STAFF-DR-01-018

REQUEST:

Refer to Direct Testimony of Gary J. Hebbeler ("Hebbeler Testimony"), page 9. Provide a comparison of the estimated cost to relocate interior meters as part of the ASRP and the costs to operate, maintain, inspect, and survey interior meters that would be avoided after relocation.

RESPONSE:

Please see response to Staff-DR-01-003. The cost to operate, maintain, inspect and survey interior meters that would be avoided after relocation is approximately $25 per meter on going every three years at the current regulations.

PERSON RESPONSIBLE: Gary Hebbeler

STAFF-DR-01-019

REQUEST:

Refer to Hebbeler Testimony, pages 9-10, and the application, paragraphs 13 and 29.

a. Explain whether Duke Kentucky will be required to purchase any rights-of way or easements in conjunction with the proposed ASRP.

b. If the answer to part a. of this request is affirmative, explain how Duke Kentucky plans to recover such costs.

c. Provide the estimated annual cost of curb-to-meter service line maintenance necessitated by Duke Kentucky's taking ownership of service lines.

d. Explain how Duke Kentucky proposes to recover any costs related to the curb-to-meter maintenance referenced in part c. of this request.

RESPONSE:

a. Duke Energy Kentucky does not anticipate purchasing any rights-of-way or easements in conjunction with the proposed ASRP. The replacement of main-to-curb or curb to meter will usually be in a similar location as the existing service.

b. N/A

c. Duke Energy Kentucky currently takes ownership of service lines upon replacement in accordance with prior Commission authorizations in previous rate cases. The estimated incremental annual cost of the curb to meter service line maintenance necessitated by Duke Energy Kentucky's taking ownership of service lines replaced under the ASRP should be minimal. Duke Energy Kentucky already performs leak surveys, even on line segments.

d. There will be no change in the method of recovery, *i.e.* base rates.

PERSON RESPONSIBLE: a-c: Gary Hebbeler
d: Peggy Laub

STAFF-DR-01-020

REQUEST:

Refer to Direct Testimony of William Don Wathen Jr. ("Wathen Testimony"), the table on page 4. The expense amount shown for 2012 of $22.4 million is 5.7 percent more than the amount for the next highest year, $21.2 million in 2014, and 8.7 percent more than the average expense for the five periods other than 2012 shown in the table. The table on page 5 of Wathen Testimony indicates that they lowest return on equity ("ROE") for any of the six time periods included in the two tables was in 2012. Out of the six time periods, explain why the expense amount, excluding the cost of gas, was the highest in 2012.

RESPONSE:

It is important to note that the O&M data provided in Mr. Wathen's testimony is "per books" without any of the adjustments that may be made in a general rate proceeding. For example, there were two expense items recorded in 2012 that contribute to that calendar year being the highest in terms of O&M, Excluding Purchased Gas Cost. The first item disparately impacting O&M expense for 2012 relates to the Progress Energy merger. Although such costs would be removed from O&M at the time of a rate case, the 'actual' expenses are reflected in the Company's published financial data, such as the Form 2. For calendar year 2012, 'costs to achieve' recorded in Duke Energy Kentucky's gas O&M was higher than in any other year. Approximately, $1.6 million in costs to achieve were recorded in 2012, $1 million greater than in any other year since the merger with Progress Energy.

Another factor contributing to the differences in total O&M, Excluding Purchased Gas Costs, for 2012 compared to other years is a reclassification of DSM costs and related amortization expenses. In 2013, 2014, and the twelve months ending June 30, 2015, such costs are recorded in Account 813, as shown in Exhibit WDW-2. Account 813 is excluded from the calculation in Exhibit WDW-2 for Total O&M Excluding Purchased Gas. For 2012, this charge was recorded in Account 874 and, because it was recorded in Account 874, it is included in the Total O&M, Excluding Purchased Gas. If this charge was recorded in Account 813 for 2012, as was done in the subsequent years, the Total O&M, Excluding Purchased Gas Costs, would decline by $872,893 for that year. This is the single biggest item in 2012 that contributes to 2012 seeming to have the highest cost level of any of the years represented in Exhibit WDW-2.

With only these two adjustments, the Total O&M, Excluding Purchased Gas Cost, for 2012 is essentially in line with the totals for most of the years shown.

To reiterate, the O&M expenses shown in Mr. Wathen's testimony and his Exhibit WDW-2 are unadjusted and do not reflect the sort of adjustments that would be made at the time of the rate case.

PERSON RESPONSIBLE: William Don Wathen Jr.

STAFF-DR-01-021

REQUEST:

Refer to Wathen Testimony, the table on page 5. The last two columns in the table are, respectively, for the 12 months ended December 31, 2014 and the 12 months ended June 30, 2015, which means that the last six months of 2014 are included in the time period represented by each of the two columns. To eliminate the impact of this overlap, provide the ROE for just the six months ended June 30, 2015.

RESPONSE:

8.72%.

It should be noted that this figure is not comparable to any of the other figures shown in the table on page 5 of Wathen's Direct Testimony, as it only reflects activity during the first six months of the year, where all other figures are for a full calendar year. Historically, the Company's sales are much more heavily weighted to the first half of the year; so, dividing net income for a period less than one year will be significantly influenced by which season is being reviewed. The only meaningful way to compare ROEs is over a full twelve month period, whether it coincides with the calendar year or not.

PERSON RESPONSIBLE: William Don Wathen Jr.

STAFF-DR-01-022

REQUEST:

Refer to Wathen Testimony, the table on page 7 that includes ROEs for the same time periods as the table on page 5 of the testimony, adjusted to reflect normal weather during the six periods. The impact of normalizing for weather reduces the ROE in the periods in which Heating Degree Days ("HDD") were above normal and increases the ROE in the periods in which HDD were below normal, based on the HDD reflected in the chart on page 8 of the testimony. It appears that the decreases in the ROE are consistently greater than the increases, as demonstrated by observing the years 2012 and 2013. Explain why weather normalizing 2012, for which the chart on page 8 shows a negative variance between actual and normal HDD of 702, increases the 2012 ROE by only 36 basis points (from 5.43 to 5.79 percent), while normalizing 2013, for which the chart shows a positive variance between actual and normal of only 143, decreases the 2013 ROE by 106 basis points (from 11.06 to 10.00 percent).

RESPONSE:

The relationship between sales and HDDs is also not linear; consequently, the relationship between earnings and HDDs is not linear. Typical customer behavior is such that as HDDs decline (*i.e.*, it gets warmer), customer usage gradually reverts back to some base amount. The change in the rate of consumption at warmer temperatures is more gradual than the rate of change in consumption when temperatures get colder. As

HDDs increase (*i.e.*, it gets colder), customers increasingly consume more fuel for heat. So, one would expect greater and greater 'sensitivity' to the weather as it gets increasingly cold. Similarly, because some of the Company's rates are fixed charges, *i.e.*, the customer charge, there is also a 'base' amount of revenue which has the effect of muting the impact on earnings from temperature changes, particularly, during warmer periods.

PERSON RESPONSIBLE: Phillip Stillman

Duke Energy Kentucky
Case No. 2015-00210
Staff First Set Data Requests
Date Received: September 3, 2015

STAFF-DR-01-023

REQUEST:

Refer to Wathen Testimony, the chart on page 8. The calculated differences between actual and normal HDD levels for the six time periods shown in the chart match the variance shown in the chart in 2010 but not in the other five periods. Explain why the differences do not match the variances from 2011 to the present.

RESPONSE:

There is an error in the table on page 8. The "Total" row does not foot for all years other than 2010. The error is corrected below. All other information in the table is correct.

Heating Degree Days for Winter Months (CVG)

	2010	2011	2012	2013	2014	2015[a]
Jan	1,180	1,191	917	951	1,287	1,083
Feb	1,046	809	765	895	1,023	1,165
Mar	603	642	319	858	794	714
Oct	244	320	353	304	295	n/a
Nov	592	476	676	707	774	n/a
Dec	1,182	792	759	919	858	n/a
Total	4,847	***4,230***	***3,789***	***4,634***	***5,031***	***2,962***
Normal	4,491	4,491	4,491	4,491	4,491	4,491
Variance	356	-261	-702	143	540	398

PERSON RESPONSIBLE: William Don Wathen Jr.

Duke Energy Kentucky
Case No. 2015-00210
Staff First Set Data Requests
Date Received: September 3, 2015

STAFF-DR-01-024

REQUEST:

Refer to Wathen Testimony, the chart on page 9. If shows, for the same six time periods contained in the other tables in the testimony, actual throughput broken down between "Retail" and "Transportation".

a. Provide the weather-normalized throughput for the six time periods in a table using the same format as in the chart on page 9 of the testimony.

b. Provide a narrative description of the methodology Duke Kentucky uses to weather-normalize throughout that includes, at minimum, its determination of its base natural gas load, the number of years used to establish normal HDD, and the base temperature used.

c. The "Transportation" throughput shown in the chart reflects continuous increases in every time period from 2010 to the present without the annual variation of the "Retail" category. Clarify the extent, if any, to which the "Transportation" throughput is weather-sensitive.

d. Explain whether Duke Kentucky believes a weather normalization rider would help stabilize its earnings. If not, explain why.

RESPONSE:

a. See the chart below.

<u>Weather Normalized</u> Total Throughput (Dekatherms x 1,000)

	2010	2011	2012	2013	2014	2015[a]
Retail	9,965.6	9,895.1	9,618.5	10,006.4	10,537.9	10,519.0
Transportation	3,119.4	3,248.6	3,402.2	3,551.8	3,617.0	3,739.9
	13,085.0	13,143.7	13,020.7	13,558.2	14,154.9	14,258.9

b. To weather normalize historical sales, the starting point is determining the historical relationship between daily weather and energy usage. This relationship is quantified for each customer class by using econometric models and statistical techniques. In general, the econometric models include the following components:

(1) MCF = a + b*(E) + c*(HDD) where:

MCF = Sales

E = Economic and other variables.

HDD = Heating Degree-days

a, b, c = Equation Coefficients.

In the case of historical sales figures, actual sales resulted from actual weather conditions so equation (1) can be rewritten as:

(2) MCFact = a + b*(E) + c*(HDDact), with the "act" subscript referring to actual sales and actual weather conditions.

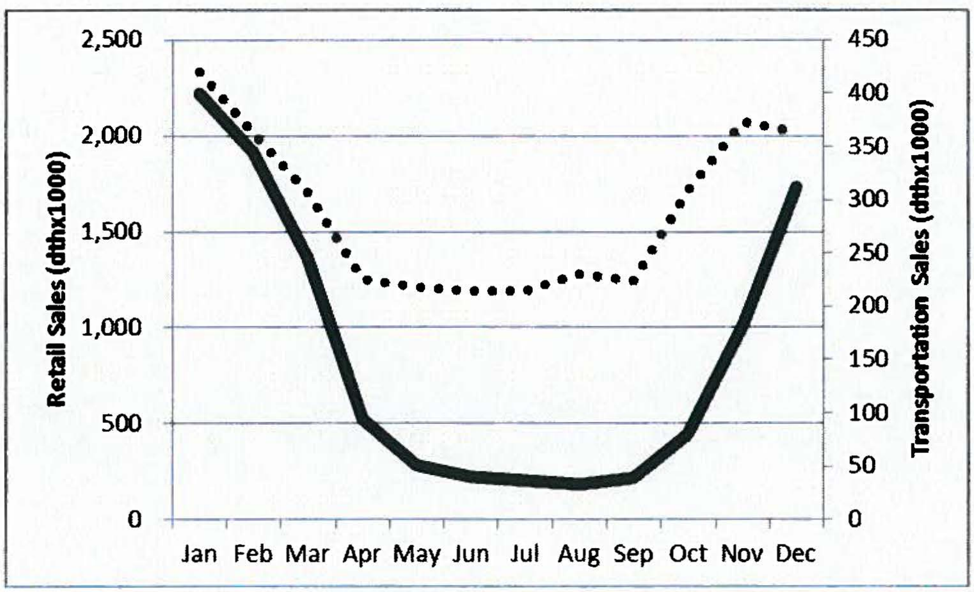
Similarly, under "normal" conditions, equation (1) would be:

(3) MCFnml = a + b*(E) + c*(HDDnml), with the "nml" subscript referring to normal sales and weather conditions.

We currently are using 2008-2012 data to determine coefficients to be applied in weather-normalization. We assume a base temperature of HDD_59 for weather normalization purposes.

c. The chart below shows the average actual sales (in dekatherms) for both retail and for transportation customers. The data points are the averages of each month, as taken from the Form 2, 3Qs, available on the www.FERC.gov website for Duke Energy Kentucky.

The solid line represents retail sales and the dotted line represents transportation sales. Although not as pronounced as for retail sales, the chart clearly shows that volumetric sales to transportation customers are also influenced by the seasons.



d. It is intuitive that weather influences volumetric sales for natural gas. The costs associated with providing natural gas distribution service, excluding the commodity itself, are mostly fixed. So, when revenue fluctuates due to changes in volumetric sales, weather-related or not, the Company's earnings will fluctuate in a similar manner.

Decoupling volumetric sales from revenue will serve to 'stabilize' revenue and, consequently, will stabilize earnings. A weather-normalization rider is one alternative to accomplish this objective. Duke Energy Kentucky's affiliate in Ohio, Duke Energy Ohio, accomplishes this decoupling by largely eliminating the relationship between volumetric sales for residential customers (*i.e.*, the most weather sensitive rate class) with the use of a mostly fixed charge for monthly gas service. In its 2009 rate case, Duke Energy Kentucky made a similar proposal to move towards decoupling by proposing to move to straight fixed-variable rate design where more of its retail rate recovery would be from a higher fixed monthly charge and less from volumetric charges. In settling the case, the Company agreed to essentially maintain the status quo of a modest fixed charge and more recovery via the volumetric rates.

PERSON RESPONSIBLE: a-c: Phillip Stillman
d: William Don Wathen Jr.

STAFF-DR-01-025

REQUEST:

Refer to Direct Testimony of Roger A. Morin, Ph.D. ("Morin Testimony"), pages 32-33. Provide the most recent 30-year treasury yield as a basis of comparison to the 4.5 percent risk-free rate estimate.

RESPONSE:

The current yield on 30-year Treasury bonds as reported in Value Line is 3.1% as of September 11th. Dr. Morin's 4.5% risk-free estimate is a forecast yield and is not directly comparable to the current yield. As Dr. Morin states in his testimony, financial models are forward-looking models based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, financial models must be applied using data that reflects the expectations of actual investors in the market. While investors examine history as a guide to the future, it is the expectations of future events that influence security values and the cost of capital.

PERSON RESPONSIBLE: Roger A. Morin, Ph. D

STAFF-DR-01-026

REQUEST:

Refer to Morin Testimony, page 37, lines 6011, and Exhibits RAM-8 and RAM-9. Confirm that the Exhibits show that since 2007, when the long-term Treasury Bond yield was 4.5 percent, the long-term Treasury Bond yield has been 4.5 percent or above only once, in 2009.

RESPONSE:

It is confirmed. However, Dr. Morin points out that during the entire period of 86 years covered in Exhibit RAM-8, the long-term Treasury bond yield has exceeded 4.5% more than half the years, that is, 46 years out of 86. The average yield during the entire period is 5.2%. As far as Exhibit RAM-9 is concerned, the long-term Treasury bond yield has exceeded 4.5% more than two-thirds of the years covered, that is, 22 years out of 30. The average yield during the entire period covered in that exhibit is 5.6%.

PERSON RESPONSIBLE: Roger A. Morin, Ph. D

STAFF-DR-01-027

REQUEST:

Refer to Morin Testimony, page 38, and Exhibit RAM-6. The average beta shown on page 1 of Exhibit RAM-6 for the natural gas utilities group is 0.79. The average beta shown on page 2 of Exhibit RAM-6 for the combination electric and gas utilities group is 0.74.

a. Confirm that the average of the natural gas utilities group is .785 before rounding, and that the average of the two groups before rounding is 0.763 and not .77.
b. Confirm that the beta shown for Duke Energy on page 2 of Exhibit RAM-6 is .60, that only one utility in either of the two groups has a beta as low as .60, and that no utility in the two groups has a beta lower than .60.
c. Explain why it is reasonable to use the unadjusted average .77 beta in the Capital Asset Pricing Model analysis when the parent company of Duke Kentucky has the lowest beta of all the utility companies in both proxy groups.

RESPONSE:

a. The average beta of the gas group is 0.79 after rounding. The average beta of the electric group is 0.74. The average of the two groups after rounding is 0.77.
b. It is confirmed.
c. Although Dr. Morin did not perform a study of Duke Energy Kentucky's parent company and its attendant risks, its low beta is consistent with that company's

diversified business activities, including diversification of regulatory risks across several jurisdictions.

From a statistical point of view, it would be imprudent and unreasonable to rely on a beta estimate based on a sample of one single company when implementing the CAPM model. From a statistical standpoint, confidence in the reliability of the beta estimate is considerably enhanced when basing the beta estimate on a large group of companies. Any distortions introduced by measurement errors in the beta estimate are mitigated. Utilizing a large portfolio of companies reduces the influence of either overestimating or underestimating the beta of one individual company. For example, in a large group of companies, positive and negative deviations from the expected beta will tend to cancel out owing to the law of large numbers, provided that the errors are independent.

PERSON RESPONSIBLE: Roger A. Morin Ph. D

Duke Energy Kentucky
Case No. 2015-00210
Staff First Set Data Requests
Date Received: September 3, 2015

STAFF-DR-01-028

REQUEST:

Refer to Morin Testimony, page 44.

a. Line 8 indicates that the expected market return on aggregate equities is 11.7 percent. Confirm that subtracting the forecast risk-free rate of 4.5 percent from the expected market return results in an implied risk premium of 7.2 percent and not 7.3 percent, as indicated on line 10.

b. Confirm than that the average of the historical Market Risk Premium ("MRP") of 7.0 percent and the corrected prospective MRP of 7.2 percent is 7.1 percent.

c. Provide any revisions necessary to Table 6 of page 60 of the Morin Testimony based on any input corrections noted above.

RESPONSE:

a. It is confirmed.

b. It is confirmed.

c. No material change in the results occurs as a result of this correction. Table 6 revised is as follows:

Table 6 Summary of Results

STUDY	ROE
Traditional CAPM	10.2%
Empirical CAPM	10.6%
Historical Risk Premium S&P Utility Index	10.2%
Allowed Risk Premium	10.6%
DCF Natural Gas Utilities Value Line Growth	10.7%

DCF Natural Gas Utilities Analyst Growth	9.1%
DCF Combination Elec & Gas Util Value Line Growth	10.1%
DCF Combination Elec & Gas Util Analyst Growth	9.8%

PERSON RESPONSIBLE: Roger A. Morin, Ph. D

STAFF-DR-01-029

REQUEST:

Refer to Morin Testimony, page 60, and Exhibit RAM-9, page 1, footnote 2. State whether the removal of the 9.1 percent "outlying result" from the calculation that produced the average 10.4 percent ROE is supported by the individual January through June 2015 rate case decisions that are reported in the cited Regulatory Research Associates publication.

RESPONSE:

Dr. Morin does not quite understand the question as to whether 9.1% is supported by rate case decisions thus far in 2015. There were 22 gas and electric decisions reported in the Regulatory Research Associates publication in 2015. The allowed ROEs ranged from 9.0 to 12.0% with a midpoint of 10.5%. The 9.1% outlying result is one standard deviation away from the mean. Based on these considerations and relative to all the results produced by the various methodologies, Dr. Morin removed the 9.1% outlying estimate.

PERSON RESPONSIBLE: Roger A. Morin, Ph. D

STAFF-DR-01-030

REQUEST:

Refer to Morin Testimony, page 61, and Exhibit RAM-10. Explain whether all the proxy gas utilities and combination electric and gas utilities used in the ROE analysis have a cost-recovery mechanism (referred to as a risk mitigator). If not, explain whether Duke Kentucky believes the list should be revised to include only those that do have such mechanisms.

RESPONSE:

The quick answer is yes, all the companies in Dr. Morin's sample have risk-mitigators.

The following gas companies are contained in Dr. Morin's original gas sample:

AGL Resources
Atmos Energy
Chesapeake
Laclede Group
NiSource
Northwest Nat. Gas
Piedmont Natural Gas
South Jersey Inds.
Southwest Gas
WGL Holdings

As seen below, the companies operate in the following state jurisdictions:

STATE	Decoupling	Risk Mitigators
Arizona	X	X
California	X	X
Colorado	X	X
Delaware	X	X
District of Columbia	X	X
Florida	X	X
Georgia	X	X
Indiana	X	X
Kentucky	X	X
Louisiana		X
Maryland	X	X
Massachusetts	X	X
Mississippi	X	X
Missouri	X	X
Nevada	X	X
New Jersey	X	X
New York	X	X
North Carolina	X	X
Ohio	X	X
Oregon	X	X
Pennsylvania		X
South Carolina	X	X
Tennessee	X	X
Texas		X
Virginia	X	X
Washington	X	X

The check marks indicate the presence of a decoupling mechanism in the first column and the presence of a risk-mitigator in the second column. Eighteen of the twenty-two states have some form of decoupling in place, and all twenty-two states where these gas companies operate have risk-mitigating mechanisms (decoupling, forward test years, fuel balancing account, other balancing accounts, capex cost trackers, CWIP in rate base).

This table is based on the attached study by Edison Electric Institute, Staff DR-01-30-Attachment 1.

Decoupling policies are quite prevalent in Dr. Morin's electric sample as well, as shown in STAFF-DR-01-030 - Attachment 2, taken from a recent Puget Sound Energy rate case[1] in which Dr. Morin participated as a rate of return witness. All results in the tables are shown with an "X" indicating that at least one subsidiary of a holding company in the sample has a decoupling policy. This table shows that a majority of the holding companies in the sample have subsidiaries that have some form of decoupling policy in place. STAFF-DR-01-030 - Attachment 3 shows that the degree of participation in risk-mitigating mechanisms, especially capital expenditure riders, is quite prevalent in the sample, while STAFF-DR-01-030 - Attachment 4 shows that the use of fuel and power adjustment clauses is 100% for at least one subsidiary in each holding company.

PERSON RESPONSIBLE: Roger A. Morin, Ph. D

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[1] See Washington Utilities and Transportation Commission Docket No. UE-121697/UG-121705, Docket No. UE-130137/130138

True-up Decoupling and Fixed Variable Rates in the Sample

No.	Holding Company Name	Decoupling with Revenue True Ups, Electric or Gas	Fixed Variable Rates, Electric or Gas
1	Alliant Energy		
2	Ameren Corp.		X
3	Avista Corp.	X	
4	Black Hills		
5	CenterPoint Energy	X	X
6	CMS Energy Corp.		
7	Consol. Edison	X	
8	Dominion Resources		X
9	DTE Energy		
10	Duke Energy	X	X
11	Exelon Corp.	X	X
12	Integrys Energy	X	X
13	MGE Energy		
14	Northeast Utilities	X	X
15	NorthWestern Corp.		
16	NV Energy Inc.		
17	OGE Energy		X
18	Pepco Holdings	X	
19	PG&E Corp.	X	
20	Public Serv. Enterprise		
21	SCANA Corp.	X	
22	Sempra Energy	X	
23	TECO Energy		X
24	UIL Holdings	X	
25	UNS Energy		
26	Vectren Corp.	X	X
27	Wisconsin Energy		
28	Xcel Energy Inc.		X
	Total Holding Companies*	13	11
	Percent Holding Companies*	46%	39%
		HC has at least one Mechanism	
	Total Holding Companies	18	
	Percent Holding Companies	64%	

Notes:

*Total and percent of HCs where at least one state-regulated subsidiary has the policy

Source:Edison Electric Institute, *Alternative Regulation for Evolving Utility Challenges: An Updated Survey*, Prepared by: Pacific Economics Group Research LLC, Jan. 2013, M. Vilbert, J. Wharton. C. Gibbons, M. Rosenberg, Yang Wei Neo, *The Impact of Revenue Decoupling on the Cost of Capital for Electric Utilities: An Empirical Investigation*, April 20, 2014, and supporting workpapers; SNL Corporate Profile Database October 21, 2014; and Brattle additions.

No.	Holding Company Name	Multi-year Revenue Cap Possibly with RAM	Capital Expenditures Riders	Formula Rates	Performance Based Ratemaking	CWIP
1	Alliant Energy				X	X
2	Ameren Corp.		X	X	X	
3	Avista Corp.					
4	Black Hills		X			X
5	CenterPoint Energy		X	X	X	
6	CMS Energy Corp.					X
7	Consol. Edison		X			
8	Dominion Resources	X	X			X
9	DTE Energy				X	
10	Duke Energy	X	X		X	X
11	Exelon Corp.		X	X		
12	Integrys Energy		X			X
13	MGE Energy					
14	Northeast Utilities	X	X			
15	NorthWestern Corp.		X			
16	NV Energy Inc.	X	X		X	
17	OGE Energy		X	X		
18	Pepco Holdings					
19	PG&E Corp.		X			
20	Public Serv. Enterprise		X			
21	SCANA Corp.		X	X		X
22	Sempra Energy		X	X		
23	TECO Energy		X			
24	UIL Holdings					
25	UNS Energy				X	
26	Vectren Corp.		X		X	
27	Wisconsin Energy					
28	Xcel Energy Inc.	X	X		X	X
	Total Holding Companies*	5	19	6	9	8
	Percent Holding Companies*	18%	68%	21%	32%	29%

	Holding Company has at least one Mechanism
Total Holding Companies	23
Percent Holding Companies	82%

Notes:
* Total and percent of HCs where at least one state-regulated subsidiary has the policy

Source: Edison Electric Institute, *Alternative Regulation for Evolving Utility Challenges: An Updated Survey*, Prepared by: Pacific Economics Group Research LLC, Jan. 2013, and supporting workpapers;SNL Corporate Profile Database October 21, 2014, and Brattle additions.

Regulatory Mechanisms Across U.S.

State	Forward Test Years	Decoupling		Fuel/Purchase Power Balancing Account	Other Balancing Accounts	Capex Cost Tracker	CWIP in Rate Base	DSM Performance Incentives
		Full	Partial					
[1]*	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Alabama	Yes			Yes	Yes			
Alaska				Yes				
Arizona			E		Yes			Yes
Arkansas	Hybrid		E	Yes	Yes	G&E		Yes
California**	Yes	G&E		Yes	Yes	G&E		Yes
Colorado**	Pending	G	E	Yes	Yes	E	Yes	Yes
Connecticut**	Yes	E	G		Yes			Yes
Delaware	Hybrid				Yes			
D.C.	Hybrid	E			Yes			
Florida**	Yes		G	Yes	Yes	E	Yes	Pending
Georgia	Yes		G	Yes	Yes	G&E	Yes	Yes
Hawaii	Yes	E		Yes	Yes	E		Yes
Idaho		E		Yes	Yes			Pending
Illinois**	Yes	G	G		Yes	G		
Indiana**		G	E	Yes	Yes	G&E	Yes	Yes
Iowa**				Yes	Yes	E		
Kansas			E	Yes	Yes	G&E	Pending	Pending
Kentucky**	Yes		G&E	Yes	Yes	G&E		Yes
Louisiana				Yes	Yes	E	Yes	
Maine	Yes				Yes	E		
Maryland		G&E			Yes		Yes	
Massachusetts**		G&E	G&E		Yes	G&E		Yes
Michigan**	Yes	G&E			Yes		Pending	Yes
Minnesota**	Yes	G, E-Pending		Yes	Yes	E	Yes	Yes
Mississippi	Yes		E	Yes	Yes	E	Yes	
Missouri			G, E-Pending	Yes	Yes	G		Pending
Montana			G					Pending
Nebraska				Yes	Yes		Yes	
Nevada		G	E		Yes			
New Hampshire		G, E-Pending			Yes			Yes
New Jersey**	Hybrid	G			Yes	G&E		
New Mexico	Pending	E-Pending		Yes	Yes		Pending	Yes
New York	Yes	G&E			Yes	G&E		Yes
North Carolina**		G	E	Yes	Yes		Yes	Yes
North Dakota	Yes		G	Yes	Yes		Pending	
Ohio**	Hybrid	E-Pending	E		Yes	G&E		Yes
Oklahoma			G&E	Yes	Yes	E	Pending	Yes
Oregon	Yes	G&E	G		Yes	G&E		
Pennsylvania**	Hybrid				Yes	E		
Rhode Island	Yes	G&E			Yes			Yes
South Carolina**			E	Yes	Yes		Yes	Yes
South Dakota			E	Yes	Yes		Pending	
Tennessee	Yes	G		Yes	Yes			
Texas						E	Yes	Yes
Utah	Yes	G, E-Pending	E-Pending	Yes	Yes	G		Pending
Vermont		G&E			Yes	E		Yes
Virginia**		G	E-Pending		Yes	E	Yes	
Washington		G		Yes	Yes			
West Virginia				Yes	Yes		Yes	
Wisconsin**	Yes	G&E		Yes	Yes		Yes	Yes
Wyoming	E Only	G	E	Yes	Yes			

* See next page for sources, notes, and definitions

** States where PG&E's and TURN's PG&E comparator utilities operate

Sources:

[2] – [4], [7] -[8]: From "Innovative Regulation: A Survey of Remedies of Regulatory Lag", Edison Electric Institute, April 2011, Table 1 and Table 9.
http://www.eei.org/whatwedo/PublicPolicyAdvocacy/StateRegulation/Documents/innovative_regulation_survey.pdf

[5], [9]: From "IEE State Electric Efficiency Regulatory Frameworks Report," July 2012.
http://www1.eere.energy.gov/buildings/betterbuildings/neighborhoods/pdfs/iee_state_reg_frame.pdf

[6]: Adjustment Clauses and Rate Riders ~ A State-By-State Overview ~, Regulatory Research Associates, March 21, 2012.

Notes:

[5], [8], [9]: Data is for electric utilities only.

[6]: Information on other balancing accounts is listed in the following state-by-state table.

Definitions:

[2]: A forward test year is a twelve month period that begins after the rate case is filed.

[3] - [4]: Full decoupling or partial decoupling (lost revenue adjustment mechanisms and/or fixed customer charge) assists the utility in recovering authorized revenue requirements associated with fixed operating costs, despite increases or decreases in sales.

[5]: Fuel/Purchase Power Balancing Accounts include 1) fuel riders that allows fuel costs to adjust intra-year if recoveries or deferrals differ from budget by more than specified amount and 2) Energy Cost Recovery (ECR) mechanisms established on the basis of estimates of electric sales, fuel-related costs, and purchased power costs, and reflects accumulated over- or under-recovered amounts

[7]: Trackers for the annual cost of plant additions are sometimes called capital expenditure ("capex") trackers.

[8]: Many commissions address the delay in receiving a return on investment by including costs of construction work in progress ("CWIP") in the rate base, so that a return on investment can start sooner.

[9]: Performance Incentives are mechanisms that reward utilities for reaching certain energy efficiency program goals, and, in some cases, impose a penalty for performance below the agreed-upon goals.

Other Balancing Accounts by States

Alabama

The Certificated New Plant (Rate CNP) adjustment clause for Alabama Power provides for: the recovery of costs related to the commercial operation of certified generating facilities; the recovery of the costs (excluding fuel) associated with certified purchased power agreements; and, recovery of costs associated with environmental mandates. The tariffs of the major energy utilities include adjustment provisions to allow for recovery of changes in income taxes, and certain general and local taxes.

Alaska

Power cost adjustment mechanisms only.

Arizona

Adjustment mechanisms used by APS are: a system benefits charge for recovery of prudent costs incurred by the utility to comply with the ACC's electric competition rules or costs associated with certain public purpose programs (conservation, wind power development, etc.) authorized by the ACC; a transmission cost adjustor to flow through changes in Federal Energy Regulatory Commission-approved transmission rates; a renewable energy surcharge (RES); a demand-side management adjustment charge; and, an environmental improvement surcharge.

Arkansas

The electric and gas utilities have in place rate riders that provide for the recovery of the costs associated with PSC-approved energy efficiency (EE) programs. Entergy Arkansas utilizes a production cost allocation (PCA) rider, which provides for timely recovery of the costs associated with "rough equalization" of electric generation production costs among the Entergy operating companies, as required by the Federal Energy Regulatory Commission. EA also utilizes a storm recovery charge rider to collect from ratepayers the amounts required to service its related securitization bonds. Oklahoma Gas & Electric (OG&E) uses a storm damage rider to recover incremental storm restoration costs incurred in 2008. OG&E also uses a transmission cost recovery rider and a "Smart Grid" rider.

Other Balancing Accounts by States

California

The CPUC conducts a Biennial or Triennial Cost Allocation Proceeding to allocate non-fuel gas costs between core and non-core customer classes. The BCAP/TCAP provide for the amortization of balances in specified balancing and tracking accounts. The costs tracked through the balancing account mechanisms are subject to annual reasonableness reviews, and a true-up is implemented in the years between the proceedings. In 2010, the CPUC adopted an electric distribution reliability improvement program for PG&E, the costs of which are to be recovered through a dedicated account outside of general rate cases. Rates are to be based on adopted cost forecasts with a balancing account to accumulate any difference in revenue requirement based on recorded costs compared to the adopted forecast.

Colorado

Legislation enacted in 2010, allows a utility that is earning below its authorized equity return and operating under an emissions reduction plan designed to achieve a conversion or closure of coal-based generating capacity by Jan. 1, 2015, to, under certain circumstances, be accorded a special ratemaking mechanism designed to recover the costs of the approved plan. Effective Jan. 1, 2011, the Colorado PUC authorized PSCO to recover, subject to certain adjustments, operations and maintenance and capital costs associated with the company's investment in the gas-fired 652-MW Rocky Mountain Energy Center and the 310-MW Blue Spruce Energy Center via the purchased capacity cost adjustment clause until PSCO's next electric rate case. PSCO is permitted to recover, through a transmission cost adjustment (TCA) clause implemented in 2008, prudent costs incurred in planning, developing, and completing construction or expansion of transmission facilities.

Connecticut

Tracking mechanisms are in place for CL&P and UI that provide for semi-annual adjustments to reflect Federal Energy Regulatory Commission-approved transmission costs. As part of a 2009 rate decision for UI, the Connecticut Public Utilities Regulatory Authority adopted pension and cost-of-debt tracking mechanisms, both of which were discontinued in 2011.

Delaware

DP&L is permitted to submit annual filings to update prices to reflect changes in Federal Energy Regulatory Commission-approved transmission charges.

Other Balancing Accounts by States

Florida

Electric utilities may recover all prudently incurred site selection and preconstruction costs, including carrying charges, for nuclear and integrated gasification combined-cycle (IGCC) power plants through the capacity cost recovery clause (CCRC). Certain fees and taxes, such as franchise fees and gross receipts taxes, are recovered through a line item on customer bills, with the charge adjusted based on customer usage.

Georgia

Atlanta Gas Light (ATGL) has been authorized to recover clean-up costs related to former manufactured gas plant sites through an environmental response cost recovery rider (ERCRR). Costs that are recoverable under the ERCRR include investigation, testing, remediation, and/or litigation costs or other liabilities. In 2009, the PSC approved for ATGL the STRIDE program that authorizes the company to invest about $400 million in infrastructure improvements over the next ten years. Every three years, ATGL is required to file its proposed program for the next three years for PSC review and approval.

Hawaii

HECO, HELCO, and MECO utilize tracking mechanisms for pension and other-than-pension employee benefit (OPEB) costs. As part of an alternative regulation framework (ARF) approved in February 2011, Hawaiian Electric Company (HECO) implemented a cost-of-service recovery mechanism, which recognizes rate base additions and increases in operation and maintenance expenses, and certain depreciation and amortization expenses between rate cases and includes a decoupling mechanism. On Feb. 8, 2012, the PUC issued a preliminary order in HELCO's 2010-test year rate case indicating that the company will be permitted to operate under an ARF similar to HECO's. The PUC has approved recovery of certain demand-side management program costs (to the extent that they are not recovered through base rates) through an annual integrated resource planning (IRP) cost-recovery surcharge, subject to review. In 2009, the PUC authorized HECO, HELCO, and MECO to implement a surcharge mechanism to facilitate the recovery of renewable energy infrastructure investments.

Idaho

The PUC has allowed Idaho Power to increase rates outside a base rate case to recover the cash contribution to its defined benefit pension plan. In February 2011, the Commission adopted Idaho Power's regulatory account and cost recovery plan associated with the early-shut down of the Boardman coal-fired plant that, as a result of changing environmental regulations, is to cease operations 20 years earlier than expected. The PUC approved the establishment of a balancing account, whereby the incremental revenue requirement associated with the early-shut down of the plant is to be tracked for recovery.

Other Balancing Accounts by States

Illinois

Illinois Commerce Commission (ICC) approved a settlement that permits Ameren Illinois to utilize a hazardous materials adjustment clause rider, largely to address asbestos-related litigation and remediation costs. As permitted by state statutes, Ameren Illinois, ComEd, Northern Illinois Gas, Peoples Gas Light & Coke and North Shore Gas utilize riders to facilitate recovery of variations in bad-debt costs. Ameren Illinois utilizes a transmission service rider.

Indiana

The Indiana URC has approved requests to recover from ratepayers the net costs associated with the prospective sale/purchase of emissions allowances. Gas utilities track incremental changes in unaccounted-for gas costs and the gas-cost component of bad debts through gas cost adjustment filings. Legislation permits the electric utilities to recover, through a rate adjustment mechanism, 80% of the costs associated with certain federally-mandated emissions-control projects. The remaining 20% of such costs are to be deferred for future recovery. In 2007, the URC authorized the company to earn a cash return on construction work in progress associated with the Edwardsport plant and to recover the facility's operating costs once complete, through an adjustment mechanism

Iowa

In a 2010 rate decision for IP&L, the Iowa Utilities Board permitted the company to implement a transmission cost recovery mechanism for a three-year term. Revenues and costs associated with IP&L's sales or purchases of emission allowances may be reflected in the energy adjustment clause. MidAmerican Energy uses a rider to recover certain feasibility study costs related to its analysis of the merits of building a new nuclear plant.

Kansas

State statutes permit the local gas distribution companies to request KCC approval of a gas system reliability surcharge (GSRS) mechanism to recover the costs associated with gas distribution system replacement projects between base rate proceedings, subject to annual true-up. Westar and KG&E utilize Transmission Delivery Charge riders that provide for the unbundling and recovery of Federal Energy Regulatory Commission-regulated transmission charges.

Kentucky

Electric utilities utilize mechanisms to recover environmental compliance costs (including a cash return on environmental CWIP) between rate proceedings, and several gas utilities use mechanisms that provide for recovery, between rate cases, of costs associated with their main replacement programs. PSC has allowed certain companies to increase their fixed monthly customer charges to recover a greater proportion of their fixed costs through this charge.

Other Balancing Accounts by States

Louisiana

In 2009, the Louisiana Public Service Commission authorized the state's electric utilities to use an environmental adjustment clause (EAC) to recover from ratepayers the costs associated with the acquisition of emissions credits to comply with federal, state, and local environmental standards. In addition, the utilities are to credit ratepayers through the EAC any revenues associated with the sale or transfer of emission allowances.

Maine

Northern Utilities recovers manufactured gas site remediation expenses through an environmental remediation rate adjustment that is set on a semi-annual basis.

Maryland

Baltimore Gas & Electric has electric and gas riders in place, with surcharge rate changes implemented on an annual basis, to reflect recovery of electric and gas energy efficiency and demand-side program costs that are not included in base rates.

Massachusetts

Pension and post-retirement benefits other than pensions (PBOP) are in place for ME, NE, WMECO, NSTAR Electric, NSTAR Gas, Fitchburg Gas and Electric Light, New England Gas, Boston Gas/Essex Gas, Colonial Gas, and Columbia Gas of Massachusetts. The utilities file annually for recovery of pension and PBOP costs not currently reflected in rates. Such costs are to be recovered through the LDAC reconciliation mechanism for gas utilities and a separate rate component for electric utilities. The electric utilities are permitted to utilize transmission cost recovery mechanisms. A solar cost adjustment charge was approved by the DPU in conjunction with the Department's 2009 approval of Western ME's proposal to install 6 MWs of solar energy generation. In 2010, the DPU approved a solar cost adjustment charge for ME and Nantucket Electric (NE) for the utilities' installation of 5 MWs of solar generation

Michigan

CE, Detroit Edison, and UPP recover transmission costs through the power supply cost-recovery mechanism. Uncollectible expense true-up mechanisms are in place for MCG and Michigan Gas Utilities.

Minnesota

The major electric utilities use rate riders that provide for annual recovery of transmission, conservation, renewable energy, and emission reduction costs.

Other Balancing Accounts by States

Mississippi

An energy efficiency (EE) rider is in place for Entergy Mississippi (EM) through which the company recovers costs associated with its EE program. EM and Mississippi Power (MP) may recover emissions allowance expenses through their adjustment clauses. Since 1992, MP has utilized an Environmental Compliance Overview plan that establishes procedures to facilitate the PSC's review of the company's environmental compliance strategy and provides for base-rate recovery of costs (including the cost of capital) associated with PSC-approved environmental projects, on an annual basis, outside of a base rate case. Since 2005, EM has been recovering the costs of its 480-MW, gas-fired Attala power plant through a temporary rate rider. The rider is to remain in place until the company files for a general rate case.

Missouri

PSC rules allow that a portion of the utility's environmental costs may be recovered through an Environmental Cost Recovery Mechanism and a portion may be recovered through base rates. Atmos Energy, Laclede Gas, Missouri Gas Energy, and Union Electric utilize an infrastructure system replacement surcharge to recover costs associated with certain gas distribution system replacement projects.

Montana

Supply cost recovery mechanism only.

Nebraska

2009 legislation allows gas utilities to apply for Nebraska Public Service Commission (PSC) approval to implement an infrastructure system replacement cost recovery (ISRCR) rider to provide for timely recovery of certain capital investments outside of a general rate case.

Nevada

In 2009, the PUC adopted a natural gas-related bad-debt tracking mechanism for Southwest Gas designed to allow the company to recover from, or refund to, ratepayers the difference between actual bad debt expenses and the level reflected in base rates.

Other Balancing Accounts by States

New Hampshire

A transmission cost adjustment mechanism (TCAM) is in place for PSNH. The TCAM, which is designed to provide recovery of all transmission-related costs, is adjusted annually each July 1. Reliability enhancement and vegetation management programs are in effect for Granite State, PSNH, and Unitil Energy Systems. The programs provide for recovery of both the capital investment and increases to operation and maintenance expense necessary for ongoing system reliability and vegetation management efforts. Major storm reserve accounts are in effect for the state's electric utilities.

New Jersey

PUH is permitted to recover costs associated with manufactured gas site cleanup through a remediation adjustment mechanism. Such expenses are deferred and recovered over a seven-year period, including carrying costs on the balance. During 2009, 2010 and 2011, the New Jersey Board of Public Utilities approved economic stimulus programs proposed by the electric and gas utilities at the BPU's request. The programs called for the acceleration of various infrastructure development projects. The companies are permitted to recover the costs associated with these accelerated capital investment plans through surcharge mechanisms.

New Mexico

In 2009, the New Mexico Public Regulation Commission adopted a rate case settlement for Public Service Co. of New Mexico that contained an SO2 rider through which customers are credited with their share of revenues from allowance sales.

New York

Rate case plans have generally incorporated rate bases that increase over the term of the plan and deferral accounting for increases in such items as net plant, pension expense, and labor costs. Earnings in excess of an established return on equity (ROE) cap to be shared by stockholders and ratepayers.

North Carolina

The NCUC may pre-determine the prudence of a utility's decision to build a baseload generating plant and the facility's projected costs and in the following general rate case, the utility would be permitted to recover previously approved costs following completion of the project. The costs of certain materials used in reducing or treating emissions may be recovered through the fuel adjustment clause. Incremental operation and maintenance costs and annual research and development (R&D) expenses up to $1 million are also recoverable through the renewable energy portfolio standard rider.

Other Balancing Accounts by States

North Dakota

Electric utilities are permitted to file with the Commission for pre-determination of the prudence of planned construction projects. In June 2010, the PSC approved a settlement permitting MDU to recover, through its fuel and purchased power adjustment clause, roughly $9.6 million of costs associated with the cancelled Big Stone II coal plant over three-years beginning Aug. 1, 2010.

Ohio

For CEI, OE, and TED, renewable energy resource requirements for the period June 1, 2011 through May 31, 2014, are to be met through the purchase of renewable energy credits (RECs) and costs are to be recovered through a reconcilable rider. The current electric security plans for CEI, OE, and TED include the implementation of a delivery capital recovery rider that reflects a return of and on distribution, sub-transmission, and general plant-in-service not included in the companies' 2009 rate decisions. In a 2008 rate decision for Columbia Gas of Ohio, the PUC adopted a stipulation that included riders for infrastructure replacement costs and demand-side management program expenses. In a 2009 base rate decision for Vectren Energy Delivery of Ohio (Vectren), the PUC adopted a settlement that included the establishment of distribution rate rider through which the company recovers the costs associated with an accelerated main and service line replacement program.

Oklahoma

In 2009, the OCC adopted a settlement that permits OG&E to recover the costs associated with the 101-MW "OU Spirit" wind facility and Crossroads Wind Farm through a cost recovery rider. The costs associated with the project are to be reflected in the company's base rates in its next rate case decision. OG&E is permitted to recover costs (both capital- and expense-related) associated with the company's "system hardening" and "vegetation management" programs, through a rider. In 2008, the OCC authorized OG&E to implement a storm cost recovery rider. The rider is adjusted annually to reflect any differences between the level of storm costs reflected in base rates and the level of such costs actually incurred in that year.

Oregon

The renewable adjustment clause allows for recovery of renewable resources and associated transmission that are expected to be placed into service in the current year without filing a general rate. In 2009, the PUC authorized NWNG to implement a new System Integrity Program (SIP) designed to recover costs related to base steel, pipeline integrity, and other pipeline safety programs. Costs are to be tracked annually, with recovery to be sought through the purchased gas adjustment after the first $3.3 million of capital costs are incurred by the company.

Other Balancing Accounts by States

Pennsylvania

On Feb. 14, 2012, legislation was enacted to allow the Pennsylvania Public Utility Commission to approve automatic adjustment clauses to recognize between general rate cases utility investments in certain infrastructure projects. PPL Electric Utilities, Duquesne Light, Metropolitan Edison, and Pennsylvania Electric have mechanisms in place to allow changes in Federal Energy Regulatory Commission-approved PJM Interconnection transmission charges to be automatically reflected in rates, subject to annual true-up. PPL-E also has a surcharge in place to recover universal service program costs.

Rhode Island

An alternative regulation plan is in effect for the gas operations of Narragansett Electric that provides for graduated earnings sharing above the benchmark returns. NE is to flow through to ratepayers all non-firm gas margins earned in excess of $2.8 million. The company recovers any shortfall of non-firm margins below $2.8 million through a distribution adjustment clause

South Carolina

Gas utilities are subject to potential annual rate adjustments if their earned equity return is outside a band of +50 basis points around the last authorized return.

South Dakota

While operating under a rate plan, utilities are required to submit annual cost-of-service filings, and the Commission may adjust a utility's rates at any time up to one year following the conclusion of a rate plan. Plans are in place that provide for sharing of certain margins. State law permits electric utilities to seek a cash return on construction work in progress and cost recovery associated with environmental compliance and transmission investments through separate riders. The PUC is statutorily authorized to approve automatic adjustment mechanisms to facilitate the recovery of the capital and operating costs associated with investment in transmission facilities.

Tennessee

PNG recovers margin losses associated with customers who are served under negotiated contracts and are able to bypass the utility's distribution system via its purchased gas adjustment rider. In May 2010, the TRA authorized CG to implement a full revenue decoupling mechanism for its residential and small commercial customers on a three-year pilot basis. Under the gas procurement incentive mechanism, Atmos is permitted to retain 50% of savings associated with gas costs that are less than 97.7% of a predetermined benchmark (lower band), and is required to absorb 50% of gas costs that are more than 102% of the benchmark (upper band).

Other Balancing Accounts by States

Texas

There are no alternative regulation mechanisms currently in place for the electric utilities in Texas.

Utah

A 2009 law permits utilities to seek recovery of costs associated with major plant additions via limited-issue rate proceedings. A pilot infrastructure replacement adjustment (IRA) mechanism was established by the PSC for Questar Gas in an April 2010 rate decision permitting the company to track and recover between rate cases, the costs associated with the replacement of high-pressure natural gas feeder lines. The mechanism is to be adjusted at least annually

Vermont

Under state law, the PSB is permitted to adopt alternative regulation plans (ARPs) for energy utilities. Green Mountain Power's ARP contains an earnings sharing mechanism (ESM) that provides for a 150-basis-point deadband around the authorized ROE. Incremental earnings above the upper end of the range are to be returned to customers, with GMP to recover 50% of any earnings shortfalls between 75 and 125 basis points below the authorized ROE, and all earnings shortfalls in excess of 125 basis points below the authorized ROE.

Virginia

Earnings within a 100-basis-point deadband around the established ROE will be considered reasonable and no rate adjustment will be required. If the SCC determines that the company's earnings for the test periods were more than 50 basis points below the fair ROE, the Commission would be required to approve a rate increase designed to accord the company an opportunity to earn the fair ROE. If the SCC were to determine that the company's earnings for the relevant test periods were more than 50 basis points above the authorized ROE, then 60% of the incremental earnings would be refunded to ratepayers over a subsequent six-to-12-month period. SCC rules also provide for "expedited" rate proceedings, which are essentially make-whole proceedings, and are allowed to be filed by gas utilities and smaller electric utilities (e.g., PPL Corp. subsidiary Kentucky Utilities) once per year. The expedited procedure allows the utility to implement an interim rate change, subject to refund, after 30 days, and subject to applicable provisions of the law.

Washington

In November 2010, the WUTC issued a policy statement on decoupling. The WUTC indicated that it would consider adoption of a full decoupling mechanism ("designed to minimize the risk to both the utilities and to ratepayers of volatility in average use per customer by class regardless of cause, including the effects of weather"), for electric and gas utilities.

Other Balancing Accounts by States

West Virginia

State statutes allow the energy utilities to use adjustment mechanisms that reflect, on a timely basis, changes in electric fuel costs, purchased power expenses, gas costs, investments related to environmental compliance costs, new transmission facilities, and new generation facilities that burn West Virginia coal.

Wisconsin

As permitted by statute, the PSC may authorize equity returns that are applicable only to specific generation projects. Before constructing a generating facility, a utility must obtain a determination of need from the PSC, which includes an estimate of the facility's costs. Cost overruns are considered on a case-by-case basis. A utility that proposes to purchase or construct an electric generating facility may apply to the PSC for an order specifying, in advance, the rate treatment, including the authorized return on equity, that will apply to the plant over its economic life

Wyoming

On Sept. 22, 2011, the PSC approved a settlement authorizing PacifiCorp to implement an adjustment mechanism designed to recover from or refund to ratepayers 100% of the difference between actual renewable energy and SO2 credit revenue levels and the levels reflected in base rates.

Source: ADJUSTMENT CLAUSES AND RATE RIDERS ~ A State-By-State Overview ~, Regulatory Research Associates (RRA), March 21, 2012.

Individual state descriptions from RRA state reports

Fuel and Purchased Power Adjustment Clauses in the Sample

No.	Holding Company Name	Fuel and Power Adjustment Clauses
1	Alliant Energy	X
2	Ameren Corp.	X
3	Avista Corp.	X
4	Black Hills	X
5	CenterPoint Energy	X
6	CMS Energy Corp.	X
7	Consol. Edison	X
8	Dominion Resources	X
9	DTE Energy	X
10	Duke Energy	X
11	Exelon Corp.	X
12	Integrys Energy	X
13	MGE Energy	X
14	Northeast Utilities	X
15	NorthWestern Corp.	X
16	NV Energy Inc.	X
17	OGE Energy	X
18	Pepco Holdings	X
19	PG&E Corp.	X
20	Public Serv. Enterprise	X
21	SCANA Corp.	X
22	Sempra Energy	X
23	TECO Energy	X
24	UIL Holdings	X
25	UNS Energy	X
26	Vectren Corp.	X
27	Wisconsin Energy	X
28	Xcel Energy Inc.	X
	Total Holding Companies	28
	Percent Holding Companies	100%

Source: SNL Corporate Profile Database 2014; SNL *Multiple Commissions* 2014; Chistensen Associates, *Discussion of the Return on Equity and Performance Indicators of Entergy Mississippi Inc. and Mississippi Power Company*, Report to Staff of Mississippi Public Utility Commission, March 8, 2013; and Brattle additions.

Duke Energy Kentucky
Case No. 2015-00210
Staff First Set Data Requests
Date Received: September 3, 2015

STAFF-DR-01-031

REQUEST:

Refer to the Supplemental Direct Testimony of Gary J. Hebbeler ("Hebbeler Supplemental Testimony"), page 2, the sentence beginning on line 15 which reads, "The Company is requesting authority to replace these natural gas meters through a Certificate of Public Convenience and Necessity (CPCN) and requesting costs recovery as part of a pipeline replacement program." In the Hebbeler Testimony, page 9, and elsewhere in the Hebbeler Supplemental Testimony, all references to the plans for natural gas meters as part of the ASRP reflect that it is Duke Kentucky's intent to relocate, not replace, meters. Clarify that the statement cited in this request does not accurately reflect Duke Kentucky's proposal to the Commission and that it is planning to "relocate" rather than "replace" natural gas meters.

RESPONSE:

Both the Direct Testimony and Supplemental Testimony of Gary J. Hebbeler refer to both relocating and replacing the meter. The following statement is provided to help better clarify when a replacement is needed rather than relocation. If the meter is close to the meter age change compliance date, the meter will be replaced when moved to an exterior location. If the meter is not coming due to the age change compliance date, the meter will be relocated to an exterior location.

PERSON RESPONSIBLE: Gary Hebbeler

STAFF-DR-01-032

REQUEST:

Refer to the Hebbeler Supplemental Testimony, pages 5-6, wherein Mr. Hebbeler discusses KRS 278.509 and explains why the cost of relocating meters should be included in the proposed ASRP. KRS 278.509 states, in part, that the Commission "may allow recovery of costs for investment in natural gas pipeline replacement programs which are not recovered in the existing rates of a regulated utility." Identify what part of KRS 278.509 permits the recovery of the costs of "relocating" pipelines, meters, mains, etc. by a utility.

RESPONSE:

Duke Energy Kentucky is, in fact, replacing these interior service lines. The Company is taking the identified services that are considered a risk out of service and replacing these services with new equipment. The fact that the Company is replacing these particular services to an exterior location rather than in the exact same position is not limited by KRS 278.509. There is no proximal limitation contained in either the statute or in the plain meaning of word "replacement." Please refer to STAFF-DR-01-031 for the explanation of the meter relocation and replacement.

PERSON RESPONSIBLE: Legal/Gary Hebbeler