FILE

88

PUCO EXHIBIT FILING

Date of Hearing: 11/5/14

Case No. 14-841-EL-SSO/14-842-EL-ATA

PUCO Case Caption: In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer ~~Offer~~ Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation & In the Matter of the Application of Duke Energy Ohio for Authority to Amend its Certified Supplier Tariff P.U.C.O. No. 20.

List of exhibits being filed: Volume XI

Company 26
Company 27
Company 28
OCC 45

Reporter's Signature: Karen Sue Gibson
Date Submitted: 11/19/14

BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

\- - -

In the Matter of the :
Application of Duke Energy:
Ohio for Authority to :
Establish a Standard :
Service Offer Pursuant to :
Section 4928.143, Revised : Case No. 14-841-EL-SSO
Code, in the Form of an :
Electric Security Plan, :
Accounting Modifications :
and Tariffs for Generation:
Service. :

\- - -

In the Matter of the :
Application of Duke Energy:
Ohio for Authority to : Case No. 14-842-EL-ATA
Amend its Certified :
Supplier Tariff, P.U.C.O. :
No. 20. :

\- - -

PROCEEDINGS

before Ms. Christine M.T. Pirik and Mr. Nick Walstra, Attorney Examiners, at the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-A, Columbus, Ohio, called at 8:30 a.m. on Wednesday, November 5, 2014.

\- - -

VOLUME XI

\- - -

ARMSTRONG & OKEY, INC.
222 East Town Street, Second Floor
Columbus, Ohio 43215-5201
(614) 224-9481 - (800) 223-9481
Fax - (614) 224-5724

\- - -

DUKE ENERGY®

4th Quarter 2013 Statistical Supplement

CONTENTS

DUKE ENERGY CORPORATION
Consolidating Statement of Operations
(Unaudited)

	Twelve Months Ended December 31, 2013					
(in millions)	Regulated Utilities	International Energy	Commercial Power	Other	Eliminations/ Adjustments	Duke Energy
Operating Revenues						
Regulated electric [(a)]	$ 20,397	$ -	$ 117	$ 59	$ (134)	$ 20,439
Nonregulated electric, natural gas, and other	-	1,546	2,028	104	(30)	3,646
Regulated natural gas	513	-	-	-	(2)	511
Total operating revenues	20,910	1,546	2,145	163	(166)	24,598
Operating Expenses						
Fuel used in electric generation and purchased power - regulated	7,108	-	-	-	-	7,108
Fuel used in electric generation and purchased power - nonregulated	-	454	1,356	56	(44)	1,822
Cost of natural gas and coal sold	152	72	30	-	-	254
Operation, maintenance and other	4,912	364	493	262	(121)	5,910
Depreciation and amortization	2,323	100	250	135	-	2,808
Property and other taxes	1,232	10	49	8	-	1,299
Impairment charges [(b)]	399	-	-	-	-	399
Total operating expenses	16,126	1,000	2,178	461	(165)	19,600
Gains (Losses) on Sales of Other Assets and Other, Net	7	3	(23)	(3)	-	(16)
Operating Income (Loss)	4,791	549	(56)	(301)	(1)	4,982
Other Income and Expenses	221	125	13	131	(6)	484
Interest Expense	986	86	64	417	(7)	1,546
Income (Loss) from Continuing Operations before Income Taxes	4,026	588	(107)	(587)	-	3,920
Income Tax Expense (Benefit)	1,522	166	(104)	(323)	-	1,261
Income (Loss) from Continuing Operations	2,504	422	(3)	(264)	-	2,659
Less: Net Income (Loss) Attributable to Non-controlling Interest	-	14	-	(3)	-	11
Segment Income(Loss)/Net Expense	$ 2,504	$ 408	$ (3)	$ (261)	$ -	$ 2,648
Income from Discontinued Operations, Net of Tax						17
Net Income Attributable to Duke Energy Corporation						$ 2,665

(a) The amount for Commercial Power is primarily due to stability charge revenues included in Duke Energy Ohio's current Electric Stability Plan (ESP).

(b) The amount for Regulated Utilities is primarily comprised of a $295 million charge related to the agreement to forego recovery of a portion of the Cyrstal River Unit 3 regulatory asset, a $65 million charge to write-off the wholesale portion of the Levy investments and a $22 million charge resulting from the decision to suspend application of two proposed nuclear units at the Harris nuclear station.

DUKE ENERGY CORPORATION
Consolidating Statement of Operations
(Unaudited)

	Twelve Months Ended December 31, 2012					
(in millions)	Regulated Utilities	International Energy	Commercial Power	Other	Eliminations/ Adjustments	Duke Energy
Operating Revenues						
Regulated electric [a]	$ 15,609	$ -	$ 114	$ 1	$ (103)	$ 15,621
Nonregulated electric, natural gas, and other	-	1,549	1,964	73	(52)	3,534
Regulated natural gas	471	-	-	-	(2)	469
Total operating revenues	16,080	1,549	2,078	74	(157)	19,624
Operating Expenses						
Fuel used in electric generation and purchased power - regulated	5,582	-	-	-	-	5,582
Fuel used in electric generation and purchased power - nonregulated	-	530	1,211	31	(50)	1,722
Cost of natural gas and coal sold	142	73	49	-	-	264
Operation, maintenance and other	3,885	335	453	440	(106)	5,007
Depreciation and amortization	1,827	99	228	135	(1)	2,288
Property and other taxes	926	6	40	13	-	985
Impairment charges [b][c]	581	-	-	85	-	666
Total operating expenses	12,943	1,043	1,981	704	(157)	16,514
Gains (Losses) on Sales of Other Assets and Other, Net	15	-	8	(7)	-	16
Operating Income (Loss)	3,152	506	105	(637)	-	3,126
Other Income and Expenses	341	171	39	16	-	567
Interest Expense	806	76	63	297	-	1,242
Income (Loss) from Continuing Operations before Income Taxes	2,687	601	81	(918)	-	2,451
Income Tax Expense (Benefit)	941	149	(7)	(378)	-	705
Income (Loss) from Continuing Operations	1,746	452	88	(540)	-	1,746
Less: Net Income (Loss) Attributable to Non-controlling Interest	2	13	1	(2)	-	14
Segment Income/Net Expense	$ 1,744	$ 439	$ 87	$ (538)	$ -	$ 1,732
Income from Discontinued Operations, Net of Tax						36
Net Income Attributable to Duke Energy Corporation						$ 1,768

(a) The amount for Commercial Power is primarily due to stability charge revenues included in Duke Energy Ohio's current Electric Stability Plan (ESP).
(b) The amount for Regulated Utilities is primarily due to $580 million of impairment charges related to the Edwardsport IGCC project.
(c) The amount for Other is primarily due to the impairment of transmission projects included in long-term FERC mitigation costs. These amounts are recorded in the Duke Energy Carolinas and Duke Energy Progress legal entities but are classified in the Other segment.

Note: Regulated Utilities and Other include Progress Energy, Duke Energy Progress and Duke Energy Florida activity beginning July 2, 2012.

DUKE ENERGY CORPORATION

Consolidating Balance Sheet - Assets

(Unaudited)

	December 31, 2013					
(in millions)	Regulated Utilities	International Energy	Commercial Power	Other	Eliminations/ Adjustments	Duke Energy
Current Assets						
Cash and cash equivalents	$ 105	$ 1,086	$ 9	$ 301	$ -	$ **1,501**
Short-term investments	-	44	-	-	-	**44**
Receivables, net	791	239	133	123	-	**1,286**
Restricted receivables of variable interest entities, net	1,684	-	35	-	-	**1,719**
Receivables from affiliated companies	379	135	917	12,416	(13,847)	**-**
Notes receivable from affiliated companies	188	-	29	513	(730)	**-**
Inventory	3,043	79	113	15	-	**3,250**
Regulatory assets	805	-	-	90	-	**895**
Other	982	48	320	471	-	**1,821**
Total current assets	7,977	1,631	1,556	13,929	(14,577)	**10,516**
Investments and Other Assets						
Investments in equity method unconsolidated affiliates	4	82	252	52	-	**390**
Investments and advances to (from) subsidiaries	39	(16)	(9)	43,912	(43,926)	**-**
Nuclear decommissioning trust funds	5,132	-	-	-	-	**5,132**
Goodwill	15,950	326	64	-	-	**16,340**
Other	1,930	1,314	348	1,142	(1,195)	**3,539**
Total investments and other assets	23,055	1,706	655	45,106	(45,121)	**25,401**
Property, Plant and Equipment						
Cost	91,456	3,480	6,546	1,633	-	**103,115**
Accumulated depreciation and amortization	(30,846)	(960)	(999)	(820)	-	**(33,625)**
Net property, plant and equipment	60,610	2,520	5,547	813	-	**69,490**
Regulatory Assets and Deferred Debits						
Regulatory assets	8,773	-	71	347	-	**9,191**
Other	98	6	39	38	-	**181**
Total regulatory assets and deferred debits	8,871	6	110	385	-	**9,372**
Total Assets	100,513	5,863	7,868	60,233	(59,698)	**114,779**
Segment reclassifications, intercompany balances and other adjustments	(629)	(865)	(913)	(57,479)	59,886	**-**
Reportable Segment Assets	$ 99,884	$ 4,998	$ 6,955	$ 2,754	$ 188	$ **114,779**

DUKE ENERGY CORPORATION
Consolidating Balance Sheet - Liabilities and Equity
(Unaudited)

	December 31, 2013					
(in millions)	Regulated Utilities	International Energy	Commercial Power	Other	Eliminations/ Adjustments	Duke Energy
Current Liabilities						
Accounts payable	$ 1,857	$ 37	$ 147	$ 350	$ -	$ 2,391
Accounts payable to affiliated companies	12,753	4	98	938	(13,793)	-
Notes payable to affiliated companies	534	-	46	203	(783)	-
Notes payable and commercial paper	-	3	-	836	-	839
Taxes accrued	381	108	9	53	-	551
Interest accrued	286	26	-	128	-	440
Current maturities of long-term debt	361	106	80	1,557	-	2,104
Regulatory liabilities	316	-	-	-	-	316
Other	1,379	91	123	410	-	2,003
Total current liabilities	17,867	375	503	4,475	(14,576)	8,644
Long-term Debt	25,927	935	1,343	9,947	-	38,152
Notes Payable to Affiliated Companies	450	-	-	747	(1,197)	-
Deferred Credits and Other Liabilities						
Deferred income taxes	12,602	216	1,272	(1,993)	-	12,097
Investment tax credits	442	-	-	-	-	442
Accrued pension and other post-retirement benefit costs	883	1	52	386	-	1,322
Asset retirement obligations	4,907	2	41	-	-	4,950
Regulatory liabilities	5,917	-	-	32	-	5,949
Other	1,184	135	138	358	-	1,815
Total deferred credits and other liabilities	25,935	354	1,503	(1,217)	-	26,575
Equity						
Total Duke Energy Corporation shareholders' equity	30,334	4,141	4,505	46,275	(43,925)	41,330
Noncontrolling interests	-	58	14	6	-	78
Total equity	30,334	4,199	4,519	46,281	(43,925)	41,408
Total Liabilities and Equity	100,513	5,863	7,868	60,233	(59,698)	114,779
Segment reclassifications, intercompany balances and other adjustments	(629)	(865)	(913)	(57,479)	59,886	-
Reportable Segment Liabilities and Equity	$ 99,884	$ 4,998	$ 6,955	$ 2,754	$ 188	$ 114,779

REGULATED UTILITIES

Consolidating Segment Income

(Unaudited)

	Twelve Months Ended December 31, 2013						
(in millions)	Duke Energy Carolinas, LLC	Duke Energy Progress, Inc.	Duke Energy Florida, Inc.	Duke Energy Ohio, Inc.	Duke Energy Indiana, Inc.	Eliminations/ Adjustments	Regulated Utilities
Operating Revenues							
Regulated electric	$ 6,930	$ 4,960	$ 4,527	$ 1,252	$ 2,926	$ (198)	$ 20,397
Regulated natural gas	-	-	-	513	-	-	513
Total operating revenues	6,930	4,960	4,527	1,765	2,926	(198)	20,910
Operating Expenses							
Fuel used in electric generation and purchased power - regulated	1,956	1,896	1,927	429	1,131	(231)	7,108
Cost of natural gas	-	-	-	152	-	-	152
Operation, maintenance and other	1,715	1,280	859	435	623	-	4,912
Depreciation and amortization	921	534	330	200	342	(4)	2,323
Property and other taxes	374	223	327	237	71	-	1,232
Impairment charges [(a)]	-	22	358	5	-	14	399
Total operating expenses	4,966	3,955	3,801	1,458	2,167	(221)	16,126
Gains on Sales of Other Assets and Other, Net	-	1	1	5	-	-	7
Operating Income	1,964	1,006	727	312	759	23	4,791
Other Income and Expenses [(b)]	120	57	30	4	18	(8)	221
Interest Expense	359	201	180	74	170	2	986
Income from Continuing Operations before Income Taxes	1,725	862	577	242	607	13	4,026
Income Tax Expense	652	316	228	91	233	2	1,522
Segment Income	$ 1,073	$ 546	$ 349	$ 151	$ 374	$ 11	$ 2,504

(a) Amount for Duke Energy Progress is comprised of a $22 million charge related to the decision to suspend application of two proposed nuclear units at the Harris nuclear station. Amount for Duke Energy Florida is comprised of a $295 million charge related to the agreement to forego recovery of a portion of the Crystal River Unit 3 regulatory asset and a $65 million charge to write-off the wholesale portion of the Levy investments.

(b) Primarily due to an equity component of allowance for funds used during construction of $91 million for Duke Energy Carolinas, $42 million for Duke Energy Progress, $8 million for Duke Energy Florida, $1 million for Duke Energy Ohio and $15 million for Duke Energy Indiana.

REGULATED UTILITIES
Consolidating Segment Income
(Unaudited)

	Twelve Months Ended December 31, 2012						
(in millions)	Duke Energy Carolinas, LLC	Duke Energy Progress, Inc.	Duke Energy Florida, Inc.	Duke Energy Ohio, Inc.	Duke Energy Indiana, Inc.	Eliminations/ Adjustments	Regulated Utilities
Operating Revenues							
Regulated electric	$ 6,666	$ 2,524	$ 2,483	$ 1,275	$ 2,717	$ (56)	$ 15,609
Regulated natural gas	-	-	-	471	-	-	471
Total operating revenues	6,666	2,524	2,483	1,746	2,717	(56)	16,080
Operating Expenses							
Fuel used in electric generation and purchased power - regulated[a]	1,848	1,025	1,359	475	1,088	(213)	5,582
Cost of natural gas	-	-	-	142	-	-	142
Operation, maintenance and other	1,759	591	475	448	613	(1)	3,885
Depreciation and amortization	921	267	72	180	388	(1)	1,827
Property and other taxes	363	109	173	197	80	4	926
Impairment charges [b][c]	-	-	146	2	579	(146)	581
Total operating expenses	4,891	1,992	2,225	1,444	2,748	(357)	12,943
Gains on Sales of Other Assets and Other, Net	13	-	1	1	-	-	15
Operating Income (Loss)	1,788	532	259	303	(31)	301	3,152
Other Income and Expenses [d]	190	44	23	8	90	(14)	341
Interest Expense	384	103	123	60	138	(2)	806
Income (Loss) from Continuing Operations before Income Taxes	1,594	473	159	251	(79)	289	2,687
Income Tax Expense (Benefit)	560	155	52	92	(56)	138	941
Income (Loss) from Continuing Operations	1,034	318	107	159	(23)	151	1,746
Less: Net Income Attributable to Non-controlling Interest	-	1	1	-	-	-	2
Segment Income (Loss)	$ 1,034	$ 317	$ 106	$ 159	$ (23)	$ 151	$ 1,744

(a) Elimination amount includes $100 million of purchase power refunds at Duke Energy Florida related to the Crystal River Unit 3 retirement. This amount was recorded as expense by Duke Energy Florida but reflected as part of the purchase price allocation associated with the Progress Energy merger at Duke Energy.

(b) The amount for Duke Energy Florida and the elimination amount are due to an impairment charge related to the decision to retire Crystal River Unit 3. This amount was recorded as expense by Duke Energy Florida but reflected as part of the purchase price allocation associated with the Progress Energy merger at Duke Energy.

(c) The amount for Duke Energy Indiana is primarily due to impairment charges related to the Edwardsport IGCC project.

(d) Primarily due to an equity component of allowance for funds used during construction of $154 million for Duke Energy Carolinas, $37 million for Duke Energy Progress, $20 million for Duke Energy Florida, $6 million for Duke Energy Ohio and $84 million for Duke Energy Indiana.

Note: Includes Duke Energy Progress and Duke Energy Florida activity beginning July 2, 2012.

REGULATED UTILITIES
Consolidating Balance Sheet - Assets
(Unaudited)

	December 31, 2013						
(in millions)	Duke Energy Carolinas, LLC	Duke Energy Progress, Inc.	Duke Energy Florida, Inc.	Duke Energy Ohio, Inc.	Duke Energy Indiana, Inc.	Eliminations/ Adjustments [(a)]	Regulated Utilities
Current Assets							
Cash and cash equivalents	$ 23	$ 21	$ 16	$ 31	$ 15	$ (1)	$ 105
Receivables, net	186	145	375	61	22	2	791
Restricted receivables of variable interest entities, net	673	417	-	-	-	594	1,684
Receivables from affiliated companies	121	244	50	192	151	(379)	379
Notes receivable from affiliated companies	222	-	-	28	96	(158)	188
Inventory	1,065	853	571	120	434	-	3,043
Regulatory assets	295	127	221	32	118	12	805
Other	281	310	201	47	123	20	982
Total current assets	2,866	2,117	1,434	511	959	90	7,977
Investment and Other Assets							
Investments in equity method unconsolidated affiliates	-	1	2	-	1	-	4
Investments and advances to subsidiaries	29	-	-	(2)	-	12	39
Nuclear decommissioning trust funds	2,840	1,539	753	-	-	-	5,132
Goodwill	-	-	-	920	-	15,030	15,950
Other	1,000	442	249	42	266	(69)	1,930
Total investments and other assets	3,869	1,982	1,004	960	267	14,973	23,055
Property, Plant and Equipment							
Cost	34,906	22,218	13,863	6,972	12,489	1,008	91,456
Accumulated depreciation and amortization	(11,894)	(8,623)	(4,252)	(2,162)	(3,913)	(2)	(30,846)
Net property, plant and equipment	23,012	13,595	9,611	4,810	8,576	1,006	60,610
Regulatory Assets and Deferred Debits							
Regulatory assets	1,527	1,341	2,729	422	717	2,037	8,773
Other	46	32	44	9	25	(58)	98
Total regulatory assets and deferred debits	1,573	1,373	2,773	431	742	1,979	8,871
Total Assets	31,320	19,067	14,822	6,712	10,544	18,048	100,513
Segment reclassifications, intercompany balances and other adjustments	(139)	(195)	11	(63)	(48)	(195)	(629)
Reportable Segment Assets	$ 31,181	$ 18,872	$ 14,833	$ 6,649	$ 10,496	$ 17,853	$ 99,884

(a) In addition to the elimination of intercompany balances, amounts include purchase accounting adjustments and restricted receivables related to Cinergy Receivables Company.

REGULATED UTILITIES
Consolidating Balance Sheet - Liabilities and Equity
(Unaudited)

	December 31, 2013						
(in millions)	Duke Energy Carolinas, LLC	Duke Energy Progress, Inc.	Duke Energy Florida, Inc.	Duke Energy Ohio, Inc.	Duke Energy Indiana, Inc.	Eliminations/ Adjustments [(a)]	Regulated Utilities
Current Liabilities							
Accounts payable	$ 701	$ 420	$ 333	$ 196	$ 206	$ 1	$ **1,857**
Accounts payable to affiliated companies	149	72	10	13	-	12,509	**12,753**
Notes payable to affiliated companies	-	462	181	(3)	-	(106)	**534**
Taxes accrued	165	37	66	53	57	3	**381**
Interest accrued	97	70	46	17	56	-	**286**
Current maturities of long-term debt	47	174	11	47	5	77	**361**
Regulatory liabilities	65	63	144	27	16	1	**316**
Other	392	391	445	60	91	-	**1,379**
Total current liabilities	1,616	1,689	1,236	410	431	12,485	**17,867**
Long-term Debt	8,089	5,061	4,875	1,739	3,641	2,522	**25,927**
Notes Payable to Affiliated Companies	300	-	-	-	150	-	**450**
Deferred Credits and Other Liabilities							
Deferred income taxes	5,748	2,571	1,847	1,216	1,190	30	**12,602**
Investment tax credits	210	85	2	6	140	(1)	**442**
Accrued pension and other post-retirement benefit costs	161	321	286	34	163	(82)	**883**
Asset retirement obligations	1,594	1,729	833	23	30	698	**4,907**
Regulatory liabilities	2,576	1,673	618	262	782	6	**5,917**
Other	676	137	253	69	49	-	**1,184**
Total deferred credits and other liabilities	10,965	6,516	3,839	1,610	2,354	651	**25,935**
Equity	10,350	5,801	4,872	2,953	3,968	2,390	**30,334**
Total Liabilities and Equity	31,320	19,067	14,822	6,712	10,544	18,048	**100,513**
Segment reclassifications, intercompany balances and other adjustments	(139)	(195)	11	(63)	(48)	(195)	**(629)**
Reportable Segment Liabilities and Equity	$ 31,181	$ 18,872	$ 14,833	$ 6,649	$ 10,496	$ 17,853	$ **99,884**

(a) In addition to the elimination of intercompany balances, amounts include purchase accounting adjustments and notes payable related to Cinergy Receivables Company.

REGULATED UTILITIES

Operating Statistics (Regulated Utilities)

(Unaudited)

	Twelve Months Ended December 31,	
	2013	**2012** [(a)]
Sources of Electric Energy (GWh)		
Generated - net output [(b)]:		
Coal	**83,305**	85,444
Nuclear	**66,882**	65,079
Hydro	**3,388**	1,728
Oil & gas	**49,672**	41,468
Renewable Energy	**13**	10
Total generation [(c)]	**203,260**	193,729
Purchased power [(d)] and net interchange	**29,898**	33,313
Total sources of energy	**233,158**	227,042
Less: Line loss and company usage	**10,928**	10,847
Total GWh Sources	**222,230**	216,195
Electric Energy Sales (GWh) [(f)]		
Residential	**80,593**	78,651
General service	**75,513**	75,172
Industrial	**51,056**	50,819
Other energy and wholesale	**35,353**	30,587
Change in unbilled	**(275)**	887
Total GWh Sales	**242,240**	236,116
Owned MW Capacity [(b)]		
Summer	**49,626**	50,443
Winter	**53,020**	53,694
Nuclear Capacity Factor (%) [(e)]	**93**	90

(a) The prior year amounts include Duke Energy Progress and Duke Energy Florida activity prior to the July 2, 2012 merger between Duke Energy and Progress Energy.

(b) Statistics reflect Duke Energy's ownership share of jointly owned stations. 2012 capacity includes Crystal River Unit 3.

(c) Generation by source is reported net of auxiliary power.

(d) Purchased Power includes Renewable Energy purchases.

(e) Statistics reflect 100% of jointly owned stations.

(f) Represents non-weather normalized billed sales, with energy delivered but not yet billed (i.e. unbilled sales) reflected as single amount and not allocated to the respective retail classes.

REGULATED UTILITIES

Operating Statistics (Regulated Utilities)
(Unaudited)

	Twelve Months Ended December 31,	
	2013	**2012 [a]**
Revenues from Generation, Transmission and Distribution of Electricity (in millions)		
Residential	**$ 8,581**	$ 8,366
General service	**6,102**	6,090
Industrial	**3,006**	2,966
Other energy and wholesale[b]	**2,240**	2,002
Change in unbilled	**13**	94
Total Revenues	**$ 19,942**	$ 19,518
Average Number of Customers (in thousands)		
Residential	**6,217**	6,166
General service	**937**	929
Industrial	**19**	19
Other energy and wholesale	**22**	22
Total Average Number of Customers	**7,195**	7,136

(a) The prior year amounts include Duke Energy Progress and Duke Energy Florida activity prior to the July 2, 2012 merger between Duke Energy and Progress Energy.

(b) Net of JDA Intercompany sales.

REGULATED UTILITIES

Operating Statistics (Duke Energy Carolinas)
(Unaudited)

	Twelve Months Ended December 31,	
	2013	**2012**
Sources of Electric Energy (GWh)		
Generated - net output [a]:		
Coal	**29,362**	27,971
Nuclear	**43,607**	42,047
Hydro	**2,091**	759
Oil & gas	**8,654**	5,342
Renewable Energy	**13**	10
Total generation [b]	**83,727**	76,129
Purchased power [c] and net interchange	**7,083**	10,139
Total sources of energy	**90,810**	86,268
Less: Line loss and company usage	**5,020**	4,906
Total GWh Sources	**85,790**	81,362
Electric Energy Sales (GWh) [e]		
Residential	**26,895**	26,279
General service	**27,764**	27,476
Industrial	**21,070**	20,978
Other energy and wholesale	**10,215**	6,420
Change in unbilled	**(154)**	209
Total GWh Sales	**85,790**	81,362
Owned MW Capacity [a]		
Summer	**19,729**	20,350
Winter	**20,482**	21,112
Nuclear Capacity Factor (%) [d]	**96**	92

(a) Statistics reflect Duke Energy Carolinas' ownership share of jointly owned stations.
(b) Generation by source is reported net of auxiliary power.
(c) Purchased Power includes Renewable Energy purchases.
(d) Statistics reflect 100% of jointly owned stations.
(e) Represents non-weather normalized billed sales, with energy delivered but not yet billed (i.e. unbilled sales) reflected as single amount and not allocated to the respective retail classes.

REGULATED UTILITIES

Operating Statistics (Duke Energy Carolinas)
(Unaudited)

	Twelve Months Ended December 31,	
	2013	**2012**
Revenues from Generation, Transmission and Distribution of Electricity (in millions)		
Residential	$ **2,698**	$ 2,661
General service	**2,193**	2,168
Industrial	**1,186**	1,196
Other energy and wholesale	**544**	378
Change in unbilled	**1**	25
Total Revenues	$ **6,622**	$ 6,428
Average Number of Customers (in thousands)		
Residential	**2,068**	2,053
General service	**339**	337
Industrial	**7**	7
Other energy and wholesale	**14**	14
Total Average Number of Customers	**2,428**	2,411

REGULATED UTILITIES

Operating Statistics (Duke Energy Progress)

(Unaudited)

	Twelve Months Ended December 31,	
	2013	2012 [a]
Sources of Electric Energy (GWh)		
Generated - net output [b]:		
Coal	**14,957**	20,949
Nuclear	**23,275**	23,032
Hydro	**965**	598
Oil & gas	**16,610**	10,713
Total generation [c]	**55,807**	55,292
Purchased power [d] and net interchange	**6,788**	5,512
Total sources of energy	**62,595**	60,804
Less: Line loss and company usage	**2,391**	2,414
Total GWh Sources	**60,204**	58,390
Electric Energy Sales (GWh) [f]		
Residential	**17,323**	16,663
General service	**15,066**	15,062
Industrial	**10,624**	10,508
Other energy and wholesale	**17,203**	15,992
Change in unbilled	**(12)**	165
Total GWh Sales	**60,204**	58,390
Owned MW Capacity [b]		
Summer	**12,270**	12,208
Winter	**13,335**	13,981
Nuclear Capacity Factor (%) [e]	**87**	87

(a) For comparability purposes, prior year amounts include Duke Energy Progress activity prior to the July 2, 2012 merger between Duke Energy and Progress Energy.

(b) Statistics include Duke Energy Progress' ownership share of jointly owned stations.

(c) Generation by source is reported net of auxiliary power.

(d) Purchased Power includes Renewable Energy purchases.

(e) Statistics reflect 100% of jointly owned stations.

(f) Represents non-weather normalized billed sales, with energy delivered but not yet billed (i.e. unbilled sales) reflected as single amount and not allocated to the respective retail classes.

REGULATED UTILITIES

Operating Statistics (Duke Energy Progress)
(Unaudited)

	Twelve Months Ended December 31,	
	2013	**2012 [a]**
Revenues from Generation, Transmission and Distribution of Electricity (in millions)		
Residential	$ **1,822**	$ 1,733
General service	**1,290**	1,274
Industrial	**686**	688
Other energy and wholesale	**1,162**	979
Change in unbilled	**7**	10
Total Revenues	$ **4,967**	$ 4,684
Average Number of Customers (in thousands)		
Residential	**1,242**	1,231
General service	**222**	219
Industrial	**4**	4
Other energy and wholesale	**2**	3
Total Average Number of Customers	**1,470**	1,457

(a) For comparability purposes, the prior year amounts include Duke Energy Progress activity prior to the July 2, 2012 merger between Duke Energy and Progress Energy.

REGULATED UTILITIES

Operating Statistics (Duke Energy Florida)
(Unaudited)

	Twelve Months Ended December 31,	
	2013	2012 [(a)]
Sources of Electric Energy (GWh)		
Generated - net output [(b)]:		
Coal	**10,634**	10,035
Oil & gas	**23,225**	24,115
Total generation [(c)]	**33,859**	34,150
Purchased power [(d)] and net interchange	**6,719**	6,950
Total sources of energy	**40,578**	41,100
Less: Line loss and company usage	**2,604**	2,657
Total GWh Sources	**37,974**	38,443
Electric Energy Sales (GWh) [(e)]		
Residential	**18,508**	18,251
General service	**14,877**	14,945
Industrial	**3,206**	3,160
Other energy and wholesale	**1,544**	1,788
Change in unbilled	**(161)**	299
Total GWh Sales	**37,974**	38,443
Owned MW Capacity [(b)]		
Summer	**9,095**	9,948
Winter	**10,191**	10,999

(a) For comparability purposes, the prior year amounts include Duke Energy Florida activity prior to the July 2, 2012 merger between Duke Energy and Progress Energy.
(b) Statistics reflect Duke Energy Florida's ownership share of jointly owned stations. 2012 capacity includes Crystal River Unit 3.
(c) Generation by source is reported net of auxiliary power.
(d) Purchased Power includes Renewable Energy purchases.
(e) Represents non-weather normalized billed sales, with energy delivered but not yet billed (i.e. unbilled sales) reflected as single amount and not allocated to the respective retail classes.

REGULATED UTILITIES

Operating Statistics (Duke Energy Florida)
(Unaudited)

	Twelve Months Ended December 31,	
	2013	2012 [(a)]
Revenues from Generation, Transmission and Distribution of Electricity (in millions)		
Residential	**$ 2,377**	$ 2,405
General service	**1,445**	1,532
Industrial	**273**	289
Other energy and wholesale	**408**	420
Change in unbilled	**(5)**	19
Total Revenues	**$ 4,498**	$ 4,665
Average Number of Customers (in thousands)		
Residential	**1,481**	1,464
General service	**189**	187
Industrial	**2**	3
Other energy and wholesale	**2**	2
Total Average Number of Customers	**1,674**	1,656

(a) For comparability purposes, the prior year amounts include Duke Energy Florida activity prior to the July 2, 2012 merger between Duke Energy and Progress Energy.

REGULATED UTILITIES

Operating Statistics (Duke Energy Ohio - Electric)
(Unaudited)

	Twelve Months Ended December 31,	
	2013	**2012**
Sources of Electric Energy (GWh)		
Generated - net output [a]:		
Coal	**3,682**	3,112
Total generation [b]	**3,682**	3,112
Purchased power [c] and net interchange	**1,201**	1,547
Total sources of energy	**4,883**	4,659
Less: Line loss and company usage	**336**	236
Total GWh Sources	**4,547**	4,423
Electric Energy Sales (GWh) [d]		
Residential	**8,719**	8,591
General service	**9,447**	9,375
Industrial	**5,771**	5,761
Other energy and wholesale	**626**	538
Change in unbilled	**(6)**	79
Total GWh Sales	**24,557**	24,344
Owned MW Capacity [a]		
Summer	**1,039**	1,039
Winter	**1,141**	1,141

(a) Statistics reflect Duke Energy Ohio's ownership share of jointly owned stations.
(b) Generation by source is reported net of auxiliary power.
(c) Purchased Power includes Renewable Energy purchases.
(d) Represents non-weather normalized billed sales, with energy delivered but not yet billed (i.e. unbilled sales) reflected as single amount and not allocated to the respective retail classes.

Note: Total GWh Sources will not equal Total GWh Sales. Sources include only Duke Energy Kentucky's regulated generation for all periods. Sales include Duke Energy Ohio's and Duke Energy Kentucky's retail sales. Ohio retail sales are fulfilled through auction purchases under the current ESP.

REGULATED UTILITIES

Operating Statistics (Duke Energy Ohio - Electric)

(Unaudited)

	Twelve Months Ended December 31,	
	2013	**2012**
Revenues from Generation, Transmission and Distribution of Electricity (in millions)		
Residential	$ **689**	$ 658
General service	**415**	416
Industrial	**106**	102
Other energy and wholesale	**24**	21
Change in unbilled	**(1)**	20
Total Revenues	$ **1,233**	$ 1,217
Average Number of Electric Customers (in thousands)		
Residential	**737**	734
General service	**86**	86
Industrial	**3**	3
Other energy and wholesale	**3**	2
Total Average Number of Electric Customers	**829**	825

REGULATED UTILITIES

Operating Statistics (Duke Energy Ohio - Gas)
(Unaudited)

	Twelve Months Ended December 31,	
	2013	**2012**
MCF Sales		
Residential	**37,840,736**	30,481,386
General service	**23,329,465**	19,365,863
Industrial	**6,311,201**	5,125,512
Other energy and wholesale	**21,496,630**	21,744,410
Change in unbilled	**136,000**	970,000
Total MCF Sales	**89,114,032**	77,687,171
Revenues from Distribution of Gas (in millions)		
Residential	**$ 335**	$ 316
General service	**132**	120
Industrial	**19**	16
Other energy and wholesale	**21**	17
Change in unbilled	**-**	-
Total Revenues	**$ 507**	$ 469
Average Number of Gas Customers (in thousands)		
Residential	**470**	469
General service	**43**	44
Industrial	**2**	1
Total Average Number of Gas Customers	**515**	514

REGULATED UTILITIES

Operating Statistics (Duke Energy Indiana)

(Unaudited)

	Twelve Months Ended December 31,	
	2013	**2012**
Sources of Electric Energy (GWh)		
Generated - net output [a]:		
Coal	**24,674**	23,388
Hydro	**332**	371
Gas	**1,179**	1,287
Total generation [b]	**26,185**	25,046
Purchased power [c] and net interchange	**8,107**	9,165
Total sources of energy	**34,292**	34,211
Less: Line loss and company usage	**577**	634
Total GWh Sources	**33,715**	33,577
Electric Energy Sales (GWh)		
Residential	**9,148**	8,867
General service	**8,359**	8,314
Industrial	**10,385**	10,412
Other energy and wholesale	**5,765**	5,849
Change in unbilled	**58**	135
Total GWh Sales	**33,715**	33,577
Owned MW Capacity [a]		
Summer	**7,493**	6,898
Winter	**7,871**	7,241

(a) Statistics reflect Duke Energy Indiana's ownership share of jointly owned stations.

(b) Generation by source is reported net of auxiliary power.

(c) Purchased Power includes Renewable Energy purchases.

(d) Represents non-weather normalized billed sales, with energy delivered but not yet billed (i.e. unbilled sales) reflected as single amount and not allocated to the respective retail classes.

REGULATED UTILITIES

Operating Statistics (Duke Energy Indiana)
(Unaudited)

	Twelve Months Ended December 31,	
	2013	**2012**
Revenues from Generation, Transmission and Distribution of Electricity (in millions)		
Residential	**$ 995**	$ 909
General service	**759**	700
Industrial	**755**	691
Other energy and wholesale	**308**	305
Change in unbilled	**11**	20
Total Revenues	**$ 2,828**	$ 2,625
Average Number of Customers (in thousands)		
Residential	**688**	683
General service	**100**	100
Industrial	**3**	3
Other energy and wholesale	**2**	2
Total Average Number of Customers	**793**	788

INTERNATIONAL ENERGY
Operating Statistics
(Unaudited)

	Twelve Months Ended December 31,	
	2013	**2012**
Sales, GWh	**20,306**	20,132
Net proportional megawatt capacity in operation	**4,600**	4,584

COMMERCIAL POWER
Operating Statistics
(Unaudited)

	Twelve Months Ended December 31,	
	2013	**2012**
Generation (GWh)		
Coal	**18,467**	16,164
Gas	**15,052**	17,122
Renewables	**5,111**	3,452
Actual plant generation	**38,630**	36,738
Net proportional megawatt capacity in operation	**7,915**	8,094

DUKE ENERGY OHIO SUPPLEMENT
Consolidating Statement of Operations
(Unaudited)

	Twelve Months Ended December 31, 2013				
	Regulated Utilities		Commercial Power	Other	Duke Energy Ohio
(in millions)	Ohio Transmission & Distribution	Duke Energy Kentucky, Inc.			
Operating Revenues					
Regulated electric [a]	$ 908	$ 344	$ 117	$ (1)	$ **1,368**
Nonregulated electric and other	-	-	1,395	(31)	**1,364**
Regulated natural gas	406	107	-	-	**513**
Total operating revenues	1,314	451	1,512	(32)	**3,245**
Operating Expenses					
Fuel used in electric generation and purchased power - regulated	286	143	-	-	**429**
Fuel used in electric generation and purchased power - nonregulated	-	-	1,053	(33)	**1,020**
Cost of natural gas sold	106	46	-	-	**152**
Operation, maintenance and other	313	122	308	31	**774**
Depreciation and amortization	155	45	154	-	**354**
Property and other taxes	224	13	28	-	**265**
Goodwill and other impairment charges	5	-	-	-	**5**
Total operating expenses	1,089	369	1,543	(2)	**2,999**
Gains on Sales of Other Assets and Other, Net	2	3	-	-	**5**
Operating Income (Loss)	227	85	(31)	(30)	**251**
Other Income and Expenses	2	2	1	(1)	**4**
Interest Expense	58	16	4	-	**78**
Income (Loss) before Income Taxes	171	71	(34)	(31)	**177**
Income Tax Expense (Benefit)	65	26	(14)	(2)	**75**
Net Income (Loss)	$ 106	$ 45	$ (20)	$ (29)	$ **102**

(a) The amount for Commercial Power is primarily due to stability charge revenues included in Duke Energy Ohio's current Electric Stability Plan (ESP).

DUKE ENERGY OHIO SUPPLEMENT

Consolidating Statement of Operations

(Unaudited)

	Twelve Months Ended December 31, 2012				
	Regulated Utilities		Commercial Power	Other	Duke Energy Ohio
(in millions)	Ohio Transmission & Distribution	Duke Energy Kentucky, Inc.			
Operating Revenues					
Regulated electric [a]	$ 934	$ 341	$ 114	$ (3)	$ **1,386**
Nonregulated electric and other	-	-	1,344	(49)	**1,295**
Regulated natural gas	381	90	-	-	**471**
Total operating revenues	1,315	431	1,458	(52)	**3,152**
Operating Expenses					
Fuel used in electric generation and purchased power - regulated	337	138	-	-	**475**
Fuel used in electric generation and purchased power - nonregulated	-	-	882	(50)	**832**
Cost of natural gas sold	105	37	-	-	**142**
Operation, maintenance and other	312	136	299	50	**797**
Depreciation and amortization	136	44	159	(1)	**338**
Property and other taxes	182	15	26	1	**224**
Goodwill and other impairment charges	2	-	-	-	**2**
Total operating expenses	1,074	370	1,366	-	**2,810**
Gains on Sales of Other Assets and Other, Net	1	-	6	-	**7**
Operating Income (Loss)	242	61	98	(52)	**349**
Other Income and Expenses	7	1	4	1	**13**
Interest Expense	42	18	28	1	**89**
Income (Loss) before Income Taxes	207	44	74	(52)	**273**
Income Tax Expense (Benefit)	76	16	24	(18)	**98**
Net Income (Loss)	131	28	50	(34)	**175**

(a) The amount for Commercial Power is primarily due to stability charge revenues included in Duke Energy Ohio's current Electric Stability Plan (ESP).

EXHIBIT
27
Company

Duke Energy Ohio
Case Nos. 14-841-EL-SSO, 14-842-EL-ATA
IGS Second Set Interrogatories
Date Received: September 23, 2014

IGS-INT-02-006

REQUEST:

Identify all charges or costs that Duke allocates to Duke Energy One.

RESPONSE: Objection. This Interrogatory is overly broad and unduly burdensome, given that it seeks information that is unlimited as to time and that is neither relevant to this proceeding nor likely to lead to the discovery of admissible evidence in this proceeding. The question is susceptible to different interpretations and Duke Energy Ohio would have to engage in speculation or conjecture to ascertain the intended meaning of this request. Without waiving said objection, to the extent discoverable, and in the spirit of discovery, Duke Energy One is responsible for costs of its operations under the terms of Commission-approved service agreements. See also Case No. 09-495-EL-UNC.

PERSON RESPONSIBLE: As to objection – Legal
As to response – Mark E. Hollis

Duke Energy Ohio
Case Nos. 14-841-EL-SSO, 14-842-EL-ATA
IGS Second Set Interrogatories
Date Received: September 23, 2014

IGS-INT-02-004

REQUEST:

Does Duke provide Duke Energy One or any other affiliate with customer lists or account numbers.

RESPONSE:

Duke Energy Ohio does not provide Duke Energy One with customer lists or account numbers. Customer lists are only available to CRES providers pursuant to Duke Energy Ohio's supplier tariff and consistent with Commission rules. Duke Energy Ohio only provides account numbers to affiliates or third parties upon proper authorization from the customer and consistent with Commission rules.

PERSON RESPONSIBLE: Mark Hollis

OCC EXHIBIT NO. 45

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service.	)	Case No. 14-841-EL-SSO
In the Matter of the Application of Duke Energy Ohio for Authority to Amend its Certified Supplier Tariff, P.U.C.O. No. 20.	)	Case No. 14-842-EL-ATA

DIRECT TESTIMONY
OF
JEROME D. MIERZWA

On Behalf of the
Office of the Ohio Consumers' Counsel
10 West Broad St., Suite 1800
Columbus, OH 43215

SEPTEMBER 26, 2014

TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS

Q1. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. My name is Jerome D. Mierzwa. I am a principal and President of Exeter Associates, Inc. ("Exeter"). My business address is 10480 Patuxent Parkway, Suite 300, Columbia, Maryland 21044. Exeter specializes in providing public utility-related consulting services.

Q2. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A2. I graduated from Canisius College in Buffalo, New York, in 1981 with a Bachelor of Science Degree in Marketing. In 1985, I received a Master's Degree in Business Administration with a concentration in finance, also from Canisius College. In July 1986, I joined National Fuel Gas Distribution Corporation ("NFGD") as a Management Trainee in the Research and Statistical Services Department ("RSS"). I was promoted to Supervisor RSS in January 1987. While employed with NFGD, I conducted various financial and statistical analyses related to the Company's market research activity and state regulatory affairs.

In April 1987, as part of a corporate reorganization, I was transferred to National Fuel Gas Supply Corporation's ("NFG Supply") rate department where my responsibilities included utility cost of service and rate design analysis, expense and revenue requirement forecasting and activities related to federal regulation. I was also responsible for preparing NFG Supply's Purchased Gas Adjustment ("PGA") filings and developing interstate pipeline and spot market supply gas price projections. These forecasts were utilized for internal planning purposes as well as in NFGD's purchased gas cost review proceedings.

In April 1990, I accepted a position as a Utility Analyst with Exeter. In December 1992, I was promoted to Senior Regulatory Analyst. Effective April 1, 1996, I became a principal of Exeter. Since joining Exeter, I have specialized in evaluating the gas purchasing practices and policies of natural gas utilities, revenue requirement analysis, utility class cost of service and rate design analysis, sales and rate forecasting, performance-based incentive regulation, the unbundling of utility services and evaluation of customer choice natural gas transportation programs.

Q3. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS ON UTILITY RATES?

A3. Yes. I have provided testimony on more than 200 occasions in proceedings before the Federal Energy Regulatory Commission ("FERC"), and utility regulatory commissions in Delaware, Georgia, Illinois, Indiana, Louisiana, Maine, Maryland, Montana, Nevada, New Jersey, Pennsylvania, Rhode Island, Texas and Virginia, as well as before the Public Utilities Commission of Ohio ("PUCO").

II. PURPOSE OF TESTIMONY

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A4. On May 29, 2014, Duke Energy Ohio, Inc. ("Duke" or "the Utility") submitted an application with the PUCO seeking approval of a new electric security plan ("ESP") for the period June 1, 2015 through May 31, 2018. As part of its application, Duke is proposing a Distribution Capital Investment Rider ("Rider DCI") and a Distribution Storm Rider ("Rider DSR"). Exeter was retained by the Office of the Ohio Consumers' Counsel ("OCC") to evaluate Riders DCI and DSR.

Q5. PLEASE SUMMARIZE THE RESULTS OF YOUR EVALUATION OF THESE RIDERS.

A5. Riders DCI and DSR should not be approved by the PUCO for the reasons set forth in my testimony.

III. IMPLEMENTATION OF RIDERS

Q6. AS A GENERAL MATTER, DO YOU AGREE WITH THE CONCEPT OF RIDERS?

A6. No. Riders (also referred to as "trackers," "cost trackers" or "reconciliation mechanisms") allow regulated utilities to collect designated costs from customers outside of the context of a traditional base rate proceeding, where all elements of the cost of service are examined. As a general matter, riders that provide for the automatic collection of certain costs from customers are contrary to sound ratemaking principles. When a utility is permitted to collect costs through a rider, the incentive for the utility to control costs tends to be reduced or eliminated. As subsequently discussed, a rider can even potentially give a utility a perverse incentive to make uneconomic choices.

Because of these potential problems, to the extent that riders are approved, they should be limited to cost items that are substantial, unpredictable, generally beyond the utility's control, and not essential to protecting a utility from a dire financial situation. Examples of costs for which a rider could be appropriate are purchased gas costs for a gas distribution utility or fuel and purchased power for an integrated electric utility like Duke.

Duke has presented little evidence that the costs that it is seeking to collect through its proposed riders meet these criteria (costs that are substantial, unpredictable, and outside of the utility's control). Additionally, Duke has not shown that its financial integrity would be compromised if those costs could be collected only through a traditional base rate proceeding where the costs would be subject to closer scrutiny. A report by the National Research Regulatory Institute ("NRRI") titled "*How Should Regulators View Cost Trackers?*" (September 2009) presents a concise and balanced description of the regulatory issues associated with riders, and I have attached a copy of this report to my testimony (JDM Attachment-1).

Q7. BRIEFLY SUMMARIZE THE FINDINGS OF THE NRRI REPORT WITH RESPECT TO REGULATORY POLICY AND THE USE OF RIDERS.

A7. The NRRI report found that "Good regulatory policy rejects cost trackers that are not essential for protecting a utility from a dire financial situation." (JDM Attachment-1, page 14).

Q8. PLEASE EXPLAIN HOW RIDERS CAN POTENTIALLY RESULT IN UNECONOMIC INCENTIVES FOR A REGULATED UTILITY, WHICH THEN TRANSLATES INTO HIGHER RATES FOR CUSTOMERS?

A8. Suppose that a regulated utility was faced with a decision between either replacing a piece of equipment or contracting to maintain the equipment. From a present value perspective it might be more economical to incur the cost to maintain the equipment rather than replace it. However, if the utility has a rider where it can automatically recover the cost of plant additions but would have to "absorb" any incremental maintenance expense under its existing base rates, then there is obviously an incentive to make the replacement even though that might not be the more economic option.

Q9. ARE THERE ANY OTHER POTENTIAL CONCERNS WITH COLLECTION OF COSTS FROM CUSTOMERS THROUGH RIDERS?

A9. Yes. The collection of costs from customers through riders can lead to increases in utility rates and revenues (collected by the utility) even when a regulated utility does not have a revenue deficiency. By contrast, in the absence of riders, a regulated utility would be able to implement rate increases only after a comprehensive base rate proceeding where all costs and the revenues under present rates were taken into consideration. If it were determined that the rates in effect were already producing an adequate return, then no rate increase would be authorized.

IV. DISTRIBUTION CAPITAL INVESTMENT RIDER

Q10. PLEASE DESCRIBE DUKE'S PROPOSED RIDER DCI.

A10. Rider DCI, as proposed in Duke's application, is designed to recover a return on incremental capital investment and the associated depreciation and property taxes for distribution-related investment that is not otherwise recovered through base rates or another rider regardless of the Utility's level of earnings. As proposed all capital investment (excluding that recovered through Rider DR-IM, Infrastructure Modernization Rider) recorded in FERC Plant accounts 360 through 374 will be included in Rider DCI. In addition, the portion of the electric common general plant in FERC Plant accounts 303 and 389 through 398 that are allocated to distribution will also be included. In its application, Duke identifies 19 capital improvement programs that it intends to pursue and the costs associated with those 19 programs. However, the costs to be recovered under Rider DCI are not limited to those associated with these 19 projects, and there is no limit to the increase in net distribution and common general plant investment which can be made by Duke and recovered under Rider DCI. That is, there is no limit to the rate increases customers could experience under Rider DCI.

Q11. WHAT RATE OF RETURN WILL BE APPLICABLE TO THE INCREMENTAL CAPITAL INVESTMENT RECOVERED THROUGH RIDER DCI?

A11. The rate of return grossed up for taxes would be based on the weighted average cost of capital and gross revenue conversion factor approved in Duke's most recent distribution base rate case (Case No. 12-1682-EL-AIR), which is currently 10.7 percent. Included in the rate of return is a 9.84 percent return on equity. While I do not address the appropriateness of this rate of return, OCC Witness Mathew I. Kahal does.

Q12. WHAT PROCEDURAL TIMELINE IS DUKE PROPOSING FOR RIDER DCI?

A12. Duke is proposing to make quarterly filings to adjust rates under Rider DCI. Filings would be made at least 60 days prior to the effective date. Rates would be based on projected costs as of the rate effective date. For example, an adjustment to rates under Rider DCI to be effective January 1, 2015 would be made no later than November 1, 2014, and the rate adjustment would be based on projected costs as of December 31, 2014.

Q13. WHY IS DUKE PROPOSING RIDER DCI?

A13. Duke witness Marc W. Arnold claims that the Utility's current planning and operation and maintenance practices and programs coupled with the current level of spending for equipment replacement are not sufficient for Duke to maintain its present level of service reliability and meet customer expectation. Witness Arnold claims that customers are demanding increasing service reliability. To enable what the Utility contends is the necessary investment in its distribution system and allowing for the timely recovery of the costs associated with that investment, Duke is proposing Rider DCI.

Q14. WHAT IS THE ESTIMATED IMPACT OF RIDER DCI ON DISTRIBUTION BASE RATES?

A14. The estimated increase in distribution rates resulting from Rider DCI is presented in Table 1. As shown on Table 1, Duke is proposing to increase distribution rates by $104 million over four years. For the average residential customer, this would reflect an increase in rates of nearly $100 per year by 2018.

Table 1
Impact of Rider DCI on Distribution Rates (millions)[1]

	Increase	
Year	Annual	Cumulative
2015	$22	$22
2016	41	63
2017	20	83
2018	21	104

[1] Response to OCC-INT-02-010.

Q15. HAS DUKE DEMONSTRATED THAT ITS CURRENT PRACTICES AND PROGRAMS COUPLED WITH CURRENT SPENDING LEVELS ARE NOT SUFFICIENT TO MAINTAIN ITS PRESENT LEVEL OF SERVICE RELIABILITY TO ITS CUSTOMERS?

A15. No. Therefore, Duke has not justified that it is necessary to increase the rates of its customers through Rider DCI to maintain the present the level of service reliability.

Q16. HAS DUKE DEMONSTRATED THAT RELYING UPON THE TRADITIONAL BASE RATE SETTING PROCESS TO COLLECT THE COSTS ASSOCIATED WITH ANY NECESSARY INCREMENTAL DISTRIBUTION SYSTEM INVESTMENT WILL PUT IT IN A DIRE FINANCIAL SITUATION?

A16. No. Therefore, Duke has not demonstrated that Rider DCI is necessary to avoid putting it in a dire financial situation.

Q17. HAS DUKE PRESENTED ANY EVIDENCE THAT RELYING UPON THE TRADITIONAL BASE RATE SETTING PROCESS HAS ADVERSELY IMPACTED THE RELIABILITY OF ITS DISTRIBUTION SYSTEM, TO THE DETRIMENT OF ITS CUSTOMERS?

A17. No, it has not, and in fact and as subsequently explained, the reliability of Duke's distribution system has been increasing under the traditional base rate setting process.

Q18. HAS DUKE PRESENTED ANY ANALYSES OR EVALUATION OF THE EXTENT TO WHICH THE RELIABILITY OF ITS DISTRIBUTION SYSTEM WILL IMPROVE UNDER RIDER DCI?

A18. No. Therefore, the reasonableness of Duke's incremental system reliability investments cannot be determined.

Q19. IS THERE EVIDENCE THAT UNDER THE TRADITIONAL BASE RATE SETTING PROCESS DUKE HAS NOT BEEN ABLE TO MAINTAIN OR IMPROVE THE RELIABILITY OF ITS DISTRIBUTION SYSTEM FOR ITS CUSTOMERS?

A19. No. Duke witness Arnold describes three standards for measuring system reliability:

- System Average Interruption Frequency Index ("SAIFI"). The SAIFI measures the average number of service interruption per customer.
- System Average Interruption Duration Index ("SAIDI"). The SAIDI is a measure of the average time each customer is interrupted.
- Customer Average Interruption Duration Index ("CAIDI"). The CAIDI is the average time required to restore a service interruption measured on a per interrupted customer basis.[2]

Attached to my testimony as JDM Attachment-2 is a discovery response providing a history of the values of Duke's distribution system SAIFI, CAIDI, and SAIDI since 2005. As shown there, Duke's SAIFI, which reflects the average number of service interruptions per customer, excluding storms, has declined from 1.49 in 2005 to 0.98

[2] Direct testimony of Marc W. Arnold, p. 7.

in 2013 or by nearly 35 percent, thus improving service reliability. The PUCO's performance standard for the SAIFI is 1.24.

Duke's SAIDI, or the average length of time each customer is interrupted has also improved recently. Duke's SAIDI, excluding storms, averaged 130.03 for the period 2005-2011, and declined to an average of 113.58, or by 13 percent for the period 2012-2013. The only index not reflecting improvement since 2005 is the CAIDI, which is a measure of the average time to restore a service interruption. For the period 2005-2011 Duke's CAIDI, excluding storms, averaged 97.49 and increased to an average of 110.53 for the period 2012-2013. Despite this increase, Duke's most recent CAIDI of 117.80 is better than the PUCO's performance standard of 118.14. Because Duke is experiencing improvements in the SAIFI and SAIDI, there is no demonstration that the current method of capital funding for infrastructure is insufficient or inadequate.

Q20. DESPITE THESE SERVICE RELIABILITY IMPROVEMENTS MR. ARNOLD CLAIMS THAT DUKE'S CUSTOMERS ARE DEMANDING INCREASING SERVICE RELIABILITY. WHAT IS THE BASIS FOR THESE CLAIMS?

A20. Duke subscribes to and has participated in J.D. Power annual electric utility residential customer and business customer satisfaction studies. At the direction of the PUCO, Duke also performs a quarterly survey of customer satisfaction. Mr. Arnold claims that the Utility gauges its performance in relation to customer expectations and satisfaction based upon the results of these surveys. Although Mr. Arnold does not explicitly so state, it is logical to conclude from his testimony that

Duke strives to maintain or increase its customer satisfaction levels, and doing so would generally be considered a reasonable goal for any utility.

Q21. MR. ARNOLD CLAIMS THAT THE J.D. POWER STUDIES SUPPORT THE CONCLUSION THAT CUSTOMERS ARE DEMANDING MORE RELIABLE SERVICE. UPON WHAT IN THOSE STUDIES IS MR. ARNOLD RELYING TO SUPPORT HIS CLAIM?

A21. Mr. Arnold claims that the J.D. Power 2013 Electric Utility Residential Customer Satisfaction Study℠ ("J.D. Power 2013 Residential Study") supports the conclusion that customer outage tolerances are declining while expectations are increasing. He claims that on a national average, overall satisfaction is flat to slightly declining, even among customers who experience no outages. Mr. Arnold concludes that customer expectations are high with respect to service reliability and power quality.

Q22. WHAT IS YOUR RESPONSE TO MR. ARNOLD'S CLAIMS WITH RESPECT TO THE FINDINGS OF THE J.D. POWER 2013 RESIDENTIAL STUDY?

A22. The J.D. Power 2013 Residential Study measures customer satisfaction with electric utility companies by examining six factors:

- Price
- Power quality and reliability
- Billing and payment
- Corporate citizenship
- Communications

- Customer service

Mr. Arnold only considers one of these factors, "power quality and reliability". He fails to consider the overall impact of price on customer satisfaction as a result of the estimated $104 million increase in rates which will occur under Rider DCI. A J.D. Power press release attached to my testimony on the 2013 Residential Study indicates that declines in power quality and reliability do not necessarily result in declines in customer satisfaction. (JDM Attachment-3.) The press release states:

> Despite ongoing severe weather across the United States resulting in longer outage periods per event, customer satisfaction with residential electric utilities has increased substantially from 2012 driven primarily by improvement in billing/payment, price and outage communications, according to the J.D. Power 2013 Electric Utility Residential Customer Satisfaction Study[SM] released today.

Q23. IS PRICE AN IMPORTANT DRIVER OF CUSTOMER SATISFACTION?

A23. Yes. Price is a key driver of customer satisfaction, and customer perceptions can be impacted by price. For example, everyone wants better quality service but how much they want better quality service is directly related to what it would cost to provide better quality service.

Q24. DO YOU HAVE ANY OTHER OBSERVATIONS CONCERNING THE J.D. POWER 2013 RESIDENTIAL STUDY?

A24. Yes. The J.D. Power 2013 Residential Study places equal weight on each factor to determine overall customer satisfaction levels. The J.D. Power 2013 Residential Study does not account for the varying levels of importance of each factor. This fails to give appropriate consideration to price. In addition, the support for Mr. Arnold's claims are national averages, which may not be reflective of the sentiments of Duke's customers. Instead of focusing on the national perspective, I discuss the findings of the surveys conducted by Duke with respect to the factors considered important to Duke's customers next in my testimony. I believe the results of Duke's customer surveys should be given greater consideration than national perspectives because they are more reflective of the actual satisfaction levels of Duke's customers.

Q25. MR. ARNOLD CLAIMS THAT THE SURVEYS PERFORMED BY DUKE AT THE PUCO'S DIRECTION SUPPORTS THE CONCLUSION THAT CUSTOMERS ARE DEMANDING MORE RELIABLE SERVICE. UPON WHAT IN THOSE SURVEYS DOES HE RELY UPON TO SUPPORT THOSE CLAIMS?

A25. Mr. Arnold claims that these surveys show that Duke's customers have very high expectations related to the number and duration of outages. But, he does not indicate how these surveys support the notion that customers have increasing expectations of reliability and power quality. More importantly, he does not identify whether customers are willing to pay an additional price associated with increased service reliability.

Q26. WHAT IS YOUR INITIAL RESPONSE TO THE CLAIM THAT CUSTOMER EXPECTATIONS REGARDING SERVICE RELIABILITY ARE INCREASING?

A26. As explained earlier, Duke's SAIFI and SAIDI, two measures of reliability, have shown improvement since 2005. Therefore, under the current traditional base rate setting process, customers are receiving the increased service reliability the Utility claims they are demanding. In addition, the surveys performed by Duke asked customers how much they would be willing to pay to avoid interruptions of various durations (i.e., one hour, two hours, four hours).

Approximately 50 percent of residential customers indicated they would not be willing to pay any additional costs to avoid service interruptions and for increased service reliability over today's service reliability standards (Attachment MWA-5). Approximately 60 percent of business customers indicated they would not be willing to pay anything further to avoid service interruptions and for increased service reliability (Attachment MWA-6). This suggests that the majority of the customers served by Duke do not significantly value increased service reliability without regard to cost. In other words, price is a more important factor to customers than increased reliability.

Q27. IS THERE OTHER EVIDENCE TO INDICATE THAT THE PRICE OF ELECTRIC SERVICE IS MORE IMPORTANT TO DUKE'S CUSTOMERS THAN INCREASED SERVICE RELIABILITY?

A27. Yes. In the survey conducted by Duke included as Attachment MWA-4, the Utility asked its residential customers what they liked best and what they liked least about Duke. For the latest quarter available, 53 percent of the respondents identified that what they liked best about Duke was reliable power and quick responses to outages.[3] Only four percent responded what they liked best about Duke was its low rates.[4] With respect to what customers liked least about Duke, 33 percent cited high bills and rates, and only six percent cited power quality and reliability concerns.[5] From a customer satisfaction perspective, these survey results indicate that Duke's proposal to increase rates by $104 million for increased service reliability is unwarranted.

In addition, in Duke's last distribution base rate proceeding (Case No. 12-1682-EL-AIR), members of the public presented their views on Duke's requested distribution base rate increase of $87 million. My review of the transcripts from the local public hearings in those proceedings indicates that the public's overwhelming concern was increasing rates, not service reliability.[6] The PUCO's Order in Duke's last distribution base rate proceeding noted that most of the testimony received at the local public hearings expressed a general opposition to any increase in Duke's rates.[7] Despite customers' opposition to further rate increases under the Utility's proposal in this case, customers would pay $104 million over four years for increased service reliability, without any assurance that service reliability will actually improve.

---

[3] Attachment MWA-4 at 9.

[4] Attachment MWA-4 at 9.

[5] Id. at 10.

[6] Case No. 12-1685-EL-AIR, Local Public Hearing Transcripts for hearing held on February 19, 20, 25, and 28 (March 29, 2014).

[7] Id.

Q28. SHOULD RIDER DCI BE APPROVED BY THE PUCO?

A28. No. Duke claims that Rider DCI is necessary to satisfy customer demands for increased service reliability. Yet Duke has failed to demonstrate that customers are willing to pay the additional costs necessary to fund the DCI for improvements in service reliability. Moreover, under the comprehensive distribution base rate setting process, customers are currently receiving increasingly reliable service. Therefore, it appears that Duke is already dedicating sufficient resources to the reliability of its distribution system. Duke has presented no analyses or studies to support its claim that current spending levels are not sufficient to maintain service reliability. Duke has not demonstrated that its proposed capital improvement programs are necessary to maintain service reliability.

Even if these capital improvement programs were necessary, Duke has not demonstrated that the traditional base rate setting process is inadequate to allow it to collect the costs associated with these programs in the future. In addition, as just explained, the evidence indicates that customers are more concerned with price and avoiding rate increases than increased service reliability. Therefore, Duke's expectation that its customers want additional service reliability and are willing to pay for it is inconsistent with its customers' perception that service reliability is currently adequate and that customers do not want to see their rates increase in order to increase service reliability. Finally, as subsequently discussed, there are flaws with the mechanics of Rider DCI, which merit its rejection.

Q29. WHAT CONCERNS DO YOU HAVE WITH THE MECHANICS OF RIDER DCI?

A29. I have concerns with the use of projected data, the failure to recognize operation and maintenance ("O&M") expense savings, the calculation of property taxes, and the inclusion of allocated common general plant.

Q30. PLEASE EXPLAIN YOUR CONCERN RELATED TO THE USE OF PROJECTED DATA.

A30. Duke is proposing to set rates under Rider DCI based on projected costs. As such, the potential exists for Duke to recover through rates costs which it has not actually incurred. Duke has proposed no mechanism to reconcile projected and actual costs under Rider DCI. This could result in customers being charged for costs that Duke does not incur. If Rider DCI were to be approved by the PUCO, it should be based on actual costs.

Q31. PLEASE EXPLAIN YOUR CONCERN WITH RIDER DCI AND O&M EXPENSE SAVINGS.

A31. The incremental investment that Duke is proposing to make if Rider DCI is approved will result in O&M expense savings. Duke is proposing to retain all of these savings until the Utility files its next base rate case, whenever that may be. At that time the O&M expense savings would be reflected in base rates.

It is not reasonable or equitable for customers to pay for all of the costs associated with Duke's incremental investment and not receive any of the benefits from the

O&M savings between base rate cases. Duke's treatment of O&M expense savings is inconsistent with how O&M expense savings were treated under its natural gas Accelerated Mains Replacement Program ("AMRP").[8] It is my understanding that the AMRP program enabled Duke to accelerate the replacement of bare steel and cast iron distribution mains that potentially posed a safety and service reliability problem.[9] One of the customer benefits from the AMRP was that O&M cost savings were immediately credited to help reduce the cost of the AMRP on customers.[10] If Rider DCI is approved by the PUCO, I recommend that Duke be required to identify any O&M expense savings and that these savings be reflected as a credit to Rider DCI.

Q32. PLEASE EXPLAIN YOUR CONCERN WITH RIDER DCI AND THE CALCULATION OF PROPERTY TAXES.

A32. Duke is assessed Tangible Personal Property ("TPP") and Real Property ("RP") taxes on its plant in service. For the TPP tax, when plant is placed in service, it is not assessed the TPP tax until the following year and the TPP tax would not be paid until the year after. For example, plant placed in service in 2015 will be assessed in the 2016 tax year and paid in 2017. For the RP tax, plant is assessed as of January 1st of each year, but is not billed until the following year. For example, plant assessed on

---

[8] *In The Matter of The Application of The Cincinnati Gas & Electric Company for an Increase in Its Gas Rates in Its Service Territory*, Case No. 01-1228-GA-AIR, Opinion and Order (May 30 2001).

[9] Id., Opinion and Order at 4 (May 30, 2002).

[10] Id., Stipulation and Recommendation at 9, paragraph 6 (April 17, 2002).

January 1, 2015 will not be paid until 2016, and any plant placed in service in 2015 after January 1, 2015 would not require the payment of the RP tax until 2017. Under Rider DCI, Duke would include the applicable property taxes in rates when plant is placed in service even though the property taxes would generally not be assessed until the following year. This is unreasonable and will cause customers to pay for costs not yet incurred by Duke or reflected on its books. If Rider DCI is approved by the PUCO, property taxes should not be included until the property being taxed is recognized as taxable by the applicable taxing authority.

Q33. PLEASE EXPLAIN YOUR CONCERN RELATED TO INCLUDING ALLOCATED COMMON GENERAL PLANT IN RIDER DCI.

A33. Common general plant is allocated to Duke's electric distribution, electric transmission, unregulated electric generation, and gas distribution businesses on factors including the net plant in service of each of these businesses. With the proposed additional investment in electric distribution plant, the common general plant allocated to electric distribution service is likely to increase and the associated costs will be recovered under Rider DCI. This would occur even if Duke's total investment in common general plant did not increase. It would be unreasonable for Duke to increase rates to recover the costs associated with additional investment when no additional investment has been made. This would mean that customers would be paying for costs not actually incurred by Duke.

I would also note that it is my understanding that while riders such as Rider DCI have been implemented under the PUCO authority to approve electric security plans, including provisions regarding distribution infrastructure and modernization incentives for the electric distribution utility, they have not included general plant. Common general plant, as the name implies, is plant that relates to the general operations of the utility and is not directly related to modernization. While it is true that general plant can support distribution operations, that plant, as the title implies, also supports other utility functions. Common general plant is not distribution infrastructure and does not relate to the modernization of that infrastructure. While additions to common general plant may indirectly lead to improved electric service reliability, such additions do not represent upgrades or modernization of distribution infrastructure. Therefore, if Rider DCI is approved by the PUCO, common general plant should be excluded.

Q34. DO YOU HAVE ANY COMMENTS CONCERNING THE RATE OF RETURN THAT CUSTOMERS WILL PAY ON THE INCREMENTAL INVESTMENT UNDER RIDER DCI?

A34. Yes. As previously indicated, the rate of return applied to the incremental investment would be that from Duke's most recently concluded distribution base rate case, and includes a 9.84 percent return on equity ("ROE"). OCC witness Matthew I. Kahal testifies that Rider DCI and subsequently discussed Rider DSR will reduce Duke's business risk. As a result he recommends a lower ROE for these Riders, if they are approved.

Q35. IF THE PUCO APPROVES RIDER DCI DESPITE YOUR CONCERNS, PLEASE SUMMARIZE HOW SHOULD RIDER DCI BE MODIFIED?

A35. If the PUCO approves Rider DCI despite my concerns, I recommend that actual rather than projected data be used to calculate Rider DCI, O&M expense savings should be reflected as a credit to Rider DCI, property taxes should not be included under Rider DCI until the property being taxed is recognized as taxable by the applicable taxing authority, common general plant should be excluded. And, the PUCO should explicitly reserve the right to evaluate the prudence of the costs recovered under Rider DCI at any time and disallow any costs not found to be prudent.

V. DISTRIBUTION STORM RIDER

Q36. PLEASE DESCRIBE DUKE'S PROPOSED RIDER DSR.

A36. Duke's current distribution base rates include $4.4 million per year for major storm O&M expense recovery. Duke is proposing to establish a regulatory asset account to defer the costs above or below this base rate amount in each calendar year. The Utility is proposing to recover the balance of this deferral in its next distribution base rate case unless the cumulative balance exceeds $5 million at the end of a calendar year. Once the balance exceeds $5 million, as either a regulatory debit or a regulatory credit, Duke will either collect or return to customers the balance in the regulatory account under Rider DSR.

Q37. WILL CUSTOMERS BE CHARGED FOR CARRYING COSTS UNDER RIDER DSR?

A37. Yes. Any monthly positive or negative balance in this deferral account would accrue a carrying cost at the long-term cost of debt approved in Duke's most recently concluded distribution base rate case.

Q38. WHY IS DUKE PROPOSING RIDER DSR?

A38. Duke claims storm restoration costs are unpredictable and can be substantial, and Rider DSR will serve to mitigate excessive volatility in the Utility's earnings.

Q39. HAS DUKE MADE ANY DEMONSTRATION THAT THE CURRENT BASE RATE PROCEDURES HAVE CAUSED EXCESSIVE VOLATILITY IN ITS EARNINGS OR THREATEN ITS FINANCIAL INTEGRITY?

A39. No. I would also note that if a weather event causes the Utility to incur significant storm related restoration costs, filing a separate application with the PUCO to recover those costs would be reasonable. For example, in Case No. 09-1946-EL-RDR, Duke filed to recover $30.7 million in costs it claims were caused by Hurricane Ike. I discuss this case in additional detail later in my testimony.

Q40. WHAT ARE YOUR CONCERNS WITH RIDER DSR?

A40. Initially, I am concerned that there will only be limited review of the costs to be collected under Rider DSR. That is, all interested parties will not likely have the opportunity to fully review the costs proposed to be collected from customers. A full review of costs collected from customers would be more likely to occur in a separate docketed proceeding or a base rate case. As a result, the potential to include ineligible or improper costs to be collected under Rider DSR will be greater. In addition, there will likely be limited review of the reasonableness of the costs proposed for recovery. This means that customers' rates may increase yet again with little oversight.

Q41. IS THERE EVIDENCE TO VALIDATE YOUR CONCERNS?

A41. Yes. In Case No. 09-1946-EL-RDR, Duke filed to recover $30.7 million in storm restoration costs following the destruction caused by Hurricane Ike. The PUCO approved recovery of only $14.1 million, finding that Duke:

- Failed to show a reasonable basis for the recovery of $3.2 million in supplemental compensation paid to salaried employees;
- Improperly proposed the recovery of $371,796 in salaries already recovered in Duke's base rates;
- Improperly proposed for recovery approximately $2 million in supervision costs and labor loaders, e.g., items such as the cost of fringe benefits and payroll taxes associated with labor costs;
- Failed to prove that all of the affiliate-related costs should be recoverable, resulting in a disallowance of approximately $1.3 million in claimed costs; and
- Failed to substantiate approximately $10 million in contractor payments proposed for recovery.[11]

[11] *In re Application of Duke Energy Ohio, Inc., 131 Ohio St. 3d 487, 2012-Ohio-1509.*

Q42. SHOULD RIDER DSR BE APPROVED BY THE PUCO?

A42. No, it should not. Duke has not demonstrated that the current base rate storm restoration cost recovery procedures are unreasonable or inadequate, and customers' rates should not increase without a thorough review of the reasonableness of the costs proposed for recovery.

Q43. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION?

A43. Yes, if the PUCO were to not follow my recommendation and approve the regulatory asset account, I recommend that the PUCO order Duke to file annually for a PUCO Staff audit detailing an accounting of all storm expenses within its storm deferral account, consistent with the process in other proceedings.[12] Prior to collecting or returning to customers storm restoration costs, Duke should be required to file a separate application with the PUCO for which Duke will bear the burden of proving that the costs were prudently incurred and reasonable. The PUCO Staff and interested parties should be permitted to conduct discovery and file comments within 90 days after the application is docketed. If any objections are not resolved by the Utility, the PUCO should require that an evidentiary hearing be scheduled, with the opportunity to present testimony before the PUCO.

[12] *See In re Application of Duke Energy Ohio, Inc.*, Case No. 09-1946-EL-ATA, Application (December 11, 2009) at 4, citing Case No. 08-709-EL-AIR; *In re Application of Columbus Southern Power Company and Ohio Power Company*, Case No. 11-346-EL-SSO, Opinion and Order (August 8, 2012), at 68-69.

Q44. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A44. Yes, it does. However, I reserve the right to incorporate new information that may subsequently become available. I also reserve the right to supplement my testimony in the event that the Utility, the PUCO Staff or other parties submit new or corrected information in connection with this proceeding.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a true and correct copy of the foregoing *Direct Testimony of Jerome D. Mierzwa on Behalf of the Office of the Ohio Consumers' Counsel's, Confidential Version*, has been served upon the below-stated counsel by electronic transmission, this 26th day of September 2014.

Maureen R. Grady
Maureen R. Grady
Assistant Consumers' Counsel

SERVICE LIST

Amy.Spiller@duke-energy.com
Elizabeth.watts@duke-energy.com
Rocco.dascenzo@duke-energy.com
Jeanne.Kingery@duke-energy.com

National Regulatory
Research Institute

How Should Regulators View Cost Trackers?

Ken Costello, Principal

National Regulatory Research Institute

September 2009

09–13

Acknowledgments

The author wishes to thank Mr. Scott Hempling and Mr. Adam Pollock, both of NRRI; Professor Dr. Douglas N. Jones of The Ohio State University; Mr. Michael McFadden of McFadden Consulting Group; Professor Carl Peterson of the University of Illinois Springfield; and Mr. Joseph W. Rogers of the Massachusetts Attorney General Office for their comments on an earlier draft of this paper. The author is responsible for any remaining errors in the document.

Online Access

The reader can find this paper on the Web at http://www.nrri.org/pubs/gas/NRRI_cost_trackers_sept09-13.pdf.

Executive Summary

A cost tracker allows a utility to recover its actual costs from customers for a specified function on a periodical basis outside of a rate case. This paper discusses the major issues that state public utility commissions face in evaluating the costs and benefits of these devices.

Several state commissions have approved new cost trackers for a wide array of utility functions in both the electric and natural gas sectors. State commissions have traditionally limited the use of cost trackers, partially because of the perception that they create "bad" incentives and shift risks to a utility's customers. The recent approvals depart from past regulatory practices that sanction trackers only under highly restricted conditions.

The author asserts that state commissions have not given adequate attention to the negative features of cost trackers, which are at odds with the public interest. Specifically, cost trackers diminish the positive effects of regulatory lag and retrospective reviews in deterring utility waste and cost inefficiency. Trackers also could reduce regulatory scrutiny in evaluating cost prudence.

This paper contends that regulators should view cost recovery in a rate case as the "default" practice. A rate case assures scrutiny of a utility's costs and provides strong motivation for the utility to control those costs between rate cases. The utility therefore bears burden to show why a cost tracker is in the public interest. The utility should demonstrate that it would suffer severe financial difficulties under "extraordinary circumstances" without the tracker.

This paper also recommends that regulators consider the advantages of replacing cost trackers (excluding fuel and purchased gas cost trackers) with a single rate-of-return tracker in the form of an earnings-sharing mechanism. This alternative can overcome some of the problems with cost trackers, namely perverse or weak incentives for cost control, the mismatching of total costs and revenues, and inadequate regulatory oversight of costs. An earnings-sharing mechanism also achieves the major objective of cost trackers, which is to prevent a utility from suffering serious financial problems between rate cases.

Table of Contents

How Should Regulators View Cost Trackers?

This paper discusses the major issues regulators face in evaluating the costs and benefits of cost trackers.[1] This paper responds to state public utility commissions' recent actions in approving new cost trackers for a wide array of utility functions in both the electric and natural gas sectors. Historically, state commissions have limited the use of cost trackers, partially because of the perception that they create "bad" incentives and shift risks to a utility's customers. The recent approvals differ from past regulatory practices that sanctioned trackers only under highly restricted conditions.

The author contends that state commissions have not given adequate attention to the negative features of cost trackers. By conflicting with certain regulatory objectives, cost trackers thwart the public interest. Cost trackers undercut the positive effects of regulatory lag and retrospective reviews in deterring utility waste and cost inefficiency. They also could lessen regulatory scrutiny in evaluating the prudence of costs.

This paper defines cost trackers and discusses how they benefit utilities. It then provides the rationales for cost trackers and how they relate to regulatory principles for cost recovery. The paper examines two scenarios; in the first, regulators allow comprehensive cost trackers, while in the second they allow none. The paper ends by recommending a regulatory policy and identifying questions regulators should ask when investigating cost trackers.

I. The Definition and Mechanics of a Cost Tracker

A cost tracker allows a utility to recover its actual costs from customers for a specified function on a periodical basis outside of a rate case.[2] A tracker, in other words, involves the recovery of a utility's actual costs in the periods between rate cases. These costs could include

---

[1] Regulators sometimes refer to cost trackers as "riders."

[2] A cost tracker can either provide interim rate relief for a utility or be a permanent fixture that adjusts rates between rate cases based on upward and downward movements in those costs specified in a tracker. As an alternative to a cost tracker, a utility can file for emergency rate relief whenever it encounters a serious financial problem. The commission can specify conditions under which a utility can file an emergency or interim rate filing petitioning for immediate rate relief. This paper does not examine the different regulatory approaches to relieving utilities of any temporary or more permanent serious financial problems. Such a study could compare each approach, including cost trackers, based on its effect on different regulatory objectives.

those that deviate from some baseline or are zero-based.[3] Baseline costs, *for* example, could include bad debt costs[4] reflected in present rates as determined in the last rate case. A cost tracker could allow adjustments in rates when actual bad-debt costs depart from the baseline level. These adjustments would occur periodically as prescribed previously by a commission.

To benefit customers when actual cost falls below the baseline level, a cost tracker must be "symmetrical." The unpredictability of a cost item—which, as this paper discusses later, is one underlying rationale for a cost tracker—means that test-year cost estimates can overstate or understate the actual costs. Virtually all fuel and purchased gas cost trackers are symmetrical, with customers benefiting when commodity-energy costs fall (e.g., since the autumn of 2008).

Cost trackers also could apply to all of the costs associated with a particular business function or task. Under this zero-based approach, for example, the entire cost of a gas utility's new investments in upgrading the safety of its distribution system would be amortized and recovered later from customers in lieu of inclusion in base rates. The same cost recovery procedure can occur for a utility's energy-efficiency initiatives.

Some cost trackers, such as fuel adjustment clauses (FAC) and purchased gas adjustments (PGAs), adjust rates in response to changes in the price of fuels used by generating facilities and purchased gas for gas utilities.[5] Certain cost trackers approved over the last couple of years allow for rate adjustments when the cost for a particular business function, for whatever reason, changes. A tracker for bad debt, for example, does not distinguish between an increase because of a greater number of nonpaying customers or higher debt per customer.

---

[3] "Zero-based" refers to *all* the costs associated with a specific function, rather than just increments or decrements from test-year costs.

[4] These costs represent money owed by customers to a utility that the utility has determined to be uncollectible.

[5] NRRI has conducted several studies on FACs and PGAs. *See*, for example, Robert E. Burns, Mark Eifert, Peter Nagler, *Current PGA and FAC Practices: Implications for Ratemaking in Competitive Markets* (Columbus, Ohio: NRRI, November 1991), NRRI 91-13; Robert E. Burns and Mark Eifert, "Designing Fuel and Purchased Gas Adjustment Clauses to Provide for Incentive Compatibility in a More Competitive Environment," *Proceedings of the Eighth NARUC Biennial Regulatory Information Conference* (Columbus, Ohio: NRRI, September 1992); Kevin A. Kelly, Timothy Pryor, Nat Simons, *Electric Fuel Adjustment Clause Design* (Columbus, Ohio: NRRI, 1979), NRRI 79-3; and Douglas N. Jones, Russell J. Profozich, Timothy Biggs, *Electric and Gas Utility Rate and Fuel Adjustment Clause Increases, 1978 and 1979* (Columbus, Ohio: NRRI, 1981), NRRI 81-5.

II. Principles for Cost Recovery

A. "Reasonable opportunity" criterion

State commissions have applied myriad criteria for utility cost recovery. Regulators are legally bound to allow utilities the opportunity to recover prudently incurred costs. Prudent costs reflect utility management that makes rational and well-informed decisions. The word "opportunity" can refer to the utility having a good chance of earning its authorized rate of return and is distinct from an entitlement.[6] "Earning the authorized rate of return" means that the utility recovers its prudent variable costs (e.g., operations and maintenance) and earns a return of and on prudently incurred fixed costs, including its cost of capital as determined in the last rate case.

B. Incentive effects of cost trackers

Commissions traditionally allow cost recovery only after a rate case review. Other alternatives such as a cost tracker would require that a utility show violation of the "opportunity" condition for particular cost items. A violation can occur when a certain cost is substantial, unpredictable, and generally beyond a utility's control. Other than costs relating to fuel and purchased power and gas, few other costs fall within the confines of "special circumstances."[7] Parties to regulatory proceedings naturally disagree over when these circumstances exist. *To clarify their positions to utilities, intervening groups, and the general public, commissions should* consider issuing policy statements articulating standards for the recovery of costs through trackers.

Regulators, until recently, have taken a cautious approach to trackers, partially because they weaken the incentive of a utility to control its costs.[8] Controlling utility costs is a primary

---

[6] One interpretation is that the utility earns its authorized rate of return over a number of years, rather than each year. Regulators, investors, and utilities do not expect uniform rates of return across years. Instead, they ostensibly presume that in some years the rate of return will be below the authorized level, while in other years it would be above the authorized level. Regulators, for example, set rates based on "normal" weather. They expect that summer weather will be hotter than normal in some years and cooler than normal in others. For a typical electric utility, having a hotter-than-normal summer and a cooler-than-normal summer often means the utility earns a high rate of return and a low rate of return for those years respectively. But regulators expect normal weather over a number of years.

[7] An exception also might include the costs associated with a major storm causing extensive damage to a utility's infrastructure.

[8] The cost trackers discussed in this paper assume price adjustments based on changes in the actual cost of the utility. If instead price adjustments relate to cost changes for a peer group or other factors outside the control of the utility, the incentive problems identified in this paper would mostly disappear. Some cost trackers attempt to incorporate benchmarks that reflect performance exogenous to an individual utility. Defining the appropriate benchmark is a crucial but difficult task in designing a performance-based tracker. *See*, for example, Ken Costello and

objective of regulators because it contributes to lower rates and reflects efficient utility management. Cost trackers can, in various ways, result in higher utility costs.[9] First, they undercut the positive effects of regulatory lag on a utility's costs. "Regulatory lag" refers to the time gap between when a utility undergoes a change in cost or sales levels and when the utility can reflect these changes in new rates. Economic theory predicts that the longer the regulatory lag, the more incentive a utility has to control its costs; when a utility incurs costs, the longer it has to wait to recover those costs, the lower its earnings are in the interim. The utility, consequently, would have an incentive to minimize additional costs. Commissions rely on regulatory lag as an important tool for motivating utilities to act efficiently.[10] As economist and regulator Alfred Kahn once remarked:

> Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses, and offers rewards for their

---

James F. Wilson, *A Hard Look at Incentive Mechanisms for Natural Gas Procurement*, NRRI 06-15, November 2006, at http://www.nrri.org/pubs/gas/06-15.pdf.

[9] Theoretical and empirical studies provide some evidence of the incentive problems associated with one kind of cost trackers, FACs. *See*, for example, David P. Baron and Raymond R. DeBondt, "Fuel Adjustment Mechanisms and Economic Efficiency," *Journal of Industrial Economics*, Vol. 27 (1979): 243-69; David P. Baron and Raymond R. DeBondt, "On the Design of Regulatory Price Adjustment Mechanisms," *Journal of Economic Theory*, Vol. 24 (1981): 70-94; David L. Kaserman and Richard C. Tepel, "The Impact of the Automatic Adjustment Clause on Fuel Purchase and Utilization Practices in the U.S. Electric Utility Industry," *Southern Economics Journal*, Vol. 48 (1982): 687-700; and Frank A. Scott, Jr., "The Effect of a Fuel Adjustment Clause on a Regulated Firm's Selection of Inputs," *The Energy Journal*, Vol. 6 (1985): 117-126. The first two studies applied a general model to show that FACs tend to cause a utility to overuse fuel relative to other inputs, pay more for fuel prices, and choose non-optimal, fuel-intensive generation technologies. The third study provided empirical support for this prediction. The fourth study showed that some types of FACs cause bias in fuel use and that FACs in general weaken the incentive of a utility to search for lower-priced fuel. It provided empirical evidence that electric utilities with an FAC pay higher fuel prices than utilities without an FAC.

[10] Regulatory lag is a less-than-ideal method, however, for rewarding an efficient, and penalizing an inefficient, utility. Some of the additional costs could fall outside the control of a utility (*e.g., increase in the price of materials*), and any cost declines might not correlate with a more managerially efficient utility (e.g., deflationary conditions in the general economy). As discussed elsewhere in this paper, regulators are more receptive to cost trackers when: (1) regulatory lag can cause a substantial movement in a utility's rate of return between rate cases, and (2) the utility has little control over how much its actual costs will deviate from its test-year costs.

opposites; companies can for a time keep the higher profits they reap from a superior performance and have to suffer the losses from a poor one.[11]

Rational utility management, as a general rule, would exert minimal effort in controlling costs if it has no effect on the utility's profits.[12] This condition occurs when a utility is able to pass through (with little or no regulatory scrutiny) higher costs to customers with minimal consequences for sales. Cost containment constitutes a real cost to management. Without any expected benefits, management would exert minimum effort on cost containment. The difficult problem for the regulator is to detect when management is lax. Regulators should concern themselves with this problem; lax management translates into a higher cost of service and, if undetected, higher rates to the utility's customers. Regulators should closely monitor and scrutinize costs, such as those subject to cost trackers, that utilities have little incentive to control.

When mechanisms for cost recovery differ across functional areas, perverse incentives can arise that would make it profitable for the utility not to pursue cost-minimizing activities.[13] The result is higher rates to utility customers. A utility with a FAC might postpone maintenance of a power plant even when it would cost less than the savings in fuel costs. The utility could not immediately (or even at any time) recover additional maintenance costs, while it could pass the higher fuel costs through the FAC.

Cost trackers, in the long run, can bias a utility's technological and investment decisions. A utility recovering fuel costs through a FAC, for example, might want to adopt fuel-intensive generation technologies even if they are more expensive from a life-cycle perspective.[14] The result, again, is higher rates to utility customers.

---

[11] Alfred E. Kahn, *Economics of Regulation, Vol. 2* (New York: John Wiley & Sons, 1971), 48.

[12] I assume here that reducing cost has no effect on the quality or quantity of utility service. Controlling costs, therefore, refers to eliminating or reducing "wasteful" expenses that would result in no decline in the value of utility service. The author imagines a situation in which utilities would attempt to defer maintenance costs until the commission sets new base *rates that account for those costs.*

[13] In the example above, regulators could eliminate any perverse incentive by simply allowing a cost tracker for maintenance expenses.

[14] *See*, for example, the Baron and DeBondt studies cited in footnote 9.

Cost trackers also could motivate utilities to shift more of their costs to functions subject to trackers.[15] They might, for example, want to classify routine maintenance costs as a capital expense that receives tracker cost recovery. Such shifts could lead to earning an excessive rate of return. Regulators implementing trackers should carefully define applicable costs. They should also examine costs claimed under trackers to ensure that the utility recovers only appropriate costs through the tracker.[16]

An important incentive for cost control by regulated utilities is the threat of cost disallowance from retrospective review.[17] To the extent that cost trackers dilute the frequency and quality of these reviews, further erosion of incentives for cost control occurs. With less regulatory oversight and auditing, which often accompany rate cases, a utility might have less concern over the costs it incurs. Regulators have long recognized the importance of retrospective reviews in motivating a utility to avoid cost disallowances from grossly subpar performance.

If a utility has a number of cost trackers, the regulator might want to consider staggering the timing of retrospective reviews to avoid having inadequate staff resources to review the adjustments for individual cost trackers. Some utilities have comprehensive trackers that recover a wide array of costs (e.g., purchased gas, bad debt, energy-efficiency activities, and environmental activities). For these trackers, it would be especially challenging for a regulator to conduct an adequate retrospective review of each item simultaneously.[18]

A contradiction seemingly exists between the criterion that trackers should apply only to those costs beyond the control of a utility and the assertion that the modified incentives caused by trackers can lead to inflated costs. One response is that a utility has at least some control over most of its costs. Except for certain taxes and some other cost items, the actions of utility

---

[15] One example is when a tracker for new capital expenditures creates an incentive for a utility to shift labor costs from maintenance to capital projects. In this instance, the utility can schedule employees to work on the capital projects, and maintenance is delayed. The utility consequently reduces its maintenance costs and thereby keep the savings, and increase its capital expenditures, which it recovers through the tracker. I thank Michael McFadden for this example.

[16] I thank Adam Pollock for this insight.

[17] Many regulatory experts view retrospective reviews as dissuading a utility from poor decisions with the threat of a penalty—for example, making the utility more diligent and careful in its planning and procurement. Given asymmetric information, where a utility knows more about its operations and market supply/demand conditions than the commission, some analysts characterize retrospective views as a second-best mechanism to market-like incentives. For most gas utilities, the strong incentives for controlling purchased gas costs derive mainly from the time lag between the incurrence of a cost and its recovery from retail customers, and regulatory prudence reviews where, for example, abnormal costs attract special attention and a review.

[18] I thank Joseph Rogers for this insight.

management can affect costs. Even for fuel or purchased gas, utility management's actions can affect their total costs. Although for the most part the marketplace determines the price paid for these items, utilities can negotiate prices under long-term contracts and decide on the mix and sources of different fuels and purchased gas.[19]

Commissions also tend to avoid cost recovery that results in radical price volatility to utility customers. Such a policy could preclude monthly price adjustments from changes in fuel costs or purchased gas costs. It also might result in a phase-in of the construction costs of a new base-load-generating facility.

III. Utilities' Perspective on Cost Trackers

Under traditional ratemaking, the utility recovers all costs after a rate case review. It requires no commission activity between rate cases. Traditional ratemaking provides base rates based on the test year. A commission relies heavily on cost-of-service studies to determine base rates. Base rates have two characteristics: (1) a commission sets them in a formal rate case, and (2) they remain fixed until the utility files a new rate case and the commission makes a subsequent decision. The costs represent those calculated for a designated test year and exclude those costs recovered in trackers and other mechanisms. No matter how much the actual utility's costs and revenues deviate from their test-year levels, rates remain fixed until the commission approves new ones in a subsequent rate case. The exception is when a commission allows for interim rate relief under highly abnormal conditions that jeopardize a utility's financial condition.

Utilities have argued that a more dynamic market environment, characterized by the increased unpredictability and volatility of certain costs, justifies the recovery of certain costs through a tracker rather than in base rates.[20] Utilities have also asserted that the static nature of the "test year" sometimes denies them a reasonable opportunity to earn their authorized rate of return. They contend that cost trackers advance the ratemaking goals by matching revenues to actual costs.

In contrast to base rates, cost trackers offer a utility the advantages of: (1) shortening the time lag between the incurrence of a cost and its recovery in rates (i.e., curtailing regulatory lag),

---

[19] A utility, for example, might be lax in finding the best deals for gas supplies, in applying more resources by employing more highly qualified staff, or in acquiring superior market intelligence. *See*, for example, Ken Costello, *Gas Supply Planning and Procurement: A Comprehensive Regulatory Approach*, NRRI 08-07, June 2008, at http://nrri.org/pubs/gas/Gas_Supply_Planning_and_Procurement_jun08-07.pdf.

[20] *See*, for example, Russell A. Feingold, "Rethinking Natural Gas Utility Rate Design: A Framework for Change," presented at the American Gas Foundation Executive Forum, held at The Ohio State University, May 23, 2006.

(2) increasing cost-recovery certainty,[21] and (3) lessening the regulatory scrutiny of its costs. Normally, in a rate case a regulator closely reviews the utility's costs before approving them for recovery from customers. Regulators often less rigorously scrutinize a utility's costs when recovered through a tracker.[22] Overall, cost trackers lower a utility's financial risk by stabilizing its earnings and cash flow.

Utilities increasingly have asked their state public utility commissions to depart from traditional regulation by approving new cost-recovery mechanisms for different business activities. Some gas utilities want to expand the scope of their PGA clauses to include a wider array of costs. Current cost trackers in the natural gas sector, other than those for purchased gas costs, apply to functions including pipeline integrity management, pipeline replacement costs (e.g., accelerated cast iron main replacement program), bad debt, energy-efficiency costs, general infrastructure costs, manufactured gas plant remediation, stranded restructuring costs, property taxes, post-retirement employee benefits, and environmental costs.

IV. Regulatory Rationales for Cost Trackers

A. "Extraordinary circumstances"

State commissions have traditionally approved cost trackers only under "extraordinary circumstances." Commissions recognize the special treatment given to costs recovered by a tracker; they consider cost trackers an exception to the general rule for cost recovery. This view places the burden on a utility to demonstrate why certain costs require special treatment.

The "extraordinary circumstances" justifying most of the cost trackers that commissions have historically approved have been for costs that are: (1) largely outside the control of a utility, (2) unpredictable and volatile,[23] and (3) substantial and recurring. Historically, commissions required that all three conditions exist if a utility wanted to have costs recovered through a tracker. Fuel costs were a good candidate because of their influence by factors beyond

[21] Between rate cases, for example, a utility might incur costs unanticipated by the test-year calculation and thus not recovered from its customers.

[22] The regulator, for example, might have less time to review these costs or just might consider them too unimportant to warrant a separate review. Another explanation might be that rate cases are transparent and well-publicized, putting pressure on regulators to closely review all aspects of a rate case filing. These reasons are just the author's speculations. A pertinent research question is whether this hypothesis has validity.

[23] Even if the forecast of a cost item is highly accurate in the long run, it can fluctuate widely in the short run, causing possible serious cash-flow problems for the utility. The utility might then have to purchase short-term debt and other financing. The author thanks Carl Peterson for this insight.

the control of a utility, their volatility, and their large size. Commissions recently have approved cost trackers when not meeting all three conditions, especially the third (substantial and recurring costs).[24]

The last "extraordinary circumstance," substantial and recurring costs, greatly restricts the costs eligible for cost tracker recovery. Differences between their test year and actual cost can have a material effect on a utility's rate of return. Legal precedent dictates that regulators must set reasonable rates that allow a prudent utility to operate successfully, maintain its financial integrity, attract capital, and compensate its investors commensurate with the risks involved.[25] A utility should recover revenues in excess of its operating expenses to provide a "fair return" to investors. Businesses including utilities need to earn a profit to compensate investors for business, financial, and other risks.[26]

Some state commissions have softened or ignored the "substantial and recurring" component of the "extraordinary circumstances" standard. Bad debt, the subject of recent cost trackers, features financial effects that are typically not substantial. Utilities have contended that the unpredictability of this cost makes it difficult to incorporate it accurately into the base rate. Yet, even if this assertion is true, it is questionable whether any bad-debt cost unaccounted for in the test year would inflict substantial financial harm on a typical utility.[27]

---

[24] Commissions' rulings seem to reflect the view that regulators have much discretion in approving cost trackers as long as these actions reflect reasonable ratemaking given the facts and circumstances.

[25] The U.S. Supreme Court outlined these conditions in its 1944 order for *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 605 (1944).

[26] The return on equity for a utility corresponds to the term "normal profits." Both terms involve the cost a utility incurs to attract funds from investors.[26] Let us assume that utility performance should replicate the performance of competitive firms where firms receive normal profits in the long run. A utility would, therefore, earn a return that is reasonable but not excessive. A reasonable return should allow the utility to maintain its credit quality and attract needed capital on reasonable terms, but do no more. Commissions usually consider a rate of return within a "zone of reasonableness" as sufficient but not excessive. They do not guarantee that the utility will earn within this zone; they merely give the utility the opportunity if it performs efficiently and economically.

[27] The outcome would vary across utilities and by period. Especially in bad economic times in conjunction with high energy prices, bad debt can quickly soar, making test-year estimates grossly inaccurate. "Substantial financial harm" has no definitive meaning. It can refer to a situation where a utility has difficulties in raising funds for new investments or faces severe cash flow problems. Such situations can harm customers in the long run, for example, by reducing service reliability and diminishing the utility's credit quality, which in turn can lead to the utility having a higher cost of capital. A tracker for bad debt can also affect how the utility responds to customers who are behind in their payments. It can, for example, make the utility

B. "Severe financial consequences"

Historically, commissions have approved cost trackers to avoid the possibility of a utility suffering a serious financial problem because of cost increases unforeseen at the time of the last rate case.[28] Justification for cost trackers is, therefore, greater when a commission relies on a historical test year that does not recognize the volatility of certain costs or their upward trend over time. Let us assume that a certain operating cost has trended upward (e.g., 2 percent per year) over the past several years. Let us also assume that the commission allows only a historical test year. In this example the utility is likely to under-recover this particular cost. What effect this outcome would have on the utility's overall rate of return depends on the magnitude of any cost increase relative to the utility's earnings and whether other costs fell while rates were in effect.

Commissions do not expect utilities to earn the authorized rate of return during each future period over which new prices are in effect.[29] Commissions implicitly impute a risk premium in the authorized rate of return, partially to account for the earnings volatility from fluctuations in costs or revenues from the test year. Trackers affect what is called "business risk." Business risk refers to the uncertainty linked to the operating cash flows of a business. Business risk is multi-dimensional, inclusive of sales, cost, and operating risks. In the Capital Asset Pricing Model (CAPM), for example, the lower the utility's expected earnings volatility, the lower the measure of the utility's risk relative to the market portfolio (i.e., "beta"). Because

---

more lax in its credit policies, which could result in fewer service disconnections, especially for low-income households. In the absence of a tracker, the utility presumably would intensify its efforts to collect money owed by delinquent customers. I thank Michael McFadden for this insight.

[28] *See,* for example, Paul L. Joskow, "Inflation and Environmental Concern: Structural Changes in the Process of Public Utility Regulation," *Journal of Law and Economics*, Vol. 17 (1974): 291-327. A premise behind the wide acceptance of fuel adjustment clauses was that because electric utilities were not responsible for the escalation of fuel costs, commissions should not hold them accountable. Virtually all electric utilities in the 1970s experienced an unprecedented rise in fuel costs, for example, inferring an exogenous event beyond the control of any single utility. Prior to this time, even though FACs were common but fuel prices were much more stable, commissions generally associated changes in the utility's rate of return between rate cases with utility-management performance. A lower rate of return reflected poor performance and a higher rate of return superior performance. (A 1974 study found that 42 out of 51 jurisdictions had some form of fuel adjustment clause. *See* National Economic Research Associates, "The Fuel Adjustment Clause: A Survey of Criticism, Justifications, and Its Applications in the Various Jurisdictions," 1974.)

[29] This statement supports the contention that commissions do not intend the prices they set in a rate case to reflect the utility's actual cost of service for each future year. Commissions, however, judge that the prices they set will allow the utility an opportunity (i.e., a reasonable chance) to earn its authorized rate of return or some return close to the authorized level.

trackers reduce a utility's business risk, a regulator might want to consider revising downward the risk premium of a utility with additional cost trackers or a revenue-decoupling tracker, resulting in a lower return on equity.

If a commission wants to guarantee that the utility will recover its authorized earnings, it would favor a rate design that allows the utility to recover all of its fixed costs in a monthly service charge or a customer charge.[30] Since generally commissions do not, they implicitly recognize the positive incentive effect from allowing a utility's actual rate of return to deviate from the authorized level. Commissions also know that if a utility is continuously earning below its authorized rate of return, the utility has the right to file a general rate increase.

The previous discussion explains why most regulators have favored adjusting rates between rate cases only when such adjustments avoid serious financial situations for utilities. If a commission wanted to assure the utility that it will always earn its authorized rate of return, it would allow the utility to recover all of its actual costs through trackers.[31] Commissions generally do not allow the tracking of all costs because of incentive and other problems, which this paper discusses in Section II.B.

C. An illustration: FACs and PGAs

The wide popularity of FACs and PGAs among utilities and most commissions reflects the perception that these mechanisms are necessary to prevent a utility from earning a rate of return substantially below what was authorized. This perception stems from the magnitude of fuel and purchased gas costs relative to a utility's earnings. Other categories of costs, such as bad debt, are much smaller in size and therefore have smaller earnings consequences.

Until fuel costs started to fluctuate sharply in the 1970s, some energy utilities had to operate without the ability to adjust prices outside a rate case.[32] These utilities shouldered the risks of events between rate cases, but they also retained any high returns from favorable happenings. Prior to around 1970, for example, many electric utilities earned rates of return that were much higher than the authorized levels because of technological improvements, high sales growth, and economies of scale, in addition to the acquiescence of commissions.[33]

---

[30] Such a rate design would not guarantee the utility earning its authorized rate of return, as unexpected variable costs would cause the utility's earnings to decline.

[31] This recovery would include fixed costs the commission found prudent in the last rate case. Guarantee of full recovery of all costs would also require a revenue tracker such as revenue decoupling, assuming that the utility recovers some of its fixed costs in the volumetric or commodity charge.

[32] The genesis for these dramatic fuel-cost increases was the Oil Embargo by OPEC and the other Persian Gulf troubles of the 1970s.

[33] Although most state commissions had authority to initiate proceedings to reduce rates, few chose to exercise it.

Not surprisingly, virtually all state commissions believed that trackers for large items such as fuel costs and purchased gas costs were necessary to prevent inordinate rate-of-return fluctuations. Implicit in this belief is the view that the burden on utility shareholders would otherwise be onerous. This factor overwhelmed the arguments against trackers. The major objective of FACs and PGAs, implanted during that era, was to shield the utility's earnings from commodity price volatility. Both debt and equity investors favor these mechanisms in reducing the riskiness of a utility's earnings and cash flow.

V. Two Extreme States of the World: Several and No Cost Trackers

A. A hodgepodge of cost trackers, or a single rate-of-return tracker

If a commission wants a utility always to earn close to its authorized rate of return, it would favor rate adjustments between rate cases for both: (1) actual costs deviating from test-year costs, and (2) actual revenues deviating from test-year revenues. This outcome would require cost trackers covering all of the utility's costs in addition to a revenue decoupling mechanism. (The revenue decoupling mechanism would allow the utility to recover all fixed costs that the commission approved for recovery in the last rate case.)

Putting the utility's future on "autopilot" seems like a reasonable course of action if financial stability is the prime regulatory objective. Considering incentive problems and excessive risk-shifting to customers, this option comes across as much less appealing.

An earnings-sharing mechanism (ESM), which consolidates different cost and revenue trackers, is one ratemaking procedure for stabilizing a utility's rate of return between rate cases. Under this mechanism, the utility adjusts its rates periodically (e.g., annually) when its actual return on equity falls outside some specified band. As an illustration, if the band encompasses a 10 to 14 percent rate of return on equity (with 12 percent as the utility's authorized rate of return established in the last rate case) when the actual return is 9 percent, the utility could adjust its rates upward to increase its return to, or bring it closer to, 10 percent.[34]

An ESM helps to stabilize a utility's rate of return without a full-scale rate case review. Earnings sharing should reduce the frequency of future rate cases and allow adjusted rates to reflect recent market developments, including those affecting a utility's costs.[35] Compared to

[34] The band implicitly reflects the range for the return on equity that the regulator deems both adequate to keep the utility from financial jeopardy and not so excessive as to be exorbitant. The interpretation of these financial conditions is subjective and open to debate.

[35] Under traditional ratemaking, reducing the frequency of rate cases might allow the utility to over-earn by a substantial amount because of the multi-year accumulation of higher-than-expected sales or lower-than-expected costs, or both. Commissions probably are not so concerned when the utility over-earns for a one- or two-year period, but would be when it over-earns by a "significant" amount over several consecutive years. This reaction would be more

traditional ratemaking, where rates remain fixed between rate cases, ESM weakens regulatory lag and thereby reduces the incentive of a utility to control its costs between rate cases.[36] A commission can lessen this problem by requiring the utility to demonstrate its prudence and offer reasons why specific cost items were higher than their test-year levels.[37]

In sum, an ESM would trigger a price adjustment between rate cases only when the aggregation of revenue and cost departures from test-year levels cause the utility's rate of return to fall outside a specified "band" region. An ESM takes into account the overall profitability of a utility. It assumes the role of a rate-of-return tracker that, in effect, amalgamates different cost trackers into a single cost-recovery mechanism.

The ESM differs from conventional trackers, which account for specific costs or functions in isolation from the utility's overall financial position. Trackers' focus on an individual cost categories can cause utilities to delay coming in for rate cases, with the utility earning an "excessively" high rate of return in the interim. Let us assume that the commission has approved a tracker for new infrastructure expenditures. The new infrastructure expects to lower the utility's maintenance and other operating costs. If the last rate case did not recognize these lower operating costs, the utility's rate of return would be higher, yet because of the tracker, the utility suffers no interim financial losses from incurring infrastructure expenditures.

---

acute if the commission believes that fortuitous cirscumstances, rather than superior utility management, caused the high earnings.

[36] This incentive problem exists only when the utility is outside the "band" region and the mechanism requires sharing of "excessive "or "deficient" earnings with customers. This fact suggests a wide "band," as the utility operating within the "band" would have "high-powered" incentives to manage costs because it retains all the economic gains.

[37] The incentive problem would be less pronounced compared to a conventional cost tracker. As long as the utility's rate of return is within the "band" region, it has a similar incentive for cost control as it would between rate cases with fixed prices. (The word "similar" is used because if the "band region" is wide enough, it could defer the next rate case to either increase or decrease rates. This deferral would further strengthen the incentive of the utility to control costs.) Outside the "band" region, the utility's incentive depends upon whether ESM *requires the sharing of high or low rates of return between the utility and its customers.* Assume, for example, that the "band" region is a 10 to 14 percent rate of return on equity. During the year, the utility earns 15 percent; if the utility has to split the difference between the higher boundary of the "band" region and the actual rate of return by adjusting its prices down, in the example the utility would realize a 14.5 percent rate of return. We assume that the mechanism is symmetrical, so if the utility earns below the lower boundary of the "band" region, say, a 9 percent rate of return, it can adjust prices up to realize a rate of return closer to the lower boundary. This sharing arrangement means that if the utility allows its costs to rise, it either suffers the full consequence (when it operates within the 'band" region) or the partial consequence (when it operates outside). The latter condition creates an incentive problem relative to traditional ratemaking with regulatory lag and fixed prices between rate cases.

On net, the utility benefits and its customers immediately pay for the infrastructure costs without benefiting from the lower operating costs (at least until new rates reflect the lower costs). Such an outcome would violate any common meaning of "fairness" and seriously calls into question the merits of using a single-function tracker without readjusting rates for the effect on a utility's other functional areas.[38] This dynamic suggests that commissions implementing trackers should require their utilities to file rate cases on predetermined intervals.

B. No cost trackers

Under the traditional approach to ratemaking, a utility cannot adjust its rates outside a rate case. No matter what happens to a utility's costs or revenues between rate cases, rates remain fixed. Let us assume that a utility's costs and revenues are volatile and difficult to predict. The utility's rate of return can then deviate substantially (on the upside or downside) from the authorized level.

It is one thing to prohibit trackers for costs that are substantial, volatile and unpredictable, and generally beyond the control of a utility; it is another to reject trackers for costs that lack one or more of these features. *Good regulatory policy rejects cost trackers that are not essential for protecting a utility from a dire financial situation.* The utility, in justifying a cost tracker, should present the regulator with credible information showing that a nontrivial probability exists that the cost item under review will rise sufficiently above the test-year level to place the utility in financial jeopardy.[39] This showing is more likely when the regulator uses a historical test year and the cost item recently has exhibited an upward trend or substantial volatility.[40]

Another conceivable justification for a cost tracker is that it transmits better price signals to a utility's customers. Prices would correspond closer to a utility's actual costs and thus improve economic efficiency. For economic efficiency, customers should see costs reflected in their rates, such that they consume less when costs are higher. The validity of this argument for

---

[38] Such a non-uniform treatment of costs could also cause perverse incentives. A utility, for example, might overspend on infrastructure structures to receive the gains from lower operating or other costs that the utility retains for itself until the next rate case.

[39] The term "financial jeopardy" has different interpretations. This state, no matter how it is defined, has the potential to harm customers as well as the utility shareholders. It could cause the deferment of needed capital investments to maintain reliable service, lowering of the utility's credit rating, and an increase in the utility's cost of capital. The time period over which these effects would cause injury to utility shareholders generally would be more immediate than the injury to customers.

[40] A future test year might not improve matters much if the cost item is inherently difficult to predict with any forecast and therefore susceptible to large error.

a cost tracker also depends upon the magnitude and nature of the costs involved.[41] This outcome assumes that a tracker involves a variable cost such as fuel or purchased gas costs. When a tracker relates to a fixed cost (e.g., infrastructure costs), the argument turns more to the "fairness" of a cost-recovery mechanism to the utility. Is a tracker justified because test-year cost calculations expose the utility to potentially high financial risk from unanticipated costs that fall primarily outside the control of a utility?

VI. Putting It All Together

Cost trackers have both positive and negative features that regulators must evaluate.[42] In reaching a decision, the regulator needs to weigh these features to determine what is in the public interest based on how they shift risks, ensure cost recovery, and affect incentives. The main challenge for regulators is to evaluate whether the positives outweigh the negatives to justify a cost tracker.[43]

A. The positive side of cost trackers

The primary benefit of cost trackers, as discussed earlier in this paper, is that they reduce the likelihood that a utility will encounter serious financial problems. If test-year costs fail to reflect accurate projections of a utility's actual cost for future periods, then the utility's earnings can deviate substantially from what a commission approved in the last rate case. Some cost items are difficult to project, as they exhibit high volatility and depend on different variables that by themselves are uncertain.

By reducing regulatory lag and the likelihood of prudence reviews, cost trackers can lower a utility's risk and thus increase its access to capital. The utility could then have a higher credit rating that, in turn, could lower the cost of financing capital projects.[44]

---

[41] Distortive price signals can relate to the difference between the utility's short-run marginal cost and the marginal price charge to customers in consuming more electricity or natural gas.

[42] For a thorough and excellent discussion of the advantages and disadvantages of cost trackers, with a focus on fuel adjustment clauses, *see* Michael Schmidt, *Automatic Adjustment Clauses: Theory and Applications* (East Lansing, MI: Michigan State University Press, 1981).

[43] For an analysis of similar issues faced by regulators in evaluating different ratemaking mechanisms in general, *see* Ken Costello, *Decision-Making Strategies for Assessing Ratemaking Methods: The Case of Natural Gas*, NRRI 07-10, September 2007, at http://nrri.org/pubs/gas/07-01.pdf.

[44] This argument is similar to the one used to support including construction work in progress (CWIP) in rate base for electricity transmission.

Cost trackers also coincide with the regulatory objective of setting prices based on the actual cost of service. This condition transmits the right price signal to customers deciding how much of the utility's services to consume.[45]

The development of infrastructure such as the smart grid or other new technology costs might warrant that commissions consider cost-recovery mechanisms such as a cost tracker to guarantee minimum cash flow for a utility. Investors might otherwise perceive excessive regulatory risks that preclude committing funding to a utility.[46] A cost tracker in this instance also might cut down on the frequency of future rate cases. Regulators in the future might want to explore less traditional ways for utilities to recover their costs for new technologies with inherently high operational and financial uncertainties.

As a final benefit, cost trackers can reduce regulatory and utility costs by reducing the number of future rate cases. Rate cases absorb substantial staff resources and time, diverting those scarce resources from other commission activities. Yet it is doubtful that many of the recently proposed trackers involving non-major cost items would have any effect on the timing of future rate cases. Another comment is that the costs associated with serious and continuing audits and the monitoring of costs recovered through a tracker could require substantial resources, either in the form of commission staff or outside consultants.

B. The negative side of cost trackers: the case for traditional ratemaking as a default policy or earnings sharing as a preferred alternative

Cost trackers can reduce utility efficiency, as described above. "Just and reasonable" rates require that customers do not pay for costs the utility could have avoided with efficient or prudent management. Regulation attempts to protect customers from excessive utility costs by scrutinizing a utility's costs in a rate case, conducting a retrospective review of costs, applying performance-based incentives, and instituting regulatory lag. Cost trackers diminish one or more of these regulatory activities. In some instances, they diminish all of them. The consequence is the increased likelihood that customers will pay for excessive utility costs.

---

[45] One issue that has emerged in states where trackers have become a major method for cost recovery relates to the allocation of those costs across customer classes. Cost allocation determines the actual prices that different customers pay for utility service.

[46] One alternative to reducing regulatory risk through trackers would be for a commission to articulate in a policy statement or other document that it would not apply 20-20 hindsight to determine the cost recovery of new investments. A commission can express, for example, that it will not subject specific utility decisions to prudence reviews. One method of doing so is providing pre-approval for projects before they enter service. For a more detailed discussion of pre-approval mechanisms, *see* Scott Hempling and Scott Strauss, *Pre-Approval Commitments: When And Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects?* NRRI 08-12, November 2008, at http://nrri.org/pubs/electricity/nrri_preapproval_commitments_08-12.pdf.

This paper recommends that regulators approve cost trackers only in special situations where the utility would have to show that alternate cost-recovery mechanisms could cause extreme financial problems. This showing requires utilities to provide a distribution of possible cost futures and an assessment of their likelihood. If a certain cost item has high volatility and unpredictability, represents a large component of the utility's revenue requirement and is recurring, and is generally beyond a utility's costs, it becomes a candidate for "tracker" recovery.

Even then, the regulator should consider the adverse incentive effects and how he or she can compensate for this problem.[47] Regulators should condition any approval of a cost tracker on the utility's filing information on its performance for those functional areas directly or indirectly affected by the tracker. For example, has the FAC caused a utility to spend less money on plant maintenance costs, jeopardizing reliability and inflating total utility costs because of higher avoidable fuel costs? These conditions can harm the utility's customers in the long run.

No other rationale merits departing from cost recovery through rate cases. This limited application of cost trackers provides the benefits of:

1. using the same cost-recovery mechanisms for all utility functions to prevent perverse incentives (perverse incentives can lead to a higher cost of service and utility rates);

2. balancing a utility's total costs and total revenues (without this balancing, it is conceivable that the utility could recover one cost item through a tracker and over-recover other costs set in the last rate case to result in the utility earning above its authorized rate of return); a rate case has the attractive feature of matching revenue with costs on an aggregate basis;

3. retaining sufficient regulatory lag to provide the utility with more motivation to control costs (regulatory lag is an important feature of traditional ratemaking in forcing the utility to shoulder the risk of higher costs between rate cases); and

4. scrutinizing a utility's costs and performance in different areas of operation (commissions review costs more rigorously in a rate case setting, decreasing the likelihood that customers will recover a utility's imprudent costs).[48]

---

[47] The commission can monitor the utility's performance or include a performance-based incentive component in the tracker mechanism. *See* the NRRI study cited in footnote 8 for a description and analysis of incentive-based gas procurement mechanisms.

[48] In theory, a commission can expend the same resources and effort toward inspecting a utility's costs recovered through a tracker as it does for costs determined in a rate case. In practice, however, the author shares the widely held view that commissions and non-utility parties devote fewer resources to this task for costs recovered through a tracker. Confirmation of this view would require a systematic study that would compare, among other things, the resources expended by the commission and non-utility stakeholders per dollar recovered under trackers and in a rate case.

The earlier discussion points to the advantages of replacing cost trackers (excluding fuel and purchased gas cost trackers) with a single rate-of-return tracker in the form of an earnings-sharing mechanism. This alternative overcomes some of the problems with cost trackers, namely perverse incentives and weak incentives for cost control, the mismatching of a utility's *total* costs and revenues, and inadequate regulatory oversight of costs.[49] An earnings-sharing mechanism is also able to achieve the major objective of cost trackers, namely preventing utilities from suffering serious financial problems between rate cases.

A single rate-of-return tracker can also address the "fairness" issue of why a utility should not recover from customers a cost increase (e.g., property taxes) between rate cases that is completely beyond its control. This mechanism would, in effect, allow the utility to recover the increased costs, but only if it was already earning a "low" rate of return (i.e., a return below the "band" region discussed above). One major problem with cost trackers is that they allow a utility to increase its prices even if the utility is already earning a higher-than-authorized rate of return (or beyond the "zone of reasonableness" set in the last rate case). A commission would not allow this outcome under traditional regulation.

VII. Questions Regulators Should Ask

This paper discusses the major issues regulators face in evaluating cost trackers. Well-informed decisions require regulators to ask certain questions, for which this paper provides some introductory responses. The following is a list of the most pertinent questions:

1. Does a cost-tracker proposal meet the regulatory test of acceptability? What minimum threshold should a regulator set for consideration of a cost tracker?

2. What special circumstances exist to warrant cost recovery outside of a rate case?

3. What evidence does a utility present showing that the absence of a tracker for a particular cost could place it in financial jeopardy?

4. In addition to cost trackers, what other cost-recovery mechanisms can regulators rely on to allow a utility to recover substantial unexpected costs between rate cases? What are the public-interest effects of these mechanisms relative to cost trackers?

5. What advantages does a cost tracker offer? What are its disadvantages?

---

[49] Regulators can overcome some of these problems. They can, for example, require that a utility with cost trackers file a rate case no less often than every three years or however often frequency regulators consider appropriate. Regulators can also require prudence reviews of utility activities associated with trackers on a regular basis. I thank Michael McFadden for these insights.

6. How should regulators weigh the downsides of cost trackers relative to the upsides? How important are adverse incentive effects relative to the value of stabilizing a utility's rate of return?

7. How should a regulator account for the net-cost effects of a new investment (e.g., capital costs less savings in operating costs) for which the utility wants cost recovery through a tracker?

8. How would the accumulation of cost trackers for a utility motivate the utility to take risks and improve its overall cost performance?

9. If a cost tracker is justified, how can regulators structure it to mitigate potential problems such as weakened incentives for cost control?

10. What conditions should a regulator attach to the approval of a cost tracker?

    a. Should it require the utility to report on its cost performance in functional areas directly and indirectly affected by the tracker?

    b. Should the regulator also require that all costs recovered through trackers be subject to a thorough prudence review?

    c. Should the regulator reduce the utility's return on equity to account for the lower risk resulting from the tracker?

The following image was scanned as received

Duke Energy Ohio
Case No. 14-841-EL-SSO, 14-842-EL-ATA
OCC Seventh Set Interrogatories
Date Received: July 18, 2014

OCC-INT-07-148

REQUEST:

Please identify for each year since 2005, the values for CAIDI, SAID, and SAIFI. Please identify these values on the basis of excluding storms and on the basis of including storms.

RESPONSE:

[illegible]						
	Excluding MEDs (storms)			Including MEDs (storms)		
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2005	[illegible]	1.48	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2007	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2009	[illegible]	1.30	[illegible]	[illegible]	2.07	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	107.60	[illegible]	[illegible]	151.78	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2013	117.80	0.98	115.40	[illegible]	[illegible]	160.65

*note: the indices do not take into account outages caused by transmission, per PUCO rules.

PERSON RESPONSIBLE: Marc W. Arnold

J.D. POWER
McGRAW HILL FINANCIAL

Press Release

J.D. Power Reports
Price and Billing/Payment are Primary Drivers of Increased Overall Customer Satisfaction with Electric Residential Utilities

Improved Communications During Long Outages Increases Satisfaction

WESTLAKE VILLAGE, Calif.: 17 July 2013 — Despite ongoing severe weather across the United States resulting in longer outage periods per event, customer satisfaction with residential electric utilities has increased substantially from 2012 driven primarily by improvements in billing/payment, price and outage communications, according to the J.D. Power 2013 Electric Utility Residential Customer Satisfaction Study℠ released today.

The study, now in its 15th year, measures customer satisfaction with electric utility companies by examining six factors: power quality and reliability; price; billing and payment; corporate citizenship; communications; and customer service.

- Overall customer satisfaction with residential electric utilities increases by 14 points year over year to 639.
- Satisfaction in the billing and payment factor (719) is the highest score among all six factors.
- Price satisfaction (551) and customer service (706) are the highest it has been in four years.

Overall satisfaction among residential customers of electric utilities has increased substantially in 2013 to 639 (on a 1000-point scale), up 14 points from 2012. While performance in all factors improves in 2013, billing and payment satisfaction (719) increases by a notable 19 points, the largest increase among the six factors. Power quality and reliability, an important driver of customer satisfaction and the second-highest-scoring factor, has improved to 692 from 677 in 2012. Communications satisfaction increases for a third consecutive year, climbing to 585 in 2013 from 579 in 2012 and 575 in 2011. Satisfaction scores in price (551) and customer service (706) are the highest they have been in the past four years, with customer service increasing by 9 points from 2012.

With severe weather events across the United States, longer outages were reported in 2012, yet, electric utilities have improved their outage communications before, during and after these events. Satisfaction increases when utilities proactively communicate outage information regularly and clearly via the channels customers prefer, including utility-initiated phone calls, emails, text messages and social media sites.

"In addition to improving outage communication, electric utilities have made great strides in improving customer perceptions regarding billing and payment," said Jeff Conklin, senior director of the energy practice at J.D. Power. "With such a dramatic increase in billing and payment satisfaction in the 2013 study, it's clear that the electric utilities have listened to the Voice of the Customer by providing them with many choices to receive and pay their bill and with improved information on their billing statements."

According to the study, satisfaction increases when customers are offered billing and payment options. Satisfaction among customers who select their own payment due date is 756, compared with 714 among those who do not select a due date. Satisfaction among customers who receive an electronic bill is 745, compared with 709 among those who receive only a paper statement. Among customers who are on a fixed budget bill payment plan, satisfaction is 736, compared with 718 among those who are not on this plan. Billing and payment satisfaction increases by 54 points when billing statements include a consumption graph (740). Satisfaction is highest among customers who use their utility's online website to check their account or pay a bill (742), followed by auto-deductions from a bank account (736); recurring credit card payments (726); and through bank's online bill payment (717). The percentage of customers who mail their payment has decreased to 26 percent in 2013 from 29 percent in 2012, indicating that customers are using alternative payment options.

Price satisfaction improves substantially for a second consecutive year (+12 points), as customers indicate lower average bill amounts, down $3 per month from 2012 to $132. Price satisfaction is 101 points higher among customer who say they are "very familiar" with their utility's energy-saving programs than among those who say they are only "somewhat familiar."

Power quality and reliability (PQ&R) increases by 15 points in 2013, driven by a 19-point increase in the West region. The study finds that utilities have increased their number of communications with customers regarding lengthy outages in 2013. The most satisfying sources of outage information are emails from the utility (762 PQ&R); text messages from the utility (736); utility's social media site (724); calls from the utility (718); and customer emails sent to the utility (703).

Study Rankings

The Electric Utility Residential Customer Satisfaction Study ranks midsize and large utility companies in four geographic regions: East, Midwest, South and West. Companies in the midsize utility segment serve between 125,000 and 499,999 residential customers, while companies in the large utility segment serve 500,000 or more residential customers.

East Region

PPL Electric Utilities ranks highest among large utilities in the East region, followed by Central Maine Power; Duquesne Light; and West Penn Power, respectively.

Among midsize utilities in the East region, Southern Maryland Electric Cooperative ranks highest for a sixth consecutive year, followed by Penn Power; Delmarva Power; and Met-Ed, respectively.

Midwest Region

MidAmerican Energy ranks highest in the large utility segment in the Midwest region for a sixth consecutive year. We Energies; Alliant Energy; and Xcel Energy-Midwest follow, respectively.

Omaha Public Power District ranks highest in the midsize utility segment in the Midwest region for a sixth consecutive year and receives an award in the study for a 13th consecutive year. Following Omaha Public Power District in the segment rankings are Kentucky Utilities; Wisconsin Public Service; and Indianapolis Power & Light, respectively.

South Region

OG&E ranks highest in the large utility segment in the South region, followed by FPL; Georgia Power; and CPS Energy, respectively.

Sawnee EMC ranks highest in the midsize utility segment in the South region, followed by Jackson EMC; Clay Electric Cooperative; and NOVEC, respectively.

West Region
Salt River Project (SRP) ranks highest in the large utility segment in the West region for a sixth consecutive year and receives an award in the study for a 12th consecutive year. Following Salt River Project in the segment rankings are SMUD; Portland General Electric; and APS, respectively.

Clark Public Utilities ranks highest in the midsize utility segment in the West region for a sixth consecutive year, followed by Colorado Springs Utilities; Seattle City Light; and Snohomish County PUD, respectively.

J.D. Power offers the following tips to consumers:

- Customers should register their account online at their utility's website to get access to detailed account history.
- Customers who want to go paperless should sign up for e-bill statements from their utility.
- Many utilities now offer text or email notifications and alerts, such as reminders about usage toward a budgeted amount or outage updates.
- Some utilities now have smartphone apps that allow you to review and pay your bills or to report outages.

The 2013 Electric Utility Residential Customer Satisfaction Study is based on responses from 102,734 online interviews conducted from July 2012 through May 2013 among residential customers of the 126 largest electric utility brands across the United States, which collectively represent nearly 94 million households.

About J.D. Power
J.D. Power is a global marketing information services company providing performance improvement, social media and customer satisfaction insights and solutions. The company's quality and satisfaction measurements are based on responses from millions of consumers annually. Headquartered in Westlake Village, Calif., J.D. Power has offices in North/South America, Europe and Asia Pacific. For more information on car reviews and ratings, car insurance, health insurance, cell phone ratings, and more, please visit JDPower.com. J.D. Power is a business unit of McGraw Hill Financial.

About McGraw Hill Financial
McGraw Hill Financial (NYSE: MHFI), a financial intelligence company, is a leader in credit ratings, benchmarks and analytics for the global capital and commodity markets. Iconic brands include Standard & Poor's Ratings Services, S&P Capital IQ, S&P Dow Jones Indices, Platts, CRISIL, J.D. Power, McGraw-Hill Construction and Aviation Week. The Company has approximately 17,000 employees in 27 countries. Additional information is available at http://www.mhfi.com.

J.D. Power Media Relations Contacts
John Tews; Troy, Mich.; 248-680-6218; media.relations@jdpa.com
Syvetril Perryman; Westlake Village, Calif.; 805-418-8103; media.relations@jdpa.com

# # #

Note: Eight charts follow.