (P)Baa1, on review for possible downgrade

Subordinate Shelf domestic currency ratings of (P)Baa2, on review for possible downgrade

Pref. Shelf domestic currency ratings of (P)Baa3, on review for possible downgrade

Commercial Paper domestic currency ratings of P-2

Commonwealth Edison Company

First Mortgage Bonds domestic currency ratings of A3

Senior Unsecured domestic currency ratings of Baa2

LT Issuer Rating ratings of Baa2

Senior Secured Shelf domestic currency ratings of (P)A3

Senior Unsec. Shelf domestic currency ratings of (P)Baa2

Commercial Paper domestic currency ratings of P-2

Backed First Mortgage Bonds domestic currency ratings of A3

Underlying First Mortgage Bonds domestic currency ratings of A3

ComEd Financing III

BACKED Pref. Stock domestic currency ratings of Baa3

PECO Energy Company

First Mortgage Bonds domestic currency ratings of A1

LT Issuer Rating ratings of A3

Pref. Stock domestic currency ratings of Baa2

Senior Secured Shelf domestic currency ratings of (P)A1

Subordinate Shelf domestic currency ratings of (P)Baa1

Pref. Shelf domestic currency ratings of (P)Baa2

Commercial Paper domestic currency ratings of P-2

Backed First Mortgage Bonds domestic currency ratings of A1

Underlying First Mortgage Bonds domestic currency ratings of A1

Peco Energy Capital Trust III

BACKED Pref. Stock domestic currency ratings of Baa1

PECO Energy Capital Trust IV

Pref. Shelf domestic currency ratings of (P)Baa1

BACKED Pref. Stock domestic currency ratings of Baa1

PECO Energy Capital Trust V

Pref. Shelf domestic currency ratings of (P)Baa1

BACKED Pref. Shelf domestic currency ratings of (P)Baa1

PECO Energy Capital Trust VI

Pref. Shelf domestic currency ratings of (P)Baa1

BACKED Pref. Shelf domestic currency ratings of (P)Baa1

Exelon Generation Company, LLC

Senior Unsecured domestic currency ratings of A3, on review for possible downgrade

LT Issuer Rating ratings of A3, on review for possible downgrade

Senior Unsec. Shelf domestic currency ratings of (P)A3, on review for possible downgrade

Pref. Shelf domestic currency ratings of (P)Baa2, on review for possible downgrade

Commercial Paper domestic currency ratings of P-2

Exelon Capital Trust I

BACKED Pref. Shelf domestic currency ratings of (P)Baa2, on review for possible downgrade

Exelon Capital Trust II

BACKED Pref. Shelf domestic currency ratings of (P)Baa2, on review for possible downgrade

Exelon Capital Trust III

BACKED Pref. Shelf domestic currency ratings of (P)Baa2, on review for possible downgrade

RATINGS RATIONALE

Exelon's Baa1 rating reflects strong consolidated credit metrics, due in large part to the financial performance of ExGen, its unregulated generation subsidiary, and the generally predictable cash flows at its T&D subsidiaries. While the T&D subsidiaries are sizeable standalone companies, Exelon's rating is largely influenced by the performance of its unregulated segment, which will be increasing in size and importance upon the expected completion of the merger with Constellation Energy Group (CEG: Baa3 senior unsecured; under review for possible upgrade).

The long-term ratings of Exelon and ExGen are under review for possible downgrade due to their plans to merge with CEG in a stock-for-stock transaction. The rating review considers the pending merger with a lower-rated entity, the increased reliance on unregulated operations that will follow from the merger, the expected increase in consolidated leverage, particularly off-balance sheet debt, at a time when electric margins are compressed, all of which is compromised by the sizeable common dividend requirements at Exelon, expected to be funded primarily by its unregulated business platform.

Rating Outlook

Exelon's rating is under review for possible downgrade reflecting the planned CEG merger. The review considers our expectation for a decline in consolidated financial metrics following the stock-for-stock merger driven primarily by continued weak power prices. The review also considers the increase in off-balance leverage that will accompany the merger due, in large part, to the addition of third party guarantees and other potential calls on capital, including tolling obligations.

At this time, we anticipate that the outcome of the rating review is likely to result in a one-notch rating downgrade of Exelon's and ExGen's senior unsecured rating to Baa2 and Baa1, respectively. However, we believe there are increased prospects that the rating outlook for Exelon and ExGen would be negative at the conclusion of the review due to the combined effect of continued weak power prices, a sizeable common dividend, and a large capital investment program. The rating review is likely to be concluded when key regulatory approvals required for the merger to move forward have been obtained.

What Could Change the Rating - Up

In light of the ongoing review for possible downgrade, Exelon's rating is not likely to be upgraded over the near term.

What Could Change the Rating - Down

The review will focus on the expected earnings and cash flow contributions from Exelon's various unregulated businesses operating in the current down cycle. The review will examine the dividend requirements of the merged corporation and the expected contribution from its rate regulated subsidiaries. Moody's notes that one of the MPSC merger approval conditions was the requirement that Baltimore Gas and Electric Company, a CEG regulated transmission and distribution company, not pay dividends through 2014. The review will further consider the various levers that we believe Exelon could consider as it relates to financing the expected negative free cash flow at the corporation, driven by its dividend requirements and various growth capital spending programs.

The principal methodology used in these ratings was Unregulated Utilities and Power Companies published in August 2009. Please see the Credit Policy page on www.moodys.com for a copy of this methodology.

REGULATORY DISCLOSURES

Although these credit ratings have been issued in a non-EU country which has not been recognized as endorsable at this date, the credit ratings are deemed "EU qualified by extension" and may still be used by financial institutions for regulatory purposes until 30 April 2012. Further information on the EU endorsement status and on the Moody's office that has issued a particular Credit Rating is available on www.moodys.com.

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Information sources used to prepare each of the ratings are the following: parties involved in the ratings, parties not involved in the ratings, public information, confidential and proprietary Moody's Investors Service information, and confidential and proprietary Moody's Analytics information.

Moody's considers the quality of information available on the rated entities, obligations or credits satisfactory for the purposes of issuing these ratings.

Moody's adopts all necessary measures so that the information it uses in assigning the ratings is of sufficient quality and from sources Moody's considers to be reliable including, when appropriate, independent third-party sources. However, Moody's is not an auditor and cannot in every instance independently verify or validate information received in the rating process.

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MOODY'S
INVESTORS SERVICE

North American Natural Gas

Low Natural Gas Prices Herald Long-Term Changes In US Energy Infrastructure

Secular shift for natural gas over next decade points to permanent changes in US power, pipeline, coal and rail sectors

» **The ongoing shift in natural gas prices reflects a permanent change across the US energy sector, and will make it more difficult for coal to compete with natural gas as a power source in the future.** A rise in gas-fired power generation will not be strong enough to raise natural gas prices on a sustained basis.

» **Without a significant pick-up in economic demand, low natural gas prices will reduce margins for unregulated power companies over the next decade.** Investment-grade companies such as Exelon, First Energy and PPL will increasingly move to re-balance their capital structure and possibly their dividend policies, while speculative-grade companies such as Energy Future Holdings, NRG Energy and GenOn will focus on preserving liquidity.

» **Coal-fired power-plant retirements will cut the power sector's demand for coal by up to 10% between 2012 and 2020, and the coal industry will become increasingly focused on exports.** Coal consumption will drop by about 100 million tons annually over the next decade or so, but such producers as Peabody Energy, Arch Coal, Consol Energy and Cloud Peak Energy Resources have already begun securing additional port capacity to reach growing export markets. Diversified producers, including Consol, Peabody and Arch, will be best-positioned to navigate the changing industry conditions.

» **New natural gas pipelines serving the shale production regions will create competitive risks for the existing interstate pipeline network.** Companies with assets near the production basins, such as NiSource and Dominion Resources, will benefit, but disappearing arbitrage opportunities will hurt the marketing arms of such utilities as AGL Resources and Vectren.

» **A drop in domestic demand for coal, one of the US railroad industry's most profitable segments, will soften freight volume growth for rail operators.** Between 20% and 30% of US Class I railroads Union Pacific, Burlington Northern Santa Fe, CSX, and Norfolk Southern's revenues are derived from coal shipments. Reduced demand for domestic coal freight will slow overall volume growth, although export opportunities persist.

Natural Gas Prices Take US Energy Infrastructure Into New Era

The dramatic drop in North American natural gas prices has set in motion significant, permanent changes across the US energy infrastructure. This in turn will shift the strategic landscape, but the full implications will emerge over the next decade or so. North American natural gas prices fell to 10-year lows in the $2.50/MMBtu range in early 2012,[1] and low natural gas prices appear sustainable, extending well beyond 2013.

Already, early signs of a fundamental shift in North America's natural gas infrastructure puts credit pressure on unregulated power generators, interstate natural gas transmission pipelines, coal miners and railroads.

Low natural gas prices without a rise in power demand over a multi-year period will continue to squeeze margins for some unregulated power companies. But low natural gas prices will not place the US coal industry in mortal danger. As coal-fired generation for power production declines, coal producers will supplement their revenues by looking for opportunities outside the domestic power market.

Low Natural Gas Prices Are Here to Stay

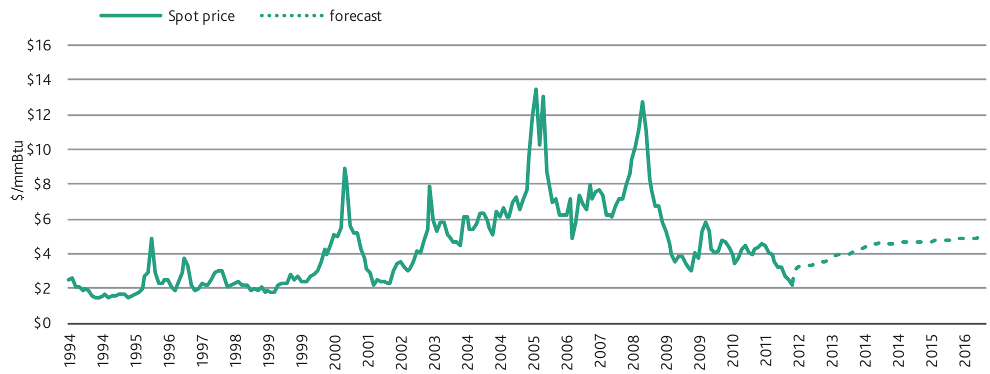
The ongoing shift in the energy sector reflects a permanent change, not just a temporary trend. Independent exploration and production (E&P) companies have transformed North America's natural gas production landscape over the past decade. The region's once-declining natural gas production has given way to strong growth. Technological advances in horizontal drilling and hydraulic fracturing, or fracking, techniques have unlocked vast shale deposits in the US and Canada, making them far more economical in recent years than ever before.

The E&P industry ramped up its shale drilling, thanks to limited exploration risk and ample funding from the equity and debt markets. Shale production in the US mid-continent, Gulf Coast and Appalachian regions have led to a natural gas glut, and the recent US recession and general economic weakness in the US have destroyed demand.

Industrial demand for natural gas has fallen significantly in recent years as various industries, such as the fertilizer sector, have relocated from the US to other countries. Residential usage has declined as consumers have broadly adopted more energy-efficient appliances. Prices have steadily fallen from an average $8.86/MMBtu in 2008 to $4.00/MMBtu in 2011. Then a mild winter in the crucial US midwest and northeast home heating markets pushed natural gas prices well below $3.00/MMBtu in early 2012, with no significant change expected until 2013 at the earliest. These low prices, as well as environmental concerns, will make it much harder for coal to compete with natural gas as a power source (see Figure 1, next page).

1 See our Outlook Update, "E&Ps Set for Continued Strength as Modest Growth Trends Keep Oil on Upward March," March 2012. Also see our special comments, "Decade-Low Prices Pinch Coal Producers, Offering Mixed Fortunes for Power and Rail," February 2012 ; and "Significant Shift in E&P Capex Brings Little Change to Natural Gas Supply," February 2012.

FIGURE 1
Henry Hub Natural Gas Spot Price and Forecast



Source: The Wall Street Journal (historical prices); Moody's Analytics (forecasts)

New Gas-Fired Generation Will Not Affect Near-Term Natural Gas Prices

Without higher demand, natural gas prices will not rise to more advantageous levels for producers. The slow economic recovery in the US has boosted some industrial demand, and low prices should raise petrochemical and other heavy industrial consumption of natural gas.

But in the near- and medium term, power generation appears to be the only material driver of rising demand for natural gas. Low natural gas prices, and stricter environmental regulation of coal-fired power has led to an increase in gas-fired generation, and we expect to see more gas-fired capacity replace coal-fired power.

Data from the US Energy Information Administration (EIA) show that the US had a natural gas capacity surplus of almost 5.0 Tcf in 2010. The next decade will usher in a wide natural gas supply and demand imbalance, with new incremental gas-fired generation offering one of the only likely sources of increased natural gas demand. Even if utilities and unregulated power companies built 80,000 MW of new natural gas combined-cycle generation to replace coal and nuclear retirements and support renewable energy, the natural gas surplus would only drop by half.

A more long-term, substantial shift from coal to natural gas in the electric power sector will take time and significant capital investment. Excess gas-fired capacity allows the utilities to substitute some coal-fired generation immediately. Even so, it can be difficult economically to cut back much of their baseload coal-fired generation.

Rumors Of Coal's Demise Have Been Greatly Exaggerated

Persistently low natural gas prices will keep chipping away at coal's hold on US power production over the coming decade. EIA data show that coal's share of electricity generation dropped from 50% in 2008 to 44% in 2011, while the share for natural gas climbed from 20% to 23%. EIA expects coal's share of US power production to drop to 39% by 2035.

Coal-to-gas substitution will continue pressuring coal producers in the short term, and sustained low natural gas prices will gradually weaken coal's market share over the longer term. But the coal industry will derive some benefit over the next decade from robust export markets, while the level of required economic investment will limit coal-to-gas conversion in North America.

Unusually warm weather in the US and low natural gas prices in 2011-2012 led to a collapse in coal prices across most coal producing regions, with utilities decreasing their coal-fired generation in favor of lower-priced gas. Low natural gas prices have also driven a shift in market share among the US coal basins. Until recently, coal producers in Central Appalachia saw the greatest impact from fuel-switching. High cash production costs in that region affected Alpha Natural Resources (Ba2 negative), Patriot Coal (B2 stable), Arch Coal (Ba3 stable), and other companies with a significant presence in Appalachia. Now Powder River Basin (PRB) producers in Montana and Wyoming have come under pressure as well.

PRB coal competes with natural gas at prices of $4.00/MMBtu and higher. But at prices below $3.00/MMBtu, natural gas begins to displace PRB coal at utilities in the US Midwest, south-central and eastern regions, due to transportation costs and available natural gas capacity. Meanwhile, Illinois Basin coal remained competitive with natural gas, even at the low prices of early 2012. Illinois Basin producers, including Peabody Energy (Ba1 stable) and Foresight Energy LLC (B3 stable), enjoy low production costs, and typically serve efficient plants equipped with scrubbers.

Today's low prices will have a muted impact on US coal producers in 2012, because most thermal coal sells under long-term contracts. Coal producers have already locked in contracts for 80%-90% of 2012 production. Yet weather and pricing trends will affect the coal producers' ability to sell uncommitted tonnage, and to earn favorable prices for their committed but unpriced coal, while some customers will attempt to delay coal deliveries already committed under contract. Anticipated production and shipment declines will contribute to earnings pressure for coal producers. Patriot, Alpha and Arch, among others, have recently announced production cuts as a result of current market conditions.

For the longer term, sustainable low natural gas prices will slowly continue to erode coal's position as a raw material for electric generation. Current plans to retire almost 30 GW of coal-fired generation between 2012 and 2020, plus further retirements yet to be announced, will reduce domestic coal consumption by up to 100 million tons a year—or by roughly 10%—in that period. Most of these retirements will take place in Central Appalachia—as many as half of them in 2014-2015, when the Environmental Protection Agency's March 2011 Mercury and Air Toxics Standards (MATS) take effect.[2]

Still, the plants now facing retirement tend to be idled, less efficient and more marginal than most of today's large, efficient super-critical base-load generation. These more efficient plants will not face retirement or curtailed production over the next decade. The time and capital investment needed to substitute baseload coal-fired generation with natural gas limits the economic feasibility of coal-to-gas conversion. US power producers reduced their coal consumption by 4.7% from 2010 to 2011—a significant but manageable decline for the coal industry. Coal will still have an important (if changing) role as a supplier to the US power industry over the next decade.

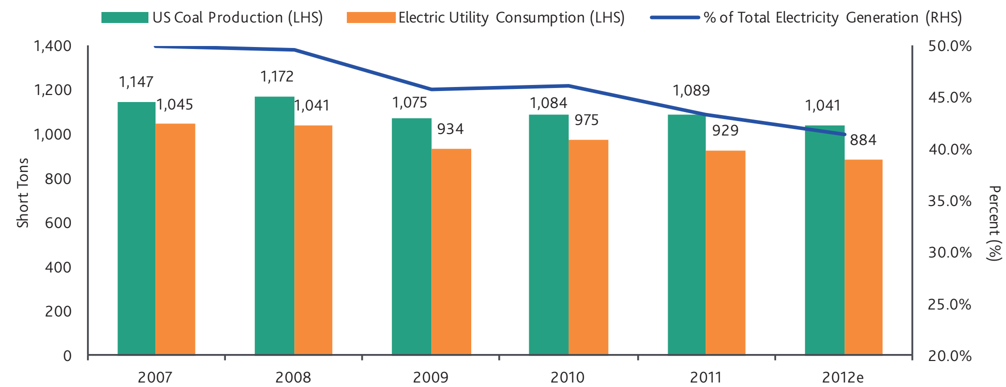
[2] MATS will require power plants to install pollution-control technologies to reduce emissions of mercury and other hazardous air pollutants. This will make it uneconomical to continue operating many older coal-fired units.

US Coal Finds Increasing Opportunity in Exports

Even though the US power sector's coal demand has been declining, total US coal production has remained fairly flat for the past three years (see Figure 2, below). US coal producers have increasingly focused on export markets, particularly exports of PRB coal to Asia. EIA said US coal producers exported 107 million tons of coal, or roughly 10% of production, in 2011—the highest level since 1991. The International Energy Agency, among other observers, projects that worldwide demand for coal will increase by up to 20% by 2020.

FIGURE 2

US Coal Production, Consumption and Share of Electricity Generation, 2007-2012



Source: US Energy Information Administration

Increases in international coal production and future greenhouse-gas restrictions overseas make it difficult to predict the future demand for US coal exports. Yet the ongoing rise in coal demand worldwide makes overseas opportunities promising, and could ultimately transform the US coal companies from swing producers of seaborne coal to strategic suppliers. Peabody, Arch, Consol Energy and Cloud Peak Energy Resources (Ba3 stable) have already begun securing additional port capacity to reach these growing export markets.

The port operators have begun to step up their capacity additions to accommodate this rise in export opportunities. Millennium Bulk Terminals (unrated) plans to raise its annual coal export capacity by 44 million tons in Longview, southern Washington, while Gateway Pacific Terminal (unrated) plans to add nearly 50 million tons of capacity in Cherry Point, at the northern end of the state. Meanwhile, projects along the lower Mississippi River would increase Gulf Coast terminal capacity by about 30 million tons. While much of this increase will take place over the long term—about 10 or 15 years—these capacity additions exceed today's entire volume of annual US coal exports.

Over the long term, we expect thermal coal production in Appalachia to continue its secular decline, with producers in this region being forced to focus increasingly on metallurgical coal. Smaller producers concentrated in Central Appalachian thermal coal, such as Xinergy (Caa1 stable) and James River Coal (B3 stable), will face challenging market conditions. Meanwhile, production will keep growing in the PRB, with an eye to the export markets, and the Illinois Basin, keeping overall US coal production relatively stable. Producers diversified in multiple coal-producing regions, such as Peabody and Arch, will be well positioned to navigate the changing market landscape. Consol Energy is also well positioned as the only US coal producer with a sizeable natural gas presence.

Low Natural Gas Prices Hurt Unregulated Power But Help Utilities

For utilities, a new era of low natural gas prices will help ensure low rates for customers, which should keep regulators inclined to authorize reasonable rate recovery for other base-rate costs and investments, including those for environmental compliance. But low natural gas prices will pressure unregulated power producers, squeezing their margins and accelerating the coal-plant retirements we discussed earlier—probably at a faster pace than what the power producers have already announced.

Unregulated power companies generate cash flow based on the margins from power sales. Since economic demand, natural gas prices and coal prices all strongly influence power prices, low coal and natural gas prices over the long term imply low power prices. But operating costs and environmental compliance costs are rising. This will hurt cash flows for power generators, unless the price of power come to reflect these additional costs. The economic recession of 2008-2009 reduced demand for electric power, and therefore its value.

Low power prices, in turn, have increasingly forced the power-generation sector to preserve its sources of liquidity. Some issuers, such as Energy Future Holdings (Caa2 negative) and GenOn Energy (B2 negative), look increasingly risky, based on their liquidity reserves. But utilities can pass cost increases on to customers through regulated rates, even if they must temporarily carry some of the costs on their balance sheets as regulatory assets.

Many investment-grade unregulated power companies will face even more challenging corporate-finance decisions through 2013 and beyond, as it becomes harder to strike the best balance between maintaining strong credit ratings and providing stable common stock dividends. Issuers like Exelon (Baa2 negative), which relies on the unregulated power subsidiary Exelon Generation (Baa1 negative) for much of its dividend, face the most at risk. First Energy (Baa3 stable), which does not rely on its unregulated power subsidiary First Energy Solutions (Baa3 stable) for its dividend, have some time to adjust to today's market fundamentals.

Renewable Generation Supplies Still Rely on Tax Subsidies

Renewables will remain uncompetitive with North American natural gas over the next decade, even though all-in costs continue to decline. The demand for renewable resources will remain high—in part because of government mandates requiring that power generation use a certain amount of renewable energy. But utilities will begin to pull back on their renewable capacity, since natural gas fired generation will likely be significantly cheaper.

Moreover, gas-fired plants can be sited and built with reasonable certainty—in terms of all-in costs and construction timeframes—without direct federal tax subsidies, They can also cycle more quickly than baseload coal or nuclear generation, and they enjoy low marginal fuel costs. Such advantages will make generators reluctant to build anything but gas-fired plants over the next decade.

Even so, fuel prices can be unpredictable, and regulated electric utilities will try to avoid overexposure to any one single fuel. The innate volatility of natural gas prices and the prospect of more stringent environmental regulations also complicate the utilities' long-term capital investment planning process. Electric utilities rank among the largest consumers of natural gas today. Natural gas could eventually rise again, and fuel diversity helps regulated electric and gas utilities avoid a large, sustained rise in the cost of any particular fuel, which consumers might resist.

Arbitrage Opportunities Disappearing On Interstate Natural Gas Pipelines

Low natural gas prices ease working capital requirements for regulated electric and gas utilities that buy fuel on behalf of their customers. Lower costs for natural gas make it easier for utilities to charge higher rates for their base services, without risking a consumer backlash. Rate increases have become crucial for the utilities industry, which must now spend heavily to meet stricter environmental standards. Since natural gas prices now compete with coal, utilities can generate more power from gas-fired plants economically, which in turn helps them satisfy environmental regulations.

The effect on the utilities' diversified operations has been mixed, however. For diversified utilities that own pipeline infrastructure nearby, the development of unconventional oil and gas resources has provided organic growth opportunities. NiSource (Baa3 stable) and Dominion Resources (Baa2 stable) both own properties near the active production areas of the Marcellus and Utica shale basins.

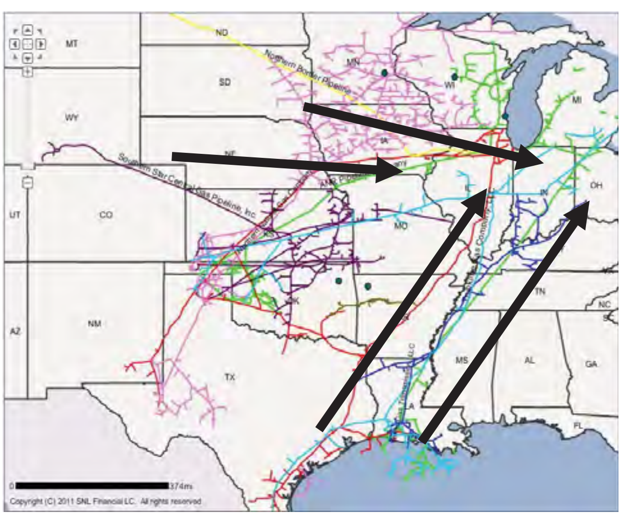
But profits have fallen for the diversified companies' unregulated gas marketing businesses, as the natural gas glut has erased the arbitrage opportunities from geographic and seasonal basis differentials. These weak market conditions have hurt the marketing arms of companies like AGL Resources (Baa1 stable) and Vectren (parent of utility subsidiary Vectren Utility Holdings, A3 stable). Weak natural gas prices have also pressured the merchant power operations of hybrid utilities.

Low Natural Gas Prices Shift North America's Pipeline Map

The rise in shale production has already transformed North America's natural gas landscape, and new producing regions have emerged in the last five years. Demand has risen for extending existing interstate pipelines and for building entirely new pipelines, offering considerable organic growth opportunities for a business that has historically grown slowly (see Figure 3, below).

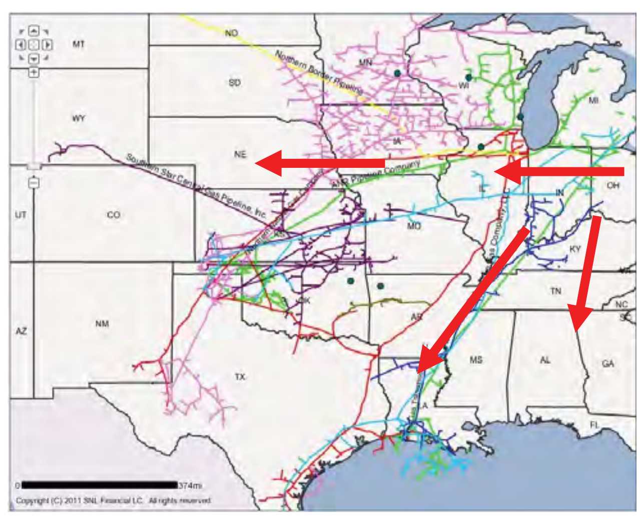
FIGURE 3

Traditional natural gas pipeline flow



Source: SNL Financial; Moody's Investors Service

Emerging natural gas pipeline flow with new shale production



Source: SNL Financial; Moody's Investors Service

Yet new pipelines serving shale production will lead to new competitive risks and more counterparty risk for the existing pipelines. Many new pipelines will rely on long-term contracts with speculative-grade E&Ps, rather than investment-grade natural gas utilities—their traditional clients.

The interstate pipeline sector looks set for a mild slowdown over the next few years as pipeline companies adjust to changes in the natural gas supply map and competitive dynamics from new pipelines. Narrower basis differentials have reduced arbitrage opportunities for traders, reducing demand for certain market-driven services. Incremental power-generation demand will not significantly improve the pipeline industry's financial performance until after 2015. Indeed, low demand over the next few years will pressure marketer shippers, including such long-haul pipelines as Texas Gas Transmission (Baa1 stable) and NGPL PipeCo. (Ba2, review for downgrade).

Rail Not Immune To Shift In Fuel Landscape

Lower natural gas prices could impact freight patterns in the railroad industry over the long run. A higher demand for low-priced natural gas, delivered mainly by pipeline, reduces demand for coal, one of the freight industry's most profitable segments.

Coal today comprises 20%-30% of total freight revenue for the four main US Class I rail transport companies. The railroads in recent years have locked in favorable pricing for shipping coal by negotiating favorable long-term contracts with utility customers. But low natural gas prices have reduced coal freight as demand from the power-generation sector drops. The railroads' revenue, yield, and margin growth have also slowed despite strong improvements from other freights. The 2% drop in domestic coal car-loadings in 2011 translated to about $300 million in lost revenue for the rail industry. Coal freight volumes continue to decline in 2012, with industry-wide year-to-date carloadings in March 2012 more than 8% below levels for the same period a year earlier.[3]

Eastern US Class I railroads CSX (Baa3 positive) and Norfolk Southern (Baa1 stable), which had benefited from relatively strong export coal levels in 2011, are experiencing a higher drop in carloadings—about 15% for the first quarter of 2012. Western companies Union Pacific (railroad subsidiaries Baa1 positive) and Burlington Northern Santa Fe (railroad subsidiaries A2 stable), have seen a less-dramatic decrease in coal freight, with a year-over-year decline of only 5% so far in 2012.

Over the next decade, this balance may shift a bit as western port capacity improves and western coal producers ramp up exports to Asia, giving UNP and BNSF small increases in freight volumes. In the east, thermal coal production will continue to dwindle, but exports of Illinois Basin coal and eastern met coal should help buffer that impact.

3 Source: Association of American Railroads, year to date through March 17, 2012.

Unknown Developments Will Not Affect Overall Picture

Many other factors will affect natural gas prices over the next decade, and we will see them only as they emerge. Production shut-ins could occur in the natural gas industry, and may be all but inevitable later in 2012 as natural gas storage capacity is filled. High crude prices would probably send rigs toward oil production, and natural gas prices could fall. Droughts could lead to cuts in coal and nuclear generation, both of which need water for cooling purposes. Aggressive development of liquefaction facilities could lead to new exports of LNG (liquefied natural gas) by the 2015-2018 timeframe. A strong community backlash against fracking could also hamper production of natural gas, leading to fewer major and national oil companies pursuing the joint ventures that support high production levels today.

For all of these risks, community and political considerations will continue to put more pressure on coal-fired generation than on gas-fired plants. Other states may begin to look at the sorts of emission-reducing regulations that California will be phasing in over the next decade, even if federal standards appear a long way off.[4] The slow progress of energy efficiency efforts, and renewable energy's relatively small contribution to the US power grid, suggest that natural gas should remain in strong demand over the next decade.

Click here to rate this research.

[4] For more on California's new emissions rules, see our Special Comment, "Refining and Marketing: California's Greenhouse Gas Regulations Pressure Refiners in Golden State," March 2012.

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» Low Natural Gas Prices Chill North American Energy Sectors, While Others See Some Gains, April 2010 (124884)

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» US Regulated Electric and Gas Utilities: Stable Despite Rising Headline Rhetoric, January 2012 (137878)

» US Coal Industry: US Coal Producers Lean on Export Markets Amid Challenges at Home, December 2011 (137742)

» North American Railroads: Railroads Crossing from Rapid Recovery to Slower Freight Volume, Pricing Growth, November 2011 (137057)

» Global Independent Exploration and Production Industry: Historically High Oil Prices Spur Production Push, Outpacing Escalating Costs for E&Ps, April 2011 (132846)

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Six Month Update

US Regulated Utilities

Outlook Stable, But Plentiful Gas Changes The Landscape

Our outlook for the investor-owned US regulated electric and gas utility sector is stable. This outlook reflects our expectations for the fundamental business conditions in the industry over the next 12 to 18 months.

- Our outlook for the US investor-owned regulated electric and gas utility sector is stable, based on generally supportive regulatory relationships and an expectation that prudently incurred costs and investments will be recovered in rates on a reasonably timely basis.
- Low natural gas prices are generally positive for the regulated utility industry but have changed the landscape, affecting dispatch curves, customer rates, coal inventory and supply management, relative competitiveness of different regions, and investment plans.
- Significant capital investment programs, primarily for transmission and distribution upgrades, environmental retro-fits and replacement generation, pose execution risks.
- On balance, we continue to see regulatory relationships as supportive of credit quality.
- Capital markets are open and welcoming to the industry, which is generally viewed as counter-cyclical, and bank liquidity appears ample.
- While we note that there are currently some significant positives for the industry, including a low interest rate environment and low natural gas and purchased power prices, we view the industry as stable overall and observe that aggregate key financial metrics continue to remain within a relatively narrow band. The regulated nature of the industry means that both the benefits of lower costs and the burden of higher costs are, in general, eventually allocated to customers, with varying degrees of regulatory lag.
- Factors that could result in a positive outlook for the industry include a broad-based shift in state regulation of utilities to a formula rate-making approach similar to that used by the Federal Energy Regulatory Commission (FERC) or a shift in the prevailing corporate financing model employed by utilities toward lower dividend payout ratios or higher levels of equity employed.
- Factors that could cause a deterioration in the outlook include a broad-based, material timing lag in the recovery of costs - especially in a period of rapid inflation, a widespread increase in affordability issues (that would likely cause a deterioration in the overall regulatory environment) or a major, prolonged dislocation in capital markets.

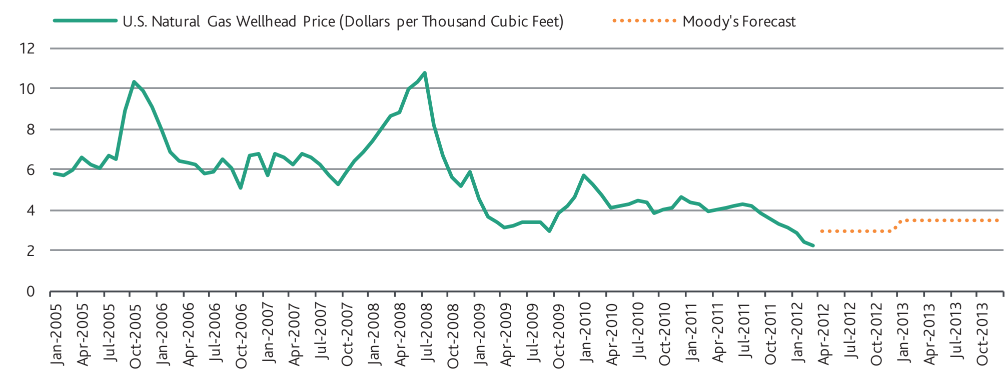
Note: Industry outlooks are not explicit signals of the likely direction of ratings in an industry. They are a view of the business conditions that factor into our ratings.

Low natural gas prices benefit the industry, with some exceptions

Natural gas prices, which peaked in 2008 well above $10 per MMBTu and were above $4 for most of 2010 and the first nine months of 2011, have languished below $3 over the past nine months, due to excess supply resulting from shale gas development combined with weak demand caused by a sputtering recovery since the Great Recession and three quarters of unusually mild weather. Since gas-fired generation has typically been the price-setting fuel for on-peak periods in most regional power markets, power prices have also registered large declines. Coal prices have decreased much more slowly – utilities purchase most of their coal under long-term contracts with slower re-pricing mechanisms, and as a global commodity, coal prices have seen some support from Asian demand. Natural gas prices were low enough relative to coal during the past nine months for gas-fired generation to supplant a substantial portion of coal – historically the predominant base load fuel.

FIGURE 1

Nat. Gas Prices and Forecast



Source: EIA.gov & Moody's

While changing fuel prices do not typically have a direct impact on the profitability of electric and gas utilities due to the preponderance of fuel and purchased power adjustment clauses, the current period of low natural gas prices is a material benefit to a large portion of the sector. Customers benefit from lower utility bills, which tend to have a positive impact on regulatory relationships and make it easier for utility commissions to authorize base rate increases for capital investment related to new plants, environmental compliance and infrastructure improvements without causing rate shock or materially altering the affordability of power and gas service. Lower customer bills combined with lower purchased power and purchased gas expenses have decreased utilities' working capital needs. Electric T&Ds, integrated electric utilities with greater gas-fired capacity and local gas distribution companies (LDCs) tend to benefit the most from these dynamics. Some benefits are specific to electric utilities. Coal-to-gas switching has decreased integrated electric utilities' air emissions and made it easier to comply with the interim Clean Air Interstate Rules. In addition, despite a general price inelasticity of demand, lower all-in rates could eventually be positive for volumes. Unlike gas LDCs, many of which have de-coupling mechanisms that insulate them from most changes in volume usage, electrics more typically do not, so they benefit from volume growth in between rate cases. Appendix C shows a ranking of integrated utilities by the percentage of electricity produced from natural gas in 2011. Companies that we believe are beneficiaries of this trend toward lower rates, lower working capital and infrastructure investment include NV Energy Inc. (Ba1 stable), Sempra Energy (Baa1 stable), Florida Power & Light Company (A2 stable), a unit of NextEra Energy, Inc. (Baa1 stable) and Northeast Utilities (Baa2 stable).

The benefits are not universal. Low gas prices create direct and indirect pressures on some regulated electric utilities. Predominantly coal-fired utilities now need to manage burgeoning coal piles, as well as supplier agreements and rail/barge transport agreements that may not have been negotiated to include the operational flexibility that current market conditions require. Commissions in some jurisdictions are questioning the prudency of these contracts. Utilities that are making large coal-fired or nuclear investments, some with relatively un-tested technologies, could face inflexible cost caps and other forms of regulatory second-guessing, given that the "path not taken" – more gas-fired generation, would probably have been more cost-effective in the short term. Utilities in states with aggressive renewable portfolio standards must purchase or build capacity that is much more expensive than the current gas-fired alternative. In our view, the bulk of these mostly pre-approved projects will make their way into rate base in a reasonably timely manner. We nonetheless believe regulators' perception of what constitutes just and reasonable rates is influenced by comparisons with the rates of utilities in the same region, which may be materially lower or higher due to different investment decisions and fuel mixes. Examples of companies exposed to these potential indirect negative effects include South Carolina Electric & Gas (SCE&G, Baa2 stable), a unit of SCANA Corporation (Baa3 stable), Georgia Power (A2 stable) and Mississippi Power (A1 RUR down), both units of the Southern Company (Southern, Baa1 stable), Pacific Gas & Electric (A3 stable) a unit of PG&E Corporation (Baa1 stable) and Southern California Edison Company (A3 stable), a unit of Edison International (Baa2 stable).

Low gas prices have a direct negative impact on hybrid utility holding companies – examples include Entergy Corporation (Baa3 stable), FirstEnergy Corp. (Baa3 stable), and PPL Corporation (PPL, Baa3 stable). Many hybrid holding companies have used substantial free cash flow from their merchant generation subsidiaries during the boom years to finance dividends, stock buybacks, or investments in regulated or unregulated businesses. As this source decreases or dries up, the importance of hedging policy, financial policy and balance sheet management on the ratings of these holding companies and their regulated subsidiaries increases.

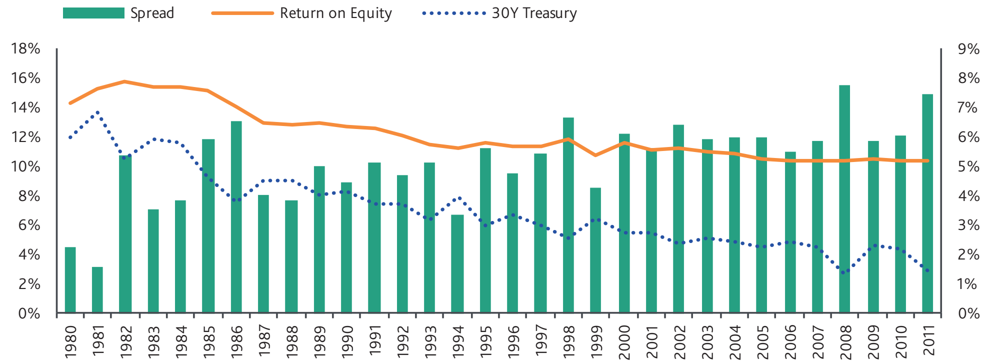
Supportive regulatory climate continues, but returns on equity inch downward

In general, regulatory relationships in the industry remain supportive, abetted by low interest rates and inflation as well as low natural gas and purchased power costs. In addition, the "back to basics" strategy of many utilities over the past 5-8 years has generally meant that they have devoted more time and attention to fostering positive regulatory relations and, in some cases, have obtained legislative outcomes that improved the legal framework for rate-setting and timely cost recovery. States where we have observed some improvement in regulatory climate include Arizona, Florida, Nevada, Oregon, Texas (for T&D utilities) and Washington.

States that we continue to view as challenging include Illinois, where the commission has not instituted some provisions of the recently passed utility legislation in some recent rate cases, West Virginia, Maryland and Texas (for integrated utilities). Ohio's recent decisions on Electric Security Plans delivered some surprises, and we will be watching the outcomes of those cases very closely to determine whether our assessment of that regulatory environment will be revised downward. Other states we will be watching closely in the next six months include California, where the major utilities all have important rate cases including cost of capital proceedings, Mississippi, where the commission recently denied CWIP recovery for the Ratcliffe/Kemper plant due to pending litigation by the Sierra Club, and North Carolina, which instituted a series of hearings related to a controversial decision by the board of Duke Energy Corporation (Duke, Baa2 stable) to replace its new CEO within hours of the closing of the merger with Progress Energy, Inc. (Progress, Baa2 stable).

FIGURE 2

Authorized Returns on Equity, Treasury Rates and Spread



Source: SNL & Bloomberg

Historically low US Treasury rates continue to be a major factor pressuring allowed ROEs. While we view allowed ROEs as only one of many components that determine the strength of a utility's cash flow, they can be a leading indicator of the regulatory relationship. In some jurisdictions, regulators are aware that the current interest rate environment is unprecedented and likely unsustainable, and they prefer to regulate financially healthy utilities that can withstand a turnaround in interest rates. In other jurisdictions, regulators appear more content to lower ROEs. In general, we see ROEs inching down for the industry.

FIGURE 3

Selected Rate Case Decisions in 2012

			Increase Authorized			Increase Requested			
Company	Service	Date	Rate Increase ($M)	Return on Rate Base(%)	Return on Equity (%)	Date	Rate Increase ($M)	Return on Rate Base (%)	Return on Equity (%)
Appalachian Power Co.	Electric	1/3/2012	26.1	NA	11.40	3/31/2011	26.9	8.36	12.15
PacifiCorp	Electric	1/10/2012	34.0	NA	NA	5/27/2011	32.7	8.25	10.50
Ameren Illinois	Natural Gas	1/10/2012	32.2	8.33	9.06	2/18/2011	49.5	9.31	10.75
Peoples Gas Light & Coke Co.	Natural Gas	1/10/2012	57.8	6.94	9.45	2/15/2011	112.6	8.11	10.85
Duke Energy Carolinas LLC	Electric	1/25/2012	92.8	8.10	10.50	8/5/2011	215.5	8.63	11.50
Duke Energy Carolinas LLC	Electric	1/27/2012	368.0	8.11	10.50	7/1/2011	525.0	8.51	11.25
Virginia Electric & Power Co.	Electric	2/2/2012	34.1	8.77	11.40	5/2/2011	35.3	8.77	11.40
Gulf Power Co.	Electric	2/27/2012	68.1	6.39	10.25	7/8/2011	101.6	7.05	11.70
Virginia Electric & Power Co.	Electric	3/23/2012	46.8	8.48	11.40	6/27/2011	50.1	9.60	13.50
Northern States Power Co. - MN	Electric	3/29/2012	72.9	8.32	10.37	11/3/2010	150.6	8.57	10.85
Westar Energy Inc.	Electric	4/18/2012	50.0	NA	NA	8/25/2011	90.8	8.68	10.60
Public Service Co. of CO	Electric	4/26/2012	234.4	8.08	10.00	11/22/2011	281.0	8.50	10.75
Puget Sound Energy Inc.	Electric	5/7/2012	63.3	7.80	9.80	6/13/2011	125.4	8.26	10.75
Consumers Energy Co.	Electric	6/7/2012	118.5	6.70	10.30	6/10/2011	180.9	6.86	10.70
Hawaiian Electric Co.	Electric	6/29/2012	43.1	8.11	10.00	7/30/2010	93.8	8.54	10.75
Washington Gas Light Co.	Natural Gas	7/2/2012	20.0	8.26	9.75	1/31/2011	28.5	8.58	10.50

Source: SNL

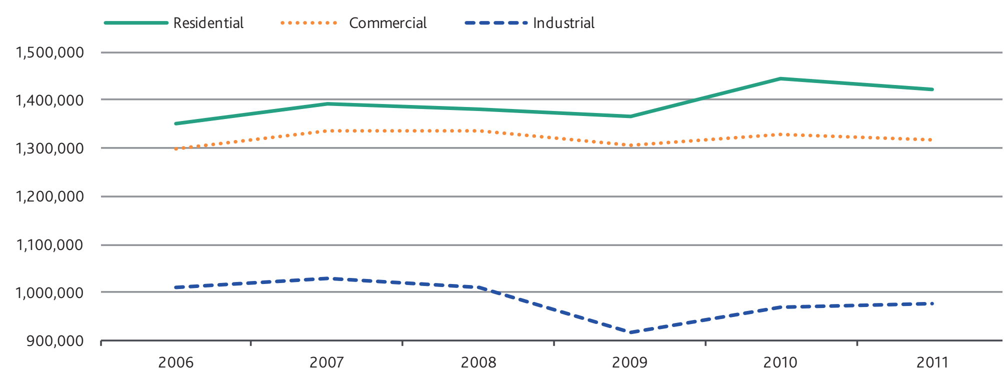
Affordability issues are currently tempered by generally lower fuel rates

The electric utility bill affordability issue raised in several prior industry outlooks has generally been tempered by lower gas prices. One measure of affordability is the percentage of average annual electric bills to disposable income shown in Appendix D. This percentage varies considerably from state to state and is impacted by usage patterns as well as the level of rates and the regional economy. Percentage changes in rates, rather than absolute rates, are the most important factor in perceptions of affordability. Appendix D also shows changes in average rates by state from 2009 to 2011. The greatest concern would be high percentage rate increases in a state with high usage patterns and relatively low disposable income. We view West Virginia and Kentucky as having a high exposure to rate increases from environmental retro-fits, South Carolina as having high exposure due to the size of the new nuclear investment program undertaken by SCANA and South Carolina Public Service Authority (Aa3 stable), and California as having high exposure (tempered to a degree by low average usage) due to additions of costly solar and wind power. The ongoing affordability of rates is an issue that is often cited by the industry and, despite the recent easing, one that remains of concern to Moody's.

Growth Volumes

Lower volumes represent an area of potential weakness for the electric utility industry, for which rate design is typically skewed toward volumetric charges (a substantial portion of most utilities' fixed costs as well as their variable costs are recovered in volume-based charges). Nationwide, volumes decreased 0.8% from 2010 to 2011, with the decline most pronounced in the residential sector, due in part to milder weather. Industrial demand increased 0.5% but remains below pre-recession levels.

FIGURE 4
Retail Sales by Customer Class
(GWh)



Source: EIA.gov

As shown in Appendix E, growth in industrial demand in 2011 was very uneven from state to state. States with exposure to energy, automobiles, and petro-chemicals fared well, as did the traditional manufacturing magnets of the southeast. The outlook for the industrial sector is less robust in light of contraction in Europe and slowing growth in China.

Volumetric de-coupling for gas LDCs is fairly pervasive, but it is more limited for electric utilities. De-coupling is sometimes accompanied by lower allowed ROEs, since risk is perceived as lower. State-wide electric de-coupling programs include those in California, Maryland and New York, while states with programs affecting only some utilities include those in Connecticut and Massachusetts.

For more information on volumes, please refer to Moody's June 2012 Special Comment "US Electric Power Generation Volumes: Shift in Electric Generation Mix Favors Natural Gas, Renewables at Expense of Coal".

Natural gas price volatility and election season posturing complicate decision-making for environmental capex

Utilities will generally be able to recover their investments in required environmental retro-fits in a reasonably timely manner. However, utilities face execution risk similar to any project with a high price tag and long lead-time – obtaining regulatory approvals, staying on budget and on time, and getting timely recovery once construction is complete. These factors increase the importance of mechanisms that ensure timely recovery of investment, including riders, trackers, rate formulas and forward test years. Companies with significant environmental capex programs include Alliant Energy Corporation (Baa1 negative), American Electric Power Company (Baa2 stable), Dominion Resources Inc. (Baa2 stable), PPL, Southern and Xcel Energy Inc. (Baa1 stable).

For the current round of expenditures, utilities face some additional uncertainties. The timeframe for compliance with the Mercury and Air Toxics Standards (MATS), like the Cross State Air Pollution Rules (CSAPR), is currently the subject of litigation that could lead to extension of the compliance deadlines. New regulations, for instance for once-through cooling, coal ash, carbon and ozone, could materially increase the expenditures required for compliance. In addition, deciding which coal plants should be replaced with gas-fired plants is complicated by the continued volatility of natural gas prices. Given the absence of a crystal ball, utilities will be making significant long-term investments with incomplete information.

While the outcome of the national elections could influence the timeframe for compliance, the scope of permitted delays/exceptions or even the exact final standards that have to be achieved, we currently expect that MATS and CSAPR will be implemented largely in their current form. In the long run, we see a trend toward stricter environmental regulations, regardless of the outcome of these elections. However, we do not currently incorporate a view that near-to-intermediate term incremental regulations will have an impact of the same magnitude that MATS will have on plant retirements and expenditures.

Consolidation likely to resume - eventually

A quartet of mergers closed in the past six months – Duke with Progress, Exelon Corporation (Exelon, Baa2 RUR down) with Constellation Energy Group, Inc., Northeast Utilities (NU, Baa2 stable) with NSTAR, LLC (NSTAR, A3 stable) and Green Mountain Power (Baa2 stable) with Central Vermont Power (Baa2 stable). However, we observe that the major impediments to mergers, leadership questions and regulatory issues, increased during the approval processes for three of these transactions.

While utilities generally expect state commissions to extract benefits for ratepayers, Connecticut conducted a surprise, late-in-the-game review of the NU/NSTAR merger and imposed a round of economic conditions after initially stating it did not have authority over the transaction. In some cases, FERC imposed stricter standards than expected for market power mitigation. Exelon/Constellation agreed to restrict the universe of potential acquirers for the sale of power plants in PJM East it had proposed –rules that could prove costly in a difficult market for merchant power plant sales. For Duke/Progress, an outright sale of plants was not an option due to North Carolina commission strictures, and FERC rejected two market mitigation plans involving substantial transmission expenditures before finally approving the third plan. The leadership plan for Duke/Progress, which was a component of the executed merger agreement, was undone by the board of the combined company within hours of the merger's close. We view these factors as having a chilling effect on additional mergers in the near term.

Nonetheless, the economic logic of further utility industry consolidation remains compelling, and mergers will eventually resume.

Liquidity ample despite turbulence at financial institutions

Liquidity for regulated utilities has remained strong, with almost all companies renewing their syndicated revolving agreements in the past 18 months – generally for five years at favorable terms. Domestic and international banks have pulled out of some US sectors, but utilities have continued to attract bank commitments due to their good default performance during the great recession and the fee business that they provide to banks, attributable in part to utilities' capital intensive nature. Capital markets remain open and welcoming.

The only sour note is the potential contraction of commodity counter-party liquidity, as a result of new regulations and because banks that are strong in commodities tend to also have a large exposure to investment banking and trading, which have a more challenged outlook in the current environment. While utilities can hedge on exchanges, over-the-counter transactions provide certain benefits – most importantly, generally lower collateral posting requirement since banks typically only require collateral for mark-to-market exposure above an unsecured threshold. Over-the-counter trades are often the only option for less liquid trading hubs and longer time periods. A decrease in commodity liquidity will have the greatest impact on utilities that seek to smooth out the volatility of natural gas purchases through forward hedging, and for hybrid utility holding companies that hedge their merchant power operations.

Aggregate financial profile remains strong but equity issuance is being deferred

The aggregate metrics for the selected peer group (see Appendix A) were somewhat less strong in 2011 than in 2010, despite a 4.5% increase in cash from operations before changes in working capital (CFO Pre-WC), reflecting an increase in sector debt. Aggregate metrics in 2011 correspond to a strong Baa2 scoring for our Rating Methodology Factor 4 – Financial Strength. After haircutting CFO Pre-WC for an assumed impact of bonus depreciation, metrics in 2011 correspond to a weak Baa2 Financial Strength scoring.

In general, we expect that the industry will need to issue equity to fund a portion of announced capital investment programs, but companies are largely choosing to defer this issuance (due in part to the positive cash flow impact of bonus depreciation).

FIGURE 5

Peer Group Aggregate Credit Metrics:

With Moody's Standard Adjustments		With Moody's Standard Adjustments & Special Bonus Depreciation Adjustment	
CFO Pre-W/C + Interest / Interest		**CFO Pre-W/C + Interest / Interest**	
FY 2009	4.2x	FY 2009	3.5x
FY 2010	4.5x	FY 2010	3.7x
FY 2011	4.5x	FY 2011	3.7x
CFO Pre-W/C / Debt		**CFO Pre-W/C / Debt**	

FIGURE 5

Peer Group Aggregate Credit Metrics:

FY 2009	18.8%
FY 2010	19.4%
FY 2011	18.4%
CFO Pre-W/C less Dividends / Debt	
FY 2009	15.0%
FY 2010	15.3%
FY 2011	14.3%
CFO pre-W/C	
FY 2009	73,678,571
FY 2010	78,004,072
FY 2011	81,552,109
Total Debt	
FY 2009	391,660,342
FY 2010	402,971,918
FY 2011	444,349,126
Capital Expenditures	
FY 2009	69,727,172
FY 2010	69,820,513
FY 2011	77,292,126
Debt to Capitalization	
FY 2009	51.3%
FY 2010	49.8%
FY 2011	50.1%
Payout Ratio	
FY 2009	62.7%
FY 2010	60.0%
FY 2011	61.6%

FY 2009	14.5%
FY 2010	15.1%
FY 2011	14.1%
CFO Pre-W/C less Dividends / Debt	
FY 2009	10.6%
FY 2010	11.1%
FY 2011	10.1%
CFO pre-W/C	56,595,414
FY 2009	60,898,046
FY 2010	62,615,538
FY 2011	61,096,506

We subtract the special bonus depreciation adjustment from CFO pre-W/C. We estimate this adjustment by multiplying capital expenditures by 70% (representing qualifying assets) and then multiplying by 35% (representing the tax benefit).

Source: MFM

Conclusion

Our stable outlook is underpinned by the nature of electric and gas utilities in the US as monopolistic, regulated enterprises. Overall, we see a constructive regulatory environment, welcoming capital markets, good liquidity and fairly stable financial profiles, such that the industry is relatively well positioned to face the challenges of a large capital expenditure program over the next several years.

Appendix A – Selected Peer Group

PORTFOLIO: Outlook Update 2012 - Peer Group

Entity Name	Current LT Rating	Outlook	Analyst
Madison Gas and Electric Company	A1	Stable	Natividad Martel
NSTAR LLC	A3	Stable	Natividad Martel
PECO Energy Company	A3	Stable	Angelo Sabatelle
Wisconsin Energy Corporation	A3	Stable	Natividad Martel
Public Service Electric and Gas Company	(P)A3	Stable	William Hunter
ALLETE, Inc.	Baa1	Stable	Natividad Martel
Alliant Energy Corporation	Baa1	Negative	Natividad Martel
Baltimore Gas and Electric Company	Baa1	Stable	Angelo Sabatelle
Integrys Energy Group, Inc.	Baa1	Stable	Scott Solomon
MidAmerican Energy Holdings Co.	Baa1	Stable	Mihoko Manabe
OGE Energy Corp.	Baa1	Stable	Mihoko Manabe
Oncor Electric Delivery Company LLC	Baa1	Negative	James Hempstead
PG&E Corporation	Baa1	Stable	Angelo Sabatelle
Sempra Energy	Baa1	Stable	Angelo Sabatelle
Southern Company (The)	Baa1	Stable	Michael Haggarty
Xcel Energy Inc.	Baa1	Stable	Mihoko Manabe
Consolidated Edison, Inc.	(P)Baa1	Stable	Mihoko Manabe
NextEra Energy, Inc.	(P)Baa1	Stable	Michael Haggarty
American Electric Power Company, Inc.	Baa2	Stable	William Hunter
Commonwealth Edison Company	Baa2	Stable	Angelo Sabatelle
Dominion Resources Inc.	Baa2	Stable	William Hunter
DTE Energy Company	Baa2	Positive	Scott Solomon
Duke Energy Corporation	Baa2	Stable	Michael Haggarty
Edison International	Baa2	Stable	Angelo Sabatelle
ITC Holdings Corp.	Baa2	Stable	Mitchell Moss
Northeast Utilities	Baa2	Stable	Natividad Martel
Pinnacle West Capital Corporation	Baa2	Stable	Mitchell Moss
Progress Energy, Inc. **see note*	Baa2	Stable	Michael Haggarty
TECO Energy, Inc.	Baa2	Stable	Mitchell Moss
IDACORP, Inc.	Baa2	Stable	Ryan Wobbrock
Westar Energy, Inc.	Baa2	Stable	Ryan Wobbrock
Ameren Corporation	Baa3	Stable	Michael Haggarty
Black Hills Corporation	Baa3	Stable	Ryan Wobbrock
CenterPoint Energy, Inc.	Baa3	Positive	Mihoko Manabe
Entergy Corporation	Baa3	Stable	William Hunter
FirstEnergy Corp.	Baa3	Stable	Scott Solomon
Great Plains Energy Incorporated	Baa3	Stable	Ryan Wobbrock
NiSource Inc.	Baa3	Stable	Mihoko Manabe

PORTFOLIO: Outlook Update 2012 - Peer Group

Entity Name	Current LT Rating	Outlook	Analyst
Pepco Holdings, Inc.	Baa3	Stable	Scott Solomon
PPL Corporation	Baa3	Stable	Angelo Sabatelle
SCANA Corporation	Baa3	Stable	William Hunter
UIL Holdings Corporation	Baa3	Stable	Ryan Wobbrock
Cleco Corporation	(P)Baa3	Stable	Mitchell Moss
CMS Energy Corporation	Ba1	Positive	Scott Solomon
DPL Inc.	Ba1	Stable	Scott Solomon
Duquesne Light Holdings, Inc.	Ba1	Stable	Michael Haggarty
NV Energy Inc.	Ba1	Stable	Angelo Sabatelle
PNM Resources, Inc.	Ba1	Stable	Mitchell Moss
Puget Energy, Inc.	Ba1	Stable	Scott Solomon
UNS Energy Corporation	Ba1	Stable	Mitchell Moss

Note: Peer metrics are based on financial data though 3/31/12. As of that date Progress Energy had not yet merged into Duke Energy.

Source: Moody's Investors Service

Appendix B – Metrics for Selected Peer Group

	CFO Pre-W/C				(CFO Pre-W/C + Interest) / Interest Expense				(CFO Pre-W/C) / Debt				(CFO Pre-W/C - Dividends) / Debt				Debt / Book Capitalization			
	FY 2009	FY 2010	FY 2011	Latest LTM	FY 2009	FY 2010	FY 2011	Latest LTM	FY 2009	FY 2010	FY 2011	Latest LTM	FY 2009	FY 2010	FY 2011	Latest LTM	FY 2009	FY 2010	FY 2011	Latest LTM
ALLETE, Inc.	210,700.00	243,166.67	269,266.67	276,966.67	5.44x	5.98x	6.09x	6.21x	23.28%	24.41%	24.30%	25.02%	17.04%	18.31%	18.69%	19.28%	43.15%	43.19%	43.27%	42.51%
Alliant Energy Corporation	843,066.67	800,200.00	771,366.67	707,466.67	7.00x	6.08x	5.93x	5.58x	28.25%	24.83%	23.48%	21.85%	22.07%	18.83%	17.24%	15.46%	41.59%	41.33%	40.58%	40.07%
Ameren Corporation	1,907,000.00	1,906,666.67	1,741,333.33	1,708,333.33	4.09x	4.25x	4.26x	4.23x	20.80%	21.72%	21.04%	20.70%	16.89%	17.44%	16.44%	16.12%	46.44%	44.99%	42.16%	43.64%
American Electric Power Company,	3,856,000.00	3,608,666.67	3,840,666.67	4,011,416.67	4.05x	3.94x	4.33x	4.52x	17.79%	17.05%	18.37%	19.00%	14.28%	13.14%	14.06%	14.71%	52.58%	50.21%	47.81%	47.56%
Baltimore Gas and Electric Company	761,320.00	604,820.00	441,000.00	489,000.00	5.16x	4.99x	3.92x	4.06x	28.91%	25.05%	16.35%	18.12%	40.78%	24.91%	13.07%	18.00%	46.00%	41.00%	42.60%	42.25%
Black Hills Corporation	249,873.00	191,044.67	264,793.33	248,040.33	3.52x	2.72x	3.17x	2.93x	18.89%	12.52%	14.97%	15.06%	14.72%	8.82%	11.62%	11.35%	49.66%	52.86%	54.36%	52.06%
CenterPoint Energy, Inc.	1,480,666.67	1,569,333.33	1,812,666.67	1,850,666.67	3.13x	3.33x	3.92x	3.99x	13.80%	15.07%	18.08%	17.04%	11.22%	12.01%	14.72%	13.91%	66.47%	62.94%	55.45%	56.89%
Cleco Corporation	141,208.00	268,773.67	343,948.00	417,217.00	2.63x	3.67x	5.59x	7.10x	9.66%	15.99%	23.63%	29.23%	5.95%	12.48%	18.96%	24.20%	48.53%	47.33%	41.29%	40.38%
CMS Energy Corporation	1,135,166.67	1,235,000.00	1,294,333.33	1,263,333.33	3.12x	3.51x	3.79x	3.77x	14.08%	14.99%	16.03%	15.79%	12.63%	13.05%	13.44%	13.07%	72.84%	71.83%	66.52%	66.09%
Commonwealth Edison Company	1,278,950.25	1,311,248.92	1,707,964.25	1,654,244.25	4.02x	3.86x	5.20x	5.16x	19.80%	19.62%	25.34%	25.09%	16.04%	14.93%	20.84%	20.49%	40.26%	39.42%	37.79%	37.15%
Consolidated Edison, Inc.	2,103,333.33	2,794,000.00	3,331,666.67	3,080,666.67	3.50x	4.76x	5.56x	5.17x	15.70%	20.66%	22.25%	20.04%	11.13%	15.93%	17.55%	15.45%	45.47%	42.84%	43.80%	44.39%
Dominion Resources Inc.	3,351,769.27	2,426,850.60	3,572,480.43	3,613,554.53	4.33x	3.46x	4.62x	4.63x	17.27%	13.06%	16.27%	16.78%	11.66%	7.00%	10.92%	11.25%	55.13%	52.17%	56.27%	54.43%
DPL Inc.	578,000.00	496,466.67	348,733.33	288,133.33	7.57x	7.70x	5.84x	4.40x	41.10%	36.28%	13.10%	10.85%	31.94%	26.07%	6.49%	3.95%	45.39%	42.33%	48.75%	48.88%
DTE Energy Company	1,894,666.67	2,289,000.00	2,031,883.33	2,064,883.33	4.03x	4.73x	4.61x	4.70x	19.73%	24.46%	20.74%	21.35%	16.11%	20.61%	16.72%	17.24%	53.31%	49.90%	48.90%	48.34%
Duke Energy Corporation	4,179,000.00	4,045,333.33	3,925,333.33	3,907,333.33	5.23x	4.78x	4.68x	4.64x	22.54%	20.94%	18.04%	18.33%	15.75%	14.24%	11.81%	12.00%	40.36%	39.61%	41.82%	41.18%
Duquesne Light Holdings, Inc.	231,200.00	251,966.67	272,000.00	N/A	2.65x	2.42x	2.43x	N/A	10.84%	12.14%	12.31%	N/A	9.35%	11.84%	12.03%	N/A	57.88%	54.89%	55.24%	N/A
Edison International	3,442,000.00	4,526,666.67	4,714,000.00	4,456,000.00	3.96x	4.93x	3.96x	3.75x	18.28%	22.07%	15.18%	14.03%	15.79%	20.07%	13.83%	12.72%	56.70%	56.00%	66.88%	66.71%
Entergy Corporation	3,074,690.33	4,418,727.67	2,965,188.00	2,966,461.00	5.14x	7.08x	5.47x	5.37x	21.75%	31.92%	19.67%	19.38%	17.67%	27.55%	15.76%	15.54%	46.53%	44.83%	46.96%	47.32%

	CFO Pre-W/C				(CFO Pre-W/C + Interest) / Interest Expense				(CFO Pre-W/C) / Debt				(CFO Pre-W/C - Dividends) / Debt				Debt / Book Capitalization			
	FY 2009	FY 2010	FY 2011	Latest LTM	FY 2009	FY 2010	FY 2011	Latest LTM	FY 2009	FY 2010	FY 2011	Latest LTM	FY 2009	FY 2010	FY 2011	Latest LTM	FY 2009	FY 2010	FY 2011	Latest LTM
FirstEnergy Corp.	2,821,333.33	3,057,000.00	3,100,666.67	3,101,666.67	3.51x	4.11x	3.66x	3.61x	15.69%	16.82%	14.38%	13.73%	11.96%	13.14%	10.30%	9.65%	62.27%	60.33%	53.28%	54.09%
Great Plains Energy Incorporated	449,875.00	684,641.67	596,008.33	588,513.33	2.88x	4.05x	3.62x	3.34x	10.99%	16.48%	13.83%	12.90%	7.94%	13.39%	10.82%	10.09%	55.22%	53.85%	53.33%	55.97%
IDACORP, Inc.	318,548.33	317,749.67	299,647.33	260,717.33	4.50x	4.27x	4.10x	3.69x	18.88%	16.98%	16.29%	14.11%	15.51%	13.89%	13.04%	10.79%	46.12%	47.22%	43.19%	42.82%
Integrys Energy Group, Inc.	839,431.67	825,015.83	817,982.50	722,682.50	5.49x	5.95x	6.69x	6.16x	27.18%	27.48%	28.31%	24.99%	20.08%	21.03%	20.90%	17.39%	45.48%	43.54%	41.00%	40.60%
ITC Holdings Corp.	297,146.67	432,705.00	323,989.67	318,147.67	3.26x	4.01x	3.18x	3.12x	12.10%	17.13%	12.10%	11.16%	9.56%	14.52%	9.47%	8.65%	65.97%	63.81%	62.12%	62.72%
Madison Gas and Electric Company	111,846.67	135,490.33	138,867.33	142,275.33	5.91x	7.39x	6.44x	6.40x	28.00%	31.34%	28.16%	28.89%	23.16%	25.29%	22.76%	30.15%	36.08%	37.90%	40.53%	39.82%
MidAmerican Energy Holdings Co.	3,559,666.67	3,354,666.67	3,686,333.33	3,927,333.33	3.72x	3.73x	4.04x	4.28x	16.83%	16.11%	17.42%	17.92%	16.83%	16.11%	17.42%	17.92%	53.42%	51.39%	49.79%	49.84%
NextEra Energy, Inc.	4,531,757.75	3,542,378.88	4,215,378.88	4,193,378.88	6.30x	4.49x	4.83x	4.77x	25.61%	17.59%	18.92%	18.01%	20.81%	13.30%	14.60%	13.80%	48.29%	49.92%	51.22%	51.84%
NiSource Inc.	1,121,866.67	1,295,200.00	1,194,666.67	1,213,566.67	3.38x	3.91x	3.84x	3.81x	13.30%	15.66%	13.66%	14.05%	10.30%	12.57%	10.71%	11.05%	56.09%	53.63%	53.65%	52.73%
Northeast Utilities	1,080,229.17	1,220,468.33	973,612.00	806,734.00	4.23x	5.28x	4.24x	3.56x	17.82%	20.04%	14.77%	11.11%	15.09%	17.03%	11.78%	8.35%	54.72%	52.52%	52.58%	54.77%
NSTAR LLC	707,742.00	506,939.00	772,731.33	N/A	4.88x	4.19x	6.23x	N/A	20.49%	15.81%	24.52%	N/A	15.85%	10.56%	18.93%	N/A	52.68%	49.74%	47.77%	N/A
NV Energy Inc.	814,367.67	809,896.00	699,804.00	697,278.00	3.14x	3.11x	2.97x	2.95x	14.31%	14.67%	13.22%	13.11%	12.62%	12.75%	11.04%	10.89%	57.10%	54.69%	52.90%	53.08%
OGE Energy Corp.	706,033.33	758,966.67	828,433.33	856,233.33	5.28x	5.86x	5.97x	5.95x	25.85%	28.73%	25.95%	25.15%	20.86%	23.24%	20.81%	20.13%	45.34%	40.84%	41.76%	43.26%
Oncor Electric Delivery Company	1,059,213.33	1,152,000.00	1,454,000.00	1,420,000.00	3.78x	4.02x	4.70x	4.62x	16.91%	17.39%	21.40%	19.96%	12.57%	14.21%	19.27%	17.57%	42.61%	42.91%	42.48%	43.43%
PECO Energy Company	1,189,975.08	1,143,385.74	1,047,487.74	1,043,341.49	6.37x	6.14x	7.82x	8.06x	33.07%	36.81%	38.22%	38.06%	24.21%	29.38%	25.26%	25.96%	42.15%	39.09%	34.34%	34.20%
Pepco Holdings, Inc.	717,000.00	799,000.00	701,666.67	811,666.67	2.82x	3.37x	3.45x	3.80x	10.75%	14.87%	12.04%	13.36%	7.18%	10.39%	7.85%	9.35%	49.31%	43.62%	44.74%	44.79%
PG&E Corporation	3,511,596.67	3,546,916.67	4,156,130.00	4,254,130.00	5.02x	5.33x	5.94x	6.03x	24.16%	22.79%	24.07%	25.15%	20.18%	18.61%	20.06%	21.01%	49.12%	48.06%	48.81%	47.44%
Pinnacle West Capital Corporatio	1,176,068.67	1,095,576.33	1,033,000.00	1,067,257.00	5.35x	4.87x	4.97x	5.13x	24.84%	24.89%	23.10%	23.03%	20.51%	19.96%	18.14%	18.24%	49.02%	43.91%	43.29%	44.50%
PNM Resources, Inc.	467,913.33	454,695.67	453,396.00	474,159.00	4.05x	4.09x	4.06x	4.24x	21.82%	19.96%	20.81%	21.11%	19.67%	17.93%	18.71%	19.14%	47.46%	50.04%	48.51%	49.04%
PPL Corporation	1,808,659.50	2,675,980.00	3,017,840.22	3,347,138.59	4.52x	5.09x	4.00x	4.18x	18.84%	17.81%	15.48%	17.01%	13.47%	13.79%	11.40%	12.79%	54.95%	55.92%	55.38%	54.51%
Progress Energy, Inc.	2,369,666.67	2,564,000.00	1,967,000.00	1,875,000.00	3.99x	4.21x	3.54x	3.43x	16.59%	17.86%	12.86%	11.78%	11.70%	12.86%	8.06%	6.68%	57.16%	54.86%	55.08%	55.54%

	CFO Pre-W/C				(CFO Pre-W/C + Interest) / Interest Expense				(CFO Pre-W/C) / Debt				(CFO Pre-W/C - Dividends) / Debt				Debt / Book Capitalization			
	FY 2009	FY 2010	FY 2011	Latest LTM	FY 2009	FY 2010	FY 2011	Latest LTM	FY 2009	FY 2010	FY 2011	Latest LTM	FY 2009	FY 2010	FY 2011	Latest LTM	FY 2009	FY 2010	FY 2011	Latest LTM
Public Service Electric and Gas	1,110,835.00	1,241,709.00	1,554,686.00	1,721,686.00	4.10x	4.55x	5.59x	6.19x	19.93%	21.35%	27.76%	30.85%	19.93%	18.77%	22.40%	25.48%	44.78%	43.53%	40.26%	39.26%
Puget Energy, Inc.	669,739.33	515,348.00	665,528.67	608,117.67	3.27x	2.56x	2.73x	2.49x	13.61%	9.60%	11.33%	10.78%	11.15%	7.66%	9.33%	9.73%	51.90%	54.75%	57.03%	55.32%
SCANA Corporation	588,281.25	975,041.67	868,308.33	857,308.33	3.19x	4.66x	4.05x	3.99x	11.90%	19.83%	16.08%	15.39%	7.16%	14.89%	11.38%	10.80%	51.90%	48.76%	49.56%	49.72%
Sempra Energy	2,220,333.33	2,177,666.67	2,204,333.33	2,227,333.33	4.95x	4.86x	4.73x	4.72x	22.00%	19.91%	17.49%	17.05%	18.53%	16.49%	13.93%	13.46%	48.86%	50.27%	51.63%	52.15%
Southern Company (The)	4,150,429.00	4,636,871.33	5,369,333.33	5,272,598.33	4.44x	5.25x	6.27x	6.19x	18.75%	20.82%	22.79%	21.70%	12.27%	13.81%	15.72%	14.74%	49.77%	47.36%	46.24%	46.72%
TECO Energy, Inc.	652,033.33	725,166.67	791,500.00	777,300.00	3.66x	3.96x	4.68x	4.65x	17.97%	21.09%	23.89%	23.78%	13.27%	15.99%	18.34%	18.05%	63.50%	60.49%	57.81%	57.54%
UIL Holdings Corporation	172,512.67	256,391.33	288,001.67	298,511.67	4.17x	4.52x	3.34x	3.45x	18.09%	12.62%	13.38%	14.01%	13.09%	10.07%	9.32%	9.91%	52.94%	58.75%	59.35%	58.43%
UNS Energy Corporation	364,567.33	335,722.00	353,514.00	343,494.00	4.45x	4.08x	4.11x	3.99x	19.61%	17.56%	17.50%	17.39%	17.38%	14.60%	14.43%	14.21%	65.52%	63.97%	62.96%	61.16%
Westar Energy, Inc.	520,769.33	666,375.33	672,022.00	633,389.00	3.67x	4.38x	4.42x	4.21x	14.87%	19.10%	18.48%	16.64%	11.36%	15.34%	14.63%	12.79%	51.99%	49.81%	48.18%	49.40%
Wisconsin Energy Corporation	988,612.50	988,812.50	1,226,312.50	1,209,412.50	4.98x	4.82x	5.70x	5.75x	19.49%	19.24%	23.08%	23.30%	16.23%	15.45%	18.38%	18.33%	52.11%	50.39%	47.86%	46.50%
Xcel Energy Inc.	1,861,908.67	2,124,362.67	2,431,303.33	2,528,714.33	4.15x	4.72x	5.11x	5.23x	19.86%	20.47%	19.01%	19.59%	15.27%	16.23%	15.24%	15.83%	46.86%	47.05%	50.36%	50.11%

Source: Moody's Financial Metrics

Appendix C – Natural Gas Exposure by Company

Company Name	% of Nat Gas Capacity as % of Total Capacity	% of MWh Produced by Nat Gas out of Total MWh : 2010	% of MWh Produced by Nat Gas out of Total MWh : 2011
NV Energy	57.6%	74.5%	76.9%
Sempra Energy	29.7%	73.7%	55.4%
NextEra Energy Inc.	30.0%	45.6%	51.6%
OGE Energy Corp.	48.9%	38.2%	37.0%
Cleco Corp.	51.4%	51.8%	35.8%
Southern Co.	30.6%	23.0%	27.9%
Entergy Corp.	53.9%	22.7%	24.5%
CMS Energy Corp.	40.5%	14.0%	19.0%
Xcel Energy Inc.	37.6%	15.0%	18.9%
Pinnacle West Capital Corp.	43.5%	17.6%	18.2%
Dominion Resources Inc.	29.0%	12.0%	16.9%
PNM Resources Inc.	23.6%	21.9%	15.7%
NiSource Inc.	15.8%	10.0%	14.9%
UNS Energy Corp.	32.8%	15.4%	14.4%
PG&E Corp.	11.4%	11.2%	14.0%
Edison International	12.4%	15.2%	11.4%
American Electric Power Co.	21.5%	7.6%	10.7%
Duke Energy Corp	25.8%	6.5%	9.9%
SCANA Corp.	19.3%	8.6%	9.1%
Westar Energy Inc.	38.4%	7.4%	8.8%
MidAmerican Energy Holdings Co	19.5%	7.2%	5.6%
Alliant Energy	37.0%	4.4%	4.5%
TECO Energy Inc.	55.4%	1.9%	3.5%
Madison Gas and Electric Co.	45.3%	1.9%	1.4%
Great Plains Energy	23.1%	1.2%	1.2%
Ameren Corp.	26.5%	1.1%	1.2%
DTE Energy Co.	15.3%	1.4%	1.0%
Integrys Energy Group Inc.	24.2%	0.8%	0.8%
IDACORP Inc.	17.3%	1.1%	0.8%
PPL Corp.	22.4%	0.6%	0.7%
Black Hills Corp	57.7%	1.7%	0.5%
Wisconsin Energy Corp.	21.6%	0.4%	0.2%

Source: SNL

Appendix D – Electric Bill Affordability Comparison

	Average Bill / Disposable Income				Average Retail Rate (cents per kilowatt hour)				
State	2007	2008	2009	2010	2007	2008	2009	2010	2007 - 2010 CAGR
West Virginia	2.8%	2.8%	3.2%	3.7%	6.73	7.06	7.90	8.79	6.90%
Idaho	1.9%	2.0%	2.3%	2.2%	6.36	6.99	7.80	7.99	5.87%
District of Columbia	3.4%	3.5%	3.7%	4.0%	11.18	12.79	13.76	14.01	5.80%
Kansas	2.7%	2.8%	2.9%	3.2%	8.19	8.88	9.53	10.03	5.19%
Michigan	2.3%	2.2%	2.4%	2.7%	10.21	10.75	11.60	12.46	5.10%
Maryland	5.3%	5.6%	6.1%	6.1%	11.89	13.84	14.98	14.32	4.75%
Virginia	4.5%	4.6%	5.0%	5.1%	8.74	9.62	10.61	10.45	4.56%
Colorado	2.0%	1.9%	2.0%	2.2%	9.25	10.13	10.00	11.04	4.51%
Ohio	3.1%	3.0%	3.2%	3.5%	9.57	10.06	10.67	11.32	4.29%
Missouri	2.6%	2.4%	2.7%	3.0%	7.69	8.00	8.54	9.08	4.24%
Nebraska	2.8%	2.6%	2.9%	3.1%	7.59	7.87	8.52	8.94	4.17%
Tennessee	3.6%	3.9%	4.2%	4.5%	7.84	8.91	9.32	9.23	4.16%
New Jersey	3.9%	3.9%	3.9%	4.2%	14.14	15.66	16.31	16.57	4.04%
Kentucky	3.6%	3.6%	3.8%	4.2%	7.34	7.94	8.37	8.57	3.95%
Hawaii	6.1%	7.6%	5.7%	6.2%	24.12	32.50	24.20	28.10	3.89%
Wisconsin	3.0%	3.0%	3.0%	3.2%	10.87	11.51	11.94	12.65	3.88%
Pennsylvania	4.0%	3.9%	4.0%	4.5%	10.95	11.35	11.65	12.70	3.78%
Indiana	3.0%	3.0%	3.1%	3.2%	8.26	8.87	9.50	9.56	3.72%
Minnesota	2.9%	2.9%	3.1%	3.2%	9.18	9.74	10.04	10.59	3.64%
New Mexico	2.1%	2.2%	2.2%	2.3%	9.12	10.01	10.02	10.52	3.64%
Alabama	5.5%	5.6%	5.5%	6.0%	9.32	10.40	10.66	10.67	3.43%
South Carolina	4.9%	5.0%	5.3%	5.7%	9.19	9.89	10.44	10.50	3.40%
Illinois	3.5%	3.5%	3.4%	3.8%	10.12	11.07	11.27	11.52	3.28%
Arizona	2.4%	2.2%	2.3%	2.2%	9.66	10.27	10.73	10.97	3.22%
Rhode Island	3.3%	3.6%	3.4%	3.5%	14.05	17.45	15.60	15.92	3.18%
Wyoming	2.4%	2.5%	2.7%	2.7%	7.75	8.21	8.58	8.77	3.13%
North Dakota	3.0%	3.0%	3.3%	3.3%	7.30	7.51	7.58	8.13	2.71%
South Dakota	2.8%	2.8%	3.0%	3.1%	8.07	8.27	8.49	8.97	2.67%
Washington	2.0%	2.0%	2.2%	2.1%	7.26	7.54	7.68	8.04	2.58%
Georgia	3.8%	3.8%	3.9%	4.2%	9.10	9.93	10.13	10.07	2.58%
Iowa	3.1%	3.0%	3.1%	3.3%	9.45	9.49	9.99	10.42	2.48%
Vermont	2.9%	2.8%	3.0%	3.1%	14.15	14.48	14.90	15.57	2.43%
New Hampshire	3.6%	3.6%	3.9%	3.9%	14.88	15.68	16.26	16.32	2.34%
New York	3.2%	3.3%	3.1%	3.4%	17.10	18.30	17.50	18.74	2.32%
Oregon	2.7%	2.6%	2.7%	2.5%	8.19	8.49	8.68	8.87	2.03%
North Carolina	3.2%	3.1%	3.3%	3.6%	9.40	9.52	9.99	10.12	1.87%
Alaska	4.2%	4.4%	4.7%	4.3%	15.18	16.55	17.14	16.26	1.73%

State	Average Bill / Disposable Income 2007	2008	2009	2010	Average Retail Rate (cents per kilowatt hour) 2007	2008	2009	2010	2007 - 2010 CAGR
Utah	2.1%	2.0%	2.1%	2.2%	8.15	8.26	8.48	8.71	1.66%
Oklahoma	3.7%	3.8%	3.6%	4.1%	8.58	9.09	8.49	9.14	1.58%
Mississippi	4.0%	4.1%	4.0%	4.2%	9.36	10.39	10.22	9.87	1.34%
Delaware	4.1%	4.0%	4.1%	4.3%	13.16	13.93	14.07	13.80	1.19%
Nevada	3.7%	3.4%	3.7%	3.5%	11.82	11.93	12.86	12.36	1.13%
Montana	2.7%	2.5%	2.5%	2.4%	8.77	9.13	8.93	9.16	1.08%
California	3.3%	3.1%	3.3%	3.1%	14.42	13.81	14.74	14.75	0.56%
Florida	5.0%	4.6%	5.1%	4.9%	11.22	11.65	12.39	11.44	0.48%
Arkansas	3.5%	3.4%	3.4%	3.6%	8.73	9.27	9.14	8.86	0.37%
Connecticut	4.7%	4.4%	4.6%	4.4%	19.11	19.55	20.33	19.25	0.18%
Louisiana	4.0%	4.1%	3.4%	3.9%	9.37	10.28	8.10	8.98	-1.07%
Maine	3.7%	3.3%	3.3%	3.2%	16.52	16.20	15.65	15.71	-1.25%
Texas	5.6%	5.6%	5.5%	5.2%	12.34	13.04	12.38	11.60	-1.54%
Massachusetts	4.3%	4.4%	4.2%	3.9%	16.23	17.68	16.87	14.59	-2.63%

Source: EIA.gov and BEA.gov

Appendix E – Comparison by State of Yearly Growth in Industrial Usage

MWh Usage by Industrial Users

		YoY % Change				
		2007	2008	2009	2010	2011
North Dakota	ND	11.0%	2.0%	-1.5%	5.7%	11.5%
Pennsylvania	PA	1.4%	-0.9%	-9.5%	4.4%	9.1%
Louisiana	LA	1.6%	-3.1%	-4.9%	10.0%	6.6%
Arizona	AZ	0.2%	4.8%	-13.0%	2.2%	6.0%
Utah	UT	4.8%	3.7%	-5.4%	2.5%	5.9%
South Dakota	SD	10.8%	7.7%	-2.9%	4.4%	5.4%
Mississippi	MS	3.0%	0.0%	-7.7%	5.1%	4.6%
Washington	WA	-5.7%	1.8%	10.6%	14.0%	4.4%
New Mexico	NM	1.9%	-1.7%	-6.2%	3.9%	4.4%
Oklahoma	OK	1.2%	1.3%	-7.5%	6.5%	3.9%
Alabama	AL	-0.3%	-3.3%	-15.9%	9.9%	3.5%
Delaware	DE	-0.7%	-3.1%	-8.2%	-7.7%	3.4%
Montana	MT	30.2%	-5.4%	-18.2%	-18.5%	3.4%
South Carolina	SC	-2.5%	-4.5%	-13.1%	7.4%	3.1%
Nebraska	NE	1.4%	5.7%	-1.2%	7.4%	2.6%
Iowa	IA	4.3%	0.6%	-5.3%	3.6%	2.5%
Oregon	OR	1.0%	-1.3%	-9.1%	-0.4%	2.4%
Georgia	GA	-1.5%	-4.5%	-9.8%	5.8%	2.1%
Arkansas	AR	-0.8%	-4.5%	-13.7%	14.0%	2.0%
Nevada	NV	2.0%	-0.5%	-2.7%	-2.0%	1.8%
Kansas	KS	-5.0%	-1.1%	-6.3%	5.6%	1.3%
Indiana	IN	0.9%	-3.2%	-11.1%	8.1%	1.2%
Ohio	OH	6.0%	-1.0%	-15.6%	7.3%	1.2%
Wyoming	WY	4.4%	9.5%	-0.1%	5.4%	1.1%
Michigan	MI	-0.6%	-4.1%	-15.7%	12.6%	1.0%
Colorado	CO	4.0%	5.4%	-1.8%	11.8%	1.0%
West Virginia	WV	5.4%	0.5%	-25.5%	5.8%	0.8%
Virginia	VA	-0.4%	-2.6%	-9.5%	2.8%	0.7%
Minnesota	MN	1.7%	3.3%	-17.5%	16.1%	0.7%
US-TOTAL	US-TOTAL	1.6%	-1.8%	-9.1%	5.8%	0.5%
North Carolina	NC	-1.0%	-4.2%	-9.6%	4.8%	0.3%
Florida	FL	-2.7%	-1.5%	-10.7%	2.1%	0.1%
Alaska	AK	11.3%	-2.8%	-2.4%	1.0%	-0.1%
Hawaii	HI	-0.8%	-1.6%	-3.2%	-0.3%	-0.2%
Wisconsin	WI	0.6%	-3.0%	-9.3%	4.7%	-0.2%

MWh Usage by Industrial Users

		YoY % Change				
		2007	2008	2009	2010	2011
Illinois	IL	1.1%	0.2%	-8.8%	6.4%	-0.4%
Idaho	ID	5.7%	-0.9%	-12.0%	7.3%	-0.4%
New Hampshire	NH	2.0%	-5.0%	-11.1%	5.8%	-0.7%
Missouri	MO	1.1%	-3.6%	-15.7%	15.1%	-1.1%
Massachusetts	MA	-1.6%	-1.3%	79.5%	2.2%	-1.2%
Maryland	MD	-1.3%	-5.5%	-6.4%	-3.8%	-1.4%
Maine	ME	-14.4%	-2.4%	-10.2%	7.3%	-1.4%
Connecticut	CT	10.3%	-19.5%	-15.5%	0.6%	-1.7%
Tennessee	TN	-0.7%	-3.1%	-19.0%	8.9%	-1.9%
Vermont	VT	0.6%	-4.3%	-11.6%	4.5%	-2.0%
New York	NY	35.0%	-27.3%	-8.6%	0.5%	-2.6%
Kentucky	KY	1.2%	4.1%	-5.6%	3.3%	-3.5%
Texas	TX	3.4%	-2.3%	-8.4%	2.9%	-4.4%
Rhode Island	RI	-1.7%	-8.2%	-7.9%	-3.0%	-4.7%
District of Columbia	DC	23.7%	2.9%	-0.1%	-24.7%	-5.9%
New Jersey	NJ	-2.8%	-4.3%	-21.7%	2.2%	-6.4%
California	CA	-0.9%	1.0%	-6.3%	3.1%	-8.9%

Source: EIA.gov

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MOODY'S
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Credit Opinion: Exelon Corporation

Global Credit Research - 13 Sep 2012

United States

Ratings

Category	Moody's Rating
Outlook	Rating(s) Under Review
Issuer Rating	*Baa2
Senior Unsecured	*Baa2
Subordinate Shelf	*(P)Baa3
Pref. Shelf	*(P)Ba1
Commercial Paper	*P-2
Commonwealth Edison Company	
Outlook	Stable
Issuer Rating	Baa2
First Mortgage Bonds	A3
Senior Unsecured	Baa2
Pref. Shelf	(P)Ba1
Commercial Paper	P-2
Exelon Generation Company, LLC	
Outlook	Rating(s) Under Review
Issuer Rating	*Baa1
Senior Unsecured	*Baa1
Pref. Shelf	*(P)Baa3
Commercial Paper	P-2

* Placed under review for possible downgrade on June 11, 2012

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Key Indicators

[1]**Exelon Corporation**

	LTM06/30/2012	2011	2010	2009
(CFO Pre-W/C + Interest) / Interest	7.0x	8.5x	7.3x	6.7x
(CFO Pre-W/C) / Debt	27.4%	43.0%	37.1%	36.0%
RCF / Debt	26.2%	34.8%	33.0%	31.4%
FCF / Debt	0.8%	8.0%	6.5%	10.0%

[1] All ratios calculated in accordance with the Unregulated Utilities and Power Companies Rating Methodology

using Moody's standard adjustments.

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Strong consolidated credit metrics declining from recent historical levels

Recent merger with financially weaker unregulated power company

System wide capital requirements plus dividend requirements weaken free cash flow prospects

Competitive position & consistent operations offset by new nuclear related capital requirements

Hedging strategies influence cash flow predictability

Corporate Profile

Exelon Corporation (Exelon; Baa2 senior unsecured, under review for downgrade) is the holding company for non-regulated subsidiary, Exelon Generation Company, LLC (ExGen; Baa1 senior unsecured, under review for downgrade) and for regulated subsidiaries, Commonwealth Edison Company (ComEd; Baa2 senior unsecured, stable), PECO Energy Company (PECO; A3 Issuer Rating, stable), and Baltimore Gas and Electric Company (BGE: Baa1; senior unsecured, stable).

On March 12th, Exelon and Constellation Energy Group, Inc. (CEG) merged. Simultaneously with merger close, Exelon legally assumed CEG's obligations, including CEG's senior unsecured and junior subordinated debt and became the obligor on CEG's credit facilities.

ExGen is one of the largest competitive electric generation companies in the US, as measured by owned and controlled megawatts (MW) with net capacity of 36,295 MW, including 17,115 MW of nuclear capacity. In addition, the company controls another 6,125 MW of capacity through long-term contracts. .

ComEd is an electric transmission and distribution (T&D) utility providing service to 3.8 million customers across northern Illinois. ComEd is regulated by the Illinois Commerce Commission (ICC) and by the Federal Energy Regulatory Commission (FERC).

PECO provides T&D service to about 1.6 million electric customers in Philadelphia as well as several surrounding Pennsylvania counties. PECO also provides gas distribution service to 490,000 natural gas customers in areas outside the city. PECO is regulated by the Pennsylvania Public Utility Commission (PAPUC) and by FERC.

BGE is a regulated electric transmission and distribution and gas distribution utility providing electricity and gas services to the city of Baltimore and ten other counties in Maryland. BGE is regulated by the Maryland Public Service Commission (MPSC) and FERC.

SUMMARY RATING RATIONALE

Exelon's Baa2 rating reflects strong consolidated credit metrics, due in large part to the financial performance of its unregulated generation subsidiary, and the generally predictable cash flows at its T&D subsidiaries. While the T&D subsidiaries are sizeable standalone companies, Exelon's rating is largely influenced by the performance of its unregulated segment, which has increased in size and importance following the merger with CEG.

DETAILED RATING CONSIDERATIONS

-Consolidated credit metrics expected to decline from historical levels

Exelon's historical consolidated credit metrics position the company well in the current category as an unregulated power company; however, future financial results are expected to cause those metrics to decline over the next several years owing to lower margins caused primarily by sustained low natural gas prices.

From 2009 through 2011, we calculate that the three year average of Exelon's cash flow (CFO pre-W/C) to debt at 39%, retained cash flow to debt at 33%, free cash flow to debt at 8.0%, and cash flow coverage of interest expense at 7.3x. By comparison, through 12 months ending 06/30/2012, we calculate cash flow to debt at 27.4%, retained cash flow to debt at 26.2%, free cash flow to debt at 0.8% and cash flow coverage of interest expense of 7.0x These declines can be attributed to weaker commodity prices, lower amounts of bonus depreciation, higher level of capital expenditures plus the inclusion of CEG's consolidated debt with operating results of only one quarter in this calculation. Exelon has indicated in SEC filings that bonus depreciation enhanced cash flow by $850 million during 2011 and is expected to augment 2012 cash flow by only $300 million.

Prospectively, we expect financial results to weaken, particularly the retained cash flow and free cash flow metrics, as margins continue to compress due to soft power prices caused in large part by sustained low natural gas prices and tepid economic demand while the company maintains a sizeable dividend and pursues a sizeable company-wide capital investment program. Specifically, when one incorporates off-balance sheet tolling obligations into the consolidated metrics, we calculate that Exelon's cash flow to debt could decline to approximately 25%, retained cash flow to debt to the high-teens, and cash flow interest coverage ratio to less than 7.0x while generating significant negative free cash flow over the next several years. To the extent that power prices end up being weaker than incorporated into this view, the company's metrics will suffer in the absence of any mitigating action.

-Merger with financially weaker unregulated power company

We believe that a motivating factor behind the March 2012 merger with CEG was to address the expected declining earnings trend and weaker cash flow profile beginning in 2012. As the largest unregulated power company in terms of kilowatt hours produced and retail customers served, the merger should garner the strategic benefits of linking a company that is long on generation (Exelon) with a company (CEG) that is long on customer load. As a byproduct of this linkage, the merger should considerably reduce consolidated liquidity requirements and enable the merged company to receive somewhat better margins for its electric output given the inherent stickiness of customer load. That being said, we believe that the better balanced combined merchant operation will still be exposed to earnings and cash flow volatility due to the large unregulated business platform where financial results remain heavily influenced by market determined commodity pricing levels.

We also believe that the completion of the CEG merger increases the likelihood that Exelon will remain more focused on maintaining its leadership position among unregulated power companies. As both the largest unregulated generation company in terms of production and supplier of retail energy in North America, we believe that management, along with the board, will be more inclined to pursue future acquisitions of additional unregulated properties as a natural extension of an existing strategy, particularly given the more streamlined and less challenging regulatory approval requirements that tend to accompany unregulated acquisitions.

As a condition to completing the merger and to address market power issues, Exelon was required to reach a sales agreement with a third party for the sale of CEG's fossil-fuel assets within 150 days of merger close. In addition to the sale needing to be announced in short order, potential bidders were limited to those whose capacity ownership of generation assets within the Pennsylvania - New Jersey - Maryland Interconnection (PJM) did not exceed 3%. As such, most of the strategic buyers were precluded from bidding on the assets. Last month, Exelon announced it would sell its three coal-fired power plants in Maryland to private-equity firm Riverstone Holdings for approximately $400 million. After fees and other transaction expenses, Exelon expects to receive proceeds of approximately $380 million when the deal closes in the fourth quarter. Although all of the company's assets were marked to market when the CEG merger closed in March, Exelon will record a $275 million pre-tax loss from this pending divestiture during the third quarter. The sale to Riverstone will generate approximately $205 million of cash tax benefits, $135 million of which Exelon will realize through 2013, while it realizes the rest in later years. Combining cash proceeds, tax benefits and fees, Exelon's net sales proceeds of $560 million are approximately $100 million lower than the company expected, and $170 million lower than the net proceeds it expected during 2012.

Overall, we view Exelon as embracing a higher risk tolerance than what may have existed in the past given the large commodity platform that has been created with this transaction. For that reason, we believe the merged company's credit metrics may need to be stronger than similarly rated peers while maintaining access to amply sized sources of liquidity.

-Maintenance and growth capital requirements plus payment of sizeable dividend weakens free cash flow

As a large capital intensive commodity company, Exelon has substantial capital requirements to maintain the operation of its generation fleet while also maintaining and replacing the infrastructure of its regulated T&D utilities. Exelon is considering making up-rate investments across its nuclear fleet which, if fully completed, would add up to 1,300 MWs of additional capacity to the company's fleet at a very competitive cost. For 2012, Exelon plans to spend $6.225 billion in capital investment, including $3.925 billion at its unregulated platform, $1.3 billion at ComEd, $550 million at BGE and $425 million at PECO. With respect to the $3.925 billion earmarked for the generation business, $350 million will be invested in nuclear up-rates while $1.325 billion is planned for new renewable investments. In light of the reduced cash flow anticipated to be generated by ExGen, the sizeable dividend of $1.8 billion following the merger with CEG and capital investment requirements for maintenance and growth, we anticipate Exelon to generate more than $3 billion of negative free cash flow over the next three years.

-Hedging strategies influence cash flow predictability

As an unregulated wholesale energy company whose gross margin can be materially impacted by changes in commodity prices, a company's hedging strategy can be an important rating factor. Exelon manages its hedges over a 36 month cycle with targets of 90% or more of expected generation hedged in the first year, 70-90% in the second year, and less than 50% in the third year. At June 30, 2012 , we understand that Exelon was 99%-102% hedged for the remainder of 2012, 79%-82% for 2013 and 46%-49% for 2014. With the completion of the CEG merger, we anticipate that more of the company's electric output will be sold directly to end-use customers through the multiple venues that exist along the retail chain which should reduce the total amount of hedges executed to meet the above coverage targetes.

We also note that while proprietary trading continues to represent a very small portion of ExGen's gross margin and capital allocation, the size of the proprietary trading book has experienced a noticeable increase with the CEG acquisition. The proprietary trading activities, which included settled physical sales volumes, were 4,248 GWh and 6,077 GWh for the three and six months ended June 30, 2012, respectively, a meaningful change from the 1,496 GWh and 2,829 GWh levels for the three and six months ended June 30, 2011, respectively. Proprietary trading activities are subject to limits established by Exelon's Risk Management Committee.

-Competitive position & consistent operations remain long-term strengths

As the largest owner and operator of nuclear generation in the US, Exelon has a strong competitive position and continues to demonstrate an outstanding record as a plant operator, particularly as a nuclear operator. In the intermediate-term, we expect its competitive position to remain largely unchanged as capacity reductions from anticipated coal plant shut-downs in the region should lower reserve margins (and possibly enhance capacity revenues) but are less likely to enhance energy margins given the outlook for natural gas, the fact that most of the plants that will shut down have low capacity factors, and a continuing slow economic recovery. Longer-term, the potential implications of EPA regulations should enhance profitability as any incremental environmental control related costs are likely to result in a higher margin potential for Exelon.

-Regulatory Environment

As noted in the Regulated Electric and Gas Utilities methodology, the regulatory framework and the ability of the framework to provide timely recovery of costs and predictable returns are important factors in assessing utility credit quality.

ComEd operates in an improved, but still challenging regulatory environment for electric utilities in Illinois with some lingering concerns about the framework's predictability. On December 30, 2011, however, the Energy Infrastructure Modernization Act (EIMA) was signed into law. EIMA establishes a new formula-rate-plan (FRP) distribution ratemaking paradigm for the state's largest electric utilities and is intended to spur utility infrastructure investment. The legislation requires ComEd to invest $1.3 billion over a five-year period in electric system upgrades, modernization projects, and training facilities, and at least $1.3 billion over a 10-year period in transmission & distribution assets and smart-grid system upgrades. Key aspects of the FRP calculation include cost recovery of the utility's actual capital structure, excluding goodwill; a legislatively-set formula for purposes of calculating the allowed return on equity (ROE); and recovery of pension-related costs.

While passage of EIMA is a credit positive from a cost recovery standpoint, the ICC's implementation of EIMA has been inconsistent. On May 29th, the ICC ordered a $168.6 million rate reduction premised upon a 10.05% ROE and an 8.16% return on $6.183 billion in rate base. In its order, the ICC rejected ComEd's request to collect a debt-only return on its "pension asset" and adopted the intervening parties' recommendation to rely on an average capital structure and an average rate base calculation in prospective FRP-related revenue requirement reconciliations, versus the language in the law that contemplates the use of year-end values for capital structure and rate base. On August 17th, the Illinois House of Representatives passed a resolution, in support of ComEd's position. On August 31st, the ICC Administrative Law Judges (ALJs) issued a proposed order concerning the rehearing of ComEd's initial FRP. In the proposed order, the ALJs recommend that the ICC maintain its earlier reliance on an average capital structure and an average rate base calculation in prospective FRP-related revenue requirement reconciliations even though the legislation requires year-end capital structure and rate base. On a more positive note, the ALJs recommended that the ICC reverse its decision on the pension-asset issue. The ICC is expected to issue an order on rehearing by September 19th.

Similarly, Moody's considers the relationship between BGE and the MPSC to be fairly challenging. In order for the CEG merger to be completed, the MPSC required several conditions from Exelon. Among the conditions included were that Exelon provide a $100 rate credit to every residential customer 90 days after merger close ($113 million), that Exelon build up to 300 MW of generation within Maryland, that Exelon construct a new office building in Baltimore for its unregulated platform and that Exelon fund a $113.5 million investment in energy efficiency over the next three years. The MPSC also implemented provisions intended to insulate BGE from the rest of the organization, including language that prohibits BG&E from paying a dividend to Exelon through 2014.

On July 27, 2012, BGE filed an application with the MPSC for increases of $151 million and $53 million to its electric and gas base rates, respectively, based upon a requested ROE of 10.5%. The new electric and gas distribution base rates are expected to take effect in late February 2013.

In contrast to Illinois and Maryland, we view the regulatory environment in Pennsylvania to be generally credit supportive. This degree of credit supportiveness is exemplified by the reasonable settlements with the PAPUC, including the December 2010 approval of PECO's electric and natural gas distribution rate cases for increases of $225 million and $20 million, respectively.

In February 2012, the state's governor signed into law (Act 11) a measure that would allow for the implementation of a distribution system improvement charge (DSIC) in rates designed to recover capital project costs incurred to repair, improve or replace utilities' aging electric and natural gas distribution systems. To qualify for the DSIC, utilities are required to submit a long-term infrastructure improvement plan, which will be reviewed by the PAPUC every 5 years, and a certification that a base rate case has been or will be filed within 5 years. The DSIC cannot exceed 5% of distribution rates and will be reset to zero if the utility's return on equity exceeds the allowable rate of return under the DSIC. The law also includes a provision that allows utilities to use a fully projected future test year under which the PAPUC may permit the inclusion of projected capital costs in rate base for assets that will be placed in service during the future test year. On August 2nd, the PAPUC issued a final order that implements portions of Act 11, which among other things, provides for a DSIC for electric, natural gas, water and wastewater utilities. Moody's views the terms of this legislation as supportive to utility credit quality.

For more information on ComEd, PECO, and BGE, please refer to their credit opinions which can be found on moodys.com.

Liquidity

Overall, we believe that Exelon has good liquidity. For fiscal year 2011, we calculate that Exelon generated about $4.853 billion of cash from operations, which covered 84% of the $4.4 billion of capital outlays (including acquisitions of $387 million) and $1.4 billion of dividends, resulting in negative free cash flow of around $582 million on a consolidated basis.

As of July 27, 2012, Exelon has a total of $10.6 billion of credit facilities spread across key business segments for working capital requirements. ComEd has an unsecured credit agreement totaling $1 billion that expires March 2017 while PECO and BGE each have separate $600 million revolving credit facilities that expire in August 2017. ExGen has a $5.3 billion syndicated revolving credit due August 2017 while Exelon has $2 billion in credit facilities, $1.5 billion that expires on December 31, 2012 and $500 million that expires in August 2017. In addition to the above, Exelon has access to $840 million in bilateral arrangements while ExGen has access to a $300 million commodity linked facility.

The core syndicated credit facilities at Exelon and its subsidiaries are used primarily to provide liquidity support and for the issuance of letters of credit. While the credit agreements do not contain any rating triggers that would affect borrowing access to the commitments and do not require material adverse change (MAC) representation for borrowings or the issuance of LOCs, there is a financial covenant for each entity, all of which are compliant. The bilateral agreements are intended to supplement liquidity needs for hedging and expire at various times between 2013 and 2016.

Relative to the $10.6 billion in total commitments, as of July 27, 2012, Exelon had on a consolidated basis, $2.3 billion of letters of credit outstanding, with $1.793 billion being issued at ExGen. Additionally, Exelon had a total of $462 million of commercial paper outstanding, including $35 million at BGE, $256 million at ComEd, and $171 million at Exelon. As such, credit availability at July 27th under Exelon and its subsidiaries' facilities was substantial at $7.861 billion, including availability of $3.807 billion at ExGen.

At June 30, 2012, ExGen had cash collateral posted of $697 million and letters of credit posted of $1.189 billion. Also at June 30, 2012, ExGen held cash collateral $1.007 billion and letters of credit of $152 million. In the event that ExGen were downgraded below investment grade, ExGen could be required to post additional collateral of $2.375 billion at June 30, 2012.

Under the terms of the financial swap contract between ExGen and ComEd, if a party is downgraded below investment grade, collateral postings will never exceed $200 million from either ComEd or ExGen.

As of June 30, 2012, PECO was not required to post collateral under any of its collateral agreements. If PECO lost its investment grade credit rating as of June 30, 2012, PECO could have been required to post approximately $36 million of collateral to counterparties.

Also, at June 30, 2012, BGE was not required to post collateral for any of its collateral agreements. If BGE lost its investment grade credit rating as of June 30, 2012, BGE could have been required to post approximately $54 million of collateral to its counterparties.

During 2012, Exelon and its subsidiaries have been active issuers of long-term capital market debt. On June 18, 2012, ExGen issued $775 million of senior unsecured notes, including $275 million of 4.25% notes due 2022 and $500 million of 5.60% notes due 2042. Concurrent with the new debt issuance, ExGen announced an exchange offer of Exelon's 7.6% $700 million senior unsecured notes due 2032 (formerly CEG obligations assumed by Exelon) into either the newly issued ExGen 4.25% senior unsecured notes due 2022 and ExGen's 5.60% senior unsecured notes due 2042. ExGen purchased $442 million of the old notes in exchange for issuing $537 million of senior unsecured notes due in 2022 and 2042, plus a cash payment of approximately $60 million.

In addition to the above, in August 2012, BGE issued $250 million of 2.8% senior unsecured notes due 2022, while in September 2012, PECO offered $350 million of 2.375% first mortgage bonds due 2022. Based upon the company's recent SEC disclosures, ComEd intends to raise $375 million of first mortgage bonds before the end of 2012.

At June 30, 2012, Exelon had $1.349 billion of consolidated cash, of which $930 million resided at ExGen and $354 million resided with the regulated utilities. During the second quarter of 2012, Exelon made a $66 million equity contribution to BGE to fund the after-tax amount of the $113 million rate credit pursuant to the MPSC order.

Structural Considerations

Within the last several years, Exelon has refinanced holding company debt with debt issued at ExGen. Exelon currently has $1.3 billion of remaining holding company debt, $800 million that matures in 2015 and $500 million that matures in 2035. Additionally, at merger close, Exelon legally assumed the obligations of CEG's publicly-held debt, guarantees and other contracts at merger close adding $1.8 billion of senior debt and $450 million of subordinated debt to Exelon. As mentioned previously, $442 million of the old notes were exchanged into $537 million of ExGen securities. For these reasons, when evaluating ExGen, Moody's examines historical and projected financial metrics for ExGen with the debt of Exelon holding company incorporated into the analysis.

Rating Outlook

Exelon's Baa2 long-term rating and Prime-2 short-term rating along with the Baa1 long-term rating at ExGen are under review for possible downgrade. The review factors in our concern over the company's financing plan for the next three years which includes primarily debt financing of the expected negative free cash flow of Exelon's unregulated businesses caused by weakened operating margins and the funding of a large capital investment program and sizable common dividend. Specifically, we estimate that debt at ExGen /Exelon could increase by more than $3 billion over the next three years, a nearly 40% increase from the June 30, 2012 level of about $8.4 billion (includes the $1.3 billion of Exelon holding company debt).

Importantly, we believe that Exelon remains firmly committed to maintaining an investment grade rating at Exelon and ExGen, and we maintain that the company's current plans, as we understand them, will enable Exelon and ExGen to maintain investment grade ratings during this down commodity cycle. To that end, should the outcome of the rating review result in a rating downgrade at Exelon and ExGen, the downgrade would be limited to one notch enabling both entities to maintain an investment grade rating.

What Could Change the Rating - Up

In light of the review for possible downgrade, Exelon's rating is not likely to be upgraded in the near-term.

What Could Change the Rating - Down

The review will examine the company's near-term and intermediate term financing plans in greater detail including whether some of the tools to strengthen credit quality will be implemented. The review will also access the announced plans to grow the company's retail business, the likelihood of the company reaching its revised merger saving targets, and the feasibility of achieving anticipated reductions in required? liquidity levels across the commodity platform.

Other Considerations

Given the size of the unregulated revenues, earnings, and cash flow, Moody's evaluates Exelon's financial performance relative to the Unregulated Utility and Power Company methodology and, as depicted below, Exelon's indicated rating under the grid based on most recent historical results is Baa2 and from projected results is Baa3.

Rating Factors

Exelon Corporation

Power Companies [1][2]	**LTM06/30/2012**		**Moody's 12-18 month Forward View* As of September 2012**	
Factor 1: Market Assessment, Scale and Competitive Position (20%)	**Measure**	**Score**	**Measure**	**Score**
a) Market and Competitive Position (15%)		A		A
b) Geographic Diversity (5%)		Baa		Baa
Factor 2: Cash Flow Predictability of Business Model (20%)				
a) Hedging strategy (10%)		Ba		Baa
b) Fuel Strategy and mix (5%)		Ba		Ba
c) Capital requirements and operatinal performance (5%)		Baa		Baa
Factor 3: Financial policy (10%)		Ba		Ba
Factor 4: Financial Strength - Key Financial Metrics (50%)				
a) CFO pre-WC + Interest / Interest (15%) (3yr Avg)	7.3x	A	7.0 - 7.5x	A
b) CFO pre-WC / Debt (20%) (3yr Avg)	35.2%	Baa	23 - 27%	Baa
c) RCF / Debt (7.5%) (3yr Avg)	29.5%	A	13 - 15%	Ba
d) FCF / Debt (7.5%) (3yr Avg)	4.0%	Ba	(10) - (5)%	B
Rating:				
a) Indicated Rating from Grid		Baa2		Baa3
b) Actual Rating Assigned		Baa2		Baa2

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of 06/30/2012(L); Source: Moody's Financial Metrics

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Credit Opinion: Exelon Corporation

Global Credit Research - 06 Dec 2012

United States

Ratings

Category	Moody's Rating
Outlook	Negative
Issuer Rating	Baa2
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Subordinate Shelf	(P)Baa3
Pref. Shelf	(P)Ba1
Commercial Paper	P-2
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Outlook	Stable
Issuer Rating	Baa2
First Mortgage Bonds	A3
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ComEd is an electric transmission and distribution (T&D) utility providing service to 3.8 million customers across northern Illinois. ComEd is regulated by the Illinois Commerce Commission (ICC) and by the Federal Energy Regulatory Commission (FERC).

PECO provides T&D service to about 1.6 million electric customers in Philadelphia as well as several surrounding Pennsylvania counties. PECO also provides gas distribution service to 490,000 natural gas customers in areas outside the city. PECO is regulated by the Pennsylvania Public Utility Commission (PAPUC) and by FERC.

BGE is a regulated electric transmission and distribution and gas distribution utility providing electricity and gas services to the city of Baltimore and ten other counties in Maryland. BGE is regulated by the Maryland Public Service Commission (MPSC) and FERC.

SUMMARY RATING RATIONALE

Exelon's Baa2 rating reflects strong historical consolidated credit metrics, due in large part to the financial performance of its unregulated generation subsidiary, and the generally predictable cash flows at its T&D subsidiaries. While the T&D subsidiaries are sizeable standalone companies, Exelon's rating remains heavily influenced by the performance of its unregulated segment, which has increased in size and importance following the CEG merger.

DETAILED RATING CONSIDERATIONS

-Consolidated credit metrics expected to decline from historical levels

Exelon's historical consolidated credit metrics have positioned the company strongly in the current category as an unregulated power holding company; however, future financial results are expected to cause those metrics to materially decline over the next several years owing to lower margins caused primarily by sustained low natural gas prices.

From 2009 through 2011, we calculate that the three year average of Exelon's cash flow (CFO pre-W/C) to debt at 39%, retained cash flow to debt at 33%, free cash flow to debt at 8.0%, and cash flow coverage of interest expense at 7.3x. By comparison, through 12 months ending 09/30/2012, we calculate cash flow to debt at 24.3%, retained cash flow to debt at 23.7%, cash flow coverage of interest expense of 6.2.x with negative free cash flow to debt of (-1.6%). These declines can be attributed to weaker commodity prices, lower amounts of bonus depreciation, a higher level of capital expenditures plus the inclusion of CEG's consolidated debt with operating results of only two quarters in this calculation. Exelon has indicated in SEC filings that bonus depreciation enhanced cash flow by $850 million during 2011 and is expected to augment 2012 cash flow by $300 million.

Prospectively, we expect financial results to weaken as margins continue to compress due to soft power prices caused in large part by sustained low natural gas prices and tepid economic demand.

-Merger with financially weaker unregulated power company

We believe that a motivating factor behind the March 2012 merger with CEG was to address the expected declining earnings trend and weaker cash flow profile beginning in 2012. As the largest unregulated power company in terms of kilowatt hours produced and retail customers served, the merger should garner the strategic benefits of linking a company that is long on generation (Exelon) with a company (CEG) that is long on customer load. As a byproduct of this linkage, the merger should considerably reduce consolidated liquidity requirements and enable the merged company to receive somewhat better margins for its electric output given the inherent stickiness of retail customer load. That being said, we note the retail electric market is highly competitive with the company continuing to be exposed to earnings and cash flow volatility due to the large unregulated business platform that now exists post merger.

We also believe that the completion of the CEG merger increases the likelihood that Exelon will remain more focused on maintaining its leadership position among unregulated power companies. To that end, we view Exelon as embracing a higher risk tolerance given the very large commodity platform that has been created with this merger. As such, we believe the company's credit metrics may need to be stronger than similarly rated peers while maintaining access to amply sized sources of liquidity.

-Near term capital requirements remain material

As a large capital intensive company, Exelon has substantial capital requirements to maintain the operation of its generation fleet while also maintaining and replacing the infrastructure of its regulated T&D utilities. Exelon is considering making up-rate investments across its nuclear fleet which, if fully completed, would add up to 1,300 MWs of additional capacity to the company's fleet at a very competitive cost. For 2012, Exelon plans to spend $6.1 billion in capital investment, including $3.8 billion at its unregulated platform, $1.275 billion at ComEd, $575 million at BGE and $425 million at PECO. In October 2012, the company announced that it would defer $1.025 billion of capital investment for extended power nuclear up-rates at LaSalle and at Limerick until 2017 and that it removed $1.25 billion of growth capital investment for new renewable projects from its capital budget. As such, 2013 capital investment at ExGen is expected to only be $2.75 billion with 2013 capital investment across the three T&D utilities approximating $2.55 billion, of which $1.4 billion was expected to occur at ComEd. The actions to defer nuclear up-rate capital investments and to remove growth capital for new renewable investments will aid future prospects for free cash flow generation, a credit positive.

-Dividend requirement may be reevaluated

Exelon has a $1.8 billion annual common dividend requirement following the merger with CEG which increased that requirement by $400 million. Given the prominence of the unregulated platform, we believe that the current dividend will be largely funded by ExGen's cash flow over the next several years, or with incremental debt given the near-term prospects for unregulated operating margins. This is particularly relevant during the next few years when BG&E is prohibited from paying a dividend (through 2014) and when regulated subsidiary ComEd's internal cash flow will be largely used to fund multi-year increases in its capital investment program. While we anticipate Exelon's third regulated subsidiary, PECO, to continue being cash flow positive and a reliable source of dividends to the parent, the majority of the common dividend funding will be provided by ExGen during a period when operating margins and related cash flow are expected to decline.

During Exelon's third quarter earnings call (November 1, 2012), management stated that revisiting its dividend policy would be among the range of options for management and the board to consider in preserving its current investment-grade ratings should power prices not recover in the next six months as completely or as rapidly as Exelon's fundamental views suggest. To that end, the rating acknowledges this and other public statements concerning the company's firm commitment to maintain an investment-grade rating at all registrants within the Exelon family.

-Hedging strategies influence cash flow predictability

As an unregulated wholesale energy holding company whose gross margin can be materially impacted by changes in commodity prices, a company's commercial strategy remains an important rating factor. Exelon manages its ratable hedging program over a 36 month cycle with targets of 90% or more of expected generation hedged in the first year, 70-90% in the second year, and less than 50% in the third year. As of September 30, 2012, we understand that Exelon was 88-91% hedged for 2013, 56%-59% for 2014 and 21%-24% for 2015. By completing the merger with CEG, we anticipate that more of the company's electric output will be sold directly to end-use customers through the multiple venues that exist along the retail chain which should reduce the total amount of hedges executed to meet the above coverage targets.

-Competitive position & consistent operations remain long-term strengths

As the largest owner and operator of nuclear generation in the US, Exelon has a strong competitive position and continues to demonstrate an outstanding record as a plant operator, particularly as a nuclear operator. In the intermediate-term, we expect its competitive position to remain largely unchanged as capacity reductions from anticipated coal plant shut-downs in the region should lower reserve margins (and possibly enhance capacity revenues) but are less likely to enhance energy margins given the outlook for natural gas, the fact that most of the plants that will shut down have low capacity factors, and the continuing slow economic recovery. Longer-term, the potential implications of EPA regulations should enhance profitability as any incremental environmental control related costs are likely to result in a higher margin potential for Exelon.

-Regulatory Environment

ComEd operates in an improved, but still challenging regulatory environment for electric utilities in Illinois with some lingering concerns about the framework's predictability. On December 30, 2011, the Energy Infrastructure Modernization Act (EIMA) was signed into law. EIMA established a new formula-rate-plan (FRP) distribution ratemaking paradigm for the state's largest electric utilities and was intended to spur utility infrastructure investment. The legislation requires ComEd to invest $1.3 billion over a five-year period in electric system upgrades, modernization projects, and training facilities along with at least $1.3 billion over a 10-year period in transmission & distribution assets and smart-grid system upgrades. Key aspects of the FRP calculation include cost recovery of the utility's actual capital structure, excluding goodwill; a legislatively-set formula for purposes of calculating the allowed return on equity (ROE); and recovery of pension-related costs.

While passage of EIMA is a credit positive from a cost recovery standpoint, the ICC's implementation of EIMA has been inconsistent supporting our continuing view of a challenging regulatory environment. On May 29th, the ICC ordered a $168.6 million rate reduction premised upon a 10.05% ROE and an 8.16% return on $6.183 billion in rate base. In its order, the ICC rejected ComEd's request to collect a debt-only return on its "pension asset" and adopted the intervening parties' recommendation to rely on an average capital structure and an average rate base calculation in prospective FRP-related revenue requirement reconciliations, versus the language in the law that contemplates the use of year-end values for capital structure and rate base. On September 19th, the ICC reversed its decision on the pension-asset issue but maintained their view concerning on an average capital structure and an average rate base calculation even though the legislation requires year-end capital structure and rate base. ComEd has indicated that continued uncertainty around the implementation of EIMA will influence the speed at which capital infrastructure investment is made in Illinois.

Similarly, we consider the relationship between BGE and the MPSC to be fairly challenging. In order for the CEG merger to be completed, the MPSC required several conditions from Exelon. Among the conditions were that Exelon provide a $100 rate credit to every residential customer 90 days after merger close ($113 million), that Exelon build up to 300 MW of generation within Maryland, that Exelon construct a new office building in Baltimore for its unregulated platform and that Exelon fund a $113.5 million investment in energy efficiency over the next three years. The MPSC also implemented provisions intended to insulate BGE from the rest of the organization, including language that prohibits BG&E from paying a dividend to Exelon through 2014.

On October 22, 2012, BGE updated its application with the MPSC requesting increases of $131 million and $45 million to its electric and gas base rates, respectively, based upon a requested ROE of 10.5%. The new electric and gas distribution base rates are expected to take effect in late February 2013.

In contrast to Illinois and Maryland, we view the regulatory environment in Pennsylvania to be generally credit supportive. This degree of credit supportiveness is exemplified by the reasonable settlements with the PAPUC, including the December 2010 approval of PECO's electric and natural gas distribution rate cases for increases of $225 million and $20 million, respectively.

In February 2012, the state's governor signed into law (Act 11) a measure that would allow for the implementation of a distribution system improvement charge (DSIC) in rates designed to recover capital project costs incurred to repair, improve or replace utilities' aging electric and natural gas distribution systems. To qualify for the DSIC, utilities are required to submit a long-term infrastructure improvement plan, which will be reviewed by the PAPUC every 5 years, and a certification that a base rate case has been or will be filed within 5 years. The DSIC cannot exceed 5% of distribution rates and will be reset to zero if the utility's return on equity exceeds the allowable rate of return under the DSIC. The law also includes a provision that allows utilities to use a fully projected future test year under which the PAPUC may permit the inclusion of projected capital costs in rate base for assets that will be placed in service during the future test year. On August 2nd, the PAPUC issued a final order that implements portions of Act 11, which among other things, provides for a DSIC for electric, natural gas, water and wastewater utilities. We view the terms of this legislation as supportive to utility credit quality.

For more information on ComEd, PECO, and BGE, please refer to their credit opinions which can be found on moodys.com.

Liquidity

Overall, we believe that Exelon has good liquidity. For fiscal year 2011, we calculate that Exelon generated about $4.853 billion of cash from operations, which covered 84% of the $4.4 billion of capital outlays (including acquisitions of $387 million) and $1.4 billion of dividends, resulting in negative free cash flow of around $582 million on a consolidated basis.

Beginning in 2013, Exelon's liquidity arrangements supporting its unregulated power business will equal $6.1 billion, a decline of $4.2 billion from the $10.3 billion level that existed immediately following merger close. This decline, while substantial on a notional basis, is largely reflective of the reduced collateral requirements that occurs when a company that is long on generation is combined with one that has a large retail network. At October 24, 2012, there was $4.2 billion of availability under the $6.1 billion in Exelon and ExGen aggregated facilities, after giving effect to $1.9 billion of ExGen letters of credit issued. At October 24th, Exelon and ExGen had no commercial paper outstanding. The $6.1 billion of credit facilities that supports Exelon's unregulated power business expires in August 2017. The separate legacy CEG $1.5 billion credit facility, which was assumed by Exelon at merger close and unutilized at October 24th, will expire at year-end 2012.

On the regulated side, a total of $2.2 billion of credit facilities remain in place for working capital requirements. ComEd has an unsecured credit agreement totaling $1 billion that expires March 2017 while PECO and BGE each have separate $600 million revolving credit facilities that expire in August 2017. At October 24, 2012, no utility commercial paper was outstanding. However, there was $121 million of letters of credit issued under ComEd's $1 billion (leaving availability at $879 million and there was $1 million of letters of credit issued under each of PECO's and BG&E's $600 million credit facilities).

The core syndicated credit facilities at Exelon and its subsidiaries are used primarily to provide liquidity support and for the issuance of letters of credit. While the credit agreements do not contain any rating triggers that would affect borrowing access to the commitments and do not require material adverse change (MAC) representation for borrowings or the issuance of LOCs, there is a financial covenant for each entity, all of which are compliant.

In the event that ExGen were downgraded below investment grade, ExGen could be required to post additional collateral of $2.0 billion at September 30, 2012. If ComEd was downgrade below investment grade, it would be required to post $218 million at September 30, 2012. If PECO and BG&E were each downgraded to below investment grade, they would have been required to post $31 million and $54 million, respectively, of additional collateral at September 30, 2012.

During 2012, Exelon and its subsidiaries were active issuers of long-term capital market debt. On June 18, 2012, ExGen issued $775 million of senior unsecured notes, including $275 million of 4.25% notes due 2022 and $500 million of 5.60% notes due 2042. Concurrent with the new debt issuance, ExGen announced an exchange offer of Exelon's 7.6% $700 million senior unsecured notes due 2032 (formerly CEG obligations assumed by Exelon) into either the newly issued ExGen 4.25% senior unsecured notes due 2022 or ExGen's 5.60% senior unsecured notes due 2042. ExGen purchased $442 million of the old notes in exchange for issuing $537 million of senior unsecured notes due in 2022 and 2042, plus a cash payment of approximately $60 million.

In addition to the above, in August 2012, BGE issued $250 million of 2.8% senior unsecured notes due 2022, in September 2012; PECO offered $350 million of 2.375% first mortgage bonds due 2022; and in October 2012, ComEd issued $350 million of 3.8% first mortgage bonds due 2042.

At September 30, 2012, Exelon had $1.602 billion of consolidated cash, of which $732 million resided at ExGen and $800 million with the regulated utilities. The substantially higher than normal cash balances at the utilities reflect August and September financings which prefunded upcoming debt maturities at BG&E and PECO. During the second quarter of 2012, Exelon made a $66 million equity contribution to BGE to fund the after-tax amount of the $113 million rate credit pursuant to the MPSC order.

Structural Considerations

Within the last several years, Exelon has refinanced holding company debt with debt issued at ExGen. Exelon currently has $1.3 billion of remaining holding company debt, $800 million that matures in 2015 and $500 million that matures in 2035. Additionally, at merger close, Exelon legally assumed the obligations of CEG's publicly-held debt, guarantees and other contracts at merger close adding $1.8 billion of senior debt and $450 million of subordinated debt to Exelon. As mentioned previously, $442 million of the old notes were exchanged into $537 million of ExGen securities. For these reasons, when evaluating ExGen, Moody's examines historical and projected financial metrics for ExGen with the debt of Exelon holding company incorporated into the analysis.

Rating Outlook

The negative rating outlook for Exelon factors in the expected decline in certain key credit metrics that we anticipate occurring over the intermediate-term due to sustained weak market fundamentals even with the decline in growth capital spending. The negative outlook also acknowledges that, despite the low-cost fleet, we believe the unregulated segment would need to experience some increase in power prices above current market forwards in order to generate metrics consistent with their current rating category. The negative rating outlook further considers the sizeable dividend requirements at Exelon along with the parent's heavy reliance on the large unregulated platform which can add to cash flow volatility.

What Could Change the Rating - Up

In light of the negative rating outlook, the ratings at Exelon are not likely to be upgraded in the near-term. The rating outlook could, however, stabilize if the company continues to take actions that we believe are supportive of sustained long-term credit quality, particularly as it relates to capital allocation decisions.

What Could Change the Rating - Down

The rating could be downgraded if future capital allocation decisions result in higher than anticipated negative free cash being financed with incremental indebtedness. Specifically, management has stated their intention to examine future dividend policy in light of ongoing power prices; thus, if power price expectations remain subdued and the current dividend policy is not reevaluated, or if the modification is only modest despite relatively sustained weaknesses, the ratings are likely to be downgraded.

Other Considerations

Given the size of the unregulated revenues, earnings, and cash flow, Moody's evaluates Exelon's financial performance relative to the Unregulated Utility and Power Company methodology and, as depicted below, Exelon's indicated rating under the grid based on historical results and from projected results (next 12-18 months) is Baa2.

Rating Factors

Exelon Corporation

Power Companies [1][2]	**LTM09/30/2012**			**Moody's 12-18 month Forward View* As of November 2012**	
Factor 1: Market Assessment, Scale and Competitive Position (20%)	**Measure**	**Score**		**Measure**	**Score**
a) Market and Competitive Position (15%)		A			A
b) Geographic Diversity (5%)		Baa			Baa

Factor 2: Cash Flow Predictability of Business Model (20%)				
a) Hedging strategy (10%)		Ba		Baa
b) Fuel Strategy and mix (5%)		Ba		Ba
c) Capital requirements and operatinal performance (5%)		Baa		Baa
Factor 3: Financial policy (10%)		Ba		Ba
Factor 4: Financial Strength - Key Financial Metrics (50%)				
a) CFO pre-WC + Interest / Interest (15%) (3yr Avg)	7.3x	A	7.0 - 7.5x	A
b) CFO pre-WC / Debt (20%) (3yr Avg)	32.4%	Baa	25 - 30%	Baa
c) RCF / Debt (7.5%) (3yr Avg)	28.0%	A	13 - 17%	Baa
d) FCF / Debt (7.5%) (3yr Avg)	3.2%	Ba	(10) - 0%	B
Rating:				
a) Indicated Rating from Grid		Baa2		Baa2
b) Actual Rating Assigned		Baa2		Baa2

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of 09/30/2012(L); Source: Moody's Financial Metrics

FEBRUARY 6, 2013

INFRASTRUCTURE

MOODY'S
INVESTORS SERVICE

INDUSTRY OUTLOOK

US Regulated Utilities:

Regulatory Support, Low Natural Gas Prices Maintains Stability

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Our outlook for the investor-owned US regulated electric and gas utility sector is stable. This outlook reflects our expectations for the fundamental business conditions in the industry over the next 12 to 18 months.

» **The outlook for the US investor-owned regulated electric and gas utility sector is stable.** We expect a supportive regulatory environment to remain intact over the next 12 to 18 months, providing a timely recovery of prudently incurred costs and investments through authorized rates. We see a sustained period of low natural gas prices benefitting utilities seeking other rate base increases; steady and stabilizing financial ratios, and average annual revenue increases between 3-5%.

» **Capital markets remain highly accessible.** The sector benefits from flight-to-quality dynamics, with a return to long-term liquidity facilities as the norm.

» **We expect high capital expenditures to continue for the foreseeable future.** Large capex will contribute to rate base growth; however, management must carefully address the financing of corresponding negative free cash flow, along with the increased rate pressure on customers.

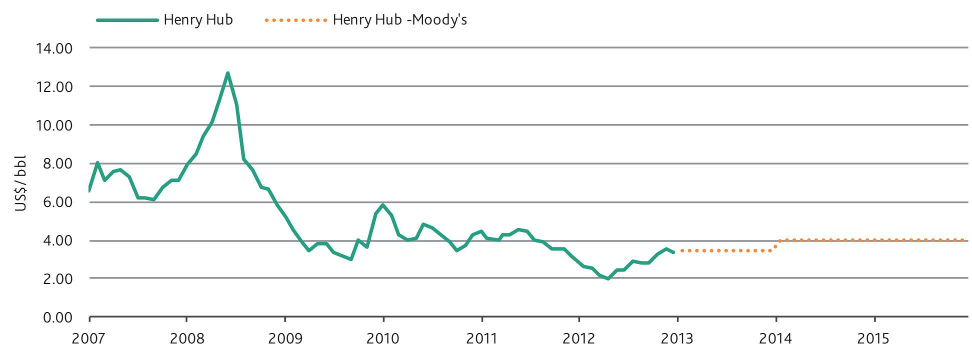
» **States to watch in 2013.** We see regulation throughout the US in a business-as-usual status over the near-term, but there are certain states where our perception of regulatory supportiveness may change in 2013. States we view as prone to positive changes are Maryland, Arizona, New Mexico and Texas. States we view as prone to negative changes are the eastern states impacted by Hurricane Sandy, Illinois, North Carolina, Ohio and Mississippi. We also see potential for negative changes at the FERC.

» **We anticipate financial metrics stabilizing over the near term.** Cash recovery of costs through special recovery mechanisms and the extension of bonus depreciation should help to offset reduced allowed returns on equity (ROE) and low customer demand. Companies pursuing large capex plans will see a decline in financial metrics and are at the highest risk for recovery delays.

Low natural gas prices continue to benefit utilities, customers and commissions

The abundant supply of domestic natural gas is a material credit positive for regulated utilities. Low natural gas prices have facilitated an easing of fuel costs and power prices throughout the nation and should continue to provide a backdrop for continued supportive regulatory relationships over the next 12-18 months. The proliferation of shale gas supplies in the US has driven natural gas prices to new lows as seen in Figure 1, below. This phenomenon, in combination with low customer demand due to a sluggish recovering economy, mild weather and the effects of energy efficiency and demand side management (DSM), has kept power prices low - a trend we expect to persist through 2013.

FIGURE 1
Natural Gas Prices and Assumptions[1]



Source:EIA.gov and Moody's

Since a peak of over $12 per MMBtu in 2008, gas prices have been on a rather steady decline. Since fuel and purchased power costs represent the single largest utility cost, and are typically a direct pass-through to rate payers, customer bills benefit significantly from reduced commodity and procurement costs.

These variable cost decreases have provided headroom in rates, enabling regulators to allow utilities to recover rising non-fuel costs through increases in base rates without a material change to the aggregate amount of a customer's bill. The offset of fixed cost increases, with variable cost decreases, is largely unnoticed by the typical residential consumer. The cost offset helps to avoid any negative customer reaction that might place political pressure on utility commissions and lead to their reluctance to allow some general rate increases for utilities.

Figure 1 also reflects our belief that the cost environment for natural gas will be low for several years. We expect this environment to give regulators additional flexibility in maintaining their support for the recovery of rising utility operating costs. Our natural gas price expectations are influenced by our view that a sudden "game-changing" growth spurt in demand is unlikely over the near term and that a gradual increase in gas consumption will occur throughout all corporate sectors in 2013. Our price assumptions show Henry Hub natural gas at $3.50 per MMBtu for 2013 and at $4.00 thereafter.

[1] Our natural gas price assumptions are derived from the Moody's energy team and its Global Oil and Natural Gas outlook. These price assumptions are used for rating purposes and as sensitivity inputs for production companies' projected performance.

Low commodity prices benefit industry liquidity

Low commodity costs have also bolstered utility liquidity profiles, as reduced collateral calls and inexpensive hedges are increasingly replacing historical positions. The sector continues to benefit from open and welcoming credit markets, as utilities remain a safe haven for investors looking for steady and predictable returns. Furthermore, bank support via long-term credit facilities (e.g., 5 year tenors) has returned, following a contraction during the Great Recession.

We expect the industry axiom of open and welcoming markets to continue over the next 12 to 18 months; however, the flight from trouble in Europe may have potentially run its course, and Basel III requirements on bank capital may weaken the appetite of lender interest in the sector. Since the next round of refinancing may be more expensive, it will provide an indication of which issuers refinance only opportunistically and which issuers refinance because maintaining longer-term liquidity is a core tenet of their financial policy.

Regulatory support is a credit positive, despite lower authorized ROEs

Given the headroom created by lower fuel and purchased power costs, regulatory support for general rate increases has continued throughout the nation with few states generating any prospect of immediate concern. The general trend for approved rate increases in the US were 61% of requested amounts granted in 2012, compared to 55% in 2011 and 57% in 2010. Our ongoing premise is that regulatory commissions prefer to regulate financially healthy utilities and that utility managements have core competencies in navigating the regulatory landscape, in order to support the long-term financial wellbeing of the companies.

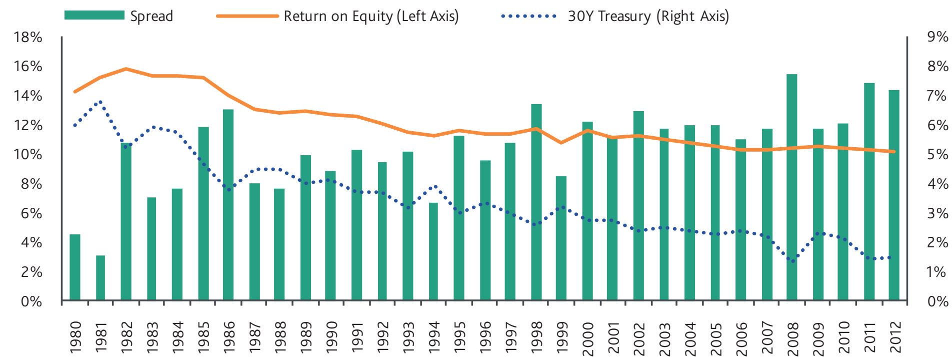
One point of interest to note is in the trend of falling allowed ROEs throughout the industry, which includes several jurisdictions recently crossing below the 10.00% threshold. For example, several issuers in Oregon (Northwest Natural Gas, A3, negative and Idaho Power, Baa1, stable) and Washington (Puget Sound Energy, Baa2, stable and Avista Corp. Baa2, stable) dropped below 10.00% allowed ROE in 2012, with some companies experiencing sub-10.00% allowed ROE in multiple jurisdictions, such as PacifiCorp (Baa1, stable) and Kansas City Power & Light (Baa2, stable - its Missouri rate case decision occurred in January 2013). According to SNL Financial, the average allowed ROE for investor owned utilities, has dropped to 10.07% in 2012 versus 10.21% in 2011. We have observed two oft-cited reasons behind a commission reducing a utility's allowed ROE; those being 1) the prevalence of single item rate making through specific riders and trackers, and 2) the current low interest rate environment.

Many commissions have reasoned that a heightened use of special cost recovery mechanisms such as environmental cost trackers, weather normalization adjustments, decoupling mechanisms, and the like, have reduced the business and financial risk of a utility, thus justifying a reduction in allowed ROE.

Similarly, various commissions cite that due to the current low interest rate environment, a utility's cost of capital has been reduced to a point that warrants a lower allowed return and reduced rates for customers. Figure 2 identifies the declining ROE trend in recent years, compared to the risk free rate of return on the 30 year US Treasury bill.

FIGURE 2

Authorized Returns on Equity, Treasury Rates and Spread

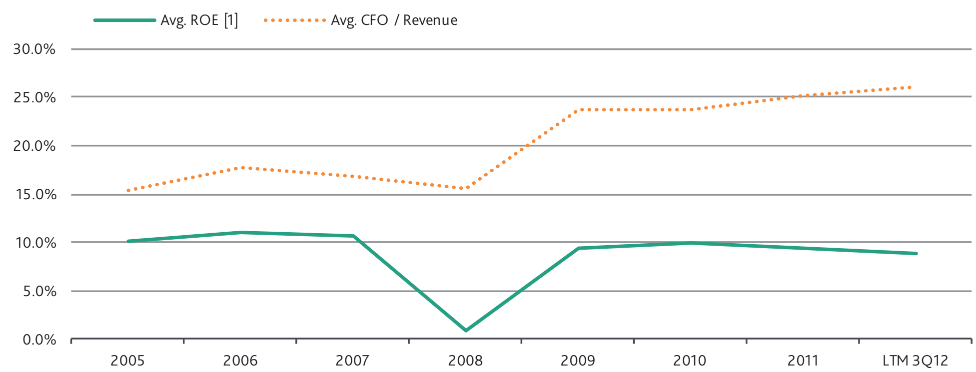


Source: SNL & Bloomberg

We expect the risk free rate of return to remain low through 2014 and that pressure on ROEs will persist over the near-term. Despite this trend, we see evidence of cash recovery being sufficient to sustain most utility financial profiles over the next 12 to 18 months. In Figure 3 below, we observe that although ROE has declined over the past two years, cash flow from operations (CFO) as a percentage of revenue has actually increased, potentially due to enhanced cost recovery provided by trackers and certainly from federal tax incentives such as accelerated bonus depreciation.

FIGURE 3

Cash Generation versus Returns



[1] 2008 Moody's Adjusted Net Income experienced significant reductions due to large losses in pension plan assets for several companies in our peer group.

Source: Moody's

If cash recovery is maintained near current levels, despite minor reductions in ROE, there should be no negative impact on ratings. However, declining allowed ROE levels are negative because we often regard the level of allowed ROE as a barometer of the relationship that a specific utility maintains with its commission. Thus we view punitive reductions to ROE as a credit negative, although the immediate impact is usually delayed, somewhat, by continued growth in rate base. Furthermore, we could see negative rating actions if ROEs were to decline to levels near 9.00%, as reduced revenues will eventually lead to declines in cash flow, or turn investor interest toward competing utilities in more investor-friendly jurisdictions, or even to different sectors.

Our primary concern about the trend toward lower industry ROEs is the eventual return of higher interest rates without the benefit of timely and commensurate adjustments toward higher allowed ROEs. That is, when the relationship between interest rates and ROEs starts to converge (identified by the green columns in Figure 2), there is risk for credit deterioration and negative rating impacts.

We view regulatory compacts that have annual updates to ROEs, such as the historical multi-year rate plans evidenced in states like New York and Vermont, to be more credit supportive in circumstances of a rising interest rate environment. The allowed ROEs in the historical rate plans of these states are formulaic, with treasury bill rates as an automatic input to the outcome of an allowed ROE. They also contain annual rate increases to capture rising costs and investment for the respective utility. Conversely, in states where there are several years between rate cases, there is a higher risk of allowed returns lagging interest rate growth and achieving all-in rates that do not reflect the reality of a more costly economic environment.

States to watch in 2013

Although our general view of regulation throughout the US is business-as-usual over the near-term, there are certain states where our perception of regulatory supportiveness may change in 2013. Figure 4 identifies those states we view a change in the current regulatory environment, either positive or negative, as a real possibility in 2013, with a bias to the negative. We also describe the circumstances motivating our vigilance in these states.

FIGURE 4

Potential Shifts in Regulatory Support

Positive Potential		Negative Potential	
State	**Comment**	**State**	**Comment**
MD	Governor recently wrote to Maryland Public Service Commission urging them to adopt a task force recommendation to allow cost recovery mechanism for investments aimed at improving reliability of a utility's distribution system.	NY, NJ, CT	Effects of Hurricane Sandy and potential for deferred recovery of costs and heightened political influence over rate making.
AZ	UNS Gas, Arizona Public Service, and Southwest all recently received credit supportive rate case outcomes and included shorter time frames for deciding cases and decoupling. Positive outlook for UNS Energy and subsidiary Tucson Electric Power (TEP) reflects our expectation for a reasonable outcome in upcoming TEP rate case.	IL	Although recent legislation has improved Commonwealth Edison and Ameren Illinois' cost recovery prospects, the regulatory and political environment remains unpredictable with adverse regulatory decisions continuing to be a continuing trend.
NM	The state recently finalized rules allowing rates to be based on a forward looking test year, but these new rules have yet to be implemented in a rate order. The legislature is also expected to promulgate rules following a recent referendum requiring more stringent qualifications for elected commissioners.	NC	At Duke Energy, management changes and other developments following the Progress Energy merger and a subsequent settlement with North Carolina Utilities Commission has increased regulatory risk at a time when both of its North Carolina utility subsidiaries are pursuing rate cases.

FIGURE 4

Potential Shifts in Regulatory Support

Positive Potential		Negative Potential	
TX	Political and regulatory intervention seeks to alter the market structure to benefit generators.	OH	Although Electric Security Plans provide some clarity through 2014, the market transition toward fully deregulated generation could negatively affect utility financials.
		MS	Unanimous Mississippi Public Service Commission vote to deny Mississippi Power's request of financing costs on Kemper County IGCC plant due to a pending Sierra Club lawsuit was a credit negative. A settlement agreement on cost recovery has since been reached.
		FERC	Changes already enacted to the FERC rate making methodology in California and the current legal battle regarding New England transmission ROE reductions threaten pervasive changes to the degree of financial support offered by the FERC.

Stable financials, but falling cash flow ratios for big spenders

In recent years, utilities have elected to take advantage of favorable tax policies which boost near term cash flow in exchange for reduced rate base growth in the future – specifically, bonus depreciation. This voluntary tax election also benefits utilities because it temporarily boosts key financial metrics such as CFO pre-WC to debt[2] and CFO pre-WC interest coverage. Since 2009, tax policy changes such as those associated with accelerated bonus depreciation, uniform capitalization and capitalized repairs have provided the industry with one-time changes to tax accounting methods that have generated significant amounts of cash flow from tax savings or refunds.

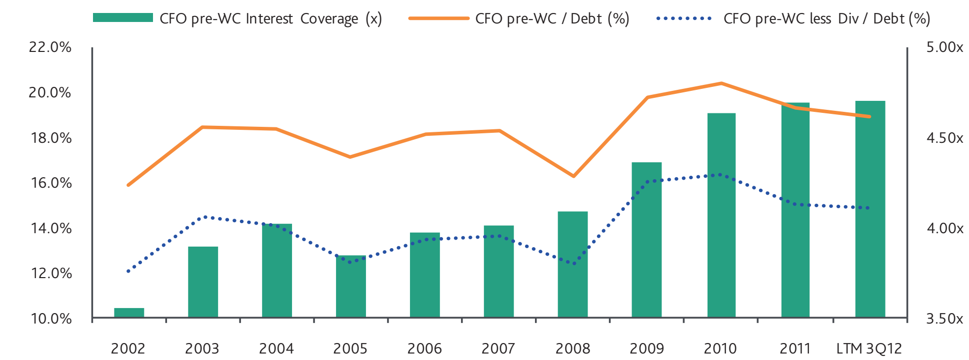
We estimate that, on average, a utility company's cash flow to debt metric benefitted anywhere from 200 to 300 basis points in any given year (2009-12), depending on the timing of when a given company exercised accounting methodology changes. Although these one-time effects have largely run their course, we note that the recent extension of 50% bonus depreciation will continue to support (or inflate, if comparing to organic run-rate potential) cash flow levels in 2013.

As seen in Figure 5, even with benefits from 100% bonus depreciation in 2011 and 50% in 2012, cash flow coverage of debt has declined for our peer group since the height of 2010.

[2] Cash Flow from Operations before Working Capital to debt

FIGURE 5

Key Cash Flow Metrics

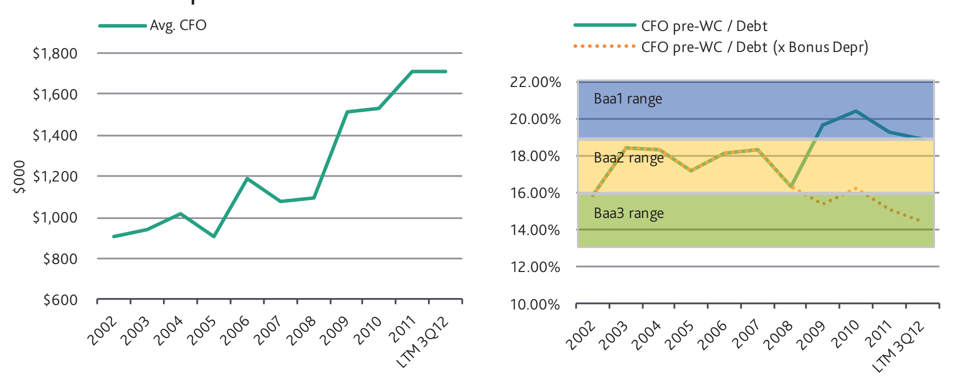


Source: Moody's

This inflation due to one-time benefits is a risk, as utilities will likely have lower cash flow when bonus depreciation ends, all else being equal. In Figure 6, we estimate the magnitude of the effects of bonus depreciation (assuming 70% of capex represents qualifying assets and a 35% tax rate) on the peer group's CFO pre-WC to debt. Without bonus depreciation, the financial profile of the group falls from a level in-line with the low Baa1 rating range of our Regulated Electric & Gas rating methodology, to a level solidly in the Baa3 range.

FIGURE 6

Effects of Bonus Depreciation



Source: Moody's

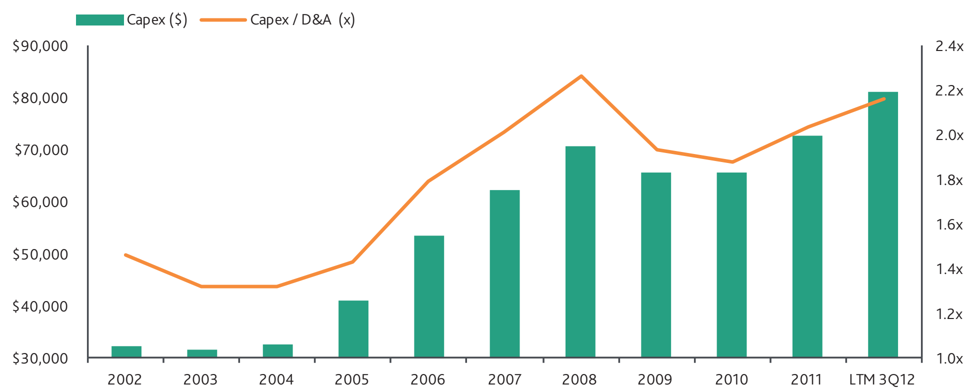
Nevertheless, we expect financial metrics to remain relatively steady in 2013, given our assumptions of ongoing rate relief, the continuance of low interest rates, cash flow stability provided by cost recovery mechanisms, government policy from the extension of bonus depreciation, and the potential for the Moving Ahead for Progress in the 21st Century Act (MAP-21) to reduce the funding requirements for pension obligations. More importantly, we think managements will utilize a balanced mix of debt and equity to keep the leverage and capitalization of their utilities in a conservative range and not test negatively biased rating actions.

Although we expect metrics for the industry to be stable, companies with robust capital programs, such as Virginia Electric and Power Company (A3, stable), Indiana Michigan Power company (Baa2, stable), SCANA Corporation (Baa3, stable), and Public Service Company of Oklahoma (Baa1, stable), could experience a decline in financial metrics due to increased debt associated with growing free cash flow deficits. In each of these cases, we anticipate that the resulting financial profile will still be appropriate for each company's current rating.

Rate shock and regulatory contentiousness are primary risks to stable outlook

Capital expenditure plans for most US utilities have rapidly outpaced depreciation and amortization (D&A) levels in recent years. The need for environmental retrofits, growth in renewable energy use and basic system maintenance and upgrades are the primary drivers for the capex growth trend observed amongst our sample utility peer group (made up of 45 industry peers; see Appendix A). Figure 7 shows the relationship between capex and D&A over the past ten years for these companies.

FIGURE 7
Capex Levels for Moody's Peer Group
($ millions)



Source: Moody's

We view capital investment in rate base positively over the longer term, as it contributes to growth in operating cash flow. Given the low commodity price environment, we assume that these growth investments will be recovered through base rate cases on a timely basis without contentious regulatory proceedings. However, given the magnitude of these investments, corresponding increases in customer bills and associated financing needs, we see the need for each company to carefully execute their capital raising strategies in order to maintain stable credit profiles across the sector. We view the relationship between rising customer bills and the current economic environment as a potential credit negative. While the risk of this scenario (i.e., significant rate shock) is considered to be remote, if there were a reversal in the plodding economic recovery, and lower variable costs were no longer sufficient to offset the higher costs of capex programs, recovery of these costs could be delayed over the intermediate-term in order to avoid customer rate shock and/or rate fatigue.

In order to gain an appreciation for the magnitude of these prospective risks, we analyzed the potential rate impact of expected capex levels for companies involved in large capital programs. Figure 8 shows the utilities that we believe have the largest potential rate increases over the near-term. The analysis includes 2013-2014 capex data made available in 2011 10K company disclosures and assumptions explained in Appendix B (also see our report "High Capital Expenditures Adding to Rate Pressure for Utilities" (October 2012)). Although the time horizon of the capital expenditures extends outside of our outlook horizon, we find it valuable to determine what companies will require substantial rate increases to recover capital expenditures, in order to monitor management's near-term response to mitigate and/or absorb future risks to rate recovery. Proactive management strategies, in our opinion, include implementing cost cutting measures, strengthening the balance sheet and bolstering liquidity. Several of these utilities were recently awarded increases in rate cases that were determined in late 2012.

FIGURE 8

Largest Potential Rate Increases

Company	Rating	Total Rate Increase for 2013-2014 Spending	Estimated Capex 2013-2014 (millions)	CFO pre-WC / Debt LTM 3Q12	Projected CFO pre-WC / Debt 2014	Metric Cushion	Supportiveness of Regulation
Louisville Gas and Electric	Baa1	18%	$1,538	27%	23%	7%	Above Average (A)
Mississippi Power	A3	18%	$1,235	14%	16%	-4%	Above Average (A)
South Carolina Electric & Gas	Baa2	12%	$2,600	17%	17%	0%	Above Average (A)
Kentucky Utilities	Baa1	11%	$1,583	23%	21%	5%	Above Average (A)
Southwestern Public Service	Baa2	11%	$1,160	24%	22%	6%	Average (Baa)
PPL Electric Utilities	Baa2	10%	$1,689	22%	21%	5%	Average (Baa)

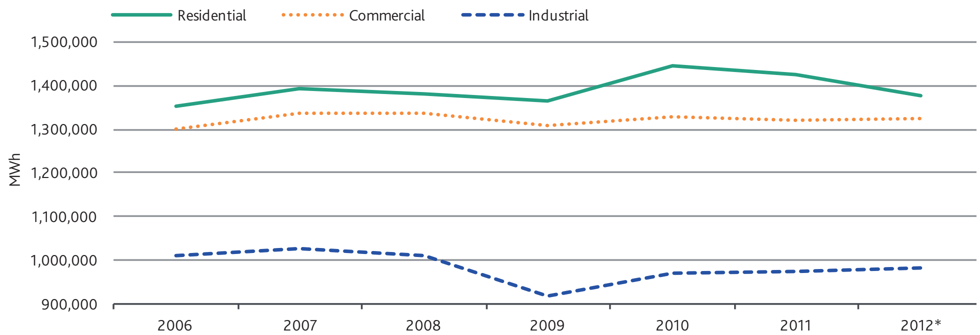
Source: SNL, 10K and EIA filings, Moody's

Over the next two years, some of these companies could find themselves poorly positioned within their rating category as a result of their cash outlay. Although we assume a 50% debt financing of these expenditures, negative ratings action could occur if management takes a more aggressive leverage policy or if cash flow recovery is slower than expected. Thus, attention will be given to the progress of each company's capex program and the regulatory developments that dictate the timing and duration of recovery.

Utilities will need to manage continued flat volume growth due to economy, energy efficiency and demand side management

Another key to our outlook assumptions is the industry's ability to pass through base rate increases (aided by low commodity costs) without the benefit of robust organic growth in customers or usage per customer. Flat to declining demand (see Figure 9) represents yet another key risk to the stability of our outlook, as it places the full amount of rising cost pressure on a static amount of customer use.

FIGURE 9
Retail Sales by Customer Class



*2012 data through November
Source: EIA.gov

Effects of a struggling economy, mild weather and continuing efforts promoting more efficient appliances and customer conservation (aka demand side management, DSM) are all contributing to very-low-to-declining demand growth across the majority of the sector. Whereas fiscal and monetary policy is still attempting to prod the economy out of the Great Recession and spur growth, federal and many state governments are taking significant measures to increase greater energy efficiency through various means including appliance and equipment standards, building codes, transportation policies and utility programs. These policies are gaining momentum across the country, with most states increasing their budget allocation for efficiency programs in recent years.

The credit implication of these initiatives are largely twofold. On one hand, we view utilities having a high degree of fixed cost recovery in the demand portion of rates as better positioned to withstand a low demand environment. Thus, utilities in states such as California and New York, where legislatively backed decoupling mechanisms have been implemented at essentially every utility, should maintain relatively stable and predictable financial results, even with slumping energy sales. On the other hand, utilities that have a greater portion of fixed costs in the energy or other variable portions of the rate payer's bill have greater exposure to fluctuations in demand and a higher potential for negative rating action in a continuing low demand environment.

Since a growing utility can recover more fixed costs through margin expansion from new customers, reducing the need for general rate increases, a low demand or no growth environment ups the ante for utility asks in rate cases. Rate cases under no growth scenarios become must-haves for a utility, in order to recover increasing operating costs. The addition of static growth to the aforementioned mixture of rising consumer rates in a depressed economic environment might lead to breach of the inflection point (i.e., the point at which customers complain to regulators about their inability to pay for continued utility rate increases) in one or more states. Appendix C details a state-by-state comparison of inflection point sensitivity, based on income, average utility bill and retail rates. States that we suspect to be potential areas of inflection point concern (e.g., Kansas, Michigan, Missouri and West Virginia) are those where utility bill rate increases have grown at a high rate since 2008, and also where the utility bill represents a relatively high percentage of the rate payer's discretionary income.

One point of growth differentiation is found with local distribution companies (LDCs) that are benefitting from the attractive economics of heating one's home or small business with natural gas versus propane or oil. Service territories containing a large amount of customers who have historically used propane or oil for heating have begun converting their heating systems to run on natural gas, given the exceedingly low cost for natural gas. Many of these conversion opportunities are significant for companies like UIL Corp. (Baa3 stable) and UGI Utilities (A3 stable) in the Northeast, which has traditionally relied on oil for space heating and the natural gas grid has been late to develop.

Federal Government actions represent a wild card

Although Congress has approved a short-term extension of the debt ceiling, ultimate policies regarding the debt ceiling and budget sequestrations are highly uncertain and have the potential to impede the already sluggish economic growth. On January 30, the Commerce Department reported that the economy shrunk by 0.1% in 4Q12 – the first economic contraction since the recession ended in 2009. Uncertainties surrounding government spending and the economy's durability in 2013 could have negative effects that exacerbate an already low power demand environment; a negative for the sector.

These economic vagaries are at play while newly re-elected President Obama's eventual nominee to replace Lisa Jackson, the head of the Environmental Protection Agency, may try to generate renewed momentum for additional environmental compliance regulations. However, the slow and litigious process for promulgating regulations means that their impact would be unlikely to have a material impact in the near-term.

Appendix A – Peer group listing

	MDY Rating	MDY Outlook
Madison Gas and Electric [1]	A1	Stable
PECO Energy	A3	Stable
Public Service Electric and Gas	A3	Stable
Wisconsin Energy	A3	Stable
ALLETE, Inc.	Baa1	Stable
Alliant Energy	Baa1	Stable
Baltimore Gas and Electric [2]	Baa1	Stable
Consolidated Edison, Inc.	Baa1	Stable
Integrys Energy Group, Inc.	Baa1	Stable
MidAmerican Energy Holdings Co.	Baa1	Stable
NextEra Energy, Inc.	Baa1	Stable
OGE Energy Corp.	Baa1	Stable
PG&E Corporation	Baa1	Stable
Sempra Energy	Baa1	Stable
Southern Company (The)	Baa1	Stable
Xcel Energy Inc.	Baa1	Stable
American Electric Power	Baa2	Stable
Commonwealth Edison [2]	Baa2	Stable
Dominion Resources Inc.	Baa2	Stable
DTE Energy	Baa2	Positive
Duke Energy	Baa2	Stable
Edison International	Baa2	Stable
IDACORP, Inc.	Baa2	Stable
ITC Holdings Corp.	Baa2	Stable
Northeast Utilities	Baa2	Stable
Pinnacle West Capital Corporation	Baa2	Stable
TECO Energy, Inc.	Baa2	Stable
Westar Energy, Inc.	Baa2	Stable
Ameren Corporation	Baa3	Stable
Black Hills Corporation	Baa3	Positive
CenterPoint Energy, Inc.	Baa3	Positive
Cleco Corporation	Baa3	Stable
Entergy Corporation	Baa3	Stable
FirstEnergy Corp.	Baa3	Stable
Great Plains Energy	Baa3	Stable
NiSource Inc. [3]	Baa3	Stable
Pepco Holdings, Inc.	Baa3	Stable
PPL Corporation	Baa3	Stable
SCANA Corporation	Baa3	Stable
UIL Holdings	Baa3	Stable
CMS Energy	Ba1	Positive
DPL Inc.	Ba1	Under Review - Down
NV Energy Inc.	Ba1	Stable
PNM Resources, Inc.	Ba1	Stable
Puget Energy, Inc.	Ba1	Stable
UNS Energy	Ba1	Positive

[1] Madison Gas and Electric is used as a proxy for its parent, MGE Energy, which is not rated.

[2] Significant operating subsidiaries are used when its parent company is not rated under the Regulated Electric & Gas Utilities methodology.

[3] The Baa3 rating is the Senior Unsecured rating at its guaranteed financing subsidiary.

Appendix B – Capex Model Assumptions

We calculated the revenue requirements for utilities assuming a 50/50 debt to equity capital structure, 10.00% ROE, and a 30-year expected life for the capex. Based on our estimates, the revenue requirements associated with the capex is approximately 13.8% of the annual spending. Increases in the equity ratio or equity and debt returns raise the revenue requirement, and increases in the useful life of the asset reduce the revenue requirement. We also assumed underlying revenue growth of 1% based on customer and usage growth. Based on our conversations with utilities, the revenue requirement varies between 12-18% depending on the capital structure, allowed returns, and other rate recovery treatment.

FIGURE 10

Generic Revenue Requirement Example

Step 1: Calculate the Weighted Average Cost of Capital

	% of Capitalization		After Tax Return		After Tax WACC	Pre-Tax WACC @ 35% rate
Debt	50%	x	5.50%	=	2.75%	2.75%
Equity	50%	x	10.00%	=	5.00%	7.7%
			WACC		7.75%	10.4%

Step 2: Calculate Revenue Requirement

Capital Expenditures	100				
Pre-Tax Debt Return	100	x	2.75%	=	2.8
Pre-Tax Equity Return	100	x	7.69%	=	7.7
Depreciation @ 30 years	100	/	30	=	3.3
Revenue Requirement					13.8

Step 3: Project Income Statement

Income Statement	
Revenue Requirement	13.8
- D&A	3.3
- Interest Exp	2.8
= Pre-Tax Income	7.7
- Tax Expense	2.7
= Net Income	5.0
+ Depreciation	3.3
= Cash from Operations (NI + D&A)	8.3
CFO / Debt	17%
Net Income	5.0
/ Equity	50
= Return on Equity	10%

Appendix C – Inflection point data

	Average Bill / Disposable Income				Average Retail Rate (cents per kilowatt hour)				
	2008	2009	2010	2011	2008	2009	2010	2011	2008 - 2011 CAGR
West Virginia	3.4%	3.7%	4.3%	4.2%	7.06	7.90	8.79	9.39	7.4%
Michigan	2.7%	2.9%	3.2%	3.3%	10.75	11.60	12.46	13.27	5.4%
Missouri	3.1%	3.3%	3.8%	3.8%	8.00	8.54	9.08	9.75	5.1%
Kansas	2.7%	3.0%	3.4%	3.4%	8.88	9.53	10.03	10.65	4.6%
Nebraska	2.7%	2.9%	3.1%	3.0%	7.87	8.52	8.94	9.32	4.3%
Pennsylvania	3.3%	3.3%	3.7%	3.7%	11.35	11.65	12.70	13.26	4.0%
Kentucky	3.9%	4.0%	4.4%	4.2%	7.94	8.37	8.57	9.20	3.7%
North Dakota	2.7%	2.9%	2.8%	2.8%	7.51	7.58	8.13	8.58	3.4%
Ohio	3.4%	3.5%	3.9%	3.7%	10.06	10.67	11.32	11.42	3.2%
Indiana	3.5%	3.7%	3.9%	3.9%	8.87	9.50	9.56	10.06	3.2%
Wisconsin	2.9%	3.0%	3.2%	3.1%	11.51	11.94	12.65	13.02	3.1%
South Dakota	2.7%	2.9%	3.0%	2.8%	8.27	8.49	8.97	9.35	3.1%
Minnesota	2.5%	2.6%	2.7%	2.7%	9.74	10.04	10.59	10.96	3.0%
Idaho	3.1%	3.6%	3.4%	3.3%	6.99	7.80	7.99	7.87	3.0%
Oregon	3.2%	3.3%	3.2%	3.4%	8.49	8.68	8.87	9.54	3.0%
Vermont	2.9%	2.9%	3.0%	3.0%	14.48	14.90	15.57	16.26	2.9%
Tennessee	4.3%	4.4%	4.7%	4.7%	8.91	9.32	9.23	9.98	2.9%
South Carolina	4.8%	5.1%	5.6%	5.3%	9.89	10.44	10.50	11.05	2.8%
Georgia	4.3%	4.5%	4.9%	4.9%	9.93	10.13	10.07	11.05	2.7%
Colorado	2.1%	2.2%	2.5%	2.5%	10.13	10.00	11.04	11.27	2.7%
Wyoming	2.0%	2.3%	2.2%	2.3%	8.21	8.58	8.77	9.11	2.6%
Virginia	3.5%	3.9%	3.9%	3.7%	9.62	10.61	10.45	10.64	2.6%
Iowa	2.9%	3.1%	3.3%	3.0%	9.49	9.99	10.42	10.46	2.5%
New Mexico	2.5%	2.6%	2.7%	2.8%	10.01	10.02	10.52	11.00	2.4%
Washington	2.5%	2.6%	2.6%	2.7%	7.54	7.68	8.04	8.28	2.4%
Utah	2.6%	2.7%	2.8%	2.8%	8.26	8.48	8.71	8.96	2.1%
Arizona	4.1%	4.5%	4.5%	4.4%	10.27	10.73	10.97	11.08	1.9%
North Carolina	4.0%	4.4%	4.8%	4.4%	9.52	9.99	10.12	10.26	1.9%
California	2.5%	2.8%	2.7%	2.6%	13.81	14.74	14.75	14.78	1.7%
Montana	2.9%	3.0%	2.9%	3.1%	9.13	8.93	9.16	9.75	1.7%
Hawaii	6.6%	4.9%	5.4%	6.2%	32.50	24.20	28.10	34.68	1.6%
Alabama	5.2%	5.3%	5.7%	5.4%	10.40	10.66	10.67	11.09	1.6%
Alaska	3.2%	3.4%	3.1%	3.3%	16.55	17.14	16.26	17.62	1.6%
Illinois	2.6%	2.7%	2.9%	2.8%	11.07	11.27	11.52	11.78	1.6%
New Hampshire	2.9%	3.1%	3.0%	3.0%	15.68	16.26	16.32	16.52	1.3%
District of Columbia	1.8%	1.9%	2.1%	1.8%	12.79	13.76	14.01	13.40	1.2%

	Average Bill / Disposable Income				Average Retail Rate (cents per kilowatt hour)				
	2008	2009	2010	2011	2008	2009	2010	2011	2008 - 2011 CAGR
Oklahoma	3.6%	3.6%	4.0%	4.0%	9.09	8.49	9.14	9.47	1.0%
United States	3.4%	3.6%	3.7%	3.6%	11.26	11.51	11.54	11.72	1.0%
New Jersey	3.0%	3.0%	3.3%	3.0%	15.66	16.31	16.57	16.23	0.9%
New York	3.1%	3.0%	3.2%	3.1%	18.30	17.50	18.74	18.26	-0.1%
Florida	4.3%	5.0%	4.6%	4.3%	11.65	12.39	11.44	11.51	-0.3%
Delaware	4.4%	4.5%	4.7%	4.3%	13.93	14.07	13.80	13.70	-0.4%
Mississippi	5.4%	5.3%	5.6%	5.3%	10.39	10.22	9.87	10.17	-0.5%
Nevada	3.8%	4.4%	4.1%	3.7%	11.93	12.86	12.36	11.61	-0.7%
Arkansas	4.1%	4.1%	4.3%	4.1%	9.27	9.14	8.86	9.02	-0.7%
Maryland	4.1%	4.4%	4.4%	3.7%	13.84	14.98	14.32	13.31	-1.0%
Maine	3.1%	3.0%	2.9%	2.8%	16.20	15.65	15.71	15.38	-1.3%
Connecticut	3.6%	3.9%	3.6%	3.3%	19.55	20.33	19.25	18.11	-1.9%
Louisiana	4.6%	3.7%	4.3%	4.1%	10.28	8.10	8.98	8.96	-3.4%
Texas	4.9%	5.0%	4.7%	4.6%	13.04	12.38	11.60	11.08	-4.0%
Massachusetts	2.9%	2.8%	2.6%	2.4%	17.68	16.87	14.59	14.67	-4.6%
Rhode Island	3.3%	2.9%	3.0%	2.6%	17.45	15.60	15.92	14.33	-4.8%

The inflection point data contains average household income statistics from the Bureau of Economic Analysis (BEA) and average retail electric prices according to the Energy Information Administration (EIA). As the EIA information contains average retail prices throughout each state, including the rates charged by municipal utilities and generation and transmission cooperatives, a specific investor owned utility's rates and CAGR may differ from the averages presented here.

Moody's Related Research

Industry Outlooks:

» 2013 Utilities and Power Outlook Presentation, December 2012 (148183)

» Six Month Update: US Regulated Utilities Outlook Stable, But Plentiful Gas Changes The Landscape, July 2012 (143891)

» Six Month Update: US Unregulated Power Companies, July 2012 (143650)

» US Regulated Electric and Gas Utilities: Stable Despite Rising Headline Rhetoric, January 2012 (137878)

» US Unregulated Power Companies: Hunkering Down in Hope for Better Prices, January 2012 (138140)

Special Comments:

» Global Oil and Natural Gas Industry: Oil Prices Support Global Investment in 2013, But Demand Challenges Remain, January 2013 (148596)

» Global Infrastructure Focus Newsletter, January 2013 (148638)

» US Extends Tax Credit for Wind Power, a Credit Positive for Developers and Utilities, January 2013 (148915)

» Questioning the New York-New Jersey Metropolitan Electrical Grid After Hurricane Sandy, December 2012 (147995)

» Sandy Hits New York Area Utilities Hard But Leaves Credit Quality Intact, November 2012 (147069)

» Pacific Northwest Utilities: Regulatory Support Paves Way for Improving Credit Profiles, November 2012 (146170)

» US Unregulated Utilities and Power Companies: Rising Rate Pressure for Investment-Grade Issuers as Speculative-Grade Restructurings Move Center Stage, November 2012 (146765)

» US Utilities: Low Gas Prices and Weak Demand are Masking US Nuclear Plant Reliability Issues, November 2012 (146663)

» US Investor-Owned Utilities: High Capital Expenditures Adding to Rate Pressure for Utilities, October 2012 (144792)

» US Investor-Owned Utilities: Bonus Depreciation and Pension Adjustments Create Short Term Cash Bridge But Longer Term Issues Persist, October 2012 (146039)

» Decoupling and 21st Century Rate Making: Increased Usage of Decoupling Mechanisms is Credit Positive, November 2011 (136797)

Rating Methodologies:

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

» Natural Gas Pipelines, November 2012 (146415)

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» contacts continued from page 1

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Credit Opinion: Exelon Corporation

Global Credit Research - 12 Feb 2013

United States

Ratings

Category	**Moody's Rating**
Outlook	Stable
Issuer Rating	Baa2
Senior Unsecured	Baa2
Subordinate Shelf	(P)Baa3
Pref. Shelf	(P)Ba1
Commercial Paper	P-2
Commonwealth Edison Company	
Outlook	Stable
Issuer Rating	Baa2
First Mortgage Bonds	A3
Senior Unsecured	Baa2
Pref. Shelf	(P)Ba1
Commercial Paper	P-2
Exelon Generation Company, LLC	
Outlook	Stable
Issuer Rating	Baa2
Senior Unsecured	Baa2
Pref. Shelf	(P)Ba1
Commercial Paper	P-2

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Key Indicators

[1]Exelon Corporation

	LTM09/30/2012	**2011**	**2010**	**2009**
(CFO Pre-W/C + Interest) / Interest	**6.2x**	**8.5x**	**7.3x**	**6.7x**
(CFO Pre-W/C) / Debt	**24.3%**	**43.0%**	**37.1%**	**36.0%**
RCF / Debt	**23.7%**	**34.8%**	**33.0%**	**31.4%**
FCF / Debt	**-1.6%**	**8.0%**	**6.5%**	**10.0%**

[1] All ratios calculated in accordance with the Unregulated Utilities and Power Companies Rating Methodology using Moody's standard adjustments.

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Consolidated credit metrics declining from strong historical levels

Challenging environment for unregulated power companies

Dividend reduction helps to stabilize credit quality

System wide capital requirements remain material

Regulated operations remain important

Hedging strategies influence cash flow predictability

IRS dispute, a credit overhang

Corporate Profile

Exelon Corporation (Exelon; Baa2, stable) is the holding company for non-regulated subsidiary, Exelon Generation Company, LLC (ExGen; Baa2, stable) and for regulated subsidiaries: PECO Energy Company (PECO; A3, stable), Baltimore Gas and Electric Company (BGE: Baa1; senior unsecured, stable) and Commonwealth Edison Company (CWE; Baa2, stable).

ExGen is one of the largest competitive electric generation companies in the US, as measured by owned and controlled megawatts (MW) with net capacity of 37,295 MW, including 17,115 MW of owned-nuclear capacity and 1,925 MW of nuclear capacity owned through a joint venture. In addition, the company controls another 6,125 MW of capacity through long-term contracts. ExGen also owns Constellation Energy Group's (CEG) retail supply business that serves about 170 terawatt-hours of load consumed by 35,000 commercial and industrial customers and millions of households through retail and wholesale sales contracts. ExGen is regulated by the Federal Energy Regulatory Commission (FERC) and by the Nuclear Regulatory Commission (NRC).

PECO provides transmission and distribution (T&D) service to about 1.6 million electric customers in Philadelphia as well as several surrounding Pennsylvania counties. PECO also provides gas distribution service to 490,000 natural gas customers in areas outside the city. PECO is regulated by the Pennsylvania Public Utility Commission (PAPUC) and by FERC.

BGE is a regulated electric T&D utility and gas distribution utility providing electricity and gas services to the city of Baltimore and ten other counties in Maryland. BGE is regulated by the Maryland Public Service Commission (MPSC) and FERC.

CWE is an electric T&D utility providing service to 3.8 million customers across northern Illinois. CWE is regulated by the Illinois Commerce Commission (ICC) and by FERC.

SUMMARY RATING RATIONALE

Exelon's Baa2 rating reflects strong consolidated credit metrics, owing to the financial performance of its unregulated generation subsidiary, and the generally predictable cash flows at its T&D subsidiaries. While the T&D subsidiaries are sizeable standalone companies, the rating is influenced primarily by the performance of its unregulated segment, which has increased in size and importance with the CEG merger. The rating recognizes that following Exelon's decision to reduce the common dividend by 40%, the parent's funding requirements for the common dividend and for other holding company expenses, including debt service, can more comfortably be provided by its rate regulated subsidiaries. This is particularly the case after 2014 as earnings from the rate regulated investments grow and as the prohibition on BGE providing a dividend to Exelon is lifted. To that end, the Baa2 rating factors in some degree of structural subordination as we view the collective credit quality of the three regulated transmission and distribution companies as carrying Baa1 rating characteristics.

DETAILED RATING CONSIDERATIONS

-Consolidated credit metrics declining from historical levels

Exelon's historical consolidated credit metrics position the company strongly in the current category as an unregulated power holding company; however, future financial results are expected to cause those metrics to decline over the next several years owing to lower margins caused primarily by sustained low natural gas prices.

From 2009 through 2011, we calculate that the three year average of Exelon's cash flow (CFO pre-W/C) to debt at

39%, retained cash flow to debt at 33%, free cash flow to debt at 8.0%, and cash flow coverage of interest expense at 7.3x. By comparison, through 12 months ending 09/30/2012, we calculate cash flow to debt at 24.3%, retained cash flow to debt at 23.7%, cash flow coverage of interest expense of 6.2.x with negative free cash flow to debt of (-1.6%).

-Operates in a very challenging sector

The unregulated power sector remains challenged owing to sustained low natural gas prices, tepid economic growth causing flat demand for electricity, increased operating costs, including pension obligations, an increase in renewable resources and increased use of energy efficient products which appears to be permanently reducing electric load in some regions. A more unsettling factor is our view that many of the factors affecting profitability and cash flows for unregulated companies are largely beyond management's control. A related sector challenge is the ability to organically grow business activities, particularly in a shareholder and creditor neutral manner. We believe that a motivating factor behind the CEG merger was intended to address earnings growth. The merger is expected to garner the strategic benefits of linking a company that is long on generation with a company that is long on customer load. As a byproduct of this linkage, the merger has considerably reduced consolidated liquidity requirements and should enable the merged company to receive somewhat better margins for its electric output given the stickiness of customer load. That being said, we believe that the better balanced combined merchant operation remains exposed to earnings and cash flow volatility due to the large size of the unregulated business platform where financial results remain heavily influenced by market determined commodity pricing levels.

-Revised dividend policy has helped to stabilize credit quality

On February 7th, Exelon announced that it would reduce its common dividend by 40% enhancing retained cash flow and free cash flow across the company by more than $700 million. We view this action along with the decision to defer growth capital investment as supportive of credit quality which highlights management's strong interest in maintaining an investment grade rating at all legal registrants. Moreover, over time, Exelon's decision to reduce the common dividend will lead to the collective earnings from the rate regulated subsidiaries being able to largely satisfy the parent's funding requirements. This is particularly the case after 2014 as earnings from the rate regulated investments are expected to grow and the prohibition on BGE providing a dividend to Exelon is lifted.

-Material capital requirements expected to continue

Exelon continues to have substantial capital requirements across its business lines. During 2012, Exelon spent $5.9 billion, of which $3.7 billion was spent in support of its unregulated operations. The remaining $2.2 billion was spent across the three regulated T&D utilities, with the largest component being spent at CWE.

In October 2012, Exelon announced that it would defer $1.025 billion of capital investment for extended power nuclear up-rates at its LaSalle and Limerick nuclear plants until 2017 and that it also removed $1.25 billion of growth capital investments for new renewable projects from its capital budget.

Still, 2013's capital investment at Exelon is substantial at $5.5 billion with ExGen spending a little more than half of this amount ($2.85 billion). Capital requirements for 2014 and 2015 remain material, exceeding $4.8 billion and $5.3 billion, respectively, with the majority of the capital investment in these two years being currently earmarked for the T&D utilities.

With the reduction in the Exelon dividend, management intends to focus around growth investments that will enhance shareholder value. We understand that these initiatives could include incremental rate regulated and contracted generation investments, both of which would likely be viewed as benign to ExGen and Exelon's credit quality. We also believe that given ExGen's sizeable unregulated footprint in the wholesale and retail energy space, incremental investments intended to augment this position will continue.

-Hedging strategies influence cash flow predictability

As an unregulated wholesale energy company whose gross margin can be materially impacted by changes in commodity prices, commercial strategy remains an important rating factor. Exelon manages its ratable hedging program over a 36 month cycle with targets of 90% or more of expected generation hedged in the first year, 70-90% in the second year, and less than 50% in the third year. At December 31, 2012, we understand that ExGen was 94-97% hedged for 2013, 62%-65% for 2014 and 27%-30% for 2015.

-Regulatory Environment

We view the regulatory environment in Pennsylvania to be generally credit supportive. The transition to market rates for electricity has proceeded relatively smoothly although the transition was aided by low natural gas prices which reduced market prices for electricity during the transition period.

In February 2012, the state's governor signed into law (Act 11) a measure that allows for the implementation of a distribution system improvement charge (DSIC) in rates designed to recover capital project costs incurred to repair, improve or replace utilities' aging electric and natural gas distribution systems. We view the terms of this legislation as supportive to utility credit quality.

To qualify for the DSIC, utilities are required to submit a long-term infrastructure improvement plan, which will be reviewed by the PAPUC every 5 years, and a certification that a base rate case has been or will be filed within 5 years. The DSIC cannot exceed 5% of distribution rates and will be reset to zero if the utility's return on equity exceeds the allowable rate of return under the DSIC. The law also includes a provision that allows utilities to use a fully projected future test year under which the PAPUC may permit the inclusion of projected capital costs in rate base for assets that will be placed in service during the future test year. On August 2nd, the PAPUC issued a final order that implements portions of Act 11, which among other things, provides for a DSIC for electric, natural gas, water and wastewater utilities.

In Maryland, we consider the relationship between BGE and the MPSC to be challenging but improving. In order for the CEG merger to be completed, the MPSC required several conditions from Exelon. Among the conditions were that Exelon provide a $100 rate credit to every residential customer 90 days after merger close ($113 million), that Exelon build up to 300 MW of generation within Maryland, that Exelon construct a new office building in Baltimore for its unregulated platform and that Exelon fund a $113.5 million investment in energy efficiency over the next three years. The MPSC also implemented provisions intended to insulate BGE from the rest of the organization, including language that prohibits BGE from paying a dividend to Exelon through 2014.

On October 22, 2012, BGE updated its application with the MPSC requesting increases of $130 million and $46 million to its electric and gas base rates, respectively, based upon a requested ROE of 10.5%. The Office of People's Counsel has recommended that the MPSC authorize the company a $55.9 million electric and gas rate increase premised upon a 9.1% return on equity for electric and 9.0% for gas. Also, the MPSC's staff has recommended a combined electric and gas rate increase of $102.8 million with an ROE of 9.35% for electric and 9.4% for gas. The MPSC is expected to issue a decision in BGE's pending distribution rate case on February 23rd.

CWE continues to operate in a somewhat improved, but still very challenging regulatory environment for electric utilities in Illinois resulting in lingering concerns about the framework's predictability. On December 30, 2011, the Energy Infrastructure Modernization Act (EIMA) was signed into law. EIMA established a new formula-rate-plan (FRP) distribution ratemaking paradigm for the state's electric utilities and was intended to spur utility infrastructure investment. The legislation requires CWE to invest $1.3 billion over a five-year period in electric system upgrades and modernization projects, along with at least $1.3 billion over a 10-year period in transmission and distribution assets and smart-grid system upgrades. Key aspects of the FRP calculation include cost recovery of the utility's actual capital structure, excluding goodwill; a legislatively-set formula for purposes of calculating the allowed ROE; and recovery of pension-related costs. While passage of EIMA is a credit positive from a cost recovery standpoint, the ICC's implementation of EIMA has been inconsistent for all Illinois electric utilities supporting our continuing view of a below average regulatory environment for Illinois electric utilities.

On May 29, 2012, the ICC ordered a $168.6 million rate reduction premised upon a 10.05% ROE. In its order, the ICC rejected CWE's request to collect a debt-only return on its "pension asset" and adopted the intervening parties' recommendation to rely on an average capital structure and an average rate base calculation in prospective FRP-related revenue requirement reconciliations versus the language in the law that contemplates the use of year-end values for capital structure and rate base. On Ocotber 3, 2012, the ICC reversed its decision on the pension-asset issue but maintained their view regarding an average capital structure and an average rate base calculation, even though the legislation contemplates year-end capital structure and rate base. The decision has been appealed to the Illinois state courts. A short-term resolution of this issue is not expected. CWE has indicated that the continued uncertainty around the implementation of EIMA will influence the speed at which capital infrastructure investment is made in Illinois.

In December 2012, ICC issued the second formula decision authorizing CWE an $72.6 million rate increase premised upon a 9.71% return on equity. While the outcome was only $2 million less than the company's ask, CWE's supported position reflected the rate impact of the ICC decision in the initial FRP proceeding, including the methodology used to calculate rate base and capital structure, both of which remain under appeal in the Illinois courts. As such, CWE's position does not reflect the full revenue requirement expected had the FRP been implemented in a manner consistent with CWE's interpretation of the legislation.

-Overhang with IRS case

On January 9, 2013, the US Court of Appeals reached a decision for the government in a lawsuit involving Consolidated Edison's (ConEd's) participation in a lease-in, lease-out (LILO) transaction that the IRS also has characterized as a tax shelter. Specifically, the Court disallowed ConEd's deductions stemming from its participation in this investment.

CWE deferred $1.2 billion of gain on the 1999 sale of its fossil generating facilities by acquiring like-kind property via a purchase leaseback transaction. The IRS has asserted that the Exelon purchase leaseback transaction is substantially similar to a leasing transaction known as a sale-in, lease-out transaction (SILO). Exelon continues to believe that its like-kind exchange transaction is not the same as or substantially similar to a SILO. Exelon expects to initiate litigation in 2013 to contest the IRS disallowance of the like-kind exchange position.

In light of the ConEd decision and Exelon's current determination that a settlement is unlikely, Exelon expects to record in the first quarter of 2013 a non-cash charge to earnings of approximately $270 million, which represents the full amount of interest expense (after-tax) and incremental state tax expense in the event that Exelon is unsuccessful in litigation.

We understand that Exelon expects to hold CWE harmless from any unfavorable impacts of the after-tax interest amounts on CWE's equity. As of March 31, 2013, in the event of a fully successful IRS challenge to Exelon's like-kind exchange position, the potential tax and after-tax interest, exclusive of penalties, that could become currently payable may be as much as $860 million, of which approximately $260 million would be attributable to CWE and the remainder to Exelon.

Liquidity

Beginning in 2013, Exelon's liquidity arrangements totaled $8.4 billion. Approximately, $6.2 billion supports its unregulated business platform, including $500 million at Exelon and nearly $5.7 billion at ExGen, while the regulated businesses have access to $2.2 billion of liquidity -- $600 million at PECO, $600 million at BGE and $1 billion at CWE. In August 2012, the Exelon and ExGen facilities along with credit facilities at PECO and BGE were extended to August 2017. The CWE facility expires March 2017.

At January 30, 2013, Exelon and ExGen had no commercial paper outstanding, but had $1.7 billion of letters of credit outstanding, leaving ample availability of $4.5 billion for the unregulated business. At the regulated utilities, at January 30th, no commercial paper was outstanding at any of three utilities and there was a $1 million letter of credit issued under the PECO line.

The core syndicated credit facilities are used primarily to provide liquidity support and for the issuance of letters of credit. While the credit agreements do not contain any rating triggers that would affect borrowing access to the commitments and do not require material adverse change (MAC) representation for borrowings or the issuance of LOCs, there is a financial covenant for each entity, all of which are compliant.

As of the last reporting period (September 30, 2012), in the event that ExGen were downgraded below investment grade, ExGen could be required to post additional collateral of $2.0 billion. If CWE was downgraded below investment grade, it would be required to post $218 million. If PECO and BGE were each downgraded to below investment grade, they would have been required to post $31 million and $54 million, respectively, of additional collateral.

During 2012, Exelon and its subsidiaries were active issuers of long-term capital market debt. On June 18, 2012, ExGen issued $775 million of senior unsecured notes, including $275 million of 4.25% notes due 2022 and $500 million of 5.60% notes due 2042. Concurrent with the new debt issuance, ExGen announced an exchange offer of Exelon's 7.6% $700 million senior unsecured notes due 2032 (formerly CEG obligations assumed by Exelon) into either the newly issued ExGen 4.25% senior unsecured notes due 2022 or ExGen's 5.60% senior unsecured notes due 2042. ExGen purchased $442 million of the old notes in exchange for issuing $537 million of senior unsecured notes due in 2022 and 2042, plus a cash payment of approximately $60 million.

In addition to the above, in August 2012, BGE issued $250 million of 2.8% senior unsecured notes due 2022; in September 2012 PECO offered $350 million of 2.375% first mortgage bonds due 2022; and in October 2012, CWE issued $350 million of 3.8% first mortgage bonds due 2042.

Structural Considerations

For the last several years, Exelon has refinanced holding company debt with debt issued at ExGen. Exelon currently has $1.3 billion of remaining holding company debt, $800 million that matures in 2015 and $500 million that matures in 2035. Additionally, at merger close, Exelon legally assumed the obligations of CEG's publicly-held debt, guarantees and other contracts adding $1.8 billion of senior debt and $450 million of subordinated debt to Exelon. Approximately $442 million of the old notes were exchanged into $537 million of ExGen securities. For these reasons, when evaluating ExGen, we examine historical and projected financial metrics for ExGen with the debt of Exelon holding company incorporated into the analysis.

Rating Outlook

The stable rating outlook for Exelon considers the benefits to credit quality from deferring growth capital investments and from the parent's decision to reduce the dividend by 40%. The stable rating outlook factors in our belief that with the dividend cut, holding company liquidity requirements will in the long-run be funded more with the cash flow generated from three large rate regulated utility systems, particularly beginning after 2014.

What Could Change the Rating - Up

In light of the challenges facing the unregulated power sector, including sustained weakened margins, the ratings at Exelon are not likely to be upgraded in the near-term. To the extent that growth initiatives center around acquisitions of rate regulated businesses, credit quality for Exelon could be enhanced, particularly if such an acquisition was financed in a credit friendly fashion.

What Could Change the Rating - Down

The rating could be downgraded if weaker than expected financial performance surfaced either as a result of a further sustained drop in operating margins across the unregulated power sector or a substantial outage at several of the company's generating assets resulting in negative free cash being financed with material incremental indebtedness. Additionally, negative rating pressure could surface if adverse regulatory decisions at one or more of the utility subsidiaries occurred particularly at CWE or PECO since both are larger than BGE. From a financial perspective, Exelon's ratings could be downgraded if cash flow to debt fell below 20%, retained cash flow to debt below 12%, and cash flow interest coverage approached 4.5x on a sustained basis.

Other Considerations

Given the size of the unregulated revenues, earnings, and cash flow, Moody's evaluates Exelon's financial performance relative to the Unregulated Utilities and Power Companies methodology and, as depicted below, Exelon's indicated rating under the grid based on historical results and from projected results (next 12-18 months) is Baa2.

Rating Factors

Exelon Corporation

Power Companies [1][2]	LTM09/30/2012		Moody's 12-18 month Forward View* As of February 2013	
Factor 1: Market Assessment, Scale and Competitive Position (20%)	**Measure**	**Score**	**Measure**	**Score**
a) Market and Competitive Position (15%)		A		A
b) Geographic Diversity (5%)		Baa		Baa
Factor 2: Cash Flow Predictability of Business Model (20%)				
a) Hedging strategy (10%)		Baa		Baa
b) Fuel Strategy and mix (5%)		Ba		Ba
c) Capital requirements and operatinal performance (5%)		Baa		Baa

Factor 3: Financial policy (10%)		Baa		Baa
Factor 4: Financial Strength - Key Financial Metrics (50%)				
a) CFO pre-WC + Interest / Interest (15%) (3yr Avg)	7.3x	A	5.5 - 6.0x	Baa
b) CFO pre-WC / Debt (20%) (3yr Avg)	32.4%	Baa	23 - 26%	Baa
c) RCF / Debt (7.5%) (3yr Avg)	28.0%	A	18 - 20%	Baa
d) FCF / Debt (7.5%) (3yr Avg)	3.2%	Ba	(2) - 0%	B
Rating:				
a) Indicated Rating from Grid		Baa2		Baa2
b) Actual Rating Assigned		Baa2		Baa2

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of 09/30/2012(L); Source: Moody's Financial Metrics

MOODY'S
INVESTORS SERVICE

MOODY'S
INVESTORS SERVICE

Credit Opinion: Commonwealth Edison Company

Global Credit Research - 05 Mar 2013

Chicago, Illinois, United States

Ratings

Category	**Moody's Rating**
Outlook	Stable
Issuer Rating	Baa2
First Mortgage Bonds	A3
Senior Unsecured	Baa2
Pref. Shelf	(P)Ba1
Commercial Paper	P-2
Parent: Exelon Corporation	
Outlook	Stable
Issuer Rating	Baa2
Senior Unsecured	Baa2
Subordinate Shelf	(P)Baa3
Pref. Shelf	(P)Ba1
Commercial Paper	P-2
ComEd Financing III	
Outlook	Stable
BACKED Pref. Stock	Baa3

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Key Indicators

[1]Commonwealth Edison Company

	2012	2011	2010	2009
(CFO Pre-W/C + Interest) / Interest Expense	4.7x	5.2x	3.9x	4.0x
(CFO Pre-W/C) / Debt	19%	25%	20%	20%
(CFO Pre-W/C - Dividends) / Debt	17%	21%	15%	16%
Debt / Book Capitalization	37%	38%	39%	40%

[1] All ratios calculated in accordance with the Global Regulated Electric Utilities Rating Methodology using Moody's standard adjustments.

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Regulatory environment remains unpredictable despite credit supportive legislation

Sizeable capital program

Strong credit metrics for rating category

Parent's dividend reduction enhances ComEd's internal cash flow

Dispute with IRS remains an overhang credit issue

Corporate Profile

Commonwealth Edison Company (ComEd) is a regulated electric transmission and distribution company and a subsidiary of Exelon Corporation (Exelon: Baa2 stable). ComEd provides energy delivery services to retail and wholesale customers in northern Illinois, including the city of Chicago. ComEd is regulated by the Illinois Commerce Commission (ICC) and the Federal Energy Regulatory Commission (FERC). At December 31, 2012, ComEd had total assets of $22.91 billion.

SUMMARY RATING RATIONALE

ComEd's Baa2 senior unsecured rating primarily reflects an improving but still unpredictable state regulatory environment in which the company operates. The 2011 passage of EIMA improved the cost recovery framework; however, implementation of the law has been a challenge for Illinois electric utilities. The rating factors in continuing strong credit metrics for its rating category, good liquidity management, a sizeable capital spending program, and a diverse regional economy which helps mitigate the financial impact from the still weak economic recovery. The rating further recognizes the expected enhancement to ComEd's internal cash flow following Exelon's decision to reduce its common dividend by 40%. A longer-term credit overhang remains owing to ComEd's ongoing exposure to litigation with the IRS.

DETAILED RATING CONSIDERATIONS

Regulatory environment remains unpredictable despite credit supportive legislation

ComEd's rating recognizes an improving, but still challenging regulatory environment for utilities in Illinois. Continuing complications with the implementation of the formula-rate-plan (FRP) has reinforced previous concerns over the predictability of the regulatory environment.

On 30 December 2011, the Energy Infrastructure Modernization Act (EIMA) became law. The EIMA established a new distribution, performance based FRP ratemaking paradigm for the state's largest electric utilities with an intention to spur utility infrastructure investment. The legislation required ComEd to invest $1.3 billion over a five-year period in electric system upgrades, modernization projects, and training facilities, and at least $1.3 billion over a 10-year period in transmission & distribution assets and smart-grid system upgrades. While EIMA has the potential to create a concrete, dependable regulatory framework, the ICC's interpretation of certain aspects of EIMA has resulted in lower than expected financial results for the utilities, including ComEd, leading to litigation, lower investment by the utilities, and the prospect of additional legislation.

On 29 May 2012, the ICC issued an order in its initial FRP filing that reduced ComEd's annual revenue requirement by $168 million, approximately $110 million more than proposed by the company. The reduction included $50 million that the ICC determined could be recovered through alternative rate proceedings, $35 million for the disallowance of a return on pension assets, $10 million for incentive compensation related adjustments, and $15 million for various adjustments on other technical items. The ICC agreed to rehear some of the issuer's appeal and on 3 October 2012, the ICC issued its final order in that rehearing, adopting ComEd's position on the return on its pension asset, resulting in an increase in ComEd's annual revenue requirement. However, in two other areas, the ICC ruled against ComEd by reaffirming use of an average rather than year-end rate base in ComEd's reconciliation revenue requirement; and amending its prior order to provide a short-term debt rate as the appropriate interest rate to apply to under/over recoveries of incurred costs. ComEd filed an appeal with the courts on 4 October 2012. New rates reflecting the impacts of the rehearing order went into effect in November 2012.

In December 2012, ICC issued the second FRP for ComEd authorizing the utility an $72.6 million rate increase. While the outcome was only $2 million less than the company's ask, ComEd's position reflected the rate impact of the ICC decision in the initial FRP proceeding, including the methodology used to calculate rate base and capital structure, both of which remain under appeal in the Illinois courts. As such, ComEd's position does not reflect the full revenue requirement expected had the FRP been implemented in a manner consistent with the company's interpretation of the legislation.

In light of these developments, the Illinois legislature has introduced Senate Bill 9 (SB 9), to further clarify the perceived ambiguity around EIMA by the ICC, specifically the FRP process. The new bill includes language indicating that the ICC should use year-end rate base values and year-end capital structures in all rate reconciliations. Additionally, SB 9 specifies that any reconciliation-related amounts should accrue interest calculated using the weighted average cost of capital. If passed, the bill will supersede the ICC's previous orders to the extent that the orders are inconsistent with the bill, allowing companies to retroactively recover any amounts not previously authorized for recovery. On 13 February 2013, the Illinois Senate Executive Committee voted unanimously to pass SB 9, and the bill will now be considered by the full Senate. We understand that there is broad bipartisan support for SB 9 in both the Senate and the House and that such a vote, when taken, will likely pass with a veto-proof majority. The 2013 legislative session is expected to conclude on May 31st.

Material Capital Investment

ComEd's capital expenditure program has increased in each of the last two years primarily to maintain and strengthen the transmission and distribution network in and around its service territory, and for infrastructure spending related to smart grid deployment. In 2011 and 2012, capital expenditures increased to $1.0 billion and $1.2 billion, respectively, as compared to the three year average of $923 million over the 2008-2010 period. Following the outcome of the above-referenced ICC rehearing in October 2012, ComEd deferred $65 million of planned spend in 2012 and plans to defer an additional $335 million of smart meter and other infrastructure spend from the 2013-2014 period to 2015 and beyond. We anticipate that capital spending will approximate $1.4 billion during 2013.

Strong Credit Metrics for the Current Rating

For the past three years, ComEd has produced very strong credit metrics for the Baa rating category. Cash flow (CFO pre W/C) to debt has averaged around 21.2%, cash flow coverage of interest expense has averaged 4.6x while retained cash flow to debt has averaged 17.6% for the past three years, all of which are reflective of a higher Baa rating. Some of this financial performance can be attributed to the receipt of bonus depreciation, which is not a sustainable source of cash flow. During 2011, Exelon's utilized the incremental cash sourced by bonus depreciation to voluntarily make a sizable contribution to ComEd's pension plan, an action we viewed as credit positive. Prospectively, and factoring in the loss of bonus depreciation in the near-term financial results, we believe that ComEd will produce credit metrics that will strongly position the company within the Baa2 rating category.

Parent's dividend reduction enhances ComEd's internal cash flow

On 7 February 2013, Exelon announced that it would reduce its common dividend by 40% which will enhance retained cash flow and free cash flow across the company by $740 million. We view this action as being supportive of credit quality and highlights management's strong commitment to maintain an investment grade rating at all legal registrants. Exelon's revised dividend policy contemplates that the utilities, including ComEd, pay out an average of 65-70% of their respective earnings.

IRS dispute remains an overhang credit issue

Exelon, through ComEd, is involved in a tax dispute with the IRS relating to a portion of the tax gain associated with the 1999 sale of ComEd's fossil generating assets. Specifically, about $1.2 billion of the gain was deferred by reinvesting the proceeds from the sale in qualifying replacement property under the like-kind exchange provisions. The like-kind exchange replacement property purchased by Exelon included interests in three municipal-owned electric generation facilities which were leased back to the municipalities.

Exelon has been unable to reach agreement with the IRS regarding the dispute over the like kind exchange position. The IRS has asserted that the Exelon purchase and leaseback transaction is substantially similar to a leasing transaction, known as a SILO, which the IRS does not respect as the acquisition of an ownership interest in property.Exelon disagrees with the IRS and continues to believe that its like-kind exchange transaction is not the same as or substantially similar to a SILO. Exelon expects to initiate litigation in 2013 to contest the IRS's disallowance of the like-kind exchange position.

On 9 January 2013, the U.S. Court of Appeals for the Federal Circuit reversed the U.S. Court of Federal Claims and reached a decision for the government disallowing Consolidated Edison's deductions stemming from its participation in a LILO transaction that the IRS also has characterized as a tax shelter.

In light of the Consolidated Edison decision and Exelon's current determination that a settlement is unlikely, Exelon has concluded that it will record a non-cash charge to earnings of approximately $270 million in the first quarter of

2013, which represents the full amount of interest expense (after-tax) and incremental state tax expense in the event that Exelon is unsuccessful in litigation. Of this amount, approximately $185 million will be recorded at ComEd and the balance at Exelon. Exelon intends to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts on ComEd's equity.

At 31 March 2013, in the event of a fully successful IRS challenge to Exelon's like-kind exchange position, the potential tax and after-tax interest, exclusive of penalties, that could become currently payable may be as much as $860 million, of which approximately $320 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless with the balance at Exelon.

Liquidity

ComEd's Prime-2 short-term rating for commercial paper reflects our view that the company will maintain adequate liquidity for the next 4 quarters.

On 28 March 2012, ComEd entered into a new five year unsecured revolving credit agreement for $1 billion, expiring in 2017. This credit facility is used primarily to provide liquidity support and for the issuance of letters of credit. As of 31 December 2012, there were no borrowings or letters of credit outstanding under the facility. While the credit agreement does not contain any rating triggers that would affect borrowing access to the commitment and does not require any material adverse change (MAC) representation for borrowings, there is a requirement to maintain a ratio of net cash flow from operations to net interest expense at a minimum level of at least 2.0 times. At 31 December 2012, ComEd's ratio of net cash flow from operations to net interest expense was 6.14x. Cash on hand at 31 December 2012 was $144 million.

In light of the ample capital investment program anticipated at the utility, we expect ComEd being free cash flow negative for the next few years. That said, in light of the higher capital spending at ComEd, we do not believe that the utility's dividend will reach the higher end of the above-referenced targeted 70% payout level. In that vein, we note that ComEd paid $105 million of dividends during 2012 representing 28% of ComEd 2012 earnings. ComEd has approximately $252 million of debt maturing in 2013 and $600 million in 2014. We anticipate the company seeking to access the capital markets to refinance a substantial portion of this debt given the capital requirements of the utility.

As of 31 December 2012, if ComEd lost its investment grade credit rating, it could be required to provide $218 million of incremental collateral.

Rating Outlook

ComEd's rating outlook is stable reflecting an expectation that financial results will remain strong for the rating category, particularly with the passage of EIMA. Although the regulatory environment remains challenging and unpredictable, we believe that the latest credit supportive legislation will improve cost recovery under the FRP. ComEd's stable outlook further incorporates our belief the company's dividend policy will continue to remain sensible in light of the utility's increased capital spending requirements.

What Could Change the Rating - Up

In light of our March 2012 one notch upgrade of ComEd's ratings, the challenges that have occurred in implementing ratemaking under EIMA, and the increased capital spending anticipated at ComEd, limited prospects exist for the utility's ratings to be upgraded in the near-term. However, upward rating pressure can surface if the new regulatory framework is seamlessly implemented and accepted as a workable model by key constituents in the state, resulting in more predictable financial results for the state's utilities. Specifically, consideration of a higher rating could emerge if ComEd's the ratio of cash flow to debt exceeds 20% and its cash flow interest coverage exceeds 5.0x on a sustainable basis.

What Could Change the Rating - Down

The rating could be downgraded if EIMA ratemaking implementation is altered dramatically or terminated, if the company's cash flow to debt declines to below 16.0% or cash flow to interest expense falls below 3.5x for an extended period. Also, negative rating pressure could materialize if the outcome of a continuing IRS challenge concerning certain sale/leaseback transactions affecting Exelon and ComEd leads to substantial payments for the utility.

Other Considerations

As depicted below, ComEd's implied rating under the grid on a historical and projected basis is Baa2 on par with the current senior unsecured rating.

Rating Factors

Commonwealth Edison Company

Regulated Electric and Gas Utilities Industry [1][2]	Current 12/31/2012		Moody's 12-18 month Forward View* As of March 2013	
Factor 1: Regulatory Framework (25%)	Measure	Score	Measure	Score
a) Regulatory Framework				
Factor 2: Ability To Recover Costs And Earn Returns (25%)		Ba		Ba
a) Ability To Recover Costs And Earn Returns		Baa		Baa
Factor 3: Diversification (10%)				
a) Market Position (10%)		Baa		Baa
b) Generation and Fuel Diversity (na)		na		na
Factor 4: Financial Strength, Liquidity And Key Financial Metrics (40%)				
a) Liquidity (10%)		Baa		Baa
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	4.6x	A	4.5x - 4.8x	A
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	21.2%	Baa	18 - 22%	Baa
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	17.6%	A	15 - 18%	A/Baa
e) Debt/Capitalization (3 Year Avg) (7.5%)	38.1%	A	35 - 38%	A
Rating:				
a) Indicated Rating from Grid		Baa2		Baa2
b) Actual Rating Assigned		Baa2		Baa2

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of 12/31/2012(L); Source: Moody's Financial Metrics

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