BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan	)))))	Case No. 13-2385-EL-SSO
In the Matter of the Application of Ohio Power Company for Approval of Certain Accounting Authority	)))	Case No. 13-2386-EL-AAM

**OHIO POWER COMPANY'S APPLICATION
TO AMEND ITS ELECTRIC SECURITY PLAN**

WORKPAPERS

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WORKPAPERS
For Selwyn J. Dias

AEP Ohio

Annual performance compared to standard

(Includes areas previously called Columbus Southern Power and Ohio Power)

Excludes major events and transmission outages

Average interruptions per customer served

SAIFI	2013	2014	2015
Performance	1.03	1.13	1.13
Standard	1.20	1.20	1.20

Average minutes per customer interruption

CAIDI	2013	2014	2015
Performance	140.97	146.61	139.03
Standard	150.00	150.00	150.00

Rule 4901:1-10-10 (Rule 10) of the Ohio Administrative Code requires Ohio's investor-owned electric utilities to file an annual report of their distribution reliability performance. Specifically, Rule 10 requires the electric utilities to report their performance using the following two reliability measures (called "indices").

The System Average Interruption Frequency Index (SAIFI) represents the average number of interruptions per customer. This index measures how often an "average" customer's power is interrupted in a year and includes both those customers experiencing several interruptions per year as well as those whose power is not interrupted at all. SAIFI is calculated using the following formula:

SAIFI = Total number of customer interruptions ÷ total number of customers served

The Customer Average Interruption Duration Index (CAIDI) represents the average interruption duration. In other words, CAIDI is the average time it takes for the electric utility to restore service following a power interruption. This index measures the electric utility's average restoration time, and therefore only includes those customers who experience power outages during the year. CAIDI is calculated using the following formula:

CAIDI = Sum of customer interruption durations ÷ total number of customer interruptions

Interruptions – As used in the calculation of SAIFI and CAIDI, an interruption is defined as a complete loss of a customer's electric power for more than five minutes.

Major Event and Transmission Exclusions – Rule 10 requires utilities to exclude "major events" and transmission outages from their reliability data before calculating their CAIDI and SAIFI performance. Major events are unusually severe weather or other events that stress the company's distribution system and cause untypical outages. Days that qualify as major events are excluded from reliability performance calculations for the year. Major events are calculated using the IEEE Standard 1366-2003 (except that transmission outages are excluded). Outages caused by the company's transmission lines, which are not part of the distribution system, are similarly excluded to concentrate on measuring only the performance of the distribution system.

Performance Standards and Rule Violations – Rule 10 requires each electric utility to file performance standards for approval by the Public Utilities Commission of Ohio. The approved standards are minimum performance levels, and missing a standard for two consecutive years constitutes a rule violation. Performance standards can be revised if the utility files an application that is approved by the Commission following a legal process that is open to interested persons. Performance standards can also be revised by Commission order.

AEP Ohio Capital Spending

Year	Capital Spend ($ million)	Gross Distribution Plant ($ million)	Plant Replaced
2012	$210.1	$3,718	5.65%
2013	$242.2	$3,873	6.25%
2014	$304.0	$4,084	7.44%
2015	$298.5	$4,284	6.97%
2016	$301.5	$4,482	6.73%
2017	$301.5	$4,682	6.44%
2018	$301.5	$4,882	6.18%
2019	$301.5	$5,081	5.93%
2020	$301.5	$5,281	5.71%
2021	$301.5	$5,480	5.50%
2022	$301.5	$5,680	5.31%
2023	$301.5	$5,880	5.13%
2024	$301.5	$6,079	4.96%
Total			78.20%

* 2012 and 2024 are annualized values

Annual AEP Ohio Capital Spend 2016 - 2024
($ million)

		%
Asset Improvement	$119.4	39.6%
Customer Service	$32.2	10.7%
Forestry	$4.8	1.6%
Electric Service Support	$49.6	16.4%
Planning Capacity	$30.8	10.2%
Reliability	$54.0	17.9%
System Restoration	$10.7	3.6%
Total	$301.5	100.0%

($ Millions)							
Category	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Asset Improvement	$119.4	$119.4	$119.4	$119.4	$119.4	$119.4	$119.4
Customer Service	$32.2	$32.2	$32.2	$32.2	$32.2	$32.2	$32.2
Forestry	$4.8	$4.8	$4.8	$4.8	$4.8	$4.8	$4.8
Electric Service Suppor	$49.6	$49.6	$49.6	$49.6	$49.6	$49.6	$49.6
Planning Capacity	$30.8	$30.8	$30.8	$30.8	$30.8	$30.8	$30.8
Reliability	$54.0	$54.0	$54.0	$54.0	$54.0	$54.0	$54.0
System Restoration	$10.7	$10.7	$10.7	$10.7	$10.7	$10.7	$10.7
Total Capital	$301.5	$301.5	$301.5	$301.5	$301.5	$301.5	$301.5
Direct Cost	**$225.0**	**$225.0**	**$225.0**	**$225.0**	**$225.0**	**$225.0**	**$225.0**

Projected Capital Investment in Direct Dollars

	2016 $(M)	2017 $(M)	2018 $(M)	2019 $(M)	2020 $(M)	2021 $(M)	2022 $(M)	2023 $(M)	2024 $(M)
Asset Improvement	$78.6		$89.1						
Customer Service	$23.0		$24.0						
Forestry	$4.6		$3.6						
General	$0.0		$0.0						
Electric Service Support	$32.6		$37.0						
Planning Capacity	$17.3		$23.0						
Reliability	$36.1		$40.3						
System Restoration	$8.0		$8.0						
Total	$200.2		$225.0						

2016 Projected Investment Based on $200 M Direct

1. Based on the 2016 DIR Work Plan as filed with Staff December 2015.
2. Capital labor was split between Asset Improvement and Reliability based on planned spend levels.

			Cap Labor	Total
Asset Improvement	62.6	68%	16.0	78.6
Reliability	28.8	32%	7.3	36.1
Total	91.4			
Capital Labor	23.3			

2018 - 2024 Projected Investment Based on $225 M Direct

1. Based on the 2016 DIR Work Plan as filed with Staff December 2015.
2. Capital labor was split between Asset Improvement and Reliability based on planned spend levels.

			Cap Labor	Total
Asset Improvement	72.6	69%	16.5	89.1
Reliability	32.8	31%	7.5	40.3
Total	105.4			
Capital Labor	24			

AEP Ohio

2015-2024 Total Forecasts

(as of 3/15/2016)

O&M: $20.6 Million Base + Proposed Incremental

Capital: $3.6 Million Base + Proposed Incremental

Approximately 2.5% annual increase starting in 2019

Total Forestry

	(Actual) 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Mileage	7902.4	8165.1	7857	7829.1	7765	8036.4	8018.8	7829.1	7765	8036.4
O&M	$45,674,782	$45,629,007	$45,630,950	$47,037,794	$48,213,739	$49,419,082	$50,654,560	$51,920,924	$53,218,947	$54,549,420
Capital	$4,684,299	$4,681,325	$4,686,794	$4,792,451	$4,912,262	$5,035,069	$5,160,946	$5,289,969	$5,422,218	$5,557,774

Approved ESSR Amount in ESP III (13-2385-EL-SSO)

	2015	2016	2017	2018
O&M	$25,000,000	$25,000,000	$25,000,000	$26,300,000
Capital	$1,000,000	$1,000,000	$1,000,000	$1,100,000

Total Forestry During Extension Period

	2018	2019	2020	2021	2022	2023	2024
O&M	$47,037,794	$48,213,739	$49,419,082	$50,654,560	$51,920,924	$53,218,947	$54,549,420
Capital	$4,792,451	$4,912,262	$5,035,069	$5,160,946	$5,289,969	$5,422,218	$5,557,774

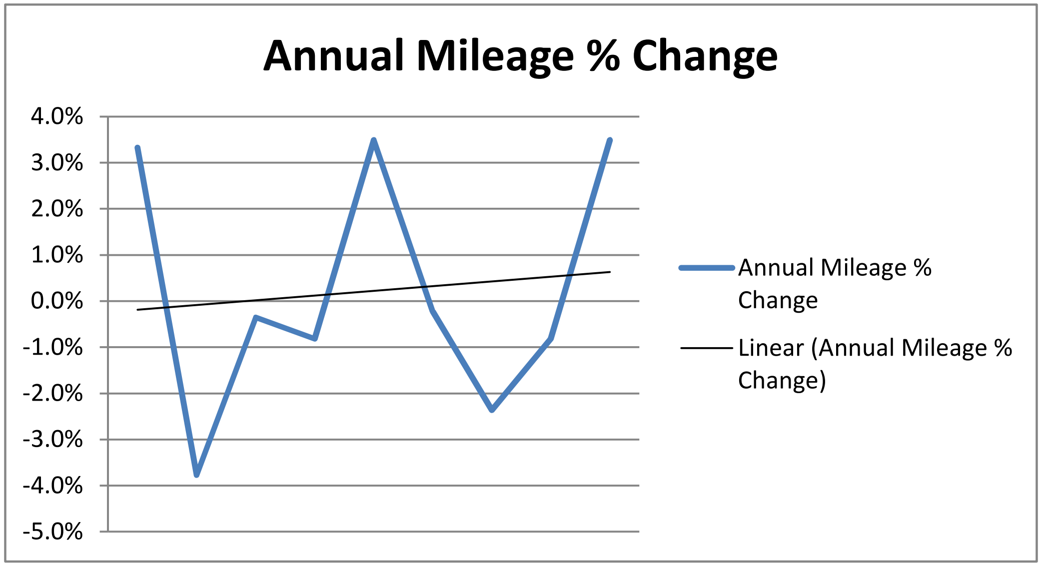
ESSR Incremental Amount During Extension Period

	2018	2019	2020	2021	2022	2023	2024
O&M	$26,467,382	$27,643,327	$28,848,670	$30,084,148	$31,350,512	$32,648,535	$33,979,008
Capital	$1,162,863	$1,282,674	$1,405,481	$1,531,358	$1,660,381	$1,792,630	$1,928,186

	2018	2019	2020	2021	2022	2023	2024
O&M	$26.5	$27.6	$28.8	$30.1	$31.4	$32.6	$34.0
Capital	$1.2	$1.3	$1.4	$1.5	$1.7	$1.8	$1.9

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Mileage	7902.4	8165.1	7857	7829.1	7765	8036.4	8018.8	7829.1	7765	8036.4	8018.8
		3.3%	-3.8%	-0.4%	-0.8%	3.5%	-0.2%	-2.4%	-0.8%	3.5%	-0.2%

Average = 0.2%



Assume 3% increase due to labor, materials, etc. Actual mileage from year to year is a flat on average.

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WORKPAPERS
For
David R. Gill

Rate / Typical Bill Assumptions

	Description	Current	Proposed	
	Base Distribution Rates	Rates as of 4/1/2016	Revenue Neutral Residential Redesign	1/
USF	Universal Service Fund Rider	Rates as of 4/1/2016	No change	
BDR	Bad Debt Rider	Rates as of 4/1/2016	No change	
kWh Tax	kWh Tax Rider	Rates as of 4/1/2016	No change	
RDCR	Residential Distribution Credit Rider	Rates as of 4/1/2016	No change	
PTBAR	Pilot Throughput Balancing Adjustment Rider	Rates as of 4/1/2016	No change	2/
DAPIR	Deferred Asset Phase-In Rider	Rates as of 4/1/2016	No change in 2017; expires in 2019	3/
GENE	Generation Energy	Rates as of 4/1/2016	GENE Estimate	4/
GENC	Generation Capacity	Rates as of 4/1/2016	GENC Estimate	4/
ACRR	Auction Cost Reconciliation Rider	Rates as of 4/1/2016	No change	15/
ETR	Electronic Transfer Rider	Rates as of 4/1/2016	No change	
PPA	Power Purchase Agreement Rider	Rates as of 4/1/2016	No change	
TCRR	Transmission Cost Recovery Rider	Rates as of 4/1/2016	Zero	5/
TURR	Transmission Under-Recovery Rider	Rates as of 4/1/2016	Zero	5/
N/A	Pilot Demand Response Rider	Rates as of 4/1/2016	No change	
EE/PDR	Energy Efficiency/Peak Demand Reduction	Rates as of 4/1/2016	EE/PDR Estimate	6/
ESRR	Enhanced Service Reliability	Rates as of 4/1/2016	ESRR Estimate	7/
gridSMART® 1	gridSMART Phase 1 Rider	Rates as of 4/1/2016	No change	
gridSMART® 2	gridSMART Phase 2 Rider	Rates as of 4/1/2016	No change	
RSR	Retail Stability Rider	Rates as of 4/1/2016	No change in 2017; expires in 2018	8/
DIR	Distribution Investment Rider	Rates as of 4/1/2016	DIR Estimate	9/
SDRR	Storm Damage Cost Recovery Rider	Rates as of 4/1/2016	No change	
AER	Alternative Energy Rider	Rates as of 4/1/2016	No change	
PIRR	Phase-In Recovery Rider	Rates as of 4/1/2016	No Change in 2017; Expires in 2019	3/
IRP	Interruptible Power Rider	Not shown	Not shown	10/
BTCR	Basic Transmission Cost Rider	Rates as of 4/1/2016	BTCR Estimate	11/
EDR	Economic Development Cost Recovery Rider	Rates as of 4/1/2016	EDR Estimate	12/
ACR	Automaker Credit Rider	N/A	Not shown	10/
CIR	Competition Incentive Rider	N/A	CIR Estimate	13/
SSOCR	SSO Credit Rider	N/A	SSOCR Estimate	13/
SR	Submetering Rider	N/A	Not shown	14/
GRR	Generation Resource Rider	N/A	Not shown	14/

1/ See Exhibit DRG-5 for revenue neutral residential rate redesign.

2/ PTBAR Energy Revenue Target will reduce pursuant to Exhibit DRG-5; this change is not modeled in the typical bills.

3/ DAPIR and PIRR currently set to expire after December 31, 2018.

4/ See WP DRG-6 for estimate of GENE and GENC rates.

5/ TCRR and TURR projected to expire in 2016.

6/ See WP DRG-3 for estimate of proposed EE/PDR rates.

7/ See WP DRG-2 for restatement of ESP III spend estimate and estimate of proposed Amended ESP III rates.

8/ RSR projected to expire in February 2018.

9/ See WP DRG-2 for restatement of ESP III caps (as of 4-1-2016) and estimate of Amended ESP III rates.

10/ IRP and ACR credits are not applicable to "typical" customers.

11/ See WP DRG-7 for application of County Fair Transmission Supplement to BTCR.

12/ See WP DRG-4 for estimate of proposed EDR rates.

13/ See Exhibits DRG-2 and DRG-3 for estimates of proposed CIR and SSOCR rates.

14/ SR and GRR are placeholders, so no basis exists to project rates.

15/ No basis exists to project proposed ACRR rates that are different than current.

ESRR and DIR Rate Estimates

Enhanced Service Reliability Rider Rate Estimate

	Year	Annual Capital	Cumulative Capital	Carrying Charge	Carrying Costs	O&M	Total	Base D**	Rate***
ESP I	2009	$ 5,000,000	$ 5,000,000	14.19%	$ 354,750	$ 26,000,000	$ 26,354,750		
	2010	$ 7,000,000	$ 12,000,000	14.19%	$ 1,206,150	$ 28,000,000	$ 29,206,150		
	2011	$ 8,000,000	$ 20,000,000	14.19%	$ 2,270,400	$ 30,000,000	$ 32,270,400		
ESP II	2012	$ 5,000,000	$ 25,000,000	14.19%	$ 3,192,750	$ 30,000,000	$ 33,192,750		
	2013	$ 5,000,000	$ 30,000,000	14.19%	$ 3,902,250	$ 34,000,000	$ 37,902,250		
	2014	$ 5,000,000	$ 35,000,000	14.19%	$ 4,611,750	$ 34,000,000	$ 38,611,750		
ESP III	2015	$ 1,000,000	$ 36,000,000	15.02%	$ 5,332,100	$ 25,000,000	$ 30,332,100		
	2016	$ 1,000,000	$ 37,000,000	15.02%	$ 5,482,300	$ 25,000,000	$ 30,482,300		7.34119%
	2017	$ 1,000,000	$ 38,000,000	15.02%	$ 5,632,500	$ 25,000,000	$ 30,632,500	$ 633,702,536	4.83389%
Amended ESP III	2018	$ 1,162,863	$ 39,162,863	14.81% *	$ 5,713,910	$ 26,467,382	$ 32,181,292	$ 633,702,536	5.07830%
	2019	$ 1,282,674	$ 40,445,537	14.81%	$ 5,895,002	$ 27,643,327	$ 33,538,329	$ 633,702,536	5.29244%
	2020	$ 1,405,481	$ 41,851,019	14.81%	$ 6,094,060	$ 28,848,670	$ 34,942,730	$ 633,702,536	5.51406%
	2021	$ 1,531,358	$ 43,382,377	14.81%	$ 6,311,533	$ 30,084,148	$ 36,395,681	$ 633,702,536	5.74334%
	2022	$ 1,660,381	$ 45,042,758	14.81%	$ 6,547,881	$ 31,350,512	$ 37,898,393	$ 633,702,536	5.98047%
	2023	$ 1,792,630	$ 46,835,388	14.81%	$ 6,803,577	$ 32,648,535	$ 39,452,112	$ 633,702,536	6.22565%
	2024	$ 1,928,186	$ 48,763,574	14.81%	$ 7,079,103	$ 33,979,008	$ 41,058,111	$ 633,702,536	6.47908%

* Exhibit MDK-5
** Calendar year 2015 actual
*** 2016 ESRR rate is actual 4/1/2016 rate

Distribution Investment Rider Rate Estimate

Year	Revenue Cap	Base D	Rate
2016*			27.11645%
2017	$ 185,000,000	$ 633,702,536	29.19351%
2018	$ 227,000,000	$ 633,702,536	35.82122%
2019	$ 261,000,000	$ 633,702,536	41.18652%
2020	$ 290,000,000	$ 633,702,536	45.76280%
2021	$ 318,000,000	$ 633,702,536	50.18127%
2022	$ 344,000,000	$ 633,702,536	54.28414%
2023	$ 370,000,000	$ 633,702,536	58.38702%
2024	$ 386,400,000	$ 633,702,536	60.97498%

* 2016 DIR rate is actual 4/1/2016 DIR rate

Energy Efficiency and Peak Demand Reduction Rider Rate Estimate

April 1, 2016 Rates (Case No. 13-1201-EL-RDR):

Tariffs	Program Costs ($)	Shared Savings ($)	Total ($)	Rider Revenue	2013-2014 Costs	Forecasted Metered Energy (kWh)	EE&PDR Rider ($/kWh)	Revenue Verification ($)	2009-2011 Rider True-Up ($/kWh)	IRP Portion EE&PDR Rider ($/kWh)	EE&PDR Rider ($/kWh)
RS	$ 120,828,016	$ 37,209,147	$ 158,037,163	$ 41,803,243	$ 116,233,920	28,926,410,940	0.0040183	116,233,920	0.0000419	$ 0.000506	0.0045666
All Other C&I	$ 119,823,996	$ 51,110,254	$ 170,934,250	$ 50,917,786	$ 120,016,464	38,166,532,976	0.0031445	120,016,464	(0.0003120)	$ 0.000506	0.0033390
GS4/IRP	$ 12,563,563	$ 5,358,584	$ 17,922,147	$ 4,956,945	$ 12,965,202	26,311,221,470	0.0004928	12,965,202	(0.0000459)	$ 0.000506	0.0009533
Total	$ 253,215,574	$ 93,677,985	$ 346,893,559	$ 97,677,974	$ 249,215,585	93,404,165,386		249,215,586			

Tariffs	IRP Credits ($)	Forecasted Metered Energy (kWh)	IRP Portion EE&PDR Rider ($/kWh)	Revenue Verification ($)
RS	$ 14,648,951	28,926,410,940	$ 0.000506	14,648,951
All Other C&I	$ 19,328,346	38,166,532,976	$ 0.000506	19,328,346
GS4/IRP	$ 13,324,564	26,311,221,470	$ 0.000506	13,324,564
Total	$ 47,301,862	93,404,165,386		47,301,862

Estimated Implementation Month Rates:

Tariffs	Program Costs ($)	Shared Savings ($)	Total ($)	Rider Revenue	Adjusted 2013-2014 Costs	Forecasted Metered Energy (kWh)	EE&PDR Rider ($/kWh)	Revenue Verification ($)	2009-2011 Rider True-Up ($/kWh)	IRP Portion EE&PDR Rider ($/kWh)	EE&PDR Rider ($/kWh)
RS	$ 120,828,016	$ 37,209,147	$ 158,037,163	$ 41,803,243	$ 116,233,920	28,926,410,940	0.0040183	116,233,920	0.0000419	$ 0.000304	0.0043642
All Other C&I	$ 119,823,996	$ 51,110,254	$ 170,934,250	$ 50,917,786	$ 112,683,519	38,166,532,976	0.0029524	112,683,519	(0.0003120)	$ 0.000304	0.0029445
GS4/IRP	$ 12,563,563	$ 5,358,584	$ 17,922,147	$ 4,956,945	$ 6,482,601	26,311,221,470	0.0002464	6,482,601	(0.0000459)	$ 0.000304	0.0005046
Total	$ 253,215,574	$ 93,677,985	$ 346,893,559	$ 97,677,974	$ 235,400,039	93,404,165,386		235,400,040			

Tariffs	IRP Credits* ($)	Forecasted Metered Energy (kWh)	IRP Portion EE&PDR Rider ($/kWh)	Revenue Verification ($)
RS	$ 8,795,752	28,926,410,940	$ 0.000304	8,795,752
All Other C&I	$ 11,605,427	38,166,532,976	$ 0.000304	11,605,427
GS4/IRP	$ 8,000,542	26,311,221,470	$ 0.000304	8,000,542
Total	$ 28,401,721	93,404,165,386		28,401,721

Cost Adjustment Factors 2014 Billed Rider Revenue - GS-1, 2, and 3		
Sec/Pri	Sub/Tran	Total
$ 29,781,193	$ 4,145,850	$ 33,927,044
88%	12%	

* Total equal to $47,301,862 divided by $8.21/kW, that quotient added to twice 275 MW, that sum multiplied by $8.21/kW, and then that product divided by two

Estimated June 1, 2018 Rates:

Tariffs	Program Costs ($)	Shared Savings ($)	Total ($)	Rider Revenue	Adjusted 2013-2014 Costs	Forecasted Metered Energy (kWh)	EE&PDR Rider ($/kWh)	Revenue Verification ($)	2009-2011 Rider True-Up ($/kWh)	IRP Portion EE&PDR Rider ($/kWh)	EE&PDR Rider ($/kWh)
RS	$ 120,828,016	$ 37,209,147	$ 158,037,163	$ 41,803,243	$ 116,233,920	28,926,410,940	0.0040183	116,233,920	0.0000419	$ 0.000333	0.0043935
All Other C&I	$ 119,823,996	$ 51,110,254	$ 170,934,250	$ 50,917,786	$ 112,683,519	38,166,532,976	0.0029524	112,683,519	(0.0003120)	$ 0.000333	0.0029737
GS4/IRP	$ 12,563,563	$ 5,358,584	$ 17,922,147	$ 4,956,945	$ 6,482,601	26,311,221,470	0.0002464	6,482,601	(0.0000459)	$ 0.000333	0.0005338
Total	$ 253,215,574	$ 93,677,985	$ 346,893,559	$ 97,677,974	$ 235,400,039	93,404,165,386		235,400,040			

Tariffs	IRP Credits** ($)	Forecasted Metered Energy (kWh)	IRP Portion EE&PDR Rider ($/kWh)	Revenue Verification ($)
RS	$ 9,642,115	28,926,410,940	$ 0.000333	9,642,115
All Other C&I	$ 12,722,149	38,166,532,976	$ 0.000333	12,722,149
GS4/IRP	$ 8,770,387	26,311,221,470	$ 0.000333	8,770,387
Total	$ 31,134,651	93,404,165,386		31,134,651

** Total equal to $28,401,721 divided by $8.21/kW then that quotient multiplied by $9/kW

<u>Economic Development Cost Recovery Rider Rate Estimate</u>

April 1, 2016 Rates (Case No. 16-260-EL-RDR)		Estimated Implementation Month Rates		Estimated June 1, 2018 Rates	
Delta Revenue and CCs	$ (185,604)	Delta Revenue and CCs	$ (185,604)	Delta Revenue and CCs	$ (185,604)
Half Sub/Tran EE/PDR Costs	$ -	Half Sub/Tran EE/PDR Costs*	$ 13,815,546	Half Sub/Tran EE/PDR Costs*	$ 13,815,546
Half IRP Credits	$ -	Half IRP Credits*	$ 28,401,721	Half IRP Credits*	$ 31,134,651
Automaker Credits	$ -	Automaker Credits **	$ 500,000	Automaker Credits**	$ 500,000
Total Revenue Requirement	$ (185,604)	Total Revenue Requirement	$ 42,531,663	Total Revenue Requirement	$ 45,264,593
Base Distribution Revenue	$ 316,851,268	Base Distribution Revenue	$ 316,851,268	Base Distribution Revenue	$ 316,851,268
Rate (% of base d)	-0.05858%	Rate (% of base d)	13.42323%	Rate (% of base d)	14.28575%

* See WP DRG-3
** Equal to annual maximum

Bill Impact Table for Testimony

Columbus Southern Power Rate Zone

	SSO Monthly Bills			
Household	**Current**	**Proposed**	**Change**	**Tariff**
1,000 kWh usage	$135	$133	-1.5%	R-R Bill
2,000 kWh usage	$257	$244	-5.0%	R-R Bill
4,000 kWh usage	$501	$466	-6.9%	R-R Bill
Small Business				
1,000 kW demand and 100,000 kWh usage	$15,323	$15,165	-1.0%	GS-2 Primary
1,000 kW demand and 350,000 kWh usage	$33,082	$31,577	-4.5%	GS-3 Primary
Industrial Business				
20,000 kW demand and 8 million kWh usage	$537,133	$508,343	-5.4%	GS-4
20,000 kW demand and 12 million kWh usage	$765,255	$725,901	-5.1%	GS-4

Ohio Power Rate Zone

	SSO Monthly Bills			
Household	**Current**	**Proposed**	**Change**	**Tariff**
1,000 kWh usage	$140	$138	-1.5%	RS Bill
2,000 kWh usage	$267	$255	-4.8%	RS Bill
4,000 kWh usage	$521	$487	-6.6%	RS Bill
Small Business				
1,000 kW demand and 100,000 kWh usage	$16,645	$16,560	-0.5%	GS-2 Primary
1,000 kW demand and 300,000 kWh usage	$31,875	$30,753	-3.5%	GS-2 Primary
Industrial Business				
20,000 kW demand and 8 million kWh usage	$569,230	$540,368	-5.1%	GS-4 Transmission
20,000 kW demand and 12 million kWh usage	$813,269	$773,843	-4.8%	GS-4 Transmission

Calculation of Blended Competitive Bid Price

Non-PIPP Load

Delivery Period: **June 2017 - May 2018***

Line	Procurement Date	No. of Tranches	Delivery Period	Clearing Price
1	Apr-15	16	June 2015 - May 2018	$ 55.58 /MWh
2	May-15	16	June 2015 - May 2018	$ 56.35 /MWh
3	Nov-15	17	June 2016 - May 2018	$ 48.29 /MWh
4	Mar-16	17	June 2016 - May 2018	$ 46.24 /MWh
5	Total	66		
6			**Blended Competitive Bid Price**	**$ 51.48 /MWh**

* Reflects approved auctions as of April 2016

Calculation of Capacity Revenue Requirement in $/MWh

Line	Description	2017/2018 Secondary	Primary	Sub/Tran	Total	
1	SSO Load - 5 CP at Meter	2,515	32	161	2,708	MW
2	Transmission and Distribution Losses	1.09	1.06	1.03		
3	5 CP at Generator (1) x (2)	2,749	34	166	2,950	MW
4	Days in Period				365	
5	MW-days (3) x (4)				1,076,597	
6	Zonal Capacity Price*				$168.06	/MW-day
7	Capacity Revenue Requirement (5) x (6)				$ 180,933,516	

Line	Description	Secondary	Primary	Sub/Tran	Total
8	Energy at Meter (MWh)	11,804,747	223,573	1,665,605	13,693,925
9	Transmission and Distribution Losses **	1.0604	1.0235	1.0031	
10	Energy for PJM Settlement (MWh) (8) x (9)	12,517,801	228,837	1,670,730	14,417,368
11	Capacity Revenue Requirement ($/MWh) (7) / (10)				$ 12.55

* Zonal Capacity Price consists of:			
	RPM Auction Clearing Price***	$149.02	/MW-day
	Zonal Scaling Factor***	1.03361	
	Forecast Pool Requirement***	1.0911	

** Loss Factors reduced by 3% for marginal loss deration

*** Reflects First Incremental Auction results

Calculation of Generation Capacity Rider Rates

2017/2018

Line	Description	Total	Residential	GS Non Demand Secondary	GS Secondary	GS Primary	GS Sub/Tran	Lighting
1	SSO Load - 5 CP at Meter	2,708	2,138	57	321	32	161	-
2	Transmission and Distribution Losses		1.0932	1.0932	1.0932	1.0552	1.0341	1.0932
3	5 CP at Generator (1) x (2)	2,950	2,337	62	350	34	166	-
4	2015/2016 Capacity Revenue Requirement on (3)	$ 180,933,516	143,347,736.77	3,815,668	21,493,141	2,092,662	10,184,308	-
5	Energy at the Meter (MWh)	13,693,925	9,555,176	342,327	1,794,745	223,573	1,665,605	112,498
6	2015/2016 Capacity Rate ($/MWh) (4) / (5)		$ 15.00	$ 11.15	$ 11.98	$ 9.36	$ 6.11	$ -
7	Tax Gross-up*		1.00435	1.00435	1.00435	1.00435	1.00435	1.00435
8	2015/2016 Rider GENC ($/MWh) (6) x (7)		$ 15.07	$ 11.19	$ 12.03	$ 9.40	$ 6.14	$ -
9	Generation Capacity Rider Rate (¢/kWh)		1.50700	1.11900	1.20300	0.94000	0.61400	0.00000

* Tax Gross-up includes: CAT Tax, PUCO and OCC Assessments

Generation Capacity Rider Design for Time-of-Day Rates

CSP Rate Zone - RLM

Description	Generation Capacity Rider Rate Design Usage (kWh)	Jan-May 2015 Generation Capacity Rider Rates	Billing	June 2017 - May 2018 Residential Service Generation Capacity Rider	Billing	Generation Capacity Rider	Billing
Winter Season							
First 750 kWh per Month	277,398	$ 0.024344	$ 6,753	$ 0.015070	$ 4,180	**$ 0.0209040**	$ 5,799
Next 150 kWh per kW Over 5 kW per Month	1,090,206	$ 0.013174	$ 14,363	$ 0.015070	$ 16,429	**$ 0.0113125**	$ 12,333
All Additional kWh per Month	1,381,854	$ 0.015407	$ 21,291	$ 0.015070	$ 20,825	**$ 0.0132301**	$ 18,282
Summer Season							
First 750 kWh per Month	126,228	$ 0.024344	$ 3,073	$ 0.015070	$ 1,902	**$ 0.0209040**	$ 2,639
Next 150 kWh per kW Over 5 kW per Month	454,573	$ 0.023126	$ 10,512	$ 0.015070	$ 6,850	**$ 0.0198576**	$ 9,027
All Additional kWh per Month	600,445	$ 0.021638	$ 12,992	$ 0.015070	$ 9,049	**$ 0.0185804**	$ 11,157
Total			$ 68,984		$ 59,236		$ 59,236

CSP Rate Zone - RS-ES / RS-TOD

Description	Generation Capacity Rider Rate Design Usage (kWh)	Jan-May 2015 Generation Capacity Rider Rates	Billing	June 2017 - May 2018 Residential Service Generation Capacity Rider	Billing	Generation Capacity Rider	Billing
On-Peak kWh	30,565	$ 0.030371	$ 928	$ 0.015070	$ 461	**$ 0.0260791**	$ 797
Off-Peak kWh	54,955	$ 0.010419	$ 573	$ 0.015070	$ 828	**$ 0.0089469**	$ 492
Total			$ 1,501		$ 1,289		$ 1,289

CSP Rate Zone - Experimental RS-TOD2

Description	Generation Capacity Rider Rate Design Usage (kWh)	Jan-May 2015 Generation Capacity Rider Rates	Billing	June 2017 - May 2018 Residential Service Generation Capacity Rider	Billing	Generation Capacity Rider	Billing
High Cost Hours	1,589,576	$ 0.175869	$ 279,557	$ 0.015070	$ 23,955	**$ 0.1510165**	$ 240,052
Low Cost Hours	18,387,409	$ 0.003864	$ 71,040	$ 0.015070	$ 277,098	**$ 0.0033175**	$ 61,000
Total			$ 350,597		$ 301,053		$ 301,052

CSP Rate Zone - RS-CPP

Description	Generation Capacity Rider Rate Design Usage (kWh)	Jan-May 2015 Generation Capacity Rider Rates	Billing	June 2017 - May 2018 Residential Service Generation Capacity Rider	Billing	Generation Capacity Rider	Billing
Winter Season							
First 800 kWh	6,400	$ 0.016017	$ 103	$ 0.015070	$ 96	**$ 0.0137536**	$ 88
Over 800 kWh	2,172	$ -	$ -	$ 0.015070	$ 33	**$ -**	$ -
Critical Peak Hours	28	$ 0.387317	$ 11	$ 0.015070	$ 0	**$ 0.3325846**	$ 9
Summer Season							
Low Cost Hours	2,289	$ 0.003873	$ 9	$ 0.015070	$ 34	**$ 0.0033259**	$ 8
Medium Cost Hours	1,082	$ 0.012144	$ 13	$ 0.015070	$ 16	**$ 0.0104278**	$ 11
High Cost Hours	892	$ 0.024824	$ 22	$ 0.015070	$ 13	**$ 0.0213161**	$ 19
Critical Peak Hours	184	$ 0.387317	$ 71	$ 0.015070	$ 3	**$ 0.3325846**	$ 61
Total			$ 229		$ 197		$ 197

CSP Rate Zone - RS-RTP

Description	Generation Capacity Rider Rate Design Usage (kWh)	Jan-May 2015 Generation Capacity Rider Rates	Billing	June 2017 - May 2018 Residential Service Generation Capacity Rider	Billing	Generation Capacity Rider	Billing

Generation Capacity Rider Design for Time-of-Day Rates

Fixed Energy Charge	14,595	$ 21.35	$ 256	$ 0.015070	$ 220	**$ 18.33**	$ 220
Total			$ 256		$ 220		$ 220

CSP Rate Zone - GS-2-LMTOD / GS-2-TOD

Description	Generation Capacity Rider Rate Design Usage (kWh)	Jan-May 2015 Generation Capacity Rider Rates	Billing	June 2017 - May 2018: General Service Non Demand Generation Capacity Rider	Billing	Generation Capacity Rider	Billing
On-Peak kWh	1,973,797	$ 0.038071	$ 75,144	$ 0.011190	$ 22,087	**$ 0.0334916**	$ 66,106
Off-Peak kWh	3,974,408	$ 0.000130	$ 517	$ 0.011190	$ 44,474	**$ 0.0001145**	$ 455
Total			$ 75,661		$ 66,560		$ 66,561

OP Rate Zone - RS-ES / RS-TOD

Description	Generation Capacity Rider Rate Design Usage (kWh)	Jan-May 2015 Generation Capacity Rider Rates	Billing	June 2017 - May 2018: Residential Service Generation Capacity Rider	Billing	Generation Capacity Rider	Billing
On-Peak kWh	2,046,613	$ 0.036343	$ 74,380	$ 0.015070	$ 30,842	**$ 0.0312073**	$ 63,869
Off-Peak kWh	5,102,322	$ 0.010012	$ 51,084	$ 0.015070	$ 76,892	**$ 0.0085971**	$ 43,865
Total			$ 125,464		$ 107,734		$ 107,734

OP Rate Zone - RDMS

(No Data, Use RS-ES / RS-TOD Scaling)

Description	Generation Capacity Rider Rate Design Usage (kWh)	Jan-May 2015 Generation Capacity Rider Rates	Billing	June 2017 - May 2018: Residential Service Generation Capacity Rider	Billing	Generation Capacity Rider	Billing
Winter Season							
kWh > 400 times billing demand	-	$ 0.020158	$ -	$ 0.015070	$ -	**$ 0.0173090**	$ -
First 500 on-peak kWh	-	$ 0.025186	$ -	$ 0.015070	$ -	**$ 0.0216269**	$ -
Over 500 on-peak kWh	-	$ 0.018756	$ -	$ 0.015070	$ -	**$ 0.0161059**	$ -
All Additional kWh per Month	-	$ 0.005710	$ -	$ 0.015070	$ -	**$ 0.0049029**	$ -
Total			$ -		$ -		$ -

OP Rate Zone - GS-1-ES

Description	Generation Capacity Rider Rate Design Usage (kWh)	Jan-May 2015 Generation Capacity Rider Rates	Billing	June 2017 - May 2018: General Service Non Demand Generation Capacity Rider	Billing	Generation Capacity Rider	Billing
On-Peak kWh	95,196	$ 0.026019	$ 2,477	$ 0.011190	$ 1,065	**$ 0.0228891**	$ 2,179
Off-Peak kWh	179,823	$ 0.005680	$ 1,021	$ 0.011190	$ 2,012	**$ 0.0049966**	$ 899
Total			$ 3,498		$ 3,077		$ 3,077

OP Rate Zone - GS-2-ES / GS-TOD

Description	Generation Capacity Rider Rate Design Usage (kWh)	Jan-May 2015 Generation Capacity Rider Rates	Billing	June 2017 - May 2018: General Service Non Demand Generation Capacity Rider	Billing	Generation Capacity Rider	Billing
On-Peak kWh	18,875,479	$ 0.020841	$ 393,380	$ 0.011190	$ 211,217	**$ 0.0183340**	$ 346,063
Off-Peak kWh	27,663,099	$ 0.007179	$ 198,591	$ 0.011190	$ 309,550	**$ 0.0063154**	$ 174,704
Total			$ 591,971		$ 520,767		$ 520,767

Calculation of Generation Energy Rider Rates

	2017/20178	
Blended Competitive Bid Price	$ 51.48	/MWh
Capacity Revenue Requirement	$ 12.55	/MWh
Residual Energy Price	$ 38.93	/MWh

Tax Gross-up* 1.00435

Rate Schedule	Season	Factors Loss**	Factors Season	RIDER GENE***	Generation Energy Rider Rate (¢/kWh)
Residential	Summer	1.0604	1.00	$ 41.46	4.14600
	Winter	1.0604	1.00	$ 41.46	4.14600
PIPP Residential	Summer	1.0604	1.00		
	Winter	1.0604	1.00		
GS Non Demand Secondary	Summer	1.0604	1.00	$ 41.46	4.14600
	Winter	1.0604	1.00	$ 41.46	4.14600
GS Secondary	Summer	1.0604	1.00	$ 41.46	4.14600
	Winter	1.0604	1.00	$ 41.46	4.14600
GS Primary	Summer	1.0235	1.00	$ 40.02	4.00200
	Winter	1.0235	1.00	$ 40.02	4.00200
GS Sub/Tran	Summer	1.0031	1.00	$ 39.22	3.92200
	Winter	1.0031	1.00	$ 39.22	3.92200
Lighting	Summer	1.0604	1.00	$ 41.46	4.14600
	Winter	1.0604	1.00	$ 41.46	4.14600

* Tax Gross-up includes: Commercial Activities Tax and PUCO and OCC Assessments
** Loss Factors reduced by 3% for marginal loss deration
*** Residual Energy Price x Tax Gross-up x Loss Factor x Seasonal Factor

Current Methodology - Case No. 15-1105-EL-RDR

Ohio Power Company
Class Contribution to NSPL

Class	Metered Class MW	Loss Factor	At Generation Class MW
Residential	2,907	1.0932	3,178.27
GS Non Demand Secondary	120	1.0932	131.31
GS Secondary	1,849	1.0932	2,021.87
GS Primary	797	1.0552	841.21
GS Sub/Tran	1,243	1.0341	1,285.61
Lighting	11	1.0932	11.90
EHG	7	1.0932	7.22
Total	6,934.8		7,477.4

	Metered Energy	Metered Demand	Loss Factor	Units @ Secondary Energy
Residential	14,225,492,718	-	1.0000	14,225,492,718
GS Non Demand Secondary	789,208,983	-	1.0000	789,208,983
GS Secondary	11,665,976,600	34,121,449	1.0000	11,665,976,600
GS Primary	6,221,462,006	13,649,825	0.9652	6,005,201,892
GS Sub/Tran	10,451,543,324	21,277,569	0.9459	9,886,517,519
Lighting	217,033,547		1.0000	217,033,547
EHG	19,740,746	98,920	1.0000	19,740,746
	43,590,457,923	69,147,763		42,809,172,004

	Demand	Demand Cost	Loss Adjusted kWh Energy	Energy Cost	Total Cost
Forecast					
Residential	3,178.3	$ 177,638,527	14,225,492,718	$ 5,461,697.63	$ 183,100,225
GS Non Demand Secondary	131.3	$ 7,339,290	789,208,983	$ 303,006.79	$ 7,642,297
GS Secondary	2,021.9	$ 113,005,566	11,665,976,600	$ 4,479,003.85	$ 117,484,570
GS Primary	841.2	$ 47,016,533	6,005,201,892	$ 2,305,621.15	$ 49,322,154
GS Sub/Tran	1,285.6	$ 71,854,922	9,886,517,519	$ 3,795,803.09	$ 75,650,725
Lighting	11.9	$ 664,959	217,033,547	$ 83,327.28	$ 748,286
EHG	7.2	$ 403,448	19,740,746	$ 7,579.21	$ 411,027
Total	7,477.4	$ 417,923,245	42,809,172,004	$ 16,436,039	$ 434,359,284

	Costs: Demand Cost	Costs: Energy Cost	Billing Units: KW	Billing Units: kWh	Rates: Demand	Rates: Energy
Residential	$ 177,638,527	$ 5,461,698	-	14,225,492,718		$ 0.0128713
GS Non Demand Secondary	$ 7,339,290	$ 303,007	-	789,208,983		$ 0.0096835
GS Secondary	$ 113,005,566	$ 4,479,004	34,121,449	11,665,976,600	$ 3.31	$ 0.0003839
GS Primary	$ 47,016,533	$ 2,305,621	13,649,825	6,221,462,006	$ 3.44	$ 0.0003706
GS Sub/Tran	$ 71,854,922	$ 3,795,803	21,277,569	10,451,543,324	$ 3.38	$ 0.0003632
Lighting	$ 664,959	$ 83,327	-	217,033,547		$ 0.0034478
EHG	$ 403,448	$ 7,579	98,920	19,740,746	$ 1.66	$ 0.0125281
Total	$ 417,923,245	$ 16,436,039	69,147,763	43,590,457,923		

Implement County Fair Transmission Supplement

Ohio Power Company
Class Contribution to NSPL

Class	Metered Class MW	Loss Factor	At Generation Class MW
Residential	2,907	1.0932	3,178.27
GS Non Demand Secondary	120	1.0932	131.59
GS Non Demand Primary	1	1.0552	1.32
GS Secondary	1,849	1.0932	2,021.60
GS Primary	796	1.0552	839.89
GS Sub/Tran	1,243	1.0341	1,285.61
Lighting	11	1.0932	11.90
EHG	7	1.0932	7.22
Total	6,934.8		7,477.4

	Metered Energy	Metered Demand	Loss Factor	Units @ Secondary Energy
Residential	14,225,492,718	-	1.0000	14,225,492,718
GS Non Demand Secondary	791,665,805	-	1.0000	791,665,805
GS Non Demand Primary	13,182,110	-	0.9652	12,723,895
GS Secondary	11,663,519,778	34,095,784	1.0000	11,663,519,778
GS Primary	6,208,279,896	13,545,696	0.9652	5,992,477,997
GS Sub/Tran	10,451,543,324	21,277,569	0.9459	9,886,517,519
Lighting	217,033,547		1.0000	217,033,547
EHG	19,740,746	98,920	1.0000	19,740,746
	43,590,457,923	69,017,969		42,809,172,004

	Demand	Demand Cost	Loss Adjusted kWh Energy	Energy Cost	Total Cost
Forecast					
Residential	3,178.3	$ 177,638,527	14,225,492,718	$ 5,461,697.63	$ 183,100,225
GS Non Demand Secondary	131.6	$ 7,354,565	791,665,805	$ 303,950.05	$ 7,658,515
GS Non Demand Primary	1.3	$ 73,721	12,723,895	$ 4,885.18	$ 78,606
GS Secondary	2,021.6	$ 112,990,291	11,663,519,778	$ 4,478,060.59	$ 117,468,352
GS Primary	839.9	$ 46,942,812	5,992,477,997	$ 2,300,735.97	$ 49,243,548
GS Sub/Tran	1,285.6	$ 71,854,922	9,886,517,519	$ 3,795,803.09	$ 75,650,725
Lighting	11.9	$ 664,959	217,033,547	$ 83,327.28	$ 748,286
EHG	7.2	$ 403,448	19,740,746	$ 7,579.21	$ 411,027
Total	7,477.4	$ 417,923,245	42,809,172,004	$ 16,436,039	$ 434,359,284

	Costs: Demand Cost	Costs: Energy Cost	Billing Units: KW	Billing Units: kWh	Rates: Demand	Rates: Energy
Residential	$ 177,638,527	$ 5,461,698	-	14,225,492,718		$ 0.0128713
GS Non Demand Secondary	$ 7,354,565	$ 303,950	-	791,665,805		$ 0.0096739
GS Non Demand Primary	$ 73,721	$ 4,885	-	13,182,110		$ 0.0059631
GS Secondary	$ 112,990,291	$ 4,478,061	34,095,784	11,663,519,778	$ 3.31	$ 0.0003839
GS Primary	$ 46,942,812	$ 2,300,736	13,545,696	6,208,279,896	$ 3.47	$ 0.0003706
GS Sub/Tran	$ 71,854,922	$ 3,795,803	21,277,569	10,451,543,324	$ 3.38	$ 0.0003632
Lighting	$ 664,959	$ 83,327	-	217,033,547		$ 0.0034478
EHG	$ 403,448	$ 7,579	98,920	19,740,746	$ 1.66	$ 0.0125281
Total	$ 417,923,245	$ 16,436,039	69,017,969	43,590,457,923		

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of	)	
Ohio Power Company for Authority to	)	
Establish a Standard Service Offer	)	Case No. 13-2385-EL-SSO
Pursuant to Section 4928.143, Revised Code,	)	
in the Form of an Electric Security Plan	)	

In the Matter of the Application of	)	
Ohio Power Company for Approval of	)	Case No. 13-2386-EL-AAM
Certain Accounting Authority	)	

**OHIO POWER COMPANY'S APPLICATION
TO AMEND ITS ELECTRIC SECURITY PLAN**

WORKPAPERS
For Adrien M. McKenzie

INDEX TO WORKPAPERS
DIRECT TESTIMONY OF
ADRIEN M. MCKENZIE, CFA

NO.	Title
WP-1	Moody's Investors Service, "Regulation Will Keep Cash Flow Stable As Major Tax Break Ends," *Industry Outlook* (Feb. 19, 2014)
WP-2	Moody's Investors Service, "Credit Opinion: Ohio Power Company," *Global Credit Research* (May 12, 2015)
WP-3	Standard & Poor's Corporation, "Summary: Ohio Power Co.," *Research* (May 8, 2014)
WP-4	Barnato, Katy, "Fed's Plosser: Low rates 'should make us nervous'," CNBC (Nov. 11, 2014)
WP-5	Federal Reserve Statistical Release, "Factors Affecting Reserve Balances of Depository Institutions and Condition Statement of Federal Reserve Banks," H.4.1
WP-6	Poole, William, "Prospects for and Ramifications of the Great Central Banking Unwind," Financial Analysts Journal (November/December 2013)
WP-7	Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports* at 71 (2006)
WP-8	Gordon, Myron J., "The Cost of Capital to a Public Utility," *MSU Public Utilities Studies* at 89 (1974)
WP-9	Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 298 (2006)
WP-10	Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.*, at 307 (2006)
WP-11	*Morningstar*, "Ibbotson SBBI 2015 Classic Yearbook," at pp. 99, 108
WP-12	Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports* at 189 (2006)
WP-13	Brigham, E.F., Shome, D.K., and Vinson, S.R., "The Risk Premium Approach to Measuring a Utility's Cost of Equity," *Financial Management* (Spring 1985)
WP-14	Harris, R.S., and Marston, F.C., "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," *Financial Management* (Summer 1992)
WP-15	Morin, Roger A., "New Regulatory Finance," Public Utilities Reports, at 128 (2006)
WP-16	Brigham, E.F., Aberwald, D.A., and Gapenski, L.C., "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly*, May, 2, 1985
WP-17	Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 335 (2006)
WP-18	Roger A. Morin, "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports, Inc.* at 166 (1994)

MCKENZIE WORKPAPERS INDEX
(Cont.)

WP-19	Direct Testimony of George J. Eckenroth (Jul. 2, 2004) at Exhibit GJE-11.1
WP-20	*Blue Chip Financial Forecasts*, Vol. 34, No. 12 (Dec. 1, 2015)
WP-21	Value Line Investment Survey, *Forecast for the U.S. Economy* (Mar. 4, 2016)
WP-22	IHS Global Insight, *The 30-Year Focus* (Third-Quarter 2015)
WP-23	Energy Information Administration, *Annual Energy Outlook 2015* (April 2015)
WP-24	Value Line *Summary & Index* (Feb. 19, 2016)
WP-25	Value Line Source Documents – Electric Group
WP-26	IBES Source Documents – Electric Group
WP-27	Zacks Source Documents – Electric Group
WP-28	Value Line Source Documents – Non-Utility Group
WP-29	IBES Source Documents – Non-Utility Group
WP-30	Zacks Source Documents – Non-Utility Group
WP-31	Duff & Phelps, "2016 Valuation Handbook – Guide to Cost of Capital (Preview Version)," John Wiley & Sons (2016)
WP-32	Utility Risk Premium – Regulatory Research Assoc. data (1974-2015)
WP-33	McKenzie Excel File

MOODY'S
INVESTORS SERVICE

US Regulated Utilities

Regulation Will Keep Cash Flow Stable As Major Tax Break Ends

Our outlook for the US regulated utility industry is stable. This outlook reflects our expectations for the fundamental business conditions in the industry.

» **Cost-recovery mechanisms, coupled with annual base-rate increases, will keep the ratio of industry-wide cash flow to debt at about 18%, within our range for a stable outlook.** Favorable rate orders are part of what we view as a broader shift toward stronger regulatory support for the industry, all the more important this year given the end of bonus depreciation. Industry regulation is the most important driver of our outlook.

» **Ratemaking mechanisms, such as revenue decoupling and riders, allow utilities to recover costs faster and improve the quality, predictability and stability of cash flow.** The ratio of cash flow to gross profit for a peer group of 122 US operating companies has been more stable on a year-over-year basis since 2009, as the use of riders in regulatory agreements has become more commonplace.

» **We are also seeing signs of improved regulatory support in historically contentious states, such as Connecticut and Illinois.** Stronger recovery mechanisms put in place last year for Connecticut Natural Gas Corp. (A3 stable) and Commonwealth Edison Co. (Baa1 stable) in Illinois will likely make cash flow more predictable for utilities in each state. This marks a turnaround in both states, where regulatory support was lacking for certain cost-recovery provisions in the past.

» **Stagnant customer demand is leading some utilities to pursue shareholder growth through financial engineering.** Some companies are restructuring their businesses by creating master limited partnerships and "yieldcos" to defend their historically high equity multiples. For now, credit risks are limited but so are any benefits for bondholders, and these structures may weaken sponsor credit quality over time.

» **What could change our outlook.** We could shift our outlook to positive if the ratio of cash flow to debt rose toward 25% on a sustainable basis, which could happen if return on equity rises or utilities deleverage significantly. A more contentious regulatory environment that resulted in a material deterioration in cash flow, such that the ratio fell to 13%, could cause us to have a negative outlook.

Supportive regulatory relationships drive our stable outlook

Regulatory support will help US electric and gas utilities maintain stable credit profiles in 2014, even with stagnant customer demand and without the cash-flow boost from bonus depreciation.

Fundamentally, the regulatory environment is the most important driver of our outlook because it sets the pace for cost-recovery. Favorable rate orders, even in states where utilities have had contentious regulatory relationships in the past, are part of what we view as a broader shift toward stronger regulatory support for the industry.

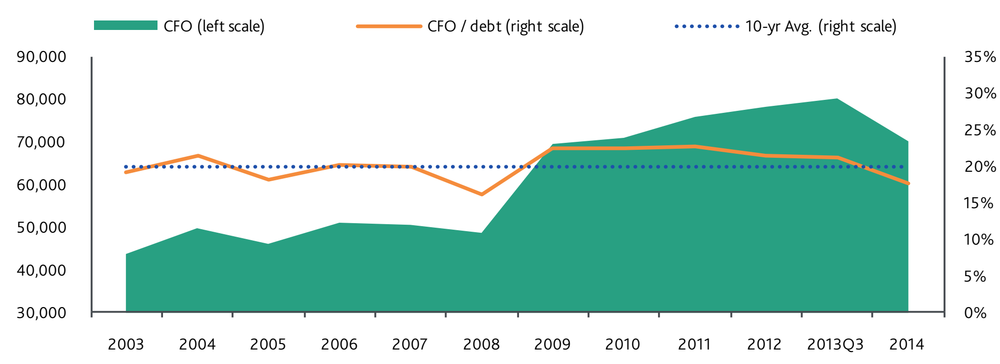
The improved regulatory framework, led by special cost-recovery mechanisms and annual base-rate increases, is all the more important this year for two reasons. First is the end of bonus depreciation, a temporary tax break that expired on December 31. We incorporate a view that bonus depreciation will not be extended; however, various corporate sectors are currently lobbying for the extension in 2014. Second is stagnant customer demand, which is also leading some utilities to pursue shareholder growth through financial engineering (please see page 6).

As Exhibit 1 shows, the ratio of cash flow to debt will decline this year to 18%, just below the 10-year trend line but within our range for a stable outlook. The decline is largely because of higher cash taxes, but utilities can still get some tax relief in 2014 by applying net operating loss carry-forwards (from factors unrelated to bonus depreciation) from past years to this year's tax payments—an option they didn't use when bonus depreciation was in effect.

We would likely shift our outlook to positive if the ratio of cash flow to debt rose to 25%, although that would take a marked increase in regulatory-allowed ROE levels or steps by utilities to scale back their dividend and stock-repurchase plans. A more contentious regulatory environment or a widespread adoption of more-aggressive financial strategies resulting in a material deterioration in cash flow, such that the ratio fell to 13%, would likely lead to a negative outlook.

EXHIBIT 1

Cash Flow to Debt Will Hover Below the 10-Year Average



Notes: Figures are in thousands of US dollars. A list of the 122 utilities included in our analysis starts on page 7. Data for the third quarter of 2013 are the latest available. Data for 2014 are our estimates.
Source: Moody's Investors Service

Improved regulatory environment means stable, more predictable cost-recovery

The US regulatory environment has improved significantly in the past year, providing for faster and more-certain cost-recovery in 2014.

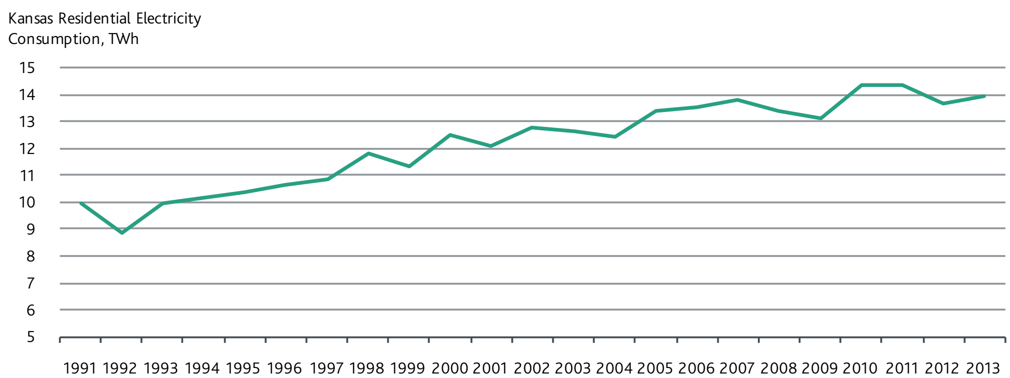
Puget Sound Energy Inc.'s (PSE; Baa1 stable) June 2013 rate order is a good example. Its regulator, the Washington Utilities and Transportation Commission, approved the decoupling of electric and gas revenue from sales volume, and a property-tax tracker that provides more-efficient recovery of property-tax expense. The commission acknowledged a need to reduce regulatory lag times by expediting the utility's rate filings and offering more real-time true-up of costs during rate filings. The regulator also provided the company with forward-looking annual revenue adjustments (about 3% for electric and 2% for gas) over the next three years. As a result of these changes, we expect that Puget Sound's cash-flow-to-debt ratio will continue to surpass 20%, exceeding the industry average, even without the cash-flow benefit of bonus depreciation.

Another example is Westar Energy Inc.'s (Baa1 stable) 2013 abbreviated rate case with the Kansas Corporation Commission. In addition to providing incremental cost-recovery for environmental upgrades, the regulator allowed Westar to increase its monthly fixed charge on customer bills. This movement in rate design will allow Westar to recover a greater portion of its fixed costs through fixed rates, rather than volumetric rates, thereby reducing Westar's dependency on selling higher volumes to recover fixed costs. The shift to a $12 residential monthly fixed charge from $9 will be a benefit amid flat customer demand in Kansas over the past three years (see Exhibit 2).

EXHIBIT 2

Demand for Electricity Has Been Stagnant in Kansas

Actual Consumption



Notes: TWh stands for terawatt hour. 2013 US Energy Information Administration (EIA) data are through October 2013. Our estimates for November and December 2013 are based on historical trends.

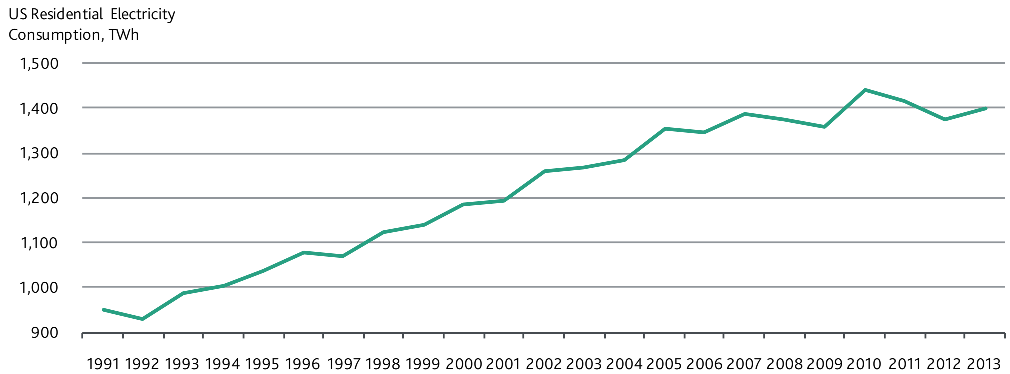
Source: US Energy Information Administration

As demand for electricity wanes, rate structures that are tied more closely to volumetric charges than to fixed charges will threaten the gross profits of most electric and gas utilities. Exhibit 3 below shows the drop-off in US electricity demand since 2010, largely attributable to weather and slow economic growth as well as conservation and efficiency measures.

EXHIBIT 3

Demand for Electricity Is Slow to Rebound

Actual Consumption



Note: 2013 EIA data is through October 2013. Our estimates for November and December 2013 are based on historical trends.
Source: US Energy Information Administration

The industry's financial profile is becoming more predictable and steady because of these special recovery mechanisms that supplement cash recovery between general rate cases. As Exhibit 4 shows, the average ratio of cash flow from operations to gross profit had a standard deviation of 2.4% on a year-over-year basis between 2003 and 2008. This compares with a 1.1% standard deviation on average between 2009 and the third quarter of 2013, the latest data available, a period marked by a more pervasive use of cost-recovery mechanisms throughout the US.

EXHIBIT 4

Cost-Recovery Mechanisms Make Cash Flow More Predictable

Year	CFO / Gross Profit	Standard Deviation Rolling Two-Year Average	Average Standard Deviation
2003	30.9%		
2004	37.0%	4.3%	
2005	34.0%	2.1%	
2006	37.3%	2.4%	
2007	34.9%	1.7%	
2008	32.9%	1.4%	2.4%
2009	44.9%		
2010	42.5%	1.7%	
2011	44.8%	1.6%	
2012	44.3%	0.3%	
3Q13	43.0%	0.9%	1.1%

Note: The latest data available are for the third quarter of 2013.
Source: Moody's Investors Service

Cost-recovery improves, but not without exceptions

Most regulated electric and gas utilities in the US have shown evidence of improved regulatory relationships. Apart from Puget Sound's and Westar's cost-recovery improvements, we have seen regulatory improvement in Illinois and Connecticut, states in which the relationships between regulators and utilities have been somewhat contentious.

Stronger recovery mechanisms put in place late last year in both Illinois and Connecticut will make utility cash flow more predictable. For example, in Illinois, **Commonwealth Edison**'s (ComEd) cash flow to debt coverage will start improving in 2014, supported by the adoption of a version of formula ratemaking (i.e., the Energy Infrastructure Modernization Act, or "EIMA," which helps define various aspects of rate structure and cost-recovery in Illinois). The implementation of EIMA will make cost-recovery more tied to factors determined by a formula and less tied to rate-case negotiations (the results of which are less predictable).

Similarly, the Connecticut legislature in 2013 passed the Comprehensive Energy Strategy, which encourages the use of decoupling mechanisms and infrastructure replacement riders (i.e., the Distribution Integrity Management Program, or DIMP), while promoting growth of local distribution companies (LDCs) through customer conversions. These measures are subject to approval by the Public Utilities Regulatory Authority in rate-case proceedings, but were approved in **Connecticut Natural Gas**'s (CNG; A3 stable) December 2013 rate case. We expect decoupling, DIMP and conversion incentives to be applied to all LDCs in the state going forward.

These moves mark a turnaround in both states from past years, when regulatory support was lacking for certain cost-recovery provisions and when general rate case outcomes were deemed less than favorable from an investor perspective. For example, the Illinois legislature passed the EIMA in 2011, but the Illinois Commerce Commission did not fully implement it, initially, which made future cost-recovery for ComEd uncertain. Likewise, Connecticut LDCs had few tracking mechanisms and were exposed to declining customer usage in rate design. Now, through the adoption of EIMA in ComEd's rate structure (clarified by Senate Bill 9 in 2013) and CNG's implementation of decoupling and the DIMP, the financial profiles of both companies will likely improve.

These cost-recovery improvements are part of the broader trend we are seeing in the industry, but there are a few high-profile exceptions. Entergy Corp. (Baa3 stable), which has a history of contentious regulatory relationships in Arkansas and Texas, is one example.

Last year, Entergy Arkansas Inc. (Baa2 stable) put forth a nearly $145 million rate request but received about $81 million (the Arkansas Public Service Commission did allow a new cost-recovery rider for certain regional transmission expenses, however). Entergy Texas Inc. (Baa3 stable) requested about $53 million in rate increases for 2014, but the Texas Public Utilities Commission's (PUC) staff recommended a rate increase of a little more than $3 million. The PUC has not issued a final decision.

Another high-profile exception is Consolidated Edison of New York's (A2 stable) pending rate settlement, which calls for a two-year freeze on electric rates and a three-year rate freeze on gas and steam rates. Although the rate freeze would curb Consolidated Edison of New York's earnings, the settlement is credit neutral because of the provision for reasonable recovery of deferred storm costs related to Hurricane Sandy and other investments.

This year, one utility that might also buck the positive trend is Jersey Central Power & Light Co. (JCP&L; Baa2 negative). JCP&L has been the target of public criticism over its handling of outages related to Hurricane Sandy, besides allegations of over-earning. The staff of the New Jersey Board of Public Utilities has proposed that base rates be cut by $207 million (not considering recovery of storm costs, which will be addressed in a separate rate proceeding). This compares with the company's request for an increase of $11 million (again, not considering storm costs).

JCP&L's financial flexibility and financial metrics have already been weakened by costs associated with Hurricane Sandy, so a material rate reduction could hurt JCP&L's rating. If JCP&L can bring its ratio of cash flow to debt to at least 14% despite a rate decrease, then our rating outlook could stabilize. JCP&L had 12% cash flow to debt through the 12 months ended the third quarter of 2013.

More utilities are turning to financial engineering

Against a backdrop of stagnant demand, some utility holding companies are turning to forms of financial engineering, such as creating master limited partnerships (MLPs) and so-called yieldcos, to defend their historically high equity multiples. For the few companies that have proceeded with these strategies so far, the credit impact is neutral because the vehicles are small relative to the corporate sponsor's consolidated credit profile. But longer term, credit risks could increase if these companies eventually lose too much cash flow from their most stable assets and don't reduce debt enough to rebalance their capital structures.

We expect some more companies to go public with these financial-engineering vehicles this year. The joint venture among OGE, CenterPoint and ArcLight—the Enable Midstream Partners MLP—plans to complete an initial public offering in the first quarter. Dominion Resources Inc. (Baa2 stable) expects to publicly offer its MLP by mid-year. In addition, NextEra Energy Inc. (Baa1 stable) expects to make a decision whether to form a yieldco by then.

Meantime, several companies have pursued acquisitions outside of their core utility holdings and service territories, like MidAmerican Energy Holdings Co. (A3 stable), TECO Energy Inc. (Baa1 stable), and Avista Corp. (Baa1 stable). This trend is bound to continue as companies try to expand their regulated footprint and achieve regulatory diversity. We expect that most M&A activity in 2014 will be conservatively financed much like these transactions, which included equity financings.

EXHIBIT 5

Regulated Utilities: M&A Activity

	Acquirer			Acquiree				
Acquirer / Acquiree	Revenue	CFO	Debt	Revenue	CFO	Debt	Financing	Credit Implication
MidAmerican Energy Holdings Co. / NV Energy, Inc.	$12,373	$505	$4,255	$2,930	$794	$5,125	$5.6 billion in debt & equity	Positive; no ratings actions
TECO Energy, Inc. / New Mexico Gas Company	$2,851	$680	$3,156	$332	$65	$250	$950 million in debt, equity, & cash	Affirmed TECO Energy ratings
Avista Corp / Alaska Energy and Resources Company (AERC)	$1,581	$295	$1,739	$42	$20	$115	$170 million in equity	Neutral for Avista
Fortis, Inc. / UNS Energy Corporation	$3,654	$976	$5,783	$1,483	$400	$ 1,937	$4.3 billion in debt & equity	Slightly positive for UNS Energy Corporation; no ratings action

Notes: Financials are in millions, as of the 12 months ended September 30, 2013. AERC financials are based on Alaska Electric Light and Power Co. (AELP) 2012 FERC Form 1 data. Fortis and New Mexico Gas financials are as reported as of fiscal 2012. We expect TECO Energy will assume $200 million of debt already existing at New Mexico Gas Company. We expect Fortis to assume approximately $1.8 billion of debt already existing at UNS Energy Corporation. In addition, we expect Fortis to finance the UNS acquisition in a manner similar to historical precedent, with a balanced mix of debt and equity issued upstream from the utility (we expect Fortis to keep UNS's current capital structure in place).

Sources: Fortis Inc. Annual Report, AELP 2012 FERC Form 1, SNL, Moody's Financial Metrics

Appendix: Peer Group

Moody's Financial Metrics

	Entity Name	LT Rating	Outlook	CFO/Debt (3-Yr Avg) LTM 3Q11-LTM3Q13
Integrated	Alabama Power Company	A1	Stable	26%
	ALLETE, Inc.	A3	Stable	22%
	Appalachian Power Company	Baa1	Stable	17%
	Arizona Public Service Company	A3	Stable	28%
	Avista Corp.	Baa1	Stable	18%
	Black Hills Power, Inc.	A3	Stable	22%
	Cleco Power LLC	Baa1	Positive	19%
	Consumers Energy Company	(P)A3	Stable	27%
	Dayton Power & Light Company	Baa3	Stable	34%
	DTE Electric Company	A2	Stable	24%
	Duke Energy Carolinas, LLC	A1	Stable	23%
	Duke Energy Corporation	A3	Stable	15%
	Duke Energy Florida, Inc.	A3	Stable	21%
	Duke Energy Indiana, Inc.	A2	Stable	16%
	Duke Energy Kentucky, Inc.	Baa1	Stable	23%
	Duke Energy Ohio, Inc.	Baa1	Stable	25%
	Duke Energy Progress, Inc.	A1	Stable	23%
	El Paso Electric Company	Baa1	Stable	25%
	Empire District Electric Company (The)	Baa1	Stable	20%
	Entergy Arkansas, Inc.	Baa2	Stable	19%
	Entergy Louisiana, LLC	Baa1	Stable	17%
	Entergy Mississippi, Inc.	Baa2	Stable	16%
	Entergy New Orleans, Inc.	Ba2	Stable	20%
	Entergy Texas, Inc.	Baa3	Stable	14%
	Florida Power & Light Company	A1	Stable	32%
	Georgia Power Company	A3	Stable	25%
	Gulf Power Company	A2	Stable	26%
	Hawaiian Electric Company, Inc.	Baa1	Stable	17%
	Idaho Power Company	A3	Stable	16%
	Indiana Michigan Power Company	Baa1	Stable	21%
	Interstate Power and Light Company	A3	Stable	18%
	Kansas City Power & Light Company	Baa1	Stable	18%
	Kansas City Power & Light Company - Greater MO	Baa2	Stable	22%
	Madison Gas and Electric Company	A1	Stable	30%
	MidAmerican Energy Company	A1	Stable	24%
	Mississippi Power Company	Baa1	Stable	14%
	Nevada Power Company	Baa1	Stable	18%

	Entity Name	LT Rating	Outlook	CFO/Debt (3-Yr Avg) LTM 3Q11-LTM3Q13
	Northern States Power Company (Minnesota)	A2	Stable	25%
	Northern States Power Company (Wisconsin)	(P)A2	Stable	30%
	NorthWestern Corporation	A3	Stable	19%
	Ohio Power Company	Baa1	Stable	32%
	Oklahoma Gas & Electric Company	A1	Stable	27%
	Otter Tail Power Company	A3	Stable	24%
	Pacific Gas & Electric Company	A3	Stable	25%
	PacifiCorp	A3	Stable	23%
	Portland General Electric Company	A3	Stable	25%
	Public Service Co. of North Carolina, Inc.	A3	Stable	25%
	Public Service Company of Colorado	A3	Stable	23%
	Public Service Company of New Hampshire	Baa1	Stable	20%
	Public Service Company of New Mexico	Baa2	Positive	21%
	Public Service Company of Oklahoma	A3	Stable	27%
	Puget Sound Energy, Inc.	Baa1	Stable	21%
	San Diego Gas & Electric Company	A1	Stable	21%
	Sierra Pacific Power Company	Baa1	Stable	16%
	South Carolina Electric & Gas Company	Baa2	Stable	17%
	Southern California Edison Company	A2	Stable	30%
	Southern Indiana Gas & Electric Company	A2	Stable	28%
	Southwestern Electric Power Company	Baa2	Stable	18%
	Southwestern Public Service Company	Baa1	Stable	21%
	Tampa Electric Company	A2	Stable	32%
	Tucson Electric Power Company	Baa1	Stable	19%
	Union Electric Company	(P)Baa1	Stable	22%
	UNS Energy Corporation	Baa2	Stable	19%
	Virginia Electric and Power Company	A2	Stable	27%
	Westar Energy, Inc.	Baa1	Stable	16%
	Wisconsin Electric Power Company	A1	Stable	17%
	Wisconsin Power and Light Company	A1	Stable	31%
	Wisconsin Public Service Corporation	A1	Stable	26%
T&Ds	AEP Texas North Company	Baa1	Stable	22%
	Ameren Illinois Company	(P)Baa1	Stable	26%
	Atlantic City Electric Company	Baa2	Stable	15%
	Baltimore Gas and Electric Company	A3	Stable	19%
	CenterPoint Energy Houston Electric, LLC	A3	Stable	16%
	Central Hudson Gas & Electric Corporation	A2	Stable	29%
	Central Maine Power Company	A3	Stable	27%
	Cleveland Electric Illuminating Company (The)	Baa3	Stable	15%
	Commonwealth Edison Company	Baa1	Stable	21%

	Entity Name	LT Rating	Outlook	CFO/Debt (3-Yr Avg) LTM 3Q11-LTM3Q13
	Connecticut Light and Power Company	Baa1	Stable	13%
	Consolidated Edison Company of New York, Inc.	A2	Stable	23%
	Delmarva Power & Light Company	Baa1	Stable	17%
	Duquesne Light Company	A3	Stable	26%
	Jersey Central Power & Light Company	Baa2	Negative	18%
	New York State Electric and Gas Corporation	A3	Stable	26%
	Niagara Mohawk Power Corporation	A3	Stable	23%
	NSTAR Electric Company	A2	Stable	29%
	Ohio Edison Company	Baa2	Stable	25%
	Oncor Electric Delivery Company LLC	Baa3	Stable	20%
	Orange and Rockland Utilities, Inc.	A3	Stable	21%
	PECO Energy Company	A2	Stable	30%
	Pennsylvania Electric Company	Baa2	Stable	18%
	Pennsylvania Power Company	Baa2	Stable	37%
	Potomac Edison Company (The)	Baa3	Stable	19%
	Potomac Electric Power Company	Baa1	Stable	16%
	Public Service Electric and Gas Company	A2	Stable	25%
	Rochester Gas & Electric Corporation	Baa1	Stable	26%
	Texas-New Mexico Power Company	Baa1	Positive	26%
	Toledo Edison Company	Baa3	Stable	8%
	United Illuminating Company	Baa1	Stable	20%
	West Penn Power Company	Baa2	Stable	25%
	Western Massachusetts Electric Company	A3	Stable	23%
LDCs	Atlanta Gas Light Company	A2	Stable	30%
	Atmos Energy Corporation	A2	Stable	23%
	Berkshire Gas Company	Baa1	Stable	29%
	Connecticut Natural Gas Corporation	A3	Stable	26%
	DTE Gas Company	Aa3	Stable	24%
	Indiana Gas Company, Inc.	A2	Stable	27%
	Laclede Gas Company	(P)A3	Stable	26%
	New Jersey Natural Gas Company	(P)Aa2	Stable	19%
	Northern Illinois Gas Company	A2	Stable	49%
	Northwest Natural Gas Company	(P)A3	Stable	20%
	Piedmont Natural Gas Company, Inc.	A2	Stable	23%
	Questar Gas Company	A2	Stable	25%
	SEMCO Energy, Inc.	Baa1	Stable	15%
	SourceGas LLC	Baa2	Stable	14%
	South Jersey Gas Company	A2	Stable	21%
	Southern California Gas Company	A1	Stable	32%
	Southern Connecticut Gas Company	Baa1	Stable	22%

Entity Name	LT Rating	Outlook	CFO/Debt (3-Yr Avg) LTM 3Q11-LTM3Q13
UGI Utilities, Inc.	A2	Stable	27%
UNS Gas, Inc.	Baa1	Stable	27%
Washington Gas Light Company	A1	Stable	35%
Wisconsin Gas LLC	A1	Stable	28%
Yankee Gas Services Company	Baa1	Stable	18%

Source: Moody's Investors Service

Moody's Related Research

Industry Outlooks:

» US Regulated Utilities: Regulation Provides Stability as Business Model Faces Challenges, July 2013 (156754)

» US Regulated Utilities: Regulatory Support, Low Natural Gas Prices Maintains Stability, February 2013 (149379)

» US Unregulated Power: Headwinds continue for the merchant power players, July 2013 (156302)

» US Coal Industry Outlook Stabilizes as Business Conditions Hit Bottom, August 2013 (157309)

» Global Oil & Gas: Persistent High Oil Prices Keep Industry Robust, but Global Supply Increasing (Summary), December 2013 (160980)

Special Comment:

» US utility sector upgrades driven by stable and transparent regulatory frameworks, January 2014 (163726)

» YieldCos: Fantastic for Shareholders; Less So for Bondholders, November 2013 (160121)

» Planned Capital Expenditures Set to Fall in 2015, And Modestly Decline Thereafter, October 2013 (158945)

» US Telecommunications and Regulated Utilities: End of Bonus Depreciation Could Prompt Cuts in Capital Spending, Dividends, September 2013 (157572)

» US Local Gas Distribution Companies: Lower risks and unique growth opportunities versus electric utility peers, May 2013 (153018)

» The Prospect of US LNG Exports Influences Pricing and Gas Markets Worldwide, May 2013 (151819)

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

Rating Methodology:

» Regulated Electric and Gas Utilities, December 2013 (157160)

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» contacts continued from page 1

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MOODY'S
INVESTORS SERVICE

Credit Opinion: Ohio Power Company

Global Credit Research - 12 May 2015

Canton, Ohio, United States

Ratings

Category	**Moody's Rating**
Outlook	Stable
Issuer Rating	Baa1
Parent: American Electric Power Company, Inc.	
Outlook	Stable
Senior Unsecured	Baa1
Jr Subordinate Shelf	(P)Baa2
Commercial Paper	P-2

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Key Indicators

[1]**OhioPowerCompany**

	3/31/2015(L)	**12/31/2014**	**12/31/2013**	**12/31/2012**	**12/31/2011**
CFO pre-WC + Interest / Interest	**6.1x**	**5.6x**	**5.1x**	**5.4x**	**5.6x**
CFO pre-WC / Debt	**24.3%**	**22.1%**	**26.1%**	**23.3%**	**24.5%**
CFO pre-WC - Dividends / Debt	**22.5%**	**20.8%**	**15.1%**	**16.7%**	**11.2%**
Debt / Capitalization	**44.6%**	**44.8%**	**53.8%**	**40.0%**	**42.0%**

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

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

Opinion

Rating Drivers

Constructive regulatory outcomes in Ohio continue through market transition

Consolidating into a lower-risk transmission and distribution utility through 2015

Slow economic recovery in Ohio, but continuous improvements are expected

Financial metrics will weaken during transition period in 2015 and 2016

Corporate Profile

Ohio Power Company (OPCo: Baa1, stable), a wholly owned subsidiary of American Electric Power Company (AEP: Baa1, stable), is engaged in transmission and distribution (T&D) services to approximately 1.5 million customers in Ohio at cost-based rates approved by the Public Utility Commission of Ohio (PUCO) or by the Federal Energy Regulatory Commission (FERC). OPCo has approximately $4.0 billion in rate base (15% of AEP's total jurisdictional rate base) with an above average pro-forma earned ROE of 12.6%.

OPCo provides power and capacity to its customers who have not switched electric providers. Effective January 1, 2014 OPCo began purchasing power from both affiliated and non-affiliated entities which are subject to auction requirements and approval to meet energy and capacity needs of customers. OPCo is a member of PJM.

Rating Rationale

OPCo's Baa1 rating reflects a low risk regulated T&D business with adequate cash flow metrics benefiting from a service territory in post-recessionary recovery and a credit supportive regulatory framework. OPCo's cash flow metrics remain adequate for the rating due to reduced debt levels stemming from the corporate separation resulting in cash flow pre-working capital (CFO pre-WC) to debt in the high teens, and debt to capitalization in the high forties.

DETAILED RATING CONSIDERATIONS

CONSTRUCTIVE REGULATORY OUTCOMES IN OHIO CONTINUE THOUGH MARKET TRANSITION

We view the Ohio regulatory environment as supportive to credit quality. On February 25, 2015 PUCO approved the implementation of electricity security plant (ESP) III covering the period June 1, 2015 through May 31, 2018. The new ESP will require OPCo to conduct six auctions to provide 100% of its standard service offer (SSO); the continuation of the distribution investment rider (DIR) based on a 10.2% return on equity, with associated capital investments carrying cost recovery of $124 million in 2015, around $146 million in 2016, $170 million in 2017, and about $100 million in 2018; the continuation of the enhanced service reliability rider (ESRR), storm damage recovery rider (SDRR), and a by-passable alternative energy rider (AER) reflecting the costs associated with the procurement of renewable energy credits; and, the proposed purchase-of-receivables mechanism. The Commission rejected the proposed sustained and skilled workforce (SSWR) rider. OPCo is currently subject to the terms of ESP II, which will expire on May 31, 2015.

In its February 25th ruling, PUCO also rejected OPCo's request for a rate rider and power purchase agreement (PPA) designed to guarantee income for its share of two coal-fired power plants operated by Ohio Valley Electric Corp. (OVEC, Baa3 stable). OPCo has a contractual commitment to roughly 20% of OVEC's coal-fired Kyger Creek and Clifty Creek plants. The PUCO authorized OPCo to implement a placeholder PPA rider, but declined to approve recovery of any costs at this time. OPCo is required to justify any requested PPA-related cost recovery in a future filing with the PUCO. This includes the financial necessity, as well as a plan forward under future environmental compliance. In July 2014 OPCo submitted an application to PUCO proposing an additional 2,671 MW to be added into a new PPA with AEP Generation Resources (AGR: not rated) over the life of the generation units. The PUCO has taken no action in this case and a decision is not expected until the second half of 2015. Pending PJM reforms and a similar FirstEnergy Corp's (Baa3, stable) case are important factors in evaluating the potential outcome of the OPCo case.

Effective January 1, 2014, FERC approved the power supply agreement between AGR and OPCo to secure available capacity for OPCo's switched and non-switched retail load from the period January 1, 2014 through May 31, 2015; and the bridge agreement among AGR , Appalachian Power Company (Baa1, stable), Kentucky Power Company (Baa2, stable), Indiana Michigan Power Company (Baa1 stable), OPCo, and AEP Service corporation (AEPSC, not rated) to address open commitments related to the termination of the previous Interconnection Agreement and responsibilities to PJM.

CONSOLIDATING INTO A LOWER RISK TRANSMISSION AND DISTRIBUTION UTILITY

We generally view the business risk of a T&D lower than that of a vertically integrated utility because of limited activities resulting in greater certainty of cash flows, a credit positive. However, a prolonged period of recovery costs associated with many of the riders or trackers under OPCo's ESPs would be credit negative because the associated securitization burden would remain on OPCo's balance sheet longer.

Moody's has historically evaluated OPCo's financial performance relative to the standard grid within the Regulated Electric and Gas Utilities methodology, which is customarily applied to vertically integrated utilities. OPCo's indicated rating under the standard grid based on historical and projected results (next 12-18 months) is Baa1.

However, we acknowledge OPCo's recent business transformation into a low risk regulated T&D and beginning in 2015 have revised our view to reflect this shift, placing OPCo under the low business risk grid within the methodology. That said, it would be unlikely that switching to the low risk business grid would result in any immediate rating upgrades for OPCo.

OHIO'S ECONOMIC RECOVERY WILL DEEPEN IN 2015; THOUGH ENERGY SECTOR PERFORMACE IS CLOUDY

Ohio's recovery has accelerated in the past several months but still lags behind those of the Midwest and the nation, according to Moody's Economy.com. Energy exploration, specifically in the Utica shale, health care, professional services and manufacturing have emerged as key growth drivers which will deepen the recovery in 2015 and are expected to drive a decrease in the unemployment rate to 4.8% by 2016 from 7.3% in 2013.

OPCo's principal industries include primary and fabricated metals, petroleum refining, chemical manufacturing, rubber and plastics products, mineral product and food products. Overall total retail sales as of December 2014 were 44,701 GWH, lower than their historical averages primarily due to the shutdown of a large aluminum smelter combined with energy efficiency and demand response initiatives set in 2008. On a positive note, excluding the aluminum smelter, industrial load was up, with gigawatts hours going from 14,008 in 2013 to 14,529 in 2014. The revenue impact from reduced sales resulting from these programs are offset by PUCO-approved trackers.

HISTORICALLY ROBUST METRICS WILL WEAKEN DURING TRANSITION PERIOD

OPCo's key financial credit metrics remain within the grid-indicated rating category for its Baa1 rating. For year-end 2013 and LTM Q1 2015 the interest coverage ratio was 5.6x and 6.1x, CFO pre-WC to debt (leverage ratio) was 22.1% and 24.3%, CFO pre-WC minus dividends to debt (RCF ratio) was 20.8% and 22.5%; and debt to capitalization was 45% for both periods. OPCo's CFO pre-WC has slightly increased from $600 million in 2014 to about $670 in LTM Q1 2015 which could imply that OPCo's cash flow metrics will stabilize reflecting the nature of the T&D business. We think capital investments will remain at an average $600 million per year.

For the next 18-24 months Moody's expects OPCo's metrics to continue being pressured due to the remaining recovery costs, which are expected to be fully recovered by May 2018. The restructuring has led to a decrease in leverage at OPCo, a credit positive. However, this is offset by the loss of revenues and deferred income tax benefits leading to a decrease in CFO pre-WC. We expect the interest coverage ratio to range from 5.3x to 5.8x; leverage ratio from 19% to 24%; RCF ratio from 13% - 18%; and debt to capitalization from 42% - 47%.

Liquidity

OPCo's liquidity is adequate. OPCo participates in the AEP Utility Money Pool with a borrowing limit of $400 million, which provides access to the parent company's liquidity. At year-end 2014, OPCo's loans to the utility pool were $312 million. OPCo also utilizes AEP's receivable securitization facility for its Ohio receivables. OPCo has $350 million in senior notes coming due in June of 2016 and no other maturities until 2017.

The restructuring at OPCo has caused a substantial decrease in cash from operations (CFO) in 2014 and management has responded by lowering both the capital investments and dividend payments, we expect to be the norm at OPCo going forward. For 2014, OPCo generated approximately $520 million of CFO, invested $460 million in capital investments and up streamed $35 million in dividend payments to parent AEP, resulting in a positive free cash flow (FCF) of approximately $25 million. In 2013 OPCo generated CFO of approximately $1 billion, invested $670 million in capital investments and up streamed $375 million in dividend payments, resulting in a negative FCF of about $45 million.

AEP's liquidity is adequate. AEP has two syndicated credit facilities totaling $3.5 billion, one is a $1.75 billion facility expiring June 2017, and the other is also a $1.75 billion facility expiring in July 2018. At year-end 2014 AEP had $602 million of commercial paper outstanding and $63 million of letters of credit issued leaving over $2.3 billion of availability on its credit facilities. AEP is not required to make a representation with respect to either material adverse change or material litigation in order to borrow under the facility. Default provisions exclude payment defaults and insolvency/bankruptcy of subsidiaries that are not significant subsidiaries per the SEC definition (in general, this would exclude subsidiaries representing less than 10% of assets or income). The facilities contain a covenant requiring that AEP's consolidated debt to capitalization (as defined) will not exceed 67.5%. AEP states the actual ratio was 51% at year-end 2014, indicating substantial headroom.

Rating Outlook

The stable rating outlook reflects our view that the regulatory environment in Ohio will continue to be supportive, and that cash flow metrics will stabilize in 2015 and consolidate in the 2016 - 2017 period, such as CFO pre-WC to debt will likely get closer to the twenties, RCF ratio in the mid-teens and debt to book capitalization in mid-forties.

What Could Change the Rating - Up

OPCo could be reviewed for upgrade if deferred costs are recovered in a timely manner and balances pending under the previous ESPs earn a reasonable return, leading to improved financial performance resulting in leverage ratio closer to the twenties and RCF ratio above the mid-teens on a sustainable basis.

What Could Change the Rating - Down

OPCo's ratings could be downgraded if the supportiveness of the regulatory environment changed leading to recovery mechanisms becoming insufficient and/or if there is significant increase in recovery lag. All of which could lead to a prolonged period of financial deterioration such that the CFO pre-WC to debt decreased to the mid-teens, and RCF ratio decline to the low teens range for an extended period of time.

Other Considerations

We acknowledge OPCo's recent business transformation into a low risk regulated T&D and beginning in 2015 have revised our view to reflect this shift, placing OPCo under the low business risk grid within the Regulated Electric and Gas Utilities methodology. That said, it would be unlikely that switching to the low risk business grid would result in any immediate rating upgrades for OPCo.

Rating Factors

OhioPowerCompany

Regulated Electric and Gas Utilities Industry Grid [1][2]	**Current LTM 3/31/2015**		[3]**Moody's 12-18 Month Forward ViewAs of 5/11/2015**	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	Baa	Baa	Baa	Baa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Baa	Baa	Baa	Baa
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity		N/A		N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	5.3x	A	5.3x - 5.8x	A
b) CFO pre-WC / Debt (3 Year Avg)	24.3%	A	19% - 24%	A
c) CFO pre-WC - Dividends / Debt (3 Year Avg)	17.5%	A	13% - 18%	A
d) Debt / Capitalization (3 Year Avg)	42.7%	A	42% - 47%	A
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A3		Baa1
HoldCo Structural Subordination Notching				
a) Indicated Rating from Grid		A3		Baa1
b) Actual Rating Assigned		Baa1		Baa1

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-

Financial Corporations. [2] As of 3/31/2015(L); Source: Moody's Financial Metrics [3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the ratings tab on the issuer/entity page on http://www.moodys.com for the most updated credit rating action information and rating history.

STANDARD & POOR'S RATINGS SERVICES
McGRAW HILL FINANCIAL

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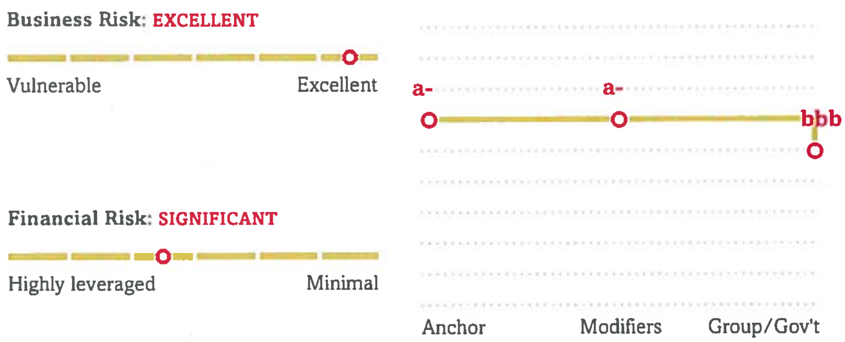
Ohio Power Co.



CORPORATE CREDIT RATING

BBB/Stable/--

Rationale

Business Risk: Excellent	Financial Risk: Significant
• Regulated transmission and distribution utility that is the sole distributor of essential electricity service in its area • Part of a large electric utility company that is geographically diverse and has a large customer base • Credit-supportive regulation • Transition to full retail choice	• Cash flow erosion from transition to retail choice in Ohio • Large capital expenditures • Strong cash flow measures • Positive free operating cash flow

Outlook: Stable

The stable rating outlook on parent American Electric Power Co. Inc. (AEP) and utility subsidiary Ohio Power Co. reflects Standard & Poor's Ratings Services' expectation that management will focus on its regulated utilities and will not expand unregulated operations beyond the existing level. We expect the company to receive timely cost recovery of rate base investments and operating expenses. The outlook also reflects our expectations that cash flow protection and debt leverage measures will remain at their currently robust levels. Our base-case forecast calls for adjusted funds from operations (FFO) to total debt of about 20%, supplemented by cash flow from operations (CFO) to debt of about 19%. We expect debt to EBITDA to be approximately 4x.

Downside scenario

We could lower the ratings if the business risk profile materially weakened or financial measures fell short of our base-case forecast on a sustained basis, including FFO to total debt falling below 13% or CFO to debt below 11%.

Upside scenario

We could raise the ratings if the business risk profile improves through growth in the utility operations and financial measures remain in line with our base-case forecast. We could also raise the ratings if we maintain our current business risk profile assessment and financial measures strengthen to the "intermediate" financial risk profile category, as defined in our criteria.

Standard & Poor's Base-Case Scenario

Assumptions

- Economic conditions in the company's service territory are improving, which will likely increase customer usage
- EBITDA growth from revenue increases and customer growth is likely to be about the same as it has been in recent years
- A retail stability rider allows for recovery of about $500 million throughout the Ohio transition period, ending May 31, 2015
- Capital spending and dividend payouts lead to negative discretionary cash flow, indicating the need for external funding

Key Metrics

In our base case, we expect Ohio Power's key adjusted financial measures to approximate historical performance during the next few years. We expect FFO to debt of 18% to 20%, and debt to EBITDA of about 4x, both in line with the "significant" category under our medial volatility benchmarks. We forecast CFO to debt of about 22%, bolstering the "significant" determination. We expect the utility to generate positive free operating cash flow over the next few years. Discretionary cash flow should be negative over the next few years, reflecting capital spending and dividend payments to parent company AEP, indicating external funding needs. Beyond our base-case forecast, we expect to see financial measures that are also similar to our base case measures.

Business Risk: Excellent

Our assessment of Ohio Power's business risk profile as "excellent," as defined in our criteria, is based on the company's "strong" competitive position, "very low" industry risk derived from the regulated utility industry, and the "very low" country risk of the U.S. The competitive position assessment reflects the strengths of an electric utility that provides service from the northwestern part of Ohio to the southeastern part of the state. Now that its generation assets have been transferred to affiliates, the utility is a transmission and distribution electric utility. Ohio Power continues to make the transition to a competitive generation market in which all retail customers shop for generation service. By June 1, 2015, Ohio Power is expected to have fully transitioned to a utility that will hold auctions to provide power to standard-service-offer customers. During the transition, transition costs are being recovered partly through a non-bypassable retail stability rider and partly by recovering from customers the difference between capacity prices set in the PJM market and a capacity price determined by the Public Utilities Commission of Ohio. Any unrecovered capacity deferral is to be accrued and recovered in rates through 2018.

Financial Risk: Significant

Based on the medial volatility financial ratio benchmarks, our assessment of Ohio Power's financial risk profile is "significant." This reflects the recurring cash flow from being a fully regulated transmission and distribution electric utility. Capital spending is necessary for maintenance purposes and new projects. Recovery of costs has generally been adequate. Financial measures over the next few years are expected to remain about the same as existing levels. Discretionary cash flow could change between positive and negative during the forecast period. If negative, it would indicate the need for external funding, and if positive, it would indicate that internal cash flow is adequate to cover capital spending and dividend payments.

Measures could improve if spending is lower than we expect or cost recovery is higher than we expect. Steady cost recovery through the regulatory process will be required to maintain cash flow coverages. For the 12 months ended Dec. 31, 2013, FFO to debt was 38%, CFO to debt was 36%, and debt to EBITDA was 2.1x. However, these ratios include Ohio Power's former generation operations that have been divested to affiliates. Therefore, as a transmission and distribution utility, our baseline forecast reflects financial measures in line with the "significant" determination, such as FFO to debt of 18% to 20% and CFO to debt of 22%.

Liquidity: Adequate

Ohio Power's liquidity reflects that of parent AEP, which we consider "adequate," as our criteria define the term. We believe the company's liquidity sources are likely to cover its uses by more than 1.1x for the next 12 months, and even with a 10% decline in EBITDA.

Large debt maturities are due during the next three years, and we expect the company to refinance these given its satisfactory standing in the credit markets.

Principal Liquidity Sources	Principal Liquidity Uses
• Cash on hand of roughly $500 million in 2014 • FFO of roughly $4.2 billion in 2014 • Credit facility availability of about $2.5 billion in 2014 • Working capital of about $350 million in 2014	• Debt maturities of about $1.5 billion in 2014 • Capital spending of about $4.3 billion in 2014 • Dividends of about $970 million in 2014

Other Modifiers

Other modifiers have no effect on the rating outcome.

Group Influence

The stand-alone credit profile of 'a-' for Ohio Power reflects its business and financial risk profiles and is two notches higher than the group credit profile for AEP, which is currently 'bbb'. Under our group rating methodology, we consider Ohio Power a core subsidiary of the AEP group and therefore, the issuer credit rating on Ohio Power is equal to the group credit profile for AEP.

Ratings Score Snapshot

Corporate Credit Rating

BBB/Stable/--

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Strong

Financial risk: Significant

- **Cash flow/Leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Financial policy:** Neutral (no impact)
- **Management and governance:** Satisfactory (no impact)

- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a-

- **Group credit profile:** bbb
- **Entity status within group:** Core (-2 notches from SACP)

Related Criteria And Research

Related Criteria

- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Jan. 2, 2014
- Corporate Methodology, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Methodology: Industry Risk, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Methodology For Linking Short-Term And Long-Term Ratings For Corporate, Insurance, And Sovereign Issuers, May 7, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- Stand-Alone Credit Profiles: One Component Of A Rating, Oct. 1, 2010
- Notching Of U.S. Investment-Grade Investor-Owned Utility Unsecured Debt Now Better Reflects Anticipated Absolute Recovery, Nov. 10, 2008
- 2008 Corporate Criteria: Rating Each Issue, April 15, 2008
- 2008 Corporate Criteria: Commercial Paper, April 15, 2008

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	**a-**	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

Fed's Plosser: Low rates 'should make us nervous'

Katy Barnato | Carolin Roth
Tuesday, 11 Nov 2014 | 4:16 AM ET
CNBC

Interest rates in the U.S. are unprecedentedly low, even allowing forfalling oil prices and "very modest" wage growth, Philadelphia Federal Reserve President Charles Plosser told CNBC on Tuesday, who expressed concern over the low levels.

Plosser, who is one of the Fed's most outspoken "hawks" expressed concern over the low rates. Last month, the Fed confirmed that it would hold the target range for the federal funds rate at 0 to 0.25 percent.

"There are many indicators that tell us interest rates are too low," Plosser told CNBC from the UBS European Conference in London.

"There is no precedented history to have rates at zero. I think we are really behaving in a way which is outside of historical norms and that should make us nervous," he added.

Plosser conceded that "wage growth has been very modest" and that falling oil prices were pressuring short-term inflation lower—but said that rates were too low nonetheless.

"Given the unemployment rate, and even given low inflation, we are below where we would normally be," he said. "I think this is something we should be cognisant of."

Plosser added that the Fed should also avoid responding to short-term fluctuations in either the U.S. dollar or the stock market.

"The dollar is not our responsibility," Plosser told CNBC.

He said the appreciation in the dollar would have "some reverberations", but these would be limited because the U.S. economy was "pretty much closed" when compared to Europe or the U.K.

Plosser is due to retire from the Fed in March next year. He was an economics professor at the University of Rochester before he became the 10th president of the Philly Fed in August 2006.

His retirement will coincide with that of Dallas Fed's Richard Fisher, another central banker who has stridently advocated paring back monetary stimulus.

Plosser and Fisher's departure could change the tenor of debate within the Fed policy-setting committee, giving it a more dovish bent.

"I am sure that a wide range of views will continue to be discussed," Plosser said regarding his retirement, for which he has no immediate plans.

"There will still be a healthy debate I'm sure."

—Writing by CNBC's Katy Barnato; reporting by Carolin Roth

Federal Reserve Statistical Release

H.4.1

Factors Affecting Reserve Balances

Skip to Content

Release Date: January 21, 2016

Data Download Program

FEDERAL RESERVE statistical release

H.4.1

Factors Affecting Reserve Balances of Depository Institutions and
Condition Statement of Federal Reserve Banks

January 21, 2016

1. Factors Affecting Reserve Balances of Depository Institutions
Millions of dollars

Reserve Bank credit, related items, and reserve balances of depository institutions at Federal Reserve Banks	Averages of daily figures: Week ended Jan 20, 2016	Change from week ended Jan 13, 2016	Change from week ended Jan 21, 2015	Wednesday Jan 20, 2016
Reserve Bank credit	4,456,214	+ 5,284	- 11,467	4,450,281
Securities held outright (1)	4,248,187	+ 4,429	+ 4,612	4,242,989
U.S. Treasury securities	2,461,412	- 59	+ 425	2,461,396
Bills (2)	0	0	0	0
Notes and bonds, nominal (2)	2,346,639	0	- 73	2,346,639
Notes and bonds, inflation-indexed (2)	98,534	0	+ 65	98,534
Inflation compensation (3)	16,240	- 58	+ 434	16,223
Federal agency debt securities (2)	32,479	- 465	- 5,109	31,318
Mortgage-backed securities (4)	1,754,295	+ 4,952	+ 9,295	1,750,275
Unamortized premiums on securities held outright (5)	188,844	- 186	- 17,479	188,545
Unamortized discounts on securities held outright (5)	-16,488	+ 37	+ 1,817	-16,477
Repurchase agreements (6)	0	0	0	0
Loans	85	+ 63	- 16	20
Primary credit	70	+ 66	- 21	4
Secondary credit	0	0	0	0
Seasonal credit	14	- 4	+ 4	16
Other credit extensions	0	0	0	0
Net portfolio holdings of Maiden Lane LLC (7)	1,717	0	+ 37	1,717
Float	-129	+ 6	+ 284	-196
Central bank liquidity swaps (8)	125	+ 7	+ 115	125
Other Federal Reserve assets (9)	33,873	+ 929	- 836	33,558
Foreign currency denominated assets (10)	19,933	+ 122	- 599	19,949
Gold stock	11,041	0	0	11,041
Special drawing rights certificate account	5,200	0	0	5,200
Treasury currency outstanding (11)	47,609	+ 14	+ 1,195	47,609
Total factors supplying reserve funds	4,539,996	+ 5,419	- 10,871	4,534,080

Note: Components may not sum to totals because of rounding. Footnotes appear at the end of the table.

1. Factors Affecting Reserve Balances of Depository Institutions (continued)
Millions of dollars

Reserve Bank credit, related items, and reserve balances of depository institutions at Federal Reserve Banks	Averages of daily figures: Week ended Jan 20, 2016	Change from week ended Jan 13, 2016	Change from week ended Jan 21, 2015	Wednesday Jan 20, 2016
Currency in circulation (11)	1,414,835	- 2,297	+ 84,022	1,414,434
Reverse repurchase agreements (12)	308,626	- 8,533	+ 60,400	322,974
Foreign official and international accounts	217,568	- 1,769	+ 105,789	216,347
Others	91,058	- 6,764	- 45,389	106,627
Treasury cash holdings	280	+ 1	+ 74	279
Deposits with F.R. Banks, other than reserve balances	314,189	- 16,951	+ 128,829	338,373
Term deposits held by depository institutions	0	0	0	0
U.S. Treasury, General Account	285,318	- 17,665	+ 115,166	318,749
Foreign official	5,288	+ 44	+ 67	5,231
Other (13)	23,584	+ 671	+ 13,597	14,393
Other liabilities and capital (14)	47,296	+ 328	- 16,575	45,942
Total factors, other than reserve balances, absorbing reserve funds	2,085,226	- 27,452	+ 256,751	2,122,002
Reserve balances with Federal Reserve Banks	2,454,769	+ 32,870	- 267,623	2,412,078

Note: Components may not sum to totals because of rounding.

1. Includes securities lent to dealers under the overnight securities lending facility; refer to table 1A.
2. Face value of the securities.
3. Compensation that adjusts for the effect of inflation on the original face value of inflation-indexed securities.
4. Guaranteed by Fannie Mae, Freddie Mac, and Ginnie Mae. The current face value shown is the remaining principal balance of the securities.
5. Reflects the premium or discount, which is the difference between the purchase price and the face value of the securities that has not been amortized. For U.S. Treasury and Federal agency debt securities, amortization is on a straight-line basis. For mortgage-backed securities, amortization is on an

Financial Analysts Journal
Volume 69 • Number 6

PERSPECTIVES

Prospects for and Ramifications of the Great Central Banking Unwind

William Poole

At the CFA Institute Global Investment Risk Symposium held in Washington, DC, on 7–8 March 2013, William Poole gave a presentation on what he calls the "great central banking unwind." Total assets on the balance sheets of the U.S. Federal Reserve and European Central Bank have exploded since 2008. The challenges and pressure faced by these and other central banks will probably have serious consequences for the global economy.

I am very uneasy about the current economic and fiscal situation in the United States and Europe. The central bank policies and fiscal disequilibrium in these countries are unlike any circumstances they have endured in the past; it is uncertain how the massive easing of the last five years is going to affect the developed nations' economies as well as the global economy. The world is in uncharted territory.

I am going to focus on the U.S. Federal Reserve System and the European Central Bank (ECB). The Fed is the most important central bank in the world: Without stability in the United States, the world economy will not have stability. Not only must central banks navigate the challenges presented by slower growth and fiscal deficits, but they also face powerful political pressures that, if succumbed to, may have harmful consequences domestically and globally.

Fed Issues vs. ECB Issues

Although both the United States and the eurozone had significant economic downturns and financial disruption during the financial crisis, the Fed's expansionary monetary policy has been motivated primarily by a concern over unemployment whereas the ECB's policy has been motivated by an effort to support the sovereign debt of fiscally weak governments—in particular, the southern European countries.

Figure 1 shows the Fed's balance sheet assets from 2007 to 2013. Before the financial crisis, its assets were around $850 billion; they have now risen to nearly $3 trillion, and the Fed keeps pumping money into the system. It is unclear when the Fed's policy of easing is going to stop or how it is going to be reversed.

But the Fed is not alone. The ECB has been pumping funds into the European markets, as shown in **Figure 2**. Total assets on the ECB's balance sheet have increased from about €1.2 trillion in 2007 to about €3 trillion in the first quarter of 2013. The Bank of England (BOE) and a number of other central banks have been following suit. A massive monetary expansion has taken place over the last five years.

The ECB is acting as a lifeboat for sinking public finances after a collision of high levels of entitlement spending and sustained low economic growth. The plight of Greece in 2012 has led the way; other nations, Italy prominent among them, will most certainly follow. Greece was unable to raise needed funds by issuing sovereign debt after December 2008 because investors would no longer buy it; the risk of default was too high.

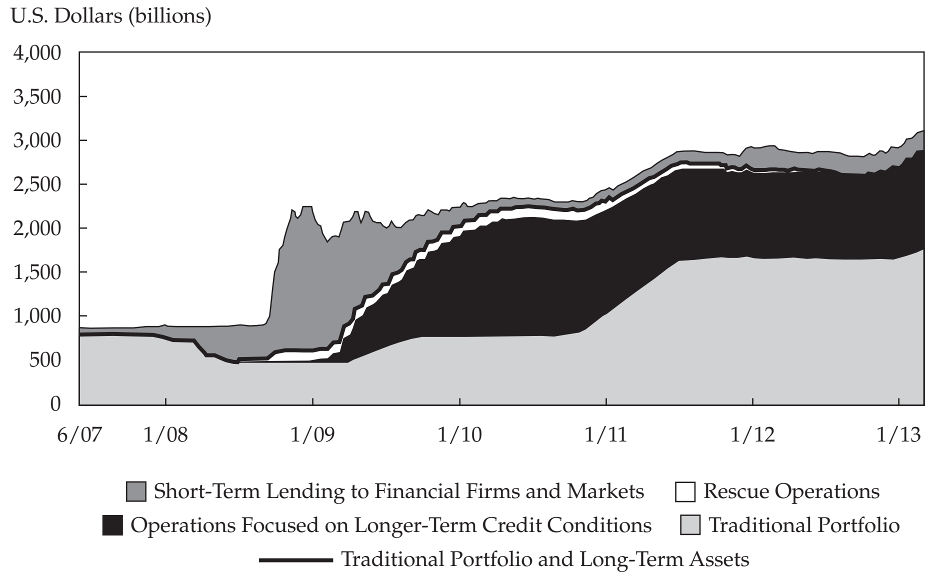
Great Fed Unwind

Given the very large buildup of assets on its balance sheet, it might appear that the Fed has to unwind the position, but that is not necessarily the case. The Fed might keep a very large portfolio indefinitely.

Reserve Ratio. The monetary mechanism that the Fed, or any central bank, uses to control the growth of money and credit is completely different from what it was in the past. The Fed's main instrument of controlling money and credit growth in the past was the reserve requirement, which sets

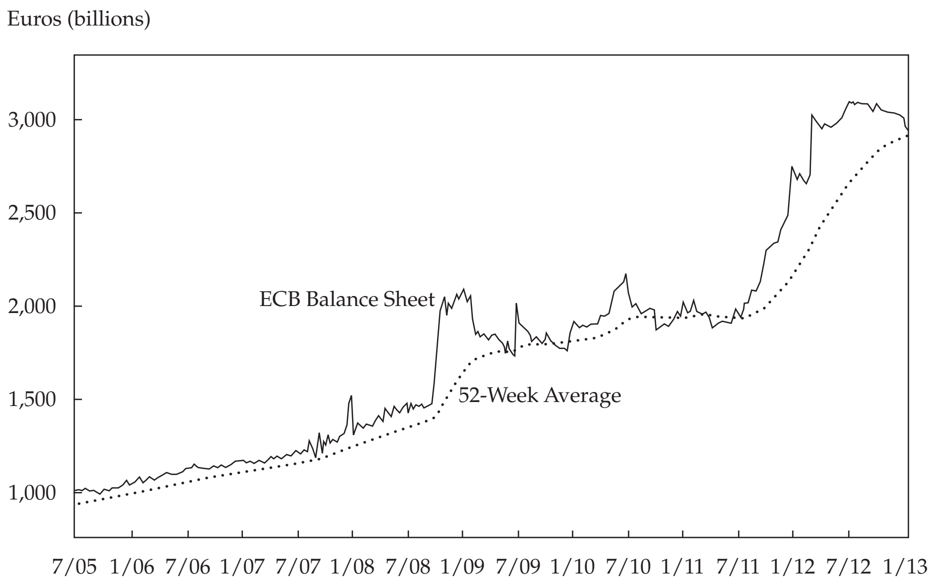
William Poole is a senior fellow at the Cato Institute, Washington, DC.

Figure 1. U.S. Federal Reserve Balance Sheet Assets, June 2007–February 2013



Source: Based on a figure from the Federal Reserve Bank of St. Louis, "U.S. Financial Data" (22 February 2013):7.

Figure 2. ECB Balance Sheet Assets, 2005–2013



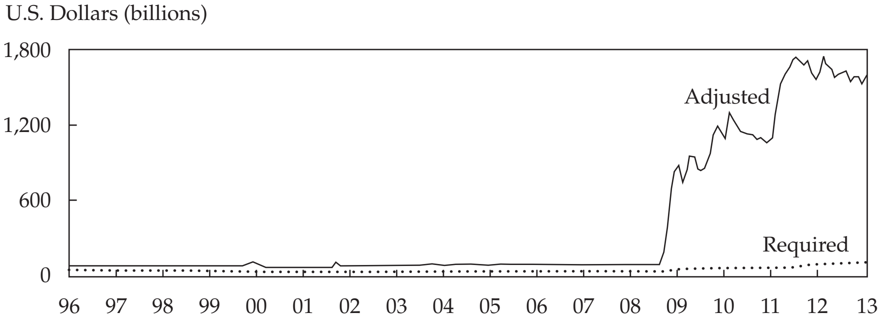
Sources: Based on data from Gold Silver Worlds and Weldon Financial.

forth the amount of reserves that banks had to keep on deposit with the Fed. The amount of a bank's deposits with the Fed is a percentage of its total demand deposits.

Today, banks are no longer constrained by the reserve ratio. In the past, the Fed had no authority to pay interest on bank reserves, so banks typically held only the minimum amount of reserves required. But in 2008, new legislation gave the Fed the authority to pay interest on reserves, which the Fed has currently set at the rate of 0.25%. That rate is above other money market rates and thus has provided an incentive for banks to increase their excess reserves at the Fed.

Figure 3 shows the dramatic increase in bank reserves since mid-2008; as of 20 February 2013, they are now more than $1.5 trillion. Given the latest round of quantitative easing (QE) by the Federal Reserve, these bank reserves will continue to grow. The dotted line in Figure 3 represents the amount of required reserves, which contrasts markedly with the enormous stockpile of excess reserves sitting

Figure 3. Adjusted and Required Federal Reserves, January 1996–February 2013



Source: Based on a figure from the Federal Reserve Bank of St. Louis, "Monetary Trends" (26 February 2013):6.

on bank balance sheets. Banks are holding these reserves rather than lending them or buying assets with them because the Fed is paying interest on them. Reserves are the raw material for a money and credit expansion, but this raw material is not being actively used. To date, money and credit growth has been moderate. There are no signs of overheating, and the same is true for inflation expectations.

Two measures of the money supply—money zero maturity (MZM) and M2—are plotted in **Figure 4** from 1996 through mid-February 2013. M2 is calculated as M1 (all physical money, such as coins and currency, plus demand deposits, or checking accounts, and Negotiable Order of Withdrawal accounts) plus time deposits, savings deposits, and noninstitutional money market funds. MZM is defined as the liquid money supply in an economy—all assets convertible to cash on demand without penalty. The bigger area of shading at the right is the most recent recession, drawn from the cycle peak in December 2007 to the cycle trough in June 2009. The smaller area of shading on the left represents the much milder recession in 2001. Money stock growth measured by both definitions has recently been well within the normal range.

Inflation expectations can be measured in a number of ways, but I prefer a market-based measure to a survey measure. A market-based measure is derived from the spread between inflation-indexed Treasury bonds and conventional bonds. **Figure 5** compares yields in percentage terms for three different maturities: 5, 10, and 30 years. The spread between the conventional and indexed bonds stays in a relatively tight range from December 2011 to February 2013, and the spreads at the 10-year mark are in the same range they have been in for the past 10–12 years.

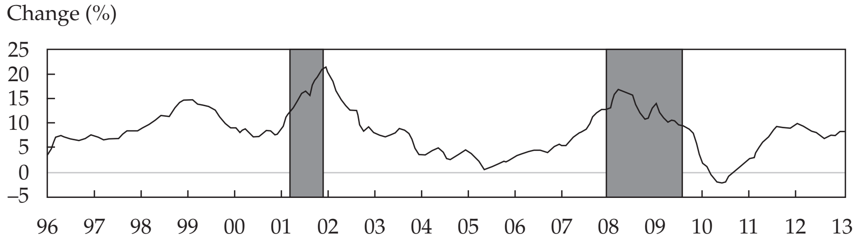
Raising the Federal Funds Rate. If inflation starts to rise, the Federal Reserve's standard strategy is to raise its target for the federal funds rate, which is the interest rate on interbank lending and borrowing. Federal funds are nothing more than bank reserves; banks are able to lend the reserve balances they have on account at the Fed. Now that the Fed pays interest on bank reserves, the interest rate on bank reserves is tied, almost to the basis point, to the federal funds rate. The Fed cannot raise the federal funds rate without also raising the rate that it pays on bank reserves, and at some point, the rate increases must be large enough to persuade banks to hold reserves rather than engage in an excessive expansion of money and credit that would create an inflation problem.

Despite all of the progress the financial industry has made in terms of modeling and statistical technology, the Fed basically decides how much to raise the federal funds rate in the same manner that a driver attempts to hold a steady speed when driving in mountainous territory. If the car is going too fast down the mountain, the driver eases up on the accelerator. If that action isn't enough, the driver eases up more and maybe taps the brakes. Likewise, the Fed reduces its assets to drive up interest rates, but the required pace of reduction is not clear *ex ante*. The basic idea is simple: If the economy is growing too fast, the Fed taps on the monetary policy brake by increasing interest rates. The Fed then adjusts its policy based on feedback and observation of recent data.

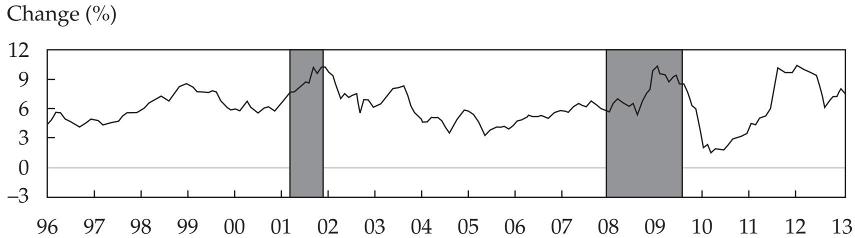
Forecasts. Everyone who deals with portfolio management knows that an action taken in response to a problem depends on the decision maker's belief about a forecast. And when making decisions, it is easy to be in denial about the most recent information. Likewise, if the Fed starts to see inflation while the unemployment rate is still high, it may choose to deny reality and take the position that the inflation bump is a temporary aberration, perhaps related to energy prices or some other issue.

Figure 4. Change in Two Measures of the Money Supply, January 1996–February 2013

A. MZM

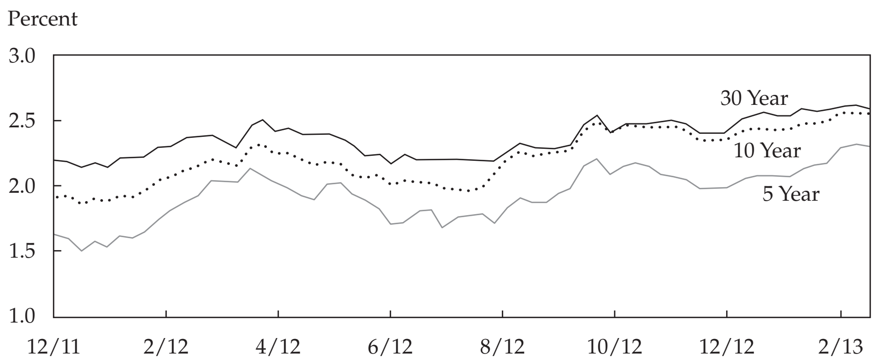


B. M2



Note: Change is the percentage change from one year ago.
Source: Based on a figure from the Federal Reserve Bank of St. Louis, "Monetary Trends" (26 February 2013):4.

Figure 5. Inflation-Indexed Treasury Yield Spreads, December 2011–February 2013



Note: Data represent averages of daily figures.
Source: Based on a figure from the Federal Reserve Bank of St. Louis, "U.S. Financial Data" (22 February 2013):12.

Such inaction on the part of the Federal Reserve might be motivated by a desire to avoid tightening policy too soon because of an overriding interest in and responsibility for advancing the rate of employment growth. But if the Fed is in denial too long, inflation can become embedded in the economy. One of the best examples of Fed inflation denial is illustrated by monetary policy from roughly 1965 to 1979; Paul Volcker took over as chairman of the Fed in August 1979 to deal with the inflation. After 1965, the Fed was concerned that tighter policy would choke off employment growth, so it allowed inflation to creep up and up until the creep became a gallop.

Political Pressure. The Fed is also likely to face political pressure to raise rates only slowly. Federal Reserve chairman Ben Bernanke talks a lot about risk management and the tradeoff between benefits and costs; he maintains that the need to balance these two issues justifies proceeding with the current policy. But Bernanke does not discuss the risk of political intervention in Fed policy despite numerous examples of the Fed giving in to political pressure and waiting too long to change its policy, which results in a detrimental outcome for the economy.

Mortgage finance interests have been extremely well organized politically and are quite influential.

Part of the Fed's QE policy is to buy $40 billion of mortgage-backed securities (MBSs) a month. Stopping that part of its expansionary policy—without even considering unwinding the portfolio—will produce a lot of political pushback. This push-back will come through the housing and mortgage interests, through representatives in Congress, and perhaps through the president. Essentially, pressure on the Fed will come from inside the government and may not be very visible; it may be limited to a few op-ed articles from the housing lobby. The true amount of political pressure will largely be hidden.

Pressure to keep rates low will come also from those who argue that the Fed should do its share to hold down the federal budget deficit. Higher interest rates will produce a rapid and enormous increase in the interest expense in the federal budget. The Fed is going to be encouraged to suppress interest rates until longer-run reforms can be put in place to address the budget deficit.

Recent discussion has centered on the impact of Fed policy on a number of issues. For example, is Fed policy creating a bubble in the bond or stock markets or in farmland prices? Is Fed policy pushing down the dollar exchange rate? Bubbles are easy to understand after the fact but very difficult to identify in real time. Many market fluctuations were thought to be unsustainable at the time but turned out to be justified by fundamentals. So, Fed policy may or may not be bubble inducing. But the real issue is the politics of monetary policy.

I believe that the Fed will not successfully resist the political winds that buffet it. I am not a political expert or a political analyst by trade. My qualification for speaking on this topic is that I have followed the interactions between monetary policy and politics for a very long time. As with all things political, the politics of the Fed means that realities often fail to match outward appearances.

I believe the Fed is likely to overdo its current QE policy of purchasing $45 billion of Treasuries and $40 billion of MBSs per month. Turning off the spigot would be difficult, but to be effective, the Fed has to stop its expansionary policy before inflation becomes embedded in the economy. For policy to be effective, it needs to be preemptive. Inflation control is better when accomplished before inflation has risen, not after.

Uncertainties. Although forecasts always contain uncertainties, the federal budget and regulatory uncertainties today are greater than at any time over the past 60 years. These budget and regulatory uncertainties are the prime explanation for the slowness of the economic recovery; businesses are hanging back until they better understand, or think they better understand, the way that the regulations are going to be written and interpreted. The load of regulations on the business sector is larger than it has been since the 1930s: the Affordable Care Act and the Dodd–Frank Wall Street Reform and Consumer Protection Act, as well as the policies of the Environmental Protection Agency and the Department of Labor. I think President Obama and his administration—in large part because they do not understand the markets as well as they might—will not hesitate to pressure the Fed, initially from the inside and perhaps ultimately from the outside by encouraging heavy public criticism once the Fed embarks on a policy of raising rates. Such an approach will likely be counterproductive, and the markets will respond very negatively.

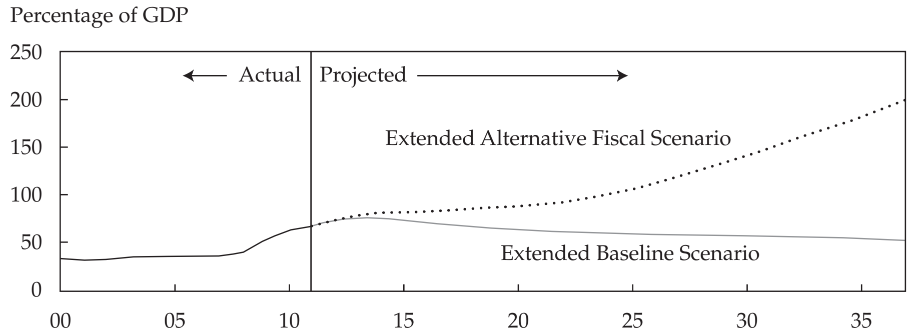
The very deep fiscal disequilibrium in the United States is best understood by looking at the data from the Congressional Budget Office (CBO). The budget games that are played with the numbers are full of screwy and misleading accounting. For example, the alternative minimum tax (AMT) was patched one year at a time so that the forward projections of revenues from the AMT would be in all the official projections of the budget. But the patchwork nature of the process created uncertainty about its final structure. Another example on the expenditure side is from more than 10 years ago: Since the Clinton years, legislation on the books has called for large reductions in Medicare reimbursements to physicians. The "doc fix" was enacted one year at a time so that the physicians would not have their reimbursements cut by a third. The budget encompassed forward projections of outlays that were lower than the outlays that would actually occur.

Figure 6 shows the federal debt forecast under two CBO long-term budget scenarios as of June 2012. This forecast is updated each summer. The dotted line shows the projected debt level over the next 25 years without the kind of budget gimmicks I just described. The shaded line shows the debt-level projection with all the budget gimmicks included. The United States is in the process of struggling with this enormous disequilibrium, although its struggle so far has been about the discretionary part of the budget, without any very serious political discussion—let alone legislative proposals—related to Social Security and Medicare expenditures, which are driving the budget. Until entitlement outlays are addressed, the budget is going to look more like the dotted line in Figure 6 than the shaded line.

Great ECB Unwind

The ECB has acquired a substantial amount of the sovereign debt of the fiscally weak southern European countries. It has also been lending to banks that have, in turn, purchased the debt of the weak

Figure 6. Federal Debt Forecast under the CBO's Long-Term Budget Scenarios, 2000–2037



Note: Forecast is as of June 2012.
Source: Based on a figure from the Congressional Budget Office, "The 2012 Long-Term Budget Outlook" (5 June 2012):2.

countries. The European banking regulations have so-called risk-weighted capital requirements, but the risk weight on all sovereign debt is zero. So, a bank can buy the bonds of Italy or Spain or even Greece and have a zero capital requirement. Obviously, the capital requirements are not truly risk weighted; they are politically weighted. The capital requirements in Europe, as in the United States, are deeply affected by the politics of bank regulation.

The situation in Europe is still very much in flux. Italy recently had a very indecisive election. The citizens of the weak nations are not embracing the austerity that is required to bring their economies back in line. They want to keep their benefits, and they do not want to pay taxes. These desires are perfectly rational but are not conducive to fiscal sustainability. So, the crisis that has long been predicted—because of much larger welfare state commitments than can be financed with an aging and retired population—has finally arrived and is by no means resolved.

The ECB cannot unwind the assets it owns unless Spain, Italy, Portugal, and Greece resolve their fiscal problems. Thus, these countries' debt might remain on the ECB's balance sheet—and the loans to these countries on European banks' balance sheets—for some time. Therefore, if Europe begins to have an inflation problem, the ECB will have its hands tied to a significant extent and will be limited in its ability to deal with rising inflation.

Europe is afraid of contagion, in which a default in one country results in investors fleeing the bond markets of the other fiscally weak countries. Thus, the weak countries remain supported by the fiscally sound countries—essentially, Germany—but Germany does not have the resources to support the weak countries indefinitely.

The ECB's charter was supposed to protect it from this situation, but the ECB has caved in to the pressure. To date, there is no evidence of inflationary problems in Europe, at least on the continent, although the United Kingdom has experienced some inflation.

It is a close call in Europe, but I believe that the fundamental fiscal weakness in Europe will end in a crisis. The European community encompasses overextended welfare states, many of which, particularly in southern Europe, have weak administration of tax law and negative politics on decreasing outlays. Many of its public enterprises are inefficient, and its labor markets are burdened by structural rigidities.

The consequences of poor fundamentals in Europe are negative economic growth and rising unemployment. It remains an open question whether Germany's voters will ultimately say that they will no longer support Italy, Spain, Portugal, and Greece. The Merkel administration has retained the support of the German people so far, but without any improvement in the situation, the time may come when Germany's voters ask themselves why they should pay for the excesses of others.

Conclusion

Because no precedents exist for the massive monetary easing that has been practiced over the past five years in the United States and Europe, the uncertainty surrounding the outcome of central bank policy is also vast. So far, inflationary pressures remain subdued, but the ability and willingness of the Fed and the ECB to react quickly to control inflation fears are in jeopardy, largely because of political forces. Total assets on the balance sheets of most developed nations' central banks have grown massively since 2008, and the timing of when the banks will unwind those positions is uncertain.

This article qualifies for 0.5 CE credit.

Question and Answer Session

William Poole

Question: Is the dual mandate of maximum employment and price stability a burden on Fed policy?

Poole: The dual mandate is not necessarily a problem. The 1977 law stated that the Fed is supposed to work toward two objectives: inflation and employment. In January 2012, the Federal Open Market Committee (FOMC) set forth the principles with which it approaches its dual mandate. At that time, the FOMC adopted an inflation target of 2%, and the target was renewed in January 2013. The published principles state that no central bank can promise to create a certain level of employment growth or a certain level of unemployment because those are real variables that are controlled by the real conditions in the economy, including such conditions as fiscal policy, and are ultimately not the responsibility of Fed policy.

Question: What is the primary weakness of the Fed?

Poole: I fault the Fed for its lack of intellectual leadership on the economy and, in particular, Bernanke's lack of forthrightness about the limits of the Fed's ability to address slow growth and fiscal disequilibrium. Most of the Federal Reserve bank presidents (with the exceptions of Charles Plosser in Philadelphia, Richard Fisher in Dallas, Jeffrey Lacker in Richmond, and to some extent, my successor in St. Louis, Jim Bullard) have been essentially silent on this issue, speaking only in vague terms about the necessity for fiscal stability and not identifying the uncertainty over that issue as a reason for the slow economic expansion.

Question: Is the Fed structured for failure?

Poole: That question is very important. Institutions need to be considered separately from the individuals who inhabit them. If certain individuals are going to make a mess of something, no institutional structure can guard against that except through a system of checks and balances. Past research has shown that central bank independence produces a better result than monetary policy run by the Treasury. Independence for the Federal Reserve began 100 years ago, when the Federal Reserve Act was signed in December 1913. The Fed's structure provides substantial independence, allowing room for strong leadership to do what has to be done in the face of adverse political pressure. The Fed's structure does not guarantee independence, but it provides the room. Paul Volcker has made significant use of that independence, whereas Arthur Burns, one of the architects of monetary policy and the inflation that culminated from it, did not. No institutional structure can guarantee a good result, but institutional structures can allow strong people to fail because they lose control.

Question: If the Fed were to adopt the equivalent of a Taylor rule today,[1] what should it be?

Poole: A simple Taylor-like rule that relates to only a couple of variables when so much is going on is unworkable at this point. An appropriate goal might be to have a central bank that is more constrained by legislative rules, but I just do not see a workable rule at this time.

Question: What is your opinion about returning to the gold standard?

Poole: I think the gold standard is unworkable. It was not as satisfactory in the 19th century, during its heyday, as is often argued. The basic problem is easy to see. When there is a flight to liquidity, when the market wants more gold, there is no more gold. The supply is fixed. All sorts of liabilities backed by gold have been issued, but those liabilities far exceed the gold supply. Therefore, the gold standard is a recipe for a banking system that collapses under stress, although it did stabilize the price level over a long period of time.

Notes

1. A Taylor rule is a monetary policy rule that stipulates how much the central bank should change the nominal interest rate in response to changes in inflation, output, or other economic conditions.

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5. Standard & Poor's
6. Morningstar
7. BARRA

Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors. The Value Line data are commercially available on a timely basis to investors in paper format or electronically. Value Line betas are derived from a least-squares regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the New York Stock Exchange Average over a period of 5 years. In the case of shorter price histories, a smaller time period is used, but 2 years is the minimum. Value Line betas are computed on a theoretically sound basis using a broadly based market index, and they are adjusted for the regression tendency of betas to converge to 1.00. This necessary adjustment to beta is discussed below.

Practical and Conceptual Difficulties

Computational Issues. Absolute estimates of beta may vary over a wide range when different computational methods are used. The return data, the time period used, its duration, the choice of market index, and whether annual, monthly, or weekly return figures are used will influence the final result.

Ideally, the returns should be total returns, that is, dividends and capital gains. In practice, beta estimates are relatively unaffected if dividends are excluded. Theoretically, market returns should be expressed in terms of total returns on a portfolio of all risky assets. In practice, a broadly based value-weighted market index is used. For example, Merrill Lynch betas use the Standard & Poor's 500 market index, while Value Line betas use the New York Stock Exchange Composite market index. In theory, unless the market index used is the true market index, fully diversified to include all securities in their proportion outstanding, the beta estimate obtained is potentially distorted. Failure to include bonds, Treasury bills, real estate, etc., could lead to a biased beta estimate. But if beta is used as a relative risk ranking device, choice of the market index may not alter the relative rankings of security risk significantly.

To enhance statistical significance, beta should be calculated with return data going as far back as possible. But the company's risk may have changed if the historical period is too long. Weighting the data for this tendency is one possible remedy, but this procedure presupposes some knowledge of how risk changed over time. A frequent compromise is to use a 5-year period with either weekly or monthly returns. Value Line betas are computed based on weekly returns over a 5-year period, whereas Merrill Lynch betas are computed with monthly returns over a 5-year period. In an empirical study of utility

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so that the current value can be widely off the mark as a measure of the expected future value.

5.4 *Other Measures of Growth*

The measure of expected growth in the dividend established in the previous two sections, the intrinsic growth rate, is not the only possible measure of the variable. Another plausible measure is some average of the past rates of growth in the dividend. Under our model of security valuation, dividend, earnings, and price per share all are expected to grow at the same rate. Hence, the rates of growth in the dividend, earnings, and price also are candidates for estimates of the expected rate of growth in the dividend.

Let us consider first the rate of growth in earnings per share. The earnings per share during T adjusted for stock splits and stock dividends to make interperiod comparisons valid is

$$\text{AYPS}(T) = \text{AFC}(T)/.5\,[\text{ANS}(T) + \text{ANS}(T-1)], \tag{5.4.1}$$

where ANS(T) is the number of shares outstanding at the end of T adjusted for stock splits and dividends. The rate of growth in earnings per share during T is

$$\text{YGR}(T) = [\text{AYPS}(T) - \text{AYPS}(T-1)]/\text{AYPS}(T-1). \tag{5.4.2}$$

For reasons to be given shortly, the smoothed rate of growth in earnings is superior to the current rate as a forecast of the expected rate. The smoothed rate of earnings growth is obtained from

$$Ln[1 + \text{YGRS}(T)] = \lambda Ln[1 + \text{YGR}(T)] + (1-\lambda) Ln[1 + \text{YGRS}(T-1)], \tag{5.4.3}$$

with $\lambda = .15$ and YGRS(1953) = .04.

The primary reason for a difference between YGR and GRTH is a change in the rate of return on the common equity. To illustrate, assume a firm that has been earning a return on common of .10 and retaining one-half of its income to finance its investment. The rate of growth under both measures will be .05. If the firm's rate

of return on common rises from .10 to .11, the retention growth rate will rise from .05 to (.5)(.11) = .055. However, the earnings growth rate will rise from .05 to .155.[5] Furthermore, the earnings growth rate in subsequent periods will be .055 if the return on common remains .11. This example suggests that the intrinsic growth rate is superior to the earnings growth rate as a measure of expected growth. Investors nonetheless may look to past data on earnings growth for information on expected future growth, and it is the growth investors expect that should be used to measure share yield.

A number of considerations suggest that investors may, in fact, use earnings growth as a measure of expected future growth. First, the intrinsic growth rate includes stock financing growth as well as retention growth. The former is difficult for us to measure and may be even more difficult for investors. Consequently, investors may use past earnings growth to forecast the future since it incorporates in one statistic growth from all sources. Second, we saw that inflation will result in a rise in the allowed rate of return on equity for a regulated company. If this response to inflation takes place with a lag, that is, the regulatory agency raises RRC over time, earnings growth will reflect the forecast rate of growth better than intrinsic growth. Finally, it appears that security analysts use past growth in earnings more than any other variable to forecast future growth.

Given that earnings growth is used by investors to forecast future growth, the smoothed value of the variable YGRS is superior to the current value. The previous illustration revealed that YGR overreacts to changes in the allowed rate of return and therefore is subject to large random fluctuations. The data on YGR confirm this conclusion.

The use of dividend growth as a forecast of future growth is subject to the same limitations as earnings if the firm pays a constant fraction of its earnings in dividends. That is, under this assumption the dividend growth rate in any period is the same as the earnings growth rate. Firms tend to change their dividend rate from one

[5] Let the book value per share at the start of T be BVS($T-1$) = \$50.00. With RRC(T) = .10, AYP(T) = \$5.00, and with RETR(T) = .5, BVS(T) = \$52.50. If RRC($T+1$) = .10, AYP($T+1$) = \$5.25, and YGR($T+1$) = RTGR($T+1$) = .05. However, if RRC($T+1$) = .11, RTGR($T+1$) = (.11)(.5) = .055, while AYP($T+1$) = \$5.775, and YGR($T+1$) = (\$5.775 − \$5.00)/\$5.00 = .155.

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The average growth rate estimate from all the analysts that follow the company measures the consensus expectation of the investment community for that company. In most cases, it is necessary to use earnings forecasts rather than dividend forecasts due to the extreme scarcity of dividend forecasts compared to the widespread availability of earnings forecasts. Given the paucity and variability of dividend forecasts, using the latter would produce unreliable DCF results. In any event, the use of the DCF model prospectively assumes constant growth in both earnings and dividends. Moreover, as discussed below, there is an abundance of empirical research that shows the validity and superiority of earnings forecasts relative to historical estimates when estimating the cost of capital.

The uniformity of growth projections is a test of whether they are typical of the market as a whole. If, for example, 10 out of 15 analysts forecast growth in the 7%–9% range, the probability is high that their analysis reflects a degree of consensus in the market as a whole. As a side note, the lack of uniformity in growth projections is a reasonable indicator of higher risk. Chapter 3 alluded to divergence of opinion amongst analysts as a valid risk indicator.

Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of g. The accuracy of these forecasts in the sense of whether they turn out to be correct is not at issue here, as long as they reflect widely held expectations. As long as the forecasts are typical and/or influential in that they are consistent with current stock price levels, they are relevant. The use of analysts' forecasts in the DCF model is sometimes denounced on the grounds that it is difficult to forecast earnings and dividends for only one year, let alone for longer time periods. This objection is unfounded, however, because it is present investor expectations that are being priced; it is the consensus forecast that is embedded in price and therefore in required return, and not the future as it will turn out to be.

Empirical Literature on Earnings Forecasts

Published studies in the academic literature demonstrate that growth forecasts made by security analysts represent an appropriate source of DCF growth rates, are reasonable indicators of investor expectations and are more accurate than forecasts based on historical growth. These studies show that investors rely on analysts' forecasts to a greater extent than on historic data only.

Academic research confirms the superiority of analysts' earnings forecasts over univariate time-series forecasts that rely on history. This latter category

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