PUC 3-1

Request:

Please provide the Company's policies or practices to address theft of utility service.

Response:

The theft of utility service is a criminal offense. Therefore, when theft of service is discovered, the Company's service representatives take all steps possible to secure evidence that would assist in leading to a successful prosecution. Employees are provided with information as to the laws associated with theft of service, criminal tampering, and larceny associated with a self-turn on, by-pass, or tampering with a utility service in each relevant jurisdiction. The procedures to be followed by the investigating service representative include the following:

1. The investigating service representative should first determine that the service is in a safe condition before attempting to secure evidence.

2. If the premises are occupied at the time of discovery and the service is found unsafe, the investigating service representative should follow normal procedures to make the service safe and notify the appropriate supervisor and the Company's Revenue Assurance department.

3. Documentation is extremely important in determining what crime occurred and how it was committed for any possible criminal prosecution. All requested information is necessary in order to further the Company's prosecution efforts. The Company's smartphone application will prompt the employee on the necessary steps/actions/information that are required, such as the following:

   a. Take photos and/or video of conditions *as found* and *as left* on site;

   b. Record all meter numbers, meter readings, and automated meter readings if possible;

   c. Secure and tag all evidence and send to Revenue Assurance;

   d. Include location;

   e. Date and time;

   f. Account holder information;

g. All findings of the *as found* and *as left* information; and

h. Thorough description of site and all findings.

4. Record all pertinent information for a police deposition. All employees that were on scene may be asked to provide a deposition for potential criminal prosecution.

Instructions on Rhode Island law:

Review and follow all applicable Rhode Island General Laws that pertain to electric and gas theft of service (see below).

Rhode Island Penal Law Offenses Related to Utility Service
2014 Rhode Island General Laws
Title 11 - Criminal Offenses
Chapter 11-35 - Public Utilities

- R.I. Gen. Laws § 11-35-6 - Interference with gas or electric or water meters.
- R.I. Gen. Laws § 11-35-7 - Bypassing meters – Use of electricity, gas or water with intent to defraud.
- R.I. Gen. Laws § 11-35-8 - Interference with electric meter.
- R.I. Gen. Laws § 11-35-9 - Bypassing electric meter – Use of electricity with intent to defraud.

Prepared by or under the supervision of: Jody Allison

PUC 3-2

Request:

How does the Company identify possible theft of utility service?

Response:

The Company uses the following techniques and resources to identify and mitigate potential theft of utility service issues:

1. Referrals from Company Customer Metering Services and/or Operational field personnel.

2. Tips from the general public (including other utilities and law enforcement).

3. Internal National Grid referrals (including, but not limited to: Customer Service, Credit and Collections, Meter Test Lab, Regulatory, and Security).

4. Internal analytics reporting and processes (including, but not limited to: Advanced Consumption, No Read, No Bill, High/Low, and Meter mismatch processes).

5. Data Analytics (including, but not limited to: Meter Event Flags (MEF), long term zero use analysis, third party advanced analytical process performed by Silver Spring, and various gas/electric meter usage processes).

Prepared by or under the supervision of: Jody Allison

PUC 3-3

Request:

How many accounts has the Company commenced legal action against a customer for theft of service for each of the past five years?

a. For the accounts listed above, how many were electric and how many were gas?

b. For each of the accounts listed above, please identify the rate class, the amount of service estimated or known to be stolen, the dollar value, and enforcement action.

c. In the aggregate, what percentage of the time was the Company successful in collecting on those accounts?

Response:

Theft of Service (TOS) - Case Load and Dollars

Year	# of Electric TOS cases	# of Electric TOS cases - dollars	Legal action pursued - # cases Electric	# of Electric TOS cases - dollars	# of Gas TOS cases	# of Gas TOS cases - dollars	Legal action pursued - # cases Gas	# of Gas TOS cases - dollars
2013	40	$ 119,370	-	$ -	22	$ 61,358	-	$ -
2014	61	$ 108,358	-	$ -	23	$ 76,387	-	$ -
2015	187	$ 456,468	-	$ -	37	$ 105,963	-	$ -
2016	225	$ 633,361	-	$ -	74	$ 449,650	-	$ -
2017	130	$ 337,023	3	$ 8,912	78	$ 373,082	7	$ 231,253

As indicated by the data provided in the chart above, the Company traditionally has not pursued legal action regarding theft of service cases. Theft of service is a criminal offense, which means the Company has to involve law enforcement to pursue legal action through criminal prosecution. The majority of theft of service cases identified by the Company involve relatively small amounts involving residential customers and smaller commercial customers. Therefore, attempts to pursue criminal charges against potentially responsible parties are not necessarily a productive use of the Company's resources, nor of public resources.

Prepared by or under the supervision of: Jody Allison

In 2017, the Company made the decision to begin pursuing legal action in certain cases that involve relatively greater amounts of lost revenue; theft over a relatively longer period of time, or are otherwise higher profile cases. The Company's objective in initiating legal actions on these specific types of cases is to create a deterrent to discourage theft by others.

Of the 10 cases initiated 2017, none have been completed nor finalized.

Prepared by or under the supervision of: Jody Allison

PUC 3-4

Request:

For each of the past five years, what is the Company's estimate of the revenue loss associated with theft of utility service? Please provide a response separately for electric and for gas.

Response:

Please see the table below for the estimated loss of revenue associated with theft of utility service for Narragansett Electric and Narragansett Gas:

Estimated Loss of Revenue				*Dollars in Thousands*
Year	Electric Revenue	Estimated Electric revenue loss	Gas Revenue	Estimated Gas revenue loss
2012	$ 802,516	$ 16,050	$ 392,014	$ 7,840
2013	$ 916,714	$ 18,334	$ 408,299	$ 8,166
2014	$ 1,002,323	$ 20,046	$ 437,421	$ 8,748
2015	$ 1,025,718	$ 20,514	$ 414,506	$ 8,290
2016	$ 908,228	$ 18,165	$ 360,886	$ 7,218

It is difficult for the Company to estimate the loss of revenue associated with theft of utility service given that it is purposely perpetrated on the Company in a manner to obviate discovery and therefore occurs outside the Company's knowledge. To estimate the losses, the Company must therefore rely primarily on industry surveys that have evaluated the impact across various gas and electric distribution systems. These sources establish a range of 0.5 percent to 3.0 percent as the impact of non-technical losses. For the table above, the Company's estimates are based on the mid-point of that range, or 2.0 percent of revenue as a reasonable assumption.

The range of values arises from estimates published by the following sources:

- U.S. Energy Information Administration – 0.5 to 3.0 percent (electricity)
- Edison Electric Institute (EEI) – 3.0 percent (electricity)
- Electric Power Research Institute – 1.0 to 2.0 percent
- American Gas Association (AGA) – 3.0 percent (gas)
- Chartwell, Inc. – 1 percent (utility revenues)

Prepared by or under the supervision of: Jody Allison

- Hydro One (electric distribution company) – 1.2 percent

Prepared by or under the supervision of: Jody Allison

PUC 3-5

Request:

Referencing Mr. Hevert's testimony on page 12, he states that risk factors include the Company's size compared to the proxy group, its projected capital expenditure plans, and its revenue stabilization mechanisms.

a. Does the Company's size increase or decrease its risk compared to the proxy group?
b. Does the Company's projected capital expenditure plans increase or decrease the risk compared to the proxy group?
c. Does the Company's revenue stabilization mechanisms increase or decrease its risk compared to the proxy group?

Response:

a. All else equal, the Company's small size relative to the proxy group increases its risk profile. For further explanation, please see pages 61-65 of Mr. Hevert's pre-filed direct testimony.

b. Higher levels of capital expenditures draw on cash flows and, therefore, have the potential to negatively affect the credit metrics used by credit rating agencies to assess a company's financial risk. Therefore, all else equal, higher levels of capital expenditures increase a company's risk profile. For further explanation, please see pages 65-68 of Mr. Hevert's direct testimony.

   This dynamic is an important consideration because much of the Company's planned capital investment is non-revenue producing (such as system maintenance and replacement). Therefore, the Company's ability to maintain its financial profile and access the capital markets at reasonable cost rates is dependent upon the Company's ability to maintain adequate cash flows to satisfy applicable credit metrics.

c. Revenue stabilization mechanisms are common among the proxy-group companies. These mechanisms, therefore, do not increase or decrease its risk compared to the proxy group. For further discussion, please see pages 68-74 of Mr. Hevert's direct testimony.

Prepared by or under the supervision of: Robert B. Hevert

PUC 3-6

Request:

Referencing Mr. Hevert's testimony on page 28, lines 5-7, does the ownership of generation change the risk profile of companies? If so, how has Mr. Hevert accounted for this difference? If not, why not?

Response:

The business risk of a regulated electric utility, whether distribution-only or vertically integrated, is dependent on a number of factors. Holding all else equal, an electric utility that owns generation may have more business risk than a distribution-only electric utility. The nature of any such risk differential, however, varies on a case-by-case basis. Among other factors, the risk of an individual company will be largely dependent on its operating environment and the supportiveness of the jurisdiction's regulation.

As explained on page 28 of Mr. Hevert's pre-filed direct testimony (Book 2 of 17), there are no "pure play", state-jurisdictional electric transmission and distribution companies that may be used as a proxy for the Company's electric distribution operations. Therefore, including vertically integrated electric companies in the proxy group is reasonable and necessary. However, in recommending a return on common equity on the lower end of the range generated using the proxy group-based analytical results, Mr. Hevert has considered the fact that the Company is a distribution-only utility.

Prepared by or under the supervision of: Robert Hevert

PUC 3-7

Request:

Referencing Schedule RBH-10 on pages 309-314, please indicate for each company where a capital investment adjustment clause was identified, please explain how that adjustment clause operates.

Response:

Mr. Hevert estimates that approximately two-thirds of state jurisdictions have approved a full or partial capital recovery mechanism for one or more utilities. In some jurisdictions, capital-investment recovery is accomplished through a revenue-decoupling mechanism and/or is supplemented by some form of annual inflation adjustment, causing a significant level of detail associated with the mechanisms' application in different jurisdictions. Typically, there is no readily available resource that provides a clear statement of the specifics on the way in which capital investment mechanisms work in each state jurisdiction. As is the case in Rhode Island, the practice used in a jurisdiction tends to be a function of the specific infrastructure development and replacement issues that the local utility is experiencing in relation to its respective operations, and the manner in which the presiding commission chooses to address the issue. That is, because no two companies are identical, the regulatory mechanisms adopted to address company-specific issues also are not likely to be identical. As a result, identifying in detail the numerous variations of capital investment mechanisms that exist across the U.S. would be a significant undertaking.

That said, in relation to Schedule RBH-10, on pages 309-314, the following details associated with capital-investment recovery mechanisms in 35 state jurisdictions are as follows:

- **Arizona**: In Arizona, utilities may recover the costs associated with a program accomplishing the replacement of distribution-related, pre-1970 vintage steel pipelines.

- **Arkansas**: In Arkansas, utilities may use a rider to recover costs associated with certain government-mandated investments. Utilities may also be subject to a formula rate plan framework to address annual changes in their cost of service.

- **Colorado**: In Colorado, utilities are allowed a pipeline system integrity adjustment mechanism for gas operations, through which the company recovers the costs associated with reliability improvements and compliance with certain federal safety regulations.

- **Connecticut**: In Connecticut, a system expansion reconciliation mechanism is in place that permits the gas utilities to reconcile gas-expansion-related revenue annually, between rate cases. In addition, the commission has allowed a Distribution Integrity Management

Program, or DIMP, mechanism that allows for recovery, between rate cases, of the costs associated with main replacement activity. Ratepayers do not see a separate charge on their bills. Instead, the DIMP charge is included in base distribution rates. For electric companies, a non-bypassable, reconciling rate recovers capital costs associated with system resiliency between rate cases.

- **District of Columbia**: In Washington D.C., the law provides for the District to issue bonds, to finance, or securitize, a portion of the costs associated with a plan to relocate certain above-ground distribution facilities below ground. In addition, the commission has allowed a rider mechanism to achieve rate recognition of the un-securitized portion of the undergrounding project. The commission has also approved a $1 billion, 40-year accelerated pipeline replacement program and approved a separate limited-issue recovery mechanism related to the first five years of the program.

- **Florida:** In Florida, the commission has approved a rider that is adjusted annually for recovery of the costs associated with accelerating the replacement of cast iron and bare steel distribution pipes on local distribution systems.

- **Georgia**: In Georgia, the public utilities commission approved a Strategic Infrastructure Development and Enhancement, or STRIDE, program in 2009, specifying infrastructure investments for the next ten years. Every three years, the gas company is required to file its proposed program for the next three years for commission review and approval. The incremental costs associated with the program's investment are included in base rates each October 1.

- **Illinois**: In Illinois, several utilities have riders in place to recover certain costs associated with maintaining infrastructure in accordance with requirements imposed by local governments. In accordance with state law, the public utilities commission is permitted to approve adjustment clauses for the local gas distribution companies to recover the costs associated with their infrastructure replacement programs, and has done so.

- **Indiana:** In Indiana, state law allows the public utilities commission to authorize the utilities to implement a transmission, distribution, and storage system improvement charge, or TDISC, rider to facilitate recovery of the costs associated with certain electric and gas infrastructure expansion projects, including those intended to improve safety or reliability, modernize the utility's system, or improve an area's economic development prospects. The commission has approved such a rider for several utilities.

- **Kansas**: In Kansas, the public utilities commission has approved a rider to recover the costs associated with certain projects to underground transmission and distribution infrastructure. State law permits the local gas distribution companies to utilize a gas system reliability surcharge, or GSRS, mechanism to recover the costs associated with gas distribution system replacement projects between base rate proceedings, subject to annual true-up. The utilities are prohibited from utilizing GSRS mechanisms for periods exceeding five years. GSRS balances are to be reset to zero, with amounts recovered through the GSRS to be rolled into base rates in the utility's next rate proceeding. In addition, a utility may not request changes in the GSRS rate more often than every 12 months.

- **Kentucky**: In Kentucky, the public utilities commission has allowed riders to facilitate recovery of certain costs associated with gas distribution infrastructure replacement programs.

- **Louisiana**: In Louisiana, the public utilities commission has allowed provisions to reflect in rates certain infrastructure costs. As part of their rate stabilization clauses, utilities have a mechanism in place that provides for the deferred recovery of costs associated with system integrity management programs. The commission has also approved an infrastructure investment recovery rider for gas operations.

- **Maine**: In Maine, the public utilities commission has approved a targeted infrastructure replacement adjustment, or TIRA, that provides for recovery of investments in targeted operational and safety-related infrastructure replacement and upgrade projects.

- **Maryland**: In Maryland, the public utilities commission has approved a grid resiliency charge to recover the costs associated with its accelerated-feeder-replacement program. The commission has also approved reliability improvement plans and an associated rider. State law permits the Maryland commission to authorize the gas utilities to implement riders to recover costs associated with approved accelerated infrastructure replacement programs, establishing the Strategic Infrastructure Development and Enhancement, or STRIDE Program.

- **Massachusetts**: In Massachusetts, utilities may recover the revenue requirement associated with their targeted infrastructure recovery factors, or TIRFs, and gas system enhancement programs, or GSEP, investment through a reconciling charge. Under state law, each of the state's gas companies files a plan called a "Gas System Safety Enhancement Program," or GSEP, with the commission to address aging or leaking natural gas infrastructure. The related costs/investments may be recovered through the GSEP factor. In addition, the revenue-decoupling mechanism for electric companies may include a tracking mechanism to reflect incremental capital investment, subject to certain limitations.

- **Michigan**: In Michigan, the public utilities commission has approved an Infrastructure Recovery Mechanism that allows a return of, and on, the costs associated with capital investment in the company's meter move-out, accelerated main replacement and pipeline integrity programs.

- **Minnesota**: In Minnesota, the public utilities commission has approved a rider to recover the costs associated with certain gas infrastructure upgrades, especially those that are safety-related, outside of a general rate case.

- **Missouri**: In Missouri, the public utilities commission has approved a rider to recover costs associated with certain government-mandated investments. In addition, the commission has approved an infrastructure system replacement rider to recover costs associated with certain gas distribution system replacement projects.

- **Nebraska**: In Nebraska, gas utilities may seek approval to use an infrastructure system replacement cost recovery, or ISRCR, rider to achieve timely recovery of certain capital investments outside of a general rate case.

- **Nevada**: In Nevada, the public utilities commission allows for the establishment of a gas infrastructure replacement mechanism that will permit the utilities to recover, between rate cases, the revenue requirement associated with their gas infrastructure replacement projects.

- **New Hampshire**: In New Hampshire, the public utilities commission has approved a cast iron/bare steel rate adjustment mechanism. Reliability enhancement and vegetation management programs and accompanying riders are in effect for several utilities. 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.

- **New Jersey**: In New Jersey, following Hurricane Sandy, the public utilities commission directed utilities to develop mitigation and hardening infrastructure modernization plans, and indicated that it would be open to innovative cost-recovery mechanisms for such plans. The commission subsequently approved modernization plans and related recovery mechanisms for several utilities.

- **New Mexico:** In New Mexico, the public utilities commission has approved riders designed to recover costs associated with undergrounding distribution projects in Rio Rancho and Albuquerque.

- **New York:** In New York, gas utilities may implement riders to recover carrying costs on incremental capital expenditures and operations and maintenance expenses associated with the replacement of leak prone pipe above targeted miles established in rates.

- **North Carolina:** In North Carolina, the public utilities commission has approved an integrity management rider, or IMR, that allows utilities to track and recover capital expenditures incurred to comply with federal pipeline safety and integrity requirements outside of a general rate case.

- **Ohio:** In Ohio, the public utilities commission has approved riders to allow recovery of a return of, and return on, incremental distribution-related investments not already included in utility base rates. The riders allow for recovery of various types of investments, including infrastructure replacement costs, accelerated main and service line replacement, and the installation of automated meter reading equipment.

- **Oklahoma:** In Oklahoma, the public utilities commission has allowed recovery, through a rider, of costs associated with incremental vegetation management, under-grounding costs, and system-hardening/grid resiliency costs. Recovery through a rider is also used in relation to automated metering infrastructure.

- **Pennsylvania:** In Pennsylvania, state law allows the public utilities commission to approve automatic adjustment clauses to recognize, between general rate cases, utility investments in Long-Term Infrastructure Improvement Programs that were approved by the commission in advance.

- **Rhode Island:** In Rhode Island, state law permits the public utilities commission to approve annual infrastructure spending plans for electric and gas distribution companies having greater than 100,000 customers, and, for electric, to allow recovery of expenses associated with an inspection and maintenance program and vegetation management program. Approved costs may be recovered through a rider.

- **South Dakota:** In South Dakota, the public utilities commission has approved an infrastructure rider to recover costs associated with certain distribution capital additions once the related facilities have achieved commercial operation and to reflect certain changes in property taxes.

- **Texas**: In Texas, the public utilities commission may approve periodic distribution cost recovery factors, or DCRFs, for both vertically integrated and transmission and distribution-only electric utilities. The commission may prohibit a utility from implementing a rate change under the mechanism if the commission determines that the utility is earning in excess of its authorized return prior to the adjustment. Amounts approved for recovery under the DCRF are to be rolled into base rates in the utility's subsequent rate case. In addition, state law permits the utilities to recover costs associated with deployment of advanced metering technology through a separate charge.

Prepared by or under the supervision of: Robert B. Hevert

- **Utah**: In Utah, the public utility commission has approved a pilot infrastructure replacement adjustment mechanism that permits recovery, between rate cases, of the incremental costs associated with the replacement of high-pressure natural gas feeder lines, subject to a cap.

- **Virginia**: In Virginia, the public utilities commission may approve annually adjusted riders for the recovery of cost/investments, including a cash return on construction work in progress, associated with utility projects to replace existing overhead distribution facilities of 69 kilovolts or less located within the Commonwealth with underground facilities, subject to certain caps. The rider's revenue requirement reflects the rate of return approved in the company's most recent base rate case or biennial review proceeding. In addition, the public utilities commission may also allow a natural gas utility that invests in natural gas facility replacement projects to recover, in the form of a rider, a return on investment, a revenue conversion factor, depreciation, property taxes, and carrying costs on over/under recovery of the related costs. Eligible infrastructure replacement is defined as natural gas facility replacement projects that: enhance safety or reliability by reducing system integrity risks associated with customer outages, corrosion, equipment failures, material failures, or natural forces; do not increase revenues by directly connecting the infrastructure replacement to new customers; reduce or have the potential to reduce greenhouse gas emissions; are commenced on or after January 1, 2010; and are not included in the natural gas utility's rate base in its most recent rate case.

- **Washington**: In Washington, pipeline replacement plans are in place for several gas utilities through 2017. Recovery is allowed through riders for the costs associated with the plans in most cases.

- **West Virginia**: In West Virginia, legislation enacted in 2015 allows the public utilities commission to approve expedited cost recovery mechanisms associated with commission-approved multi-year gas infrastructure improvement plans. In 2015, the commission approved a settlement authorizing a vegetation management rider that is to be updated twice per year, and is to remain in place for five years.

In preparing Schedule RBH-10, Mr. Hevert relied on operating company tariffs, SEC Form 10-Ks, and industry reports included in the following attachments:

Attachment PUC 3-7-1: Edison Electric Institute, *Alternative Regulation for Emerging Utility Challenges: 2015 Update,* November 11, 2015.

Attachment PUC 3-7-2: Regulatory Research Associates, *Alternative Regulation/Incentive Plans: A State-by-State Overview*, November 19, 2013.

Attachment PUC 3-7-3: American Gas Association, State Infrastructure Replacement Activity, September 15, 2016.

Attachment PUC 3-7-4: American Gas Association, *Innovative Rates, Non-Volumetric Rates, and Tracking Mechanisms: Current List*, December 2016.

Edison Electric Institute

Alternative Regulation for Emerging Utility Challenges: 2015 Update

Prepared by:
Pacific Economics Group Research LLC

Mark Newton Lowry, PhD

Matthew Makos

Gretchen Waschbusch, MBA

Prepared for:
Edison Electric Institute

November 11, 2015

Attribution Notice and Disclaimer

This work was prepared by *Pacific Economics Group ("PEG") Research LLC* for the Edison Electric Institute. When used as a reference, attribution to EEI is requested. EEI, any member of EEI, and any person acting on its behalf (a) does not make any warranty, express or implied, with respect to the accuracy, completeness or usefulness of the information, advice or recommendations contained in this work, and (b) does not assume and expressly disclaims any liability with respect to the use of, or for damages resulting from the use of any information, advice or recommendations contained in this work.

The views and opinions expressed in this work do not necessarily reflect those of EEI or any member of EEI. This material and its production, reproduction and distribution by EEI does not imply endorsement of the material.

Published by:
Edison Electric Institute
701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
Phone: 202-508-5000
Web site: www.eei.org

Contents

I. Introduction

Investor-owned electric utilities in the United States are buffeted today by varied and rapid changes in the business conditions they face. For vertically integrated electric utilities ("VIEUs") and utility distribution companies ("UDCs") alike, the traditional cost of service approach to rate regulation is often not ideal for helping utilities cope with these changes. Alternative approaches to regulation ("Altreg") can often help utilities secure better outcomes for their customers and shareholders.

The changing business climate stems primarily from three root causes. One is pressure, from policymakers and many customers, for the power industry to lighten its environmental footprint. In addition to evolving renewable portfolio standards at the state level, utilities must comply with an array of federal initiatives such as the Environmental Protection Agency's Clean Power Plan. Demand-side management ("DSM") programs and tightening building codes and appliance standards encourage energy efficiency. Some customers seek power from greener sources than the increasingly clean portfolios of utilities. Self generation from rooftop solar is one means to this end, and its cost is falling. Customer-sited distributed generation ("DG") must be accommodated, and utilities must purchase power surpluses that these facilities generate at regulated rates.

A second force for change is technological progress in metering and distribution. Advanced metering infrastructure and other smart grid technologies can improve reliability and facilitate integration of intermittent renewables. Time-sensitive pricing can encourage customers to use the grid in less costly ways. New value-added optional products and services can be offered which benefit customers.

A third force for change is increased concern about the reliability and resiliency of grid service. Some facilities are approaching advanced age, and some need more protection from severe weather. Many customers seek better quality service.

These forces are having important practical effects on utilities. Growth in the demand for their traditional services has slowed, and utilities face competition from distributed energy resources ("DERs"). Nevertheless, some utilities need capital expenditures ("capex") for cleaner generating capacity, smart grid facilities, increased resiliency, and replacement of aging assets. Many new facilities don't automatically trigger revenue growth. Increased marketing flexibility is needed to meet competitive challenges and complex, changing customer needs.

Under traditional regulation, the base rates that compensate utilities for costs of non-energy inputs are reset only in general rate cases with historical test years. These lengthy proceedings require a detailed review of all costs and their allocation amongst the utility's retail services. Revenue from secondary sources (e.g., off-system sales) is imputed against the revenue requirement.

Most base rate revenue is drawn from volumetric and other usage charges. Since the cost of base rate inputs is driven more by capacity than system use in the short run, a utility's finances are sensitive between rate cases to the gap between growth in system use and capacity. A convenient proxy for this gap is the growth in use per customer (aka "average use"). The need for rate cases increases when average use declines.

Traditional regulation is ill-suited for addressing many of today's challenges. Growth in average use was once positive, and the resulting incremental revenues helped utilities finance rising cost without rate cases. Today, growth in the average use of residential and commercial customers is typically static and often negative. Utilities needing normal or high capital expenditures are then compelled to file rate cases more frequently. These involve high regulatory cost and are nonetheless frequently uncompensatory when they involve historical test years. Frequent rate cases also reduce utility opportunities to increase earnings from improved cost containment and marketing. Traditional regulation also does not allow for many value-added or optional rates and services. Improved utility performance is thus discouraged at a time when it is increasingly needed to respond to competitive pressures.

Increased financial attrition has been a factor in the long-term decline of average credit ratings among investor-owned electric utilities. This is illustrated in Figure 1. Higher risk raises financing costs and can discourage needed investments.

Alternative approaches to regulation have been developed which handle today's business conditions better. Some, such as multiyear rate plans, formula rates, and fully-forecasted test years, can involve sweeping regulatory change. Others, like revenue decoupling and cost trackers, target specific challenges.

This survey, now updated to include precedents through mid-2015, explains Altreg options and details precedents in the regulation of retail electric utility rates. A summary of states that currently use these approaches is featured in Table 1. Information is also provided on precedents for gas and water distributors and for energy utilities in Australia, Canada, and Britain. This year's survey also discusses marketing flexibility, a new Altreg area of growing interest to EEI members.

Figure 1

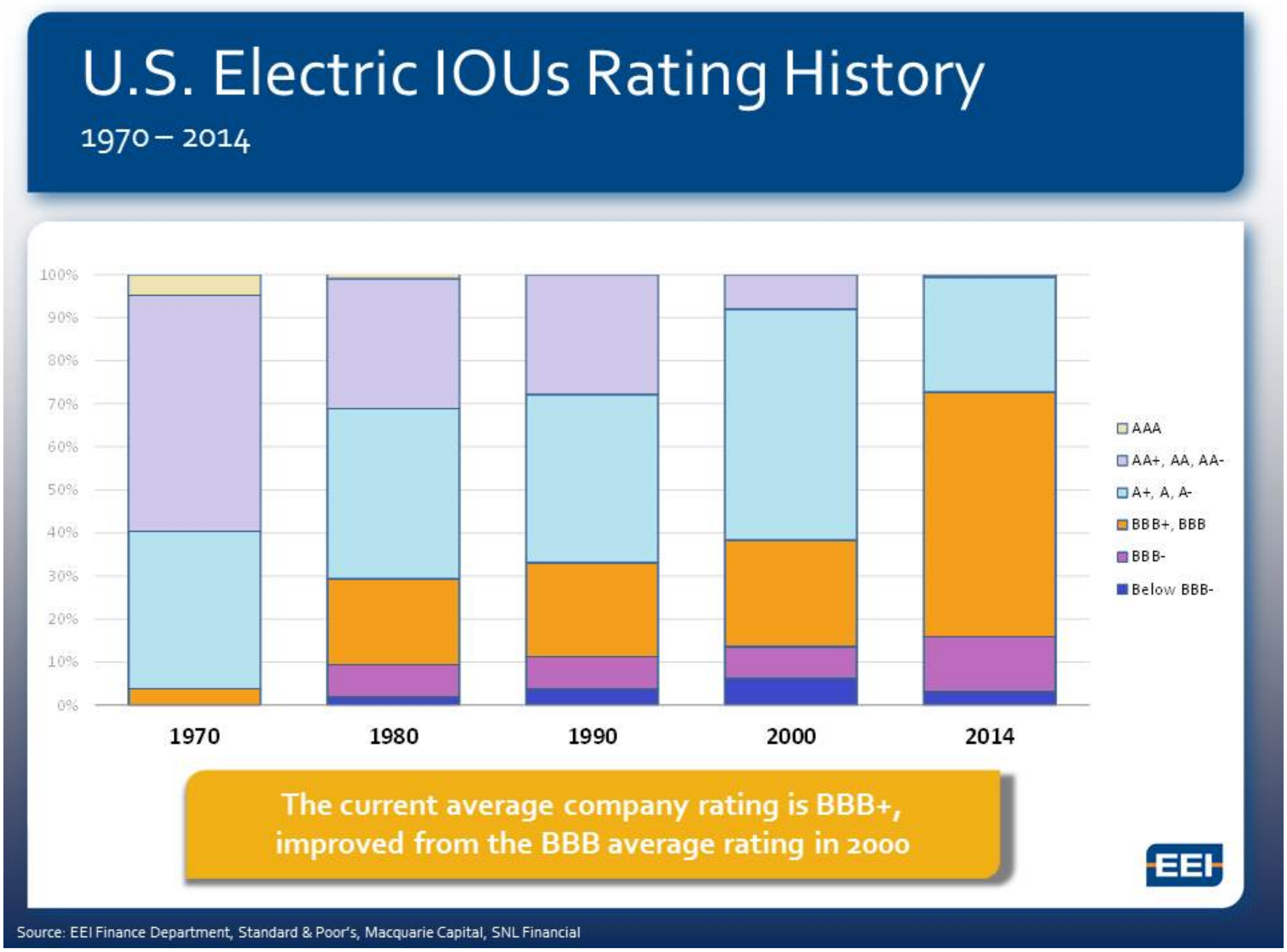

U.S. Electric IOUs Rating History
1970 – 2014
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
1970
1980
1990
2000
2014
AAA
AA+, AA, AA-
A+, A, A-
BBB+, BBB
BBB-
Below BBB-
The current average company rating is BBB+, improved from the BBB average rating in 2000
EEI
Source: EEI Finance Department, Standard & Poor's, Macquarie Capital, SNL Financial

Table 1

Alternative Regulation Tools: An Overview of Current Precedents

State	Capital Cost Trackers	Measures that Relax the Use/Revenue Link			Multiyear Rate Plans[1]	Retail Formula Rate Plans	Forward Test Years
		Decoupling True Up Plans	Lost Revenue Adjustment Mechanisms	Fixed Variable Retail Pricing			
Alabama	Electric & Gas					Electric & Gas	Yes
Alaska							
Arizona	Electric, Gas, & Water	Gas only	Electric & Gas		Electric only		
Arkansas	Electric & Gas	Gas only	Electric & Gas				
California	Electric & Gas	Electric & Gas			Electric & Gas		Yes
Colorado	Electric & Gas				Electric only		
Connecticut	Electric, Gas, & Water	Electric & Gas	Gas only	Electric & Gas			Yes
Delaware	Electric, Gas, & Water						
District of Columbia	Electric & Gas	Electric only					
Florida	Electric & Gas			Gas only	Electric only		Yes
Georgia	Electric & Gas	Gas only		Gas only	Electric only	Gas only	Yes
Hawaii	Electric only	Electric only			Electric only		Yes
Idaho	Electric only	Electric only					
Illinois	Gas & Water	Gas only		Electric & Gas		Electric only	Yes
Indiana	Electric, Gas, & Water	Gas only	Electric only		Gas only		
Iowa	Gas only			Gas only	Electric only		
Kansas	Gas only		Electric only	Gas only			
Kentucky	Electric & Gas		Electric & Gas	Gas only			Yes
Louisiana	Electric only		Electric only		Electric only	Electric & Gas	Yes
Maine	Electric, Gas, & Water	Electric only		Gas only	Gas only		Yes
Maryland	Electric & Gas	Electric & Gas					
Massachusetts	Electric & Gas	Electric & Gas	Electric & Gas		Gas only		
Michigan	Gas only	Gas only					Yes

Table 1 continued

State	Capital Cost Trackers	Measures that Relax the Use/Revenue Link			Multiyear Rate Plans[1]	Retail Formula Rate Plans	Forward Test Years
		Decoupling True Up Plans	Lost Revenue Adjustment Mechanisms	Fixed Variable Retail Pricing			
Minnesota	Electric & Gas	Electric & Gas					Yes
Mississippi	Electric & Gas		Electric & Gas	Electric only		Electric & Gas	Yes
Missouri	Gas & Water			Gas only			
Montana	Electric & Gas		Gas only				
Nebraska	Gas only			Gas only			
Nevada	Gas only	Gas only	Electric only				
New Hampshire	Electric, Gas, & Water			Gas only	Electric & Gas		
New Jersey	Electric, Gas, & Water	Gas only					
New Mexico							Yes
New York	Gas & Water	Electric & Gas	Gas only	Electric & Gas	Electric & Gas		Yes
North Carolina	Gas & Water	Gas only	Electric only				
North Dakota	Electric only			Gas only	Electric only		Yes
Ohio	Electric, Gas, & Water	Electric only	Electric only	Gas only	Electric only		
Oklahoma	Electric only		Electric only	Electric & Gas		Gas only	
Oregon	Electric & Gas	Electric & Gas	Electric & Gas				Yes
Pennsylvania	Electric, Gas, & Water			Gas only			Yes
Rhode Island	Electric & Gas	Electric & Gas					Yes
South Carolina	Electric only		Electric only			Gas only	
South Dakota	Electric only						
Tennessee	Gas only	Gas only		Gas only		Gas only	Yes
Texas	Electric & Gas			Gas only		Gas only	
Utah	Gas only	Gas only					Yes
Vermont				Gas only			
Virginia	Electric & Gas	Gas only		Gas only	Electric only		
Washington	Gas only	Electric & Gas			Electric & Gas		
West Virginia	Electric only						
Wisconsin				Gas only			Yes
Wyoming	Electric only	Gas only	Electric & Gas	Electric & Gas			Yes

[1] This column excludes plans involving rate freezes without extensive supplemental funding from trackers.

II. Cost Trackers

A cost tracker is a mechanism for expedited recovery of specific utility cost (e.g., outside of a rate case). Balancing accounts are typically used to track unrecovered costs. Cost recovery is often implemented using tariff sheet provisions called riders.

Trackers are used in various situations where they are more practical than rate cases for addressing particular costs. Utilities usually recover fuel and purchased power costs via trackers because the volatility and substantial size of these costs would otherwise lead to frequent rate cases and materially impact utility risk. Other volatile expenses that are sometimes addressed with trackers include those for pensions, severe storms, and uncollectible bills.

A second use of trackers is for costs incurred due to policies of government agencies. Examples here include franchise fees and certain taxes. Tracking costs like these is fair to utilities and encourages government agencies to consider the impact of their policies on customer bills.

Trackers are also used to compensate utilities for costs that are rapidly rising and don't otherwise trigger new revenue, whether or not they are volatile or mandated. This encourages needed expenditures and reduces risk and the frequency of rate cases. Examples of operation and maintenance ("O&M") expenses that are sometimes tracked due in large measure to their rapid growth include those for health care.

Trackers for some costs have multiple rationales. DSM expenses, for example, are often sizable and sometimes grow rapidly.[1] Utility DSM programs are often mandated. Additionally, DSM can slow growth in the average use of power and reduce the need for plant additions, important sources of earnings growth for utilities. Tracking DSM expenses helps to balance utility incentives to embrace DSM.

Capital cost trackers typically address the accumulating depreciation, return on asset value, and taxes that result from the capex.[2] Capital costs can qualify for tracker treatment on several grounds. Major plant additions are volatile. Capex might be necessitated by highway construction or changes in government safety, reliability, or environmental standards. Capex is sometimes large enough to cause brisk cost growth that would otherwise occasion frequent rate cases.

An early use of capital cost trackers in the electric utility industry was to address construction costs of large power plants. These plants can take years to construct. An allowance in rates for a return on funds used during construction was traditionally not permitted until assets were used and useful and a rate case was filed. Deferred recovery of the allowance strains utility cash flow, increases financing expenses, and induces more rate "shock" when the value of the plant and construction financing is finally added to the rate base.

[1] This survey only documents capital cost trackers. Trackers for DSM expenses are ubiquitous so that there is less need for documentation.

[2] Recovery is sometimes achieved by keeping a rate case open beyond the date of a final decision for the limited purpose of adding assets to the revenue requirement.

Many commissions have addressed these problems by making a return on construction work in progress ("CWIP") eligible for immediate recovery. Capital cost trackers have often been used in lieu of frequent rate cases to obtain CWIP recovery.

Capital costs of distribution system modernization are sometimes recovered using trackers for somewhat different reasons. The annual expenditure may not be as large as that for large generation units, and construction of specific assets usually takes less than a year. However, the capex can still be sizable and doesn't automatically trigger new revenue when completed. A tracker for accelerated modernization costs can help a company modernize its grid and improve its services without frequent rate cases.

Capital costs of generation emissions controls are often accorded tracker treatment. These controls are occasioned by the emissions policies of state and federal agencies. Additionally, the facilities do not produce revenue and some facilities typically become used and useful each year over a series of years.

There are varied treatments of costs in approved capital trackers. Regulators often approve tracked capex budgets in advance, usually after considerable deliberation. Procedures for reviewing the need for generation plant additions are especially well established. Once a budget is set, the treatment of variances between actual and budgeted cost becomes an issue. Some trackers permit conventional prudence review treatment of cost overruns. In other cases, no adjustments are subsequently made if cost exceeds the budget. In between these extremes are mechanisms in which deviations, of prescribed magnitude, from budgeted amounts are shared formulaically (e.g., 50-50) between the utility and its customers. Utilities are also permitted sometimes to share in the benefits of capex underspends. The prudence of tracked capex is often subject to a final review when the cost is added to rate base, a step that usually occurs in the next rate case.

Recent precedents for capital cost trackers are listed in Table 2 and Figures 2 and 3. It can be seen that the precedents are numerous and continue to grow. This is the most widely used Altreg tool in the United States. For electric utilities, trackers for emissions controls, generation capacity, advanced metering infrastructure, and general system modernization have been especially common in recent years. Trackers for gas distributors typically address the cost of replacing old cast iron and bare steel mains. Trackers for water utilities, sometimes called distribution system improvement charges, are also common for accelerated modernization.

Figure 2: Recent Capital Cost Tracker Precedents by State: Energy Utilities

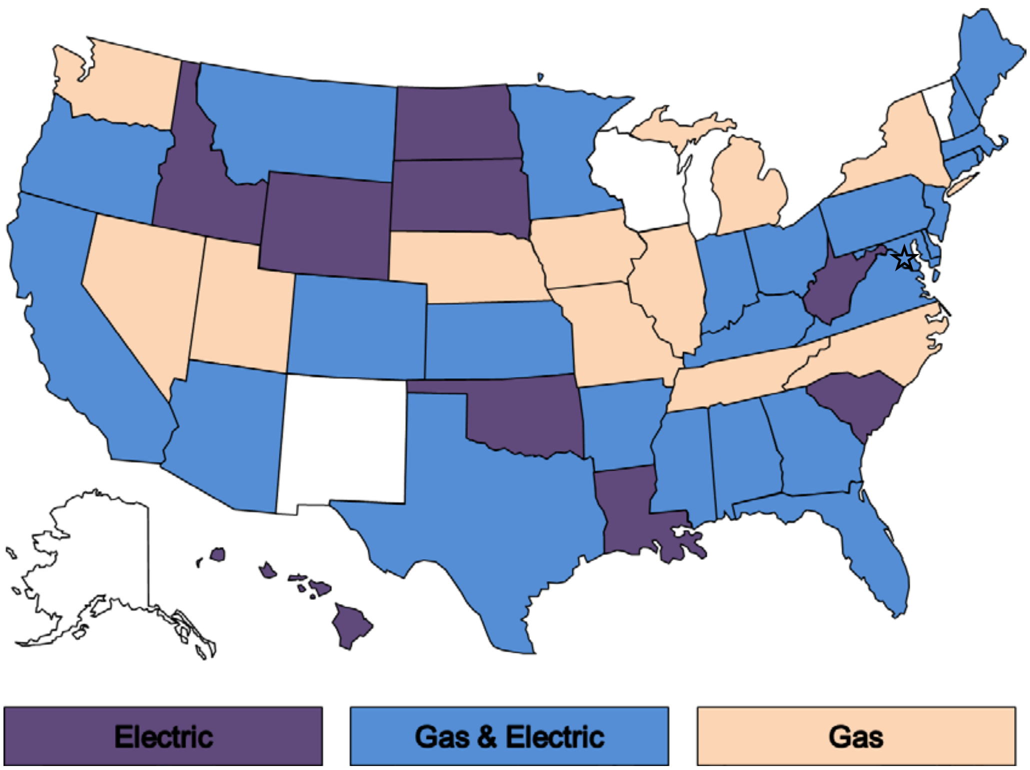


Figure 3: Recent Capital Cost Tracker Precedents by State: Water Utilities

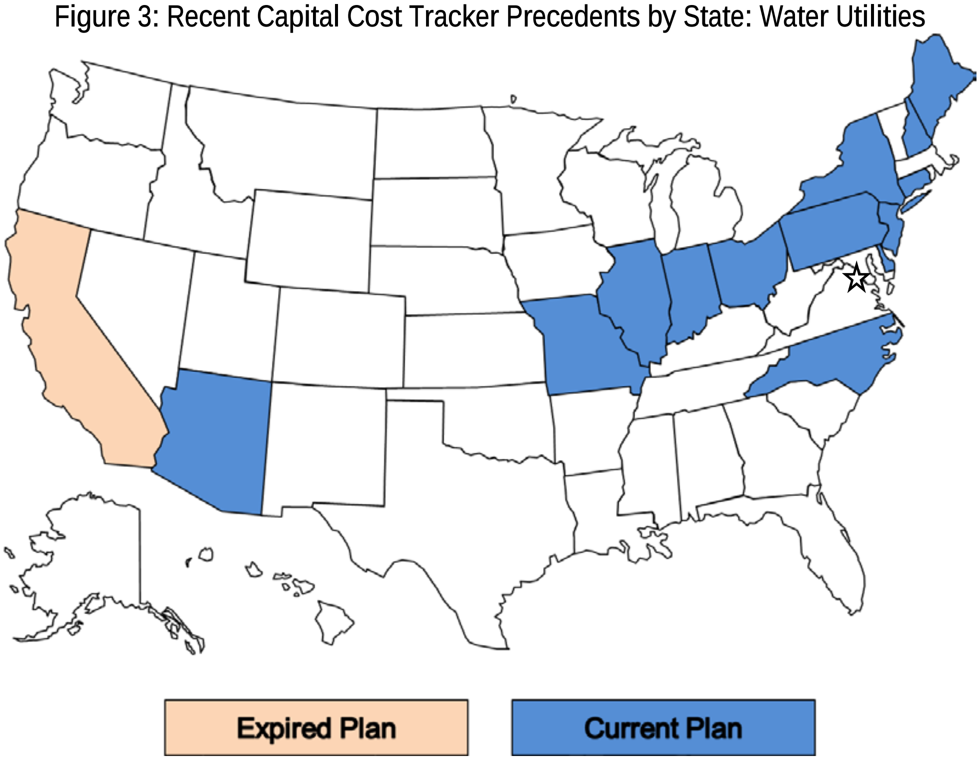


Table 2

Recent Capital Cost Tracker Precedents

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
AL	Alabama Power	Electric	Rate Certificated New Plant	Any approved by Commission through CPCN	Dockets 18117 and 18416 (November 1982)
AL	Mobile Gas Service	Gas	Cast Iron Replacement Factor	Replacement of cast iron mains	Docket 24794 (November 1995)
AR	Arkansas Oklahoma Gas	Gas	Act 310 Surcharge	Relocations of pipelines mandated by government agencies	Docket 12-088-U (July 2013)
AR	Arkansas Oklahoma Gas	Gas	System Safety Enhancement Rider	Replacement of bare steel mains, mains on low pressure systems, mains that are subject of an advisory notice by government that company deems to be unsatisfactory	Docket 13-078-U (July 2014)
AR	CenterPoint Energy Arkla	Gas	Main Replacement Rider	Replacement of cast iron and bare steel mains and services	Docket 06-161-U (October 2007)
AR	CenterPoint Energy Arkla	Gas	Government Mandated Expenditure Surcharge Rider	Replacements resulting from highway and street rebuilding	Docket 10-108-U (March 2011)
AR	Empire District Electric	Electric	Alternative Generation Environmental Recovery Rider	Environmental	Docket 15-010-U (August 2015)
AR	Oklahoma Gas & Electric	Electric	Smart Grid Rider	Systemwide smart grid implementation	Docket 10-109-U (August 2011)
AR	SourceGas Arkansas	Gas	At-Risk Meter Relocation Program Rider	Installation of new services for meters relocated due to motor vehicle collision risk	Docket 13-079-U (July 2014)
AR	SourceGas Arkansas	Gas	Main Replacement Program Rider	Replacement of bare steel and coated steel mains, mains that are subject of an advisory notice by government that company deems to be unsatisfactory, and associated services	Docket 13-079-U (July 2014)
AR	SourceGas Arkansas	Gas	Act 310 Surcharge	Bare steel and cast iron pipeline replacement, in-line inspection project, emissions controlling catalysts for compressor station engines, greenhouse gas monitoring of some regulator stations, highway relocation projects	Docket 13-072-U (April 2014)
AR	SWEPCO	Electric	Alternative Generation Recovery Rider	New generation	Docket 09-008-U (November 2009)
AR	SWEPCO	Electric	Rider Environmental Compliance Surcharge	Environmental	Docket 15-021-U (October 2015)
AZ	Arizona Public Service	Electric	Renewable Energy Standard Adjustment Schedule	Renewables not recovered in base rates	Docket E-01345A-08-0172
AZ	Arizona Public Service	Electric	Environmental Improvement Surcharge	Environmental improvement projects	Docket E-01345A-11-0224 (May 2012)
AZ	Arizona Public Service	Electric	Four Corners Rate Rider Surcharge	Generation	Docket E-01345A-11-0224 (December 2014)
AZ	Arizona Water Company	Water	Arsenic Cost Recovery Mechanism	Investments to reduce arsenic in water supply	Various (operating regions have separate decisions approving ACRMs)
AZ	Arizona Water Company - Eastern Group	Water	System Improvement Benefits Mechanism	Replacement of leak prone mains and related services, meters, and hydrants, replace meters that do not have lead free brass, other replacements for mains, services, meters, and hydrants that are at the end of their useful life	Decision 73938 (June 2013)
AZ	Southwest Gas	Gas	Customer Owned Yard Line Cost Recovery Mechanism	Replacement and ownership of customer-owned yard lines that have been shown to be leaking	Docket G-01551A-10-0458 (January 2012)
AZ	Tucson Electric Power	Electric	Environmental Compliance Adjustor	Miscellaneous environmental projects	Decision 73912 (June 2013)
CA	Pacific Gas & Electric	Electric	Smart Grid Memorandum Account	Smart grid projects that received DOE matching funds	Decision 09-09-029 (September 2009)
CA	Pacific Gas & Electric	Gas Transmission	Pipeline Safety Implementation Plan	Pipeline replacement, automated valve installation, and upgrades to pipeline	Decision 12-12-030 (December 2012)
CA	Pacific Gas & Electric	Electric	Smart Grid Pilot Deployment Project Balancing Account	Pilot programs for smart grid line sensors, volt/VAR optimization, detection and location of distribution line outages and faulted circuits, and information technology investments to improve short term demand forecasting for power procurement	Decision 13-03-032 (March 2013)
CA	San Diego Gas & Electric	Electric & Gas	Advanced Metering Infrastructure Balancing Account	AMI	Decision 07-04-043 (April 2007)
CA	San Diego Gas & Electric	Electric	Energy Storage Balancing Account	Projects to store solar energy	Decision 13-05-010 (May 2013)
CA	San Diego Gas & Electric	Gas	Post-2011 Distribution Integrity Management Program Balancing Account	DIMP related costs	Decision 13-05-010 (May 2013)
CA	San Diego Gas & Electric	Gas	Transmission Integrity Management Program Balancing Account	TIMP related costs	Decision 13-05-010 (May 2013)
CA	San Diego Gas & Electric	Gas Transmission	Safety Enhancement Capital Cost Balancing Account	Replacement of mains that fail pressure tests or that cannot be pressure tested	Decision 14-06-007 (June 2014)
CA	Southern California Edison	Electric	SmartConnect Balancing Account	Advanced metering infrastructure project	Decision 08-09-039 (September 2008)
CA	Southern California Edison	Electric	Solar PV Balancing Account	Solar generation	Decision 09-06-049 (June 2009)
CA	Southern California Gas	Gas	Advanced Metering Infrastructure Balancing Account	AMI	Decision 10-04-027 (April 2010)
CA	Southern California Gas	Gas	Post-2011 Distribution Integrity Management Program Balancing Account	DIMP related costs	Decision 13-05-010 (May 2013)
CA	Southern California Gas	Gas	Transmission Integrity Management Program Balancing Account	TIMP related costs	Decision 13-05-010 (May 2013)
CA	Southern California Gas	Gas Transmission	Safety Enhancement Capital Cost Balancing Account	Replacement of mains that fail pressure tests or that cannot be pressure tested	Decision 14-06-007 (June 2014)
CO	Black Hills Colorado Electric	Electric	Transmission Cost Adjustment Rider	Transmission projects	Docket 09-014E, Decision C09-0271 (March 2009)
CO	Black Hills Colorado Electric	Electric	Clean Air Clean Jobs Act Rider	Gas-fired generation	Docket 14AL-0393E, Decision C14-1504 (December 2014)
CO	Public Service Company of Colorado	Electric	Transmission Cost Adjustment	Transmission projects	Docket 07A-339E, Decision C07-1085 (December 2007)
CO	Public Service Company of Colorado	Gas	Pipeline Safety Integrity Adjustment	Gas distribution and transmission integrity management programs, main replacement, partial recovery of two large pipeline replacements	Docket 10-AL-963G (August 2011)

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
CO	Public Service Company of Colorado	Electric	Clean Air Clean Jobs Act Rider	Miscellaneous environmental projects including gas-fired generation, scrubbers	Proceeding 14A-680E, Decision C15-0292 (March 2015)
CO	Rocky Mountain Gas	Gas Transmission	System Safety and Integrity Rider	TIMP, DIMP, and other safety regulatory compliance projects	Docket 13AL-0046G, Decision R14-0114 (February 2014)
CT	Aquarion Water Company of Connecticut	Water	Water Infrastructure and Conservation Adjustment	Replacement of infrastructure including mains, valves, services, meters, and hydrants that have reached the end of their useful life or are no longer able to function as intended	Docket 08-06-21WI01 (December 2008)
CT	Connecticut Light & Power	Electric	System Resiliency Plan	Structural hardening	Docket 12-07-06 (January 2013)
CT	Connecticut Natural Gas	Gas	System Expansion Reconciliation Mechanism	System expansion	Docket 13-06-02 (November 2013)
CT	Connecticut Natural Gas	Gas	DIMP True-Up Mechanism	Cast iron and bare steel main replacement	Docket 13-06-08; (January 2014)
CT	Connecticut Water	Water	Water Infrastructure and Conservation Adjustment	Replacement of infrastructure including mains, valves, services, meters, and hydrants that have reached the end of their useful life or are no longer able to function as intended	Docket 08-10-15WI01 (March 2009)
CT	Southern Connecticut Gas	Gas	System Expansion Reconciliation Mechanism	System expansion	Docket 13-06-02 (November 2013)
CT	Torrington Water	Water	Water Infrastructure and Conservation Adjustment	Replacement of infrastructure including mains, valves, services, meters, and hydrants that have reached the end of their useful life or are no longer able to function as intended	Docket 09-06-17WI01 (December 2009)
CT	United Water Connecticut	Water	Water Infrastructure and Conservation Adjustment	Replacement of infrastructure including mains, valves, services, meters, and hydrants that have reached the end of their useful life or are no longer able to function as intended	Docket 09-06-17WI01 (December 2009)
CT	Yankee Gas Services	Gas	System Expansion Reconciliation Mechanism	System expansion	Docket 13-06-02 (November 2013)
DC	Potomac Electric Power	Electric	Underground Project Charge	Undergrounding of specific feeders	Formal Case 1116 (November 2014)
DC	Washington Gas Light	Gas	Plant Recovery Adjustment	Remediation/replacement of mechanical couplings	Formal Case 1027 (December 2009)
DC	Washington Gas Light	Gas	Accelerated Pipe Replacement Plan Adjustment	Replacement of cast iron mains, bare steel mains and services and "black plastic" services	Formal Case 1115 (January 2015)
DE	Artesian Water	Water	Distribution System Improvement Charge	Replacement of infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 01-474 (December 2001)
DE	Delmarva Power & Light	Gas	Utility Facility Relocation Charge	Replacements due to mandated relocations that are not otherwise reimbursed	Docket 12-546 (October 2013)
DE	Delmarva Power & Light	Electric	Utility Facility Relocation Charge	Replacements due to mandated relocations that are not otherwise reimbursed	Docket 13-115 (August 2014)
DE	Sussex Shores Water	Water	Distribution System Improvement Charge	Replacement of infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 01-470 (December 2001)
DE	Tidewater Utilities	Water	Distribution System Improvement Charge	Replacement of infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 03-210 (May 2003)
DE	United Water Delaware	Water	Distribution System Improvement Charge	Replacement of infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 01-481 (December 2001)
FL	Chesapeake Utilities	Gas	Gas Reliability Infrastructure Program Tariff	Replacement of bare steel mains and services	Docket 120036-GU (September 2012)
FL	Florida City Gas	Gas	Safety and Access Verification Expedited Program	Replacement of unprotected steel mains, relocation of certain gas mains in rear lot easements	Docket 150116-GU (September 2015)
FL	Florida Power and Light	Electric	Environmental Cost Recovery Clause	Miscellaneous environmental projects	Docket 080281-EI (August 2008)
FL	Florida Power and Light	Electric	Capacity Cost Recovery Clause	Nuclear power	Docket 090009-EI (November 2009)
FL	Florida Power and Light	Electric	Generation Base Rate Adjustment	Generation	Docket 120015-EI (December 2012)
FL	Florida Public Utilities	Gas	Gas Reliability Infrastructure Program Tariff	Replacement of bare steel mains and services	Docket 120036-GU (September 2012)
FL	Gulf Power	Electric	Environmental Cost Recovery Clause	Miscellaneous environmental projects	Docket 930613-EI (January 1994)
FL	Peoples Gas System	Gas	Cast Iron/Bare Steel Replacement Rider	Replacement of bare steel and cast iron pipes	Docket 110320-GU (September 2012)
FL	Progress Energy Florida	Electric	Environmental Cost Recovery Clause	Miscellaneous environmental projects	Docket 050078-EI (September 2005)
FL	Progress Energy Florida	Electric	Capacity Cost Recovery Clause	Nuclear power	Docket 090009-EI (November 2009)
FL	Progress Energy Florida	Electric	Generation Base Rate Adjustment	Generation	Docket 130208 (November 2013)
FL	Tampa Electric	Electric	Environmental Cost Recovery Clause	Miscellaneous environmental projects	Docket 960688-EI (August 1996)
GA	Atlanta Gas Light	Gas	Pipeline Replacement Program Cost Recovery Rider	Replacement of cast iron and bare steel pipe	Docket 29950 as STRIDE tracker in 2009
GA	Atlanta Gas Light	Gas	Strategic Infrastructure Development and Enhancement Surcharge	Pre-1985 plastic mains and services replacement, planned customer expansions, and infrastructure improvements that sustain reliability and operational flexibility	Docket 8516-U and 29950 (October 2009 and August 2013)
GA	Atmos Energy (now Liberty Utilities)	Gas	Pipe Replacement Surcharge	Replace cast iron and bare steel pipe	Docket 12509-U (December 2000)
GA	Georgia Power Company	Electric	Environmental Compliance Cost Recovery	Miscellaneous environmental projects	Docket 25060-U (December 2007)
GA	Georgia Power Company	Electric	Nuclear Construction Cost Recovery	Nuclear generation	Docket 27800, Senate Bill 31
HI	Hawaii Electric Light	Electric	Renewable Energy Infrastructure Program Surcharge	Renewable energy infrastructure	Docket 2007-0416 (December 2009)
HI	Hawaiian Electric Company	Electric	Renewable Energy Infrastructure Program Surcharge	Renewable energy infrastructure	Docket 2007-0416 (December 2009)
HI	Maui Electric	Electric	Renewable Energy Infrastructure Program Surcharge	Renewable energy infrastructure	Docket 2007-0416 (December 2009)
IA	Black Hills Energy	Gas	System Safety Maintenance Adjustment	Replacement of steel and pvc pipe, relocations mandated by local governments	Docket RPU-2012-0004 (March 2013)
ID	PacifiCorp	Electric	Energy Cost Adjustment Mechanism	Lake Side II generation facility	Case PAC-E-13-04 (October 2013)

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
IL	Ameren Illinois	Gas	Rider Qualifying Infrastructure Plant	Replacement of prone to leak distribution and transmission pipe, installation of AMI and communications infrastructure, replacing or installing transmission or distribution facilities to establish over-pressure protection, replacement of difficult to locate mains and services, replacement of high pressure transmission pipelines without a recorded maximum allowable operating pressure, replacements to facilitate an upgrade from a low pressure system to a high pressure system	Docket 14-0573 (January 2015)
IL	Consumers Illinois Water Company (Kankakee, Vermilion, Woodhaven Districts)	Water	Qualifying Infrastructure Plant Surcharge Rider	Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 01-0561 (December 2001)
IL	Illinois-American Water (Chicago Metro Division)	Water	Qualifying Infrastructure Plant Surcharge Rider	Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 09-0251 (March 2010)
IL	Illinois-American Water (Single Tariff Pricing Zone)	Water	Qualifying Infrastructure Plant Surcharge Rider	Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 04-0336 (December 2004)
IL	Northern Illinois Gas	Gas	Rider Qualifying Infrastructure Plant	Replacement of cast iron pipe, non-cast iron pipe, and copper services; relcoation of meters from inside customers' premises; upgrading of system from low pressure to medium pressure; replacement or installation of regulator stations, regulators, valves and associated facilities to establish over-pressure protection	Docket 14-0292 (July 2014)
IL	Peoples Gas Light & Coke	Gas	Rider Qualifying Infrastructure Plant	Replacement of cast and ductile iron, relcoation of meters from inside customers' premises, upgrading of system from low pressure to medium pressure, replacement of high pressure transmission pipelines at higher risk of failure or lacking records, installation of regulator stations to establish over-pressure protection	Docket 13-0534 (January 2014)
IN	Duke Energy Indiana	Electric	Qualified Pollution Control Property	Miscellaneous environmental projects	Cause 41744 (February 2001)
IN	Duke Energy Indiana	Electric	Integrated Coal Gasification Combined Cycle Generating Facility Revenue Recovery Adjustment	Integrated gasification combined cycle generating plant	Docket 43114 (November 2007)
IN	Indiana Michigan Power	Electric	Clean Coal Technology Rider	Miscellaneous environmental projects	Cause 43636 (June 2009)
IN	Indiana Water Service	Water	Distribution System Improvement Charge	Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants)	Cause 42743 DSIC-1 (December 2004)
IN	Indiana-American Water	Water	Distribution System Improvement Charge	Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants)	Cause 42351 DSIC-1 (February 2003)
IN	Indianapolis Power & Light	Electric	Environmental Compliance Cost Recovery	Miscellaneous environmental projects	Cause 42170 (November 2002)
IN	Northern Indiana Public Service	Electric	Environmental Cost Recovery Mechanism	Miscellaneous environmental projects	Cause 42150 (November 2002)
IN	Northern Indiana Public Service	Electric	Transmission, Distribution & Storage System Improvement Charge	Investments to maintain the capacity deliverability of system and replacement of aging infrastructure, economic development	Cause 44370 and 44371 (February 2014)
IN	Northern Indiana Public Service	Gas	Distribution System Improvement Charge	Gas system deliverability and system integrity projects, rural main extensions	Cause 44403 TDSIC 1 (January 2015)
IN	Utility Center Inc.	Water	Distribution System Improvement Charge	Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 42416 DSIC-1 (June 2003)
IN	Vectren Energy Delivery (Indiana Gas and Southern Indiana Gas & Electric)	Gas	Compliance and System Improvement Adjustment	System and pressure improvements, storage operations, instrumentation and communications equipment, public improvement projects, service replacements, and economic development	Cause 44429 (August 2014)
KS	Atmos Energy	Gas	Gas System Reliability Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket 10-ATMG-133-TAR (December 2009)
KS	Black Hills Energy (Aquila)	Gas	Gas System Reliability Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket 08-AQLG-852-TAR (July 2008)
KS	Kansas Gas Service	Gas	Gas System Reliability Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket 10-KGSG-155-TAR (December 2009)
KS	Midwest Energy	Gas	Gas System Reliability Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket 09-MDWE-722-TAR (May 2009)
KY	Atmos Energy	Gas	Pipe Replacement Program Rider	Replacement of bare steel service lines, curb valves, meter loops, and mandated relocations	Docket 2009-00354 (May 2010)
KY	Columbia Gas	Gas	Advanced Main Replacement Rider	Replacement of cast iron and bare steel mains and services	Docket 2009-00141 (September 2009)
KY	Delta Natural Gas	Gas	Pipe Replacement Program Surcharge	Replacement of bare steel pipe, service lines, curb valves, meter loops, and mandated pipe relocations	Case 2010-00116 (October 2010)
KY	Kentucky Power	Electric	Environmental Cost Recovery Surcharge	Miscellaneous environmental projects	Docket 2002-00169 (March 2003)
KY	Kentucky Utilities	Electric	Environmental Cost Recovery Surcharge	Miscellaneous environmental projects	Case 93-465 (July 1994)
KY	Louisville Gas & Electric	Electric	Environmental Cost Recovery Surcharge	Miscellaneous environmental projects	Case 94-332 (April 1995)
KY	Louisville Gas & Electric	Gas	Gas Line Tracker	Replacement and transfer of ownership of customer owned service risers	Case 2012-00222 (December 2012)
LA	Cleco Power	Electric	Infrastructure and Incremental Costs Recovery	Projects to be determined in subsequent filings to Commission	Docket U-30689 and U-32779 (October 2010 and June 2014)
LA	Entergy Gulf States Louisiana	Electric	Formula Rate Plan-3	Acquisition of generating facility, new generating facility or refurbishment of existing generating facility if the revenue requirement related to the project exceeds $10 million	Docket U-32707 (December 2013)
LA	Entergy Louisiana	Electric	Formula Rate Plan 7	Cost of Ninemile 6 natural gas generating facility; New generating facility, acquisition of a generating facility, or refurbishment of existing generating facility if the revenue requirement related to the project exceeds $10 million	Docket U-32708 and 31971 (January 2014 and April 2012)
MA	Bay State Gas	Gas	Targeted Infrastructure Recovery Factor	Replacement of bare steel mains and services	DPU 09-30
MA	Bay State Gas	Gas	Gas System Enhancement Adjustment Factor	Replacement of non-cathodically protected steel, cast iron, and wrought iron mains and associated services, service tie-ins, encroached pipe, and meters	DPU 14-134
MA	Berkshire Gas	Gas	Gas System Enhancement Adjustment Factor	Replacement of non-cathodically protected steel, cast iron mains and associated services, encroached pipe, and meter sets composed of non-cathodically protected steel, cast iron or copper	DPU 14-131
MA	Fitchburg Gas & Electric Light	Gas	Gas System Enhancement Adjustment Factor	Replacement of cast main and unprotected steel mains and services and encroached pipe	DPU 14-130

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
MA	Massachusetts Electric	Electric	Net CapEx Factor	Potentially all distribution investments	DPU 09-39
MA	Massachusetts Electric	Electric	Solar Cost Adjustment Provision	Solar generation	DPU 09-38
MA	Massachusetts Electric	Electric	Smart Grid Adjustment Provision	Pilot smart grid investments including AMI, high speed communications network, in-home energy management devices, distribution automation, advanced capacitor control, advanced grid monitoring, remote fault indicators	DPU 11-129
MA	Nantucket Electric	Electric	Solar Cost Adjustment Provision	Solar generation	DPU 09-38
MA	Nantucket Electric	Electric	Smart Grid Adjustment Provision	Pilot smart grid investments including AMI, high speed communications network, in-home energy management devices, distribution automation, advanced capacitor control, advanced grid monitoring, remote fault indicators	DPU 11-129
MA	National Grid (Boston-Essex Gas and Colonial Gas	Gas	Targeted Infrastructure Recovery Factor	Replacement of bare steel, cast iron, and wrought iron mains, services, meters, meter installations, and house regulators	DPU 10-55
MA	National Grid (Boston-Essex Gas and Colonial Gas	Gas	Gas System Enhancement Adjustment Factor	Replacement of non-cathodically protected steel, cast iron, and wrought iron mains and associated services, inside services, service tie-ins, encroached pipe, and meters	DPU 14-132
MA	New England Gas	Gas	Targeted Infrastructure Recovery Factor	Replacement of non-cathodically protected steel mains and services and small diameter cast-iron and wrought iron	DPU 10-114
MA	New England Gas	Gas	Gas System Enhancement Adjustment Factor	Replacement of non-cathodically protected steel, cast iron, and wrought iron mains and associated services, inside services, service tie-ins, encroached pipe, and meters	DPU 14-133
MA	NSTAR Electric	Electric	Capital Projects Scheduling List	Stray voltage inspection survey and remediation program; double pole inspections, replacements, and restorations; and manhole inspection, repair, and upgrade	DTE 05-85 and DPU 10-70-B
MA	NSTAR Electric	Electric	Smart Grid Adjustment Factor	Smart grid pilot	DPU-09-33
MA	Western Massachusetts Electric	Electric	Solar Program Cost Adjustment	Solar generation	DPU 09-05
MD	Baltimore Gas & Electric	Electric	Electric Reliability Investment Surcharge	Upgrades to improve poorest performing feeders, selective undergrounding, expanded recloser development on 13kV and 34 kV lines, diverse routing of 34 kV supply circuits	Case 9326 (December 2013)
MD	Baltimore Gas & Electric	Gas	Strategic Infrastructure Development and Enhancement Program	Replacement of bare steel mains and services, cast iron mains, copper services, and pre-1982 plastic "Ski Bar" risers	Case 9331 (January 2014)
MD	Columbia Gas of Maryland	Gas	Strategic Infrastructure Development and Enhancement Program	Replacement of bare steel and cast iron mains and bare steel services	Case 9332 (August 2014)
MD	Delmarva Power & Light	Electric	Grid Resiliency Charge	Feeder hardening	Case 9317 (September 2013)
MD	Potomac Electric Power	Electric	Grid Resiliency Charge	Feeder hardening	Case 9311 (July 2013)
MD	Washington Gas Light	Gas	Strategic Infrastructure Development and Enhancement Program Rider	Replacement of bare and unprotected steel mains and services, targeted copper and pre-1975 plastic services, mechanically coupled pipe main and services, and cast iron mains	Case 9335 (May 2014)
ME	Central Maine Power	Electric	Customer Relationship Management & Billing Rate Adjustment	Customer relationship management & billing system replacement	Docket 2015-00040 (October 2015)
ME	Maine Water Company	Water	Water Infrastructure Charge	Replacement of stationary physical plant assets needed to operate a water system	Various orders separately issued for operating divisions
ME	Northern Utilities	Gas	Targeted Infrastructure Recovery Adjustment	Cast iron, bare steel, and unprotected coated steel mains and services replacements, replacement of farm tap regulators	Docket 2013-00133 (December 2013)
MI	Consumers Energy	Gas	Enhanced Infrastructure Replacement Program	Cast iron replacements	Case U-17643 (January 2015)
MI	Michigan Consolidated Gas (now DTE Gas)	Gas	Infrastructure Recovery Mechanism	Replacement of cast iron mains, replacement of indoor meters with outdoor meters, pipeline integrity projects designed to comply with federal and state safety standards	Case U-16999 (April 2013)
MI	SEMCO Gas	Gas	Main Replacement Rider	Replacement of cast iron and unprotected steel mains and service lines	Case U-16169 and U-17824 (January 2011 and June 2015)
MN	Interstate Power & Light	Electric	Renewable Energy Recovery Adjustment	Renewable generation	Docket M-10-312 (December 2013)
MN	Minnesota Power	Electric	Arrowhead Regional Emission Abatement Rider	Miscellaneous environmental projects	Docket M-05-1678 (June 2006)
MN	Minnesota Power	Electric	Transmission Cost Recovery Rider	Incremental transmission investment	Docket M-07-965 (December 2007)
MN	Minnesota Power	Electric	Renewable Resource Rider	Renewable generation	Docket M-10-273 (July 2010)
MN	Minnesota Power	Electric	Rider for Boswell Unit 4 Emission Reduction	Miscellaneous environmental projects	Docket M-12-920 (November 2013)
MN	Northern States Power (Xcel Energy)	Electric	Metropolitan Emissions Reduction Project (later called Environmental Improvement Rider)	Miscellaneous environmental projects	Docket M-02-633 (March 2004)
MN	Northern States Power (Xcel Energy)	Electric	Transmission Cost Recovery Rider	Incremental transmission investment	Docket M-06-1103 (November 2006)
MN	Northern States Power (Xcel Energy)	Electric	Renewable Energy Standard Cost Recovery Rider	Renewable generation	M-07-872 (March 2008)
MN	Northern States Power (Xcel Energy)	Gas	State Energy Policy Rider	Cast iron replacements	Docket M-08-261 (November 2008)
MN	Northern States Power (Xcel Energy)	Electric	Mercury Cost Recovery Rider	Miscellaneous environmental projects	Docket M-09-847 (November 2009)
MN	Otter Tail Power	Electric	Renewable Resource Cost Recovery Rider	Renewable generation	Docket M-08-119 (August 2008)
MN	Otter Tail Power	Electric	Transmission Cost Recovery Rider	Incremental transmission investment	Docket M-09-881 (January 2010)
MO	AmerenUE	Gas	Infrastructure System Replacement Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Case GT-2008-0184 (February 2008)
MO	Atmos Energy	Gas	Infrastructure System Replacement Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket GO-2009-0046 (October 2008)
MO	Laclede Gas	Gas	Infrastructure System Replacement Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket GR-2007-0208 (July 2007)
MO	Missouri American Water	Water	Infrastructure System Replacement Surcharge	Replacement of mains, associated valves and hydrants, main cleaning and relining projects	Case WO-2004-0116 (December 2003)
MO	Missouri Gas Energy	Gas	Infrastructure System Replacement Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket GR-2009-0355 (February 2010)

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
MS	Atmos Energy	Gas	Supplemental Growth Rider	Extraordinary service expansions to new industrial customers for economic development	Docket 2013-UN-23 (July 2013)
MS	Centerpoint Energy	Gas	Supplemental Growth Rider	Extraordinary service expansions to new commercial and industrial customers for economic development	Docket 13-UN-214 (October 2013)
MS	Mississippi Power	Electric	Enviromental Compliance Overview Plan Rate	Miscellaneous environmental projects	Docket 92-UA-0058 and 92-UN-0059 (July 1992)
MT	Northwestern Energy	Electric	NA - Amounts recovered through electric supply service rates	Generation	Docket D.2008.6.69 (November 2008)
MT	Northwestern Energy	Gas	Natural Gas Supply Tracker	Battle Creek natural gas production resources	Docket D2012.3.25 (November 2012)
NC	Aqua North Carolina	Water	Water System Improvement Charge	Replacement of distribution system mains, valves, services, meters, and hydrants, main extensions, projects to comply with primary drinking water standards, unreimbursed facility relocation costs due to highways	Docket W-218, Sub 363 (May 2014)
NC	Aqua North Carolina	Water	Sewer System Improvement Charge	Replacement of pumps, motors, blowers, and other mechanical equipment, collection main extensions designed to implement solutions to wastewater problems, improvements necessary to reduce inflow and infiltration to the collection systems as required by state and federal law and regulations, unreimbursed costs of highway relocations	Docket W-218, Sub 363 (May 2014)
NC	Carolina Water Service	Water	Water System Improvement Charge	Replacement of distribution system mains, valves, services, meters, and hydrants, main extensions, projects to comply with primary drinking water standards, unreimbursed facility relocation costs due to highways	Docket W-354, Sub 336 (March 2014)
NC	Carolina Water Service	Water	Sewer System Improvement Charge	Replacement of pumps, motors, blowers, and other mechanical equipment, collection main extensions designed to implement solutions to wastewater problems, improvements necessary to reduce inflow and infiltration to the collection systems as required by state and federal law and regulations, unreimbursed costs of highway relocations	Docket W-354, Sub 336 (March 2014)
NC	Piedmont Natural Gas	Gas	Integrity Management Rider	Investments driven by federal pipeline safety and integrity requirements	Docket G-9, Sub 631 (December 2013)
ND	Montana-Dakota Utilities	Electric	Environmental Cost Recovery Tariff	Miscellaneous environmental projects	Case PU-13-85 (December 2013)
ND	Montana-Dakota Utilities	Electric	Generation Resource Recovery Rider Tariff	New Generation	Case PU-14-108 (August 2014)
ND	Northern States Power- MN	Electric	Transmission Cost Rider	Transmission projects	Case PU-12-813 (February 2014)
ND	Northern States Power- MN	Electric	Renewable Energy Rider	North Dakota based renewable generation	Case PU-12-813 (February 2014)
ND	Otter Tail Power	Electric	Renewable Resource Rider	Renewables	Case PU-06-466 (May 2008)
ND	Otter Tail Power	Electric	Transmission Facility Cost Recovery Tariff	Transmission investments required to serve retail customers	Case PU-11-682 (April 2012)
ND	Otter Tail Power	Electric	Environmental Cost Recovery Tariff	Miscellaneous environmental projects	Case PU-13-84 (December 2013)
NE	Black Hills Nebraska Gas Utility	Gas	Infrastructure System Replacement Recovery Charge	Non-revenue increasing projects to replace existing assets	Application NG-0074
NE	SourceGas Distribution	Gas	Pipeline Replacement Charge	Projects entering service before May 2014 that are installed to comply with safety requirements as replacements for existing facilities, projects that will extend the useful life of existing assets or enhance pipeline integrity, facility relocations	Application NG-0072 (June 2013)
NE	SourceGas Distribution	Gas	System Safety and Integrity Rider	Projects entering service after April 2014 that comply with federal regulations including transmission and distribution integrity management plans or are facility relocations costing $20,000 or more	Application NG-0078 (October 2014)
NH	Aquarion Water of New Hampshire	Water	Water Infrastructure and Conservation Adjustment Charge	Projects to upgrade or replace non-revenue producing assets including main, valve, and hydrant replacement, main cleaning and relining, and non-reimbursable relocations	Docket DW 08-098 (September 2009)
NH	Energy North	Gas	Cast Iron/Bare Steel Replacement Program	Replacement of cast iron and bare steel pipe	Docket DG-107 (June 2007)
NH	Granite State Electric	Electric	Reliability Enhancement Plan Capital Investment Allowance	Feeder hardening and asset replacement	Docket DG-107 (June 2007)
NH	Public Service Company of New Hampshire	Electric	Energy Service	Miscellaneous environmental projects	DE 11-250 (April 2012)
NH	Public Service Company of New Hampshire	Electric	Reliability Enhancement Plan	Reliability improvements	DE 09-035, DE 11-250, and DE 14-238 (June 2015)
NJ	Elizabethtown Gas	Gas	Elizabethtown Natural Gas Distribution Utility Reinforcement Effort	System hardening	Docket GO13090826 (July 2014)
NJ	New Jersey American Water	Water	Distribution System Improvement Charge	Incremental non-revenue water main replacement, rehabilitation, or mandated relocation projects, service line replacements, valve and hydrant replacement	Docket WR12070669 (October 2012)
NJ	New Jersey Natural Gas	Gas	New Jersey Reinvestment in System Enhancement	Storm hardening projects	Docket GR13090828 (July 2014)
NJ	Public Service Electric and Gas	Electric	Solar Generation Investment Program	Solar generation	Docket EO09020125 (August 2009)
NJ	Public Service Electric and Gas	Electric & Gas	Capital Infrastructure Investment Program	Electric: reliability upgrades & feeder replacement, Gas: replacement of cast iron & bare steel mains and services	Dockets GO09010050, EO11020088, GO10110862 (April 2009 and July 2011)
NJ	Public Service Electric and Gas	Electric & Gas	Energy Strong Adjustment Mechanism	Electric: substation flood mitigation, gird reconfiguration strategies, and smart grid; Gas: Metering and regulating station flood mitigation, replacement of utilization pressure cast iron in flood prone areas	Docket EO13020155, GO13020156 (May 2014)
NJ	South Jersey Gas	Gas	Storm Hardening and Reliability Program	Replacement of low pressure mains and services with high pressure mains and services, removal of regulator stations, installation of excess flow valves in coastal areas	Docket GO13090814 (August 2014)
NJ	United Water New Jersey	Water	Distribution System Improvement Charge	Repair, replace, and/or clean mains, replace valves, hydrants, and service lines	Docket WR12080724 (October 2012)
NV	Southwest Gas	Gas	Gas Infrastructure Replacement Mechanism	Early vintage pipe replacements, conversion of master metered customers to individual meters	Docket 14-10002 (December 2014)

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
NY	Corning Natural Gas	Gas	Safety and Reliability Charge	Replacement of leak prone pipe and ancillary costs to maintain a safe and reliable system	Case 11-G-0280 (October 2015)
NY	Keyspan Energy Long Island	Gas	Leak Prone Pipe Surcharge	Accelerated leak prone pipe removal program	Case 12-G-0214 (December 2014 and March 2015)
NY	Long Island American Water	Water	System Improvement Charge	Iron removal, storage tank rehabilitiation, suction well rehabilitation at selected plants, customer information system	Case 11-W-0200 (March 2012)
NY	United Water New Rochelle	Water	Long Term Main Renewal Project	Cleaning and relining of mains	Case 99-W-0948 (August 2000)
NY	United Water New York	Water	Underground Infrastructure Renewal Program	Replacement of infrastructure including mains, valves, services, meters, and hydrants	Case 06-W-0131 (December 2006)
NY	United Water New York	Water	New Water Supply Source Surcharge	Projects to provide new sources of water in the short and long term	Case 06-W-0131 (December 2006)
OH	Aqua Ohio	Water	System Infrastructure Improvement Surcharge	Replacement of service lines, mains, hydrants, valves, main extensions to resolve documented water supply problems	Case 04-1824-WW-SIC (March 2005)
OH	Cleveland Electric Illuminating	Electric	Rider AMI	Ohio Site Deployment	Cases 09-1820-EL-ATA and 12-1230-EL-SSO
OH	Cleveland Electric Illuminating	Electric	Delivery Capital Recovery Rider	Distribution, subtransmission, general, and intangible plant not included in most recent rate case	Case 10-388-EL-SSO (August 2010)
OH	Columbia Gas	Gas	Infrastructure Replacement Program Rider	Replacement of cast iron and bare steel mains & services, AMI	Cases 08-0072-GA-AIR, 08-0073-GA-ALT, 08-0074-GA-AAM, and 08-0075-GA-AAM (December 2008); Case 09-1036-GA-RDR (April 2010)
OH	Duke Energy Ohio	Gas	Accelerated Main Replacement Program Rider	Replacement of bare steel and cast iron mains and services and faulty risers	1478-GA-ALT, and 01-1539-GA-AAM (May 2002); 07-0589-GA-AIR 07-0590-GA-ALT 07-0591-GA-AAM (May 2008)
OH	Duke Energy Ohio	Gas	Advanced Utility Rider	Gas AMI	Cases 07-0589-GA-AIR, 07-0590-GA-ALT, and 07-0591-GA-AAM (May 2008)
OH	Duke Energy Ohio	Electric	Infrastructure Modernization Distribution Rider	Electric AMI	Cases 08-920-EL-SSO and 08-921-EL-AAM and 08-922-EL-UNC and 08-923-EL-ATA (December 2008)
OH	Duke Energy Ohio	Electric	Distribution Capital Investment Rider	Distribution capital investments not recovered through other trackers	Case 14-841-EL-SSO (April 2015)
OH	East Ohio Gas d/b/a Dominion East Ohio	Gas	Pipeline Infrastructure Replacement Rider	Bare steel and cast iron pipelines & faulty riser replacements	Case 08-169-GA-ALT (October 2008)
OH	East Ohio Gas d/b/a Dominion East Ohio	Gas	Automated Meter Reading Charge	AMR	Cases 07-0829-GA-AIR and 06-1453-GA-UNC (October 2008); Case 09-38-GA-UNC (May 2009); Case 09-1875-GA-RDR (May 2010)
OH	Ohio American Water	Water	System Improvement Charge	Non-revenue producing service lines, hydrants, mains, valves, main extensions that improve supply problems, main cleaning	Case 05-577-WW-SIC (August 2005)
OH	Ohio Edison	Electric	Rider AMI	Ohio Site Deployment	Cases 09-1820-EL-ATA and 12-1230-EL-SSO
OH	Ohio Edison	Electric	Delivery Capital Recovery Rider	Distribution, subtransmission, general, and intangible plant not included in most recent rate case (filed in 2007)	Case 10-388-EL-SSO (August 2010)
OH	Ohio Power	Electric	Distribution Investment Rider	Net distribution capital additions since the date certain of most recent rate case not recovered through other riders	Case 11-346-EL-SSO
OH	Ohio Power	Electric	GridSMART Rider (Phase I)	Smart grid	Case 08-917-EL-SSO and 08-918-EL-SSO (March 2009)
OH	Toledo Edison	Electric	Rider AMI	Ohio Site Deployment	Cases 09-1820-EL-ATA and 12-1230-EL-SSO
OH	Toledo Edison	Electric	Delivery Capital Recovery Rider	Power distribution, subtransmission, general, and intangible plant not included in most recent rate case (filed in 2007)	Case 10-388-EL-SSO (August 2010)
OH	Vectren Energy Delivery	Gas	Distribution Replacement Rider	Replacement of cast iron and bare steel mains and services	Cases 07-1081-GA-ALT, 07-1080-GA-AIR and 08-0632-GA-AAM (January 2009)
OK	Oklahoma Gas & Electric	Electric	System Hardening Recovery Rider	Undergrounding and other circuit hardening	Cause PUD 20080387, Order 567670 (May 2009)
OK	Oklahoma Gas & Electric	Electric	Smart Grid Rider	Smart grid	Cause PUD 201000029 (July 2010)
OK	Oklahoma Gas & Electric	Electric	Crossroads Rider	Crossroads Wind Farm	Cause PUD 201000037 (July 2010)
OK	Public Service Company of Oklahoma	Electric	System Reliability Rider	Grid resiliency projects	Cause PUD 201300202 (January 2014)
OK	Public Service Company of Oklahoma	Electric	Advanced Metering Infrastructure Tariff	Advanced metering infrastructure deployment	Cause PUD 201300217 (April 2015)
OR	Northwest Natural Gas	Gas	System Integrity Program	Bare steel replacement, transmission integrity management program, distribution integrity management program	Docket UM 1406, Order 09-067 (March 2009)
OR	PacifiCorp	Electric	Renewable Adjustment Clause	Renewable generation	Docket UM 1330 (December 2007)
OR	PacifiCorp	Electric	Lake Side 2 Tariff Rider	Generation	Docket UE 263, Order 13-474 (December 2013)
OR	PacifiCorp	Electric	M2O Transmission Rider	Mona to Oquirrh transmission line only if line is placed into service within 6 months of May 31, 2013	Docket UE 246, Orders 12-493 and 13-195 (December 2012 and May 2013)
OR	Portland General Electric	Electric	Renewable Adjustment Clause	Renewable generation	Docket UM 1330 (December 2007)
PA	Columbia Gas	Gas	Distribution System Improvement Charge	Replacement of cast iron, bare steel, and first generation plastic mains and services, install excess flow valves, install or relocate automated meters, and replace risers, meter bars, and service regulators	P-2012-2338282 (March 2013)
PA	Columbia Water Company	Water	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-00021979
PA	Duquesne Light	Electric	Smart Meter Charge Rider	AMI	Docket M-2009-2123948 (April 2010)
PA	Equitable Gas	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2013-2342745 (July 2013)
PA	Metropolitan Edison	Electric	Smart Meters Technologies Charge	AMI	Docket M-2009-2123950 (April 2010)

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
PA	PECO	Electric	Smart Meter Cost Recovery Rider	AMI	Docket M-2009-2123944 (April 2010)
PA	PECO	Electric	Distribution System Improvement Charge	Storm hardening and resiliency measures, underground cable replacement, substation retirements, and facility relocations	Docket P-2015-2471423 (October 2015)
PA	PECO	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2013-2347340 (September 2015)
PA	Pennsylvania Electric	Electric	Smart Meters Technologies Charge	AMI	Docket M-2009-2123950 (April 2010)
PA	Pennsylvania Power	Electric	Smart Meters Technologies Charge	AMI	Docket M-2009-2123950 (April 2010)
PA	Pennsylvania-American Water	Water	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-000961031 (August 1996)
PA	Peoples Natural Gas	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2013-2344596 (May 2013)
PA	Peoples TWP	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2013-2344595 (May 2013)
PA	Philadelphia Gas Works	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2012-2337737 (April 2013)
PA	Philadelphia Surburban Water	Water	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-00961035 (August 1996)
PA	PPL Electric Utilities	Electric	Act 129 Compliance Rider	AMI	Docket M-2009-2123945 (January 2010)
PA	PPL Electric Utilities	Electric	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., poles, wires)	Docket P-2012-2325034 (May 2013)
PA	UGI Central Penn Gas	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2013-2398835 (September 2014)
PA	UGI Penn Natural Gas	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2013-2397056 (September 2014)
PA	West Penn Power	Electric	Smart Meter Surcharge	AMI	Docket M-2009-2123951 (June 2011)
RI	Narragansett Electric (electric operations)	Electric	Electric Infrastructure, Safety, and Reliability Plan Factor	Replacements and load growth	Docket 4218 (December 2011)
RI	Narragansett Electric (gas operations)	Gas	Gas Infrastructure, Safety, and Reliability Plan Factor	Previous accelerated capital replacement program investments plus main and service replacements and reliability investments	Docket 4219 (September 2011)
SC	South Carolina Electric & Gas	Electric	NA	Nuclear generation	Docket 2008-196-E (March 2009)
SD	Black Hills Power	Electric	Environmental Improvement Adjustment tariff	Miscellaneous environmental projects	Docket EL11-001
SD	Black Hills Power	Electric	Phase in plan rate	Gas-fired generation	Docket EL12-062 (September 2013)
SD	Northern States Power- MN	Electric	Environmental Cost Recovery Tariff	Miscellaneous environmental projects	Docket EL07-026 (January 2009)
SD	Northern States Power- MN	Electric	Transmission Cost Recovery Tariff	Transmission	Docket EL07-007 (January 2009)
SD	Northern States Power- MN	Electric	Infrastructure Rider	Generation	Docket EL 12-046 (April 2013)
SD	Otter Tail Power	Electric	Transmission Cost Recovery Tariff	Retail sales portion of specific transmission projects	Docket EL 10-015 (November 2011)
SD	Otter Tail Power	Electric	Environmental Quality Cost Recovery Tariff	Miscellaneous environmental projects	Docket EL 14-082 (December 2014)
TN	Piedmont Natural Gas	Gas	Integrity Management Rider	Distribution and transmission integrity management planning as required by the US Department of Transportation	Docket 13-00118 (May 2014)
TX	AEP Texas Central	Electric	Advanced Metering System Surcharge	AMI	Docket 36928
TX	AEP Texas North	Electric	Advanced Metering System Surcharge	AMI	Docket 36928
TX	Atmos Energy Mid Tex	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity including mains replacement	Texas Utilities Code 104.301 and Gas Utilities Docket 9615
TX	Atmos Energy Pipelines	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity including mains replacement	Gas Utilities Dockets 9615 and 10640
TX	Atmos Energy West Texas Division	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity including mains replacement	Texas Utilities Code 104.301 and Gas Utilities Docket 9608
TX	Centerpoint Energy Entex - Houston Division	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity including mains replacement	Texas Utilities Code 104.301 and Gas Utilities Docket 10067
TX	Centerpoint Energy Houston Electric	Electric	Advanced Metering System Surcharge	AMI	Docket 35620 (August 2008)
TX	Centerpoint Energy Houston Electric	Electric	Distribution Cost Recovery Factor	Change in net distribution rate base since last rate case	Docket 44572 (August 2015)
TX	Oncor Electric Delivery	Electric	Advanced Metering System Surcharge	AMI	Docket 35718 (August 2008)
TX	Texas-New Mexico Power	Electric	Advanced Metering System Surcharge	AMI	Docket 38306 (July 2011)
UT	Questar Gas	Gas	Infrastructure Rate Adjustment Tracker	Replacement of aging high-pressure feeder lines	Docket 09-057-16 (June 2010)
VA	Appalachian Power	Electric	Environmental & Reliability Cost Recovery Surcharge	Miscellaneous environmental & reliability projects	Docket PUE-2007-00069 (December 2007)
VA	Appalachian Power	Electric	Environmental Rate Adjustment Clause	Miscellaneous environmental projects	Case PUE-2011-00035 (November 2011)
VA	Appalachian Power	Electric	Generation Rate Adjustment Clause	Dresden plant	Docket PUE-2011-00036 (January 2012)
VA	Atmos Energy	Gas	Infrastructure Reliability and Replacement Adjustment	Replacement of first generation plastic pipe and service lines and bare steel mains and services	Case PUE-2012-00049 (August 2012)
VA	Columbia Gas of Virginia	Gas	SAVE Rider	Replacement of bare steel and cast iron mains, some early plastic pipe, isolated bare steel services, and risers prone to failure	Case PUE-2011-00049 (November 2011)
VA	Roanoke Gas Company	Gas	SAVE Rider	Replacement of cast iron mains, bare steel mains and services and pre-1973 plastic pipe	Case PUE-2012-00030 (August 2012)
VA	Virginia Electric Power	Electric	Rider S	Virginia City Hybrid Energy Center	Case PUE-2007-00066 (March 2008)
VA	Virginia Electric Power	Electric	Rider R	Bear Garden Generating Station	Case PUE-2009-00017 (March 2010)
VA	Virginia Electric Power	Electric	Rider W	Warren County Power Station	Case PUE-2011-00042 (February 2012)
VA	Virginia Electric Power	Electric	Rider B	Biomass conversions	Case PUE-2011-00073 (March 2012)
VA	Virginia Electric Power	Electric	Rider BW	Brunswick County Power Station (natural gas combined cycle generating station)	Case PUE-2012-00128 (August 2013)

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
VA	Virginia Natural Gas	Gas	SAVE Rider	Replacement of first generation plastic mains, cast and wrought iron mains, bare and ineffectively coated steel mains, and service lines installed prior to 1971	Case PUE-2012-00012 (June 2012)
VA	Washington Gas Light	Gas	SAVE Rider	Replacement of bare and unprotected steel services and mains, mechanically coupled pipe, copper services, cast iron main, and pre-1975 plastic services	Cases PUE-2010-00087 and PUE-2012-00096 (April 2011 and November 2012)
WA	Cascade Natural Gas	Gas	Pipeline Replacement Program Cost Recovery Mechanism	Replacement of bare steel and poorly coated pipelines and distribution systems	Docket PG-131838 (October 2013)
WV	Appalachian Power	Electric	Construction/765kW Surcharge	Generation, environmental	Case 11-0274-E-GI (June 2011)
WV	Monongahela Power	Electric	Vegetation Management Surcharge	Capitalized distribution vegetation management expenses	Case 14-0702-E-42T (February 2015)
WV	Potomac Edison	Electric	Vegetation Management Surcharge	Capitalized distribution vegetation management expenses	Case 14-0702-E-42T (February 2015)
WV	Wheeling Power	Electric	Construction/765kW Surcharge	Generation, environmental	Case 11-0274-E-GI (June 2011)
WY	Black Hills Power	Electric	Cheyenne Prairie Generating Station rate rider tariff	Construction of Cheyenne Prairie Generating Station	Docket 20002-84-ET-12 (November 2012)
WY	Cheyenne Light, Fuel, & Power	Electric	Cheyenne Prairie Generating Station rate rider tariff	Construction of Cheyenne Prairie Generating Station	Docket 20003-123-ET-12 (November 2012)

III. Relaxing the Link Between Revenue and System Use

Policymakers are increasingly interested in relaxing the link between the revenues utilities realize, and the kWh and kW of system use by customers. This reduces the financial attrition that results from slowing growth in system use (given legacy rate designs) more efficiently than frequent rate cases. In addition, utilities have more incentive to embrace DSM. Three approaches to relaxing the revenue/usage link are well established: lost revenue adjustment mechanisms ("LRAMs"), revenue decoupling, and fixed/variable pricing.

A. Lost Revenue Adjustment Mechanisms

LRAMs keep utilities whole for short-term losses in base rate revenues that are due to their DSM programs (and potentially also DG). Recovery usually is effected through a special rate rider. Estimates of load losses are needed.

LRAMs encourage utilities to embrace DSM that is eligible for LRAM treatment. They do not provide recovery for the revenue impact of external forces, like DSM programs managed by independent agencies, which slow load growth. Estimates of load savings from utility DSM can be complex and are sometimes controversial. The scope of DSM initiatives addressed by LRAMs is therefore frequently limited to those for which load impacts are easier to measure. When usage charges are high, the utility remains at risk for revenue fluctuations in volumes and peak load due to weather, local economic activity, and other volatile demand drivers.

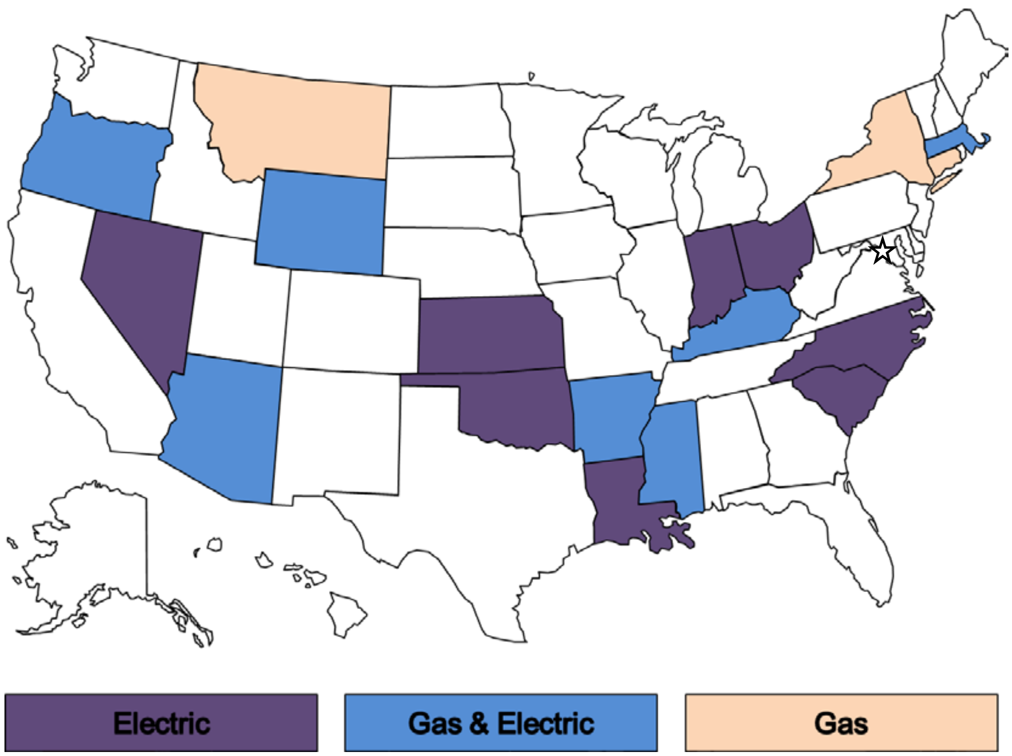
Precedents for LRAMs are detailed in Table 3 and Figure 4 below.[3] LRAMs are currently the most popular means of relaxing the link between revenue and system use in the US electric utility industry. Since our 2013 survey, LRAMs have been adopted for electric utilities in Arizona, Louisiana, and Mississippi. A few utilities have LRAMs that address DG. LRAMs are less popular for gas distributors since the declining average use they have typically experienced for many years is due chiefly to external forces that LRAMs don't address. Some utilities have LRAMs for some services and revenue decoupling for others. In New York, for example, some natural gas distributors have decoupling for residential and commercial customers and LRAMs for some large load customers.

B. Revenue Decoupling

Revenue decoupling adjusts a utility's rates periodically to help its actual revenue track its allowed revenue more closely. Most decoupling systems have two basic components: a revenue decoupling mechanism ("RDM") and a revenue adjustment mechanism ("RAM"). The RDM tracks variances between actual and allowed revenue and adjusts rates to reduce them. The RAM escalates allowed revenue to provide relief for growing cost pressures.

[3] Some mechanisms similar to LRAMs are excluded from this survey.

Figure 4: Current LRAMs by State



RDMs can make true ups annually or more frequently. More frequent adjustments cause actual revenue to track allowed revenue more closely so that rate adjustments are smaller. The size of the rate adjustment that is permitted in a given year is sometimes capped. A "soft" cap permits utilities to defer for later recovery account balances that cannot be drawn down immediately. A "hard" cap does not.

RDMs vary in the scope of services to which they apply. Quite commonly, only revenues from residential and commercial business customers are decoupled. These customers account for a high share of a distributor's base rate revenue and are often the primary focus of DSM programs. RDMs also vary in terms of the services for which revenues are pooled for true up purposes. In some plans all services are placed in the same "basket." Other plans have multiple baskets, and these insulate customers of services in each basket from changes in revenue for services in other baskets.

Some RDMs are "partial" in the sense that they exclude from decoupling the revenue impact of certain kinds of demand fluctuations. For example, true ups are sometimes allowed only for the difference between allowed revenue and weather normalized actuals. An RDM that instead accounts for *all* sources of demand variance is called a "full" decoupling mechanism.

Table 3

Current LRAM Precedents[1]

State	Company	Services	Approval Date	Case Reference
AR	Arkansas Oklahoma Gas	Gas	June 2011	Docket 07-077-TF, Order Number 30
AR	Centerpoint Energy Arkla	Gas	June 2011	Docket 07-081-TF, Order Number 31
AR	Entergy Arkansas	Electric	June 2011	Docket 07-085-TF, Order Number 40
AR	Oklahoma Gas & Electric	Electric	June 2011	Docket 07-075-TF, Order 26
AR	SourceGas Arkansas	Gas	June 2011	Docket 07-078-TF, Order 26
AR	Southwestern Electric Power	Electric	June 2011	Docket 07-082-TF, Orders 35 and 36
AZ	Arizona Public Service	Electric	May 2012	Docket E-01345A-11-0224, Decision 73l83
AZ	Tucson Electric Power	Electric	June 2013	Docket E-01933A-12-0291; Decision 73912
AZ	UNS Electric	Electric	September 2013	Docket E-04204A-12-0504; Decision 74235
AZ	UNS Gas	Gas	May 2012	Docket G-04204A-11-0158 Decision 73142
CT	Southern Connecticut Gas	Gas	August 1995	Docket 93-03-09
CT	Yankee Gas Service	Gas	January 2012	Docket 11-10-03
IN	Duke Energy Indiana (PSI)	Electric	February 2010	Cause 43374
IN	Indiana-Michigan Power	Electric	September 2010	Cause 43827
IN	Northern Indiana Public Service	Electric	May 2011	Cause 43618
IN	Southern Indiana Gas & Electric	Electric	August 2011 (large commercial and industrials), June 2012 (residential and small commercial)	Causes 43938 and 43405 DSMA 9 S1
KS	Kansas Gas & Electric	Electric	January 2011	Docket 10-WSEE-775-TAR
KS	Westar Energy	Electric	January 2011	Docket 10-WSEE-775-TAR
KY	Atmos Energy	Gas	September 2009	Case 2008-00499
KY	Columbia Gas of Kentucky	Gas	October 2009	Case 2009-00141
KY	Delta Natural Gas	Gas	July 2008	Docket 2008-00062
KY	Duke Energy Kentucky	Electric	December 1995 and February 2005	Cases 95-321 and 2004-00389
KY	Duke Energy Kentucky	Gas	February 2005	Case 2004-00389
KY	Kentucky Power	Electric	December 1995	Case 95-427
KY	Kentucky Utilities	Electric	May 2001	Case 2000-0459
KY	Louisville Gas & Electric	Electric & Gas	November 1993	Case 93-150
LA	Cleco Power	Electric	October 2014	Docket R-31106
LA	Entergy Gulf States Louisiana	Electric	October 2014	Docket R-31106
LA	Entergy Louisiana	Electric	October 2014	Docket R-31106
LA	Southwestern Electric Power	Electric	October 2014	Docket R-31106
MA	All Electric distributors	Electric	July 2012	D.P.U. 12-01A
MA	Berkshire Gas	Gas	October 1992	D.P.U. 91-154
MA	Commonwealth Gas d/b/a NSTAR Gas	Gas	November 1994	D.P.U. 94-128

Table 3 (cont'd)

State	Company	Services	Approval Date	Case Reference
MA	NSTAR Electric	Electric	April 1992, June 1994, and June 2010	D.P.U. 90-335, D.P.U. 94-2/3-CC, and D.P.U. 10-06
MS	Atmos Energy	Gas	August 2014	Docket 2014-UA-017
MS	Centerpoint Energy	Gas	August 2014	Docket 2014-UA-007
MS	Entergy Mississippi	Electric	September 2014	Docket 2009-UN-064
MS	Mississippi Power	Electric	March 2015	Docket 2014-UN-10
MT	Montana-Dakota Utilities	Gas	October 2006	Docket D2005.10.156; Order 6697c
NC	Duke Energy Carolinas	Electric	February 2010	Docket E-7, Sub 831
NC	Progress Energy Carolinas (Carolina Power & Light)	Electric	November 2009	Docket E-2, Sub 931
NC	Virginia Electric Power	Electric	October 2011	Docket E-22, Sub 464
NV	Nevada Energy	Electric	May 2011	Docket 10-10024
NV	Sierra Pacific Power	Electric	May 2011	Docket 10-10025
NY	Keyspan Long Island	Gas	December 2009	Case 06-G-1186; Currently effective for all customers not in RDM
NY	Keyspan New York	Gas	December 2009	Case 06-G-1185; Currently effective for all customers not in RDM
OH	American Electric Power (Ohio Power, Columbus Southern Power)	Electric	May 2010	Docket 09-1089-EL-POR; Effective for classes not included in RDM
OH	Dayton Power & Light	Electric	June 2009	Docket 08-1094-EL-SSO
OH	Duke Energy Ohio (Cincinnati Gas & Electric)	Electric	July 2007 and August 2012	Dockets 06-0091-EL-UNC and 11-4393-EL-RDR; Effective for classes not included in RDM
OH	First Energy Ohio (Cleveland Electric Illuminating, Toledo Edison, Ohio Edison)	Electric	March 2009	Docket 08-935-EL-SSO
OK	Empire District Electric	Electric	November 2009	Cause 200900146 Order 571326
OK	Oklahoma Gas & Electric	Electric	July 2008	Cause 200800059 Order 556179
OK	Public Service of Oklahoma	Electric	January 2010	Cause PUD 200900196; Order 572836
OR	Cascade Natural Gas	Gas	April 2006	Order 06-191; UG 167 Effective for classes not included in RDM
OR	Portland General Electric	Electric	September 2001	Order 01-836; UE 79 Effective for classes not included in RDM
OR	Avista Utilities	Gas	December 1993	Order 93-1881
SC	Duke Energy Carolinas	Electric	January 2010	Docket 2009-226-E Order 2010-79
SC	Progress Energy Carolinas	Electric	June 2009	Docket 2008-251-E Order 2009-373
SC	South Carolina Electric & Gas	Electric	July 2010	Docket 2009-261-E, Order 2010-472
WY	Cheyenne Light, Fuel, and Power	Electric & Gas	September 2011	Dockets 20003-108-EA-10 and 30005-140-GA-10
WY	Montana-Dakota Utilities	Electric	January 2007	Docket 20004-65-ET-06

[1] LRAMs listed here include only those mechanisms that compensate utilities for actual revenues lost due to DSM and DG.

The great majority of decoupling systems have a RAM since, if allowed revenue is static, the utility will experience financial attrition as its costs inevitably rise. Utilities that do not have RAMs in their decoupling systems often file frequent rate cases or are allowed to use capital cost trackers to address attrition. The more important issue in a proceeding to consider decoupling is therefore the design of the RAM rather than the need for one.

Most RAMs escalate allowed revenue only for customer growth. Escalation for customer growth is sensible because it is an important driver of cost and also highly correlated with other drivers such as peak demand. The need for rate cases is thereby reduced but is rarely eliminated since cost has other drivers such as input price inflation. When RAMs are escalated only for customer growth, utilities usually retain the freedom to file rate cases to address other cost factors and often do. Some RAMs are "broad-based" in the sense that they provide enough revenue growth to compensate the utility for several kinds of cost pressures. This can materially reduce the need for rate cases and provide a foundation for a multiyear rate plan.

Revenue decoupling compensates utilities for declining average use even if it is driven in part by external forces such as independently administered DSM programs. The lost revenue disincentive is removed for a wide array of utility initiatives to encourage DSM without requiring load impact calculations or rate designs that discourage DSM. To the extent that recovery of allowed revenue is ensured, utilities can use rate designs with usage charges more aggressively to foster DSM. This makes environmental intervenors strong supporters of decoupling. Controversy over billing determinants in rate cases with future test years is reduced.

Revenue decoupling is a popular means of relaxing the link between a utility's revenue and customers' kWh consumption. States that have tried gas and electric revenue decoupling are indicated on the maps below in Figures 5a and 5b, respectively. Revenue decoupling precedents in the United States and Canada are detailed in Table 4. In the electric utility industry, decoupling has been favored in states that strongly support DSM. Since our 2013 survey, decoupling has been adopted for electric utilities in Connecticut, Maine, Minnesota, and Washington state. Decoupling is the most widespread means of relaxing the revenue/usage link for gas distributors. This reflects the fact that gas distributors often experience declining average use and that this has been driven chiefly by external forces. Table 4 indicates the kinds of RAMs chosen in approved decoupling systems. Note that RAMs for electric utilities are frequently broad-based.

C. Fixed/Variable Pricing

Fixed/variable pricing is an approach to rate design that uses fixed charges (charges that do not vary with the actual sales volume or peak demand) to compensate utilities for fixed costs of service. For residential and small commercial services, customer charges (a flat monthly fee per customer) are the most common fixed charge used. Base revenue thus tends to grow at the gradual pace of customer growth. A *straight* fixed/variable ("SFV") rate design recovers *all* base revenue through fixed charges. A rate design that recovers a substantial but smaller share of fixed costs through fixed charges is sometimes called *modified* fixed/variable pricing.

Figure 5a: Electric Revenue Decoupling by State

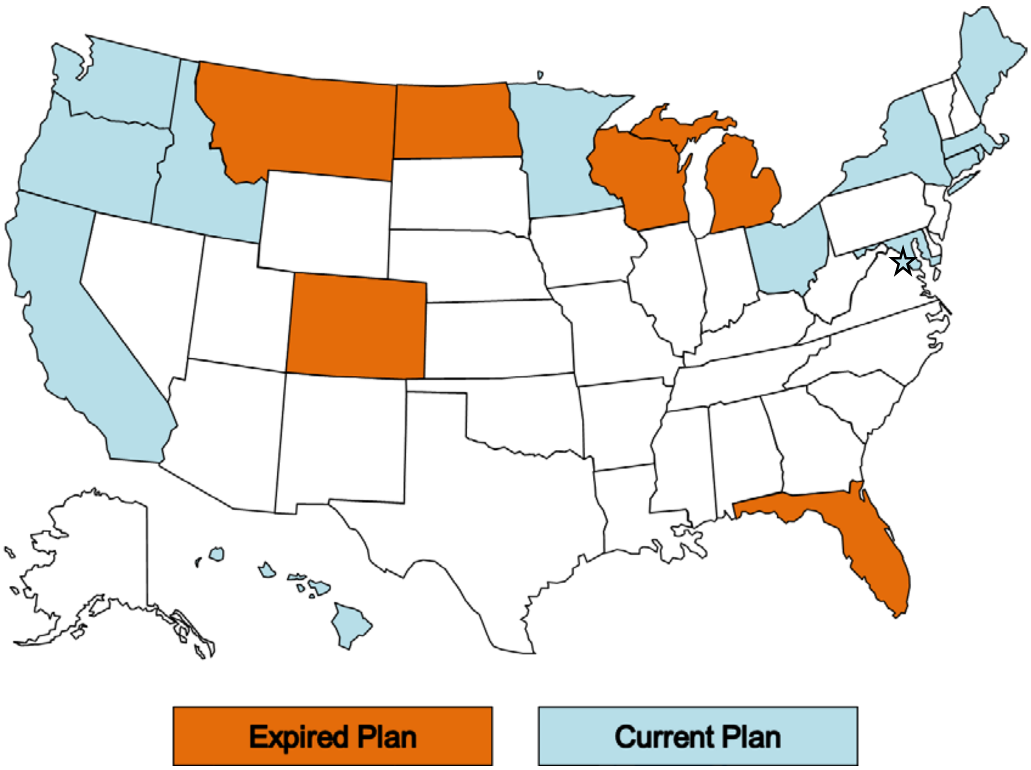


Figure 5b: Gas Revenue Decoupling by State

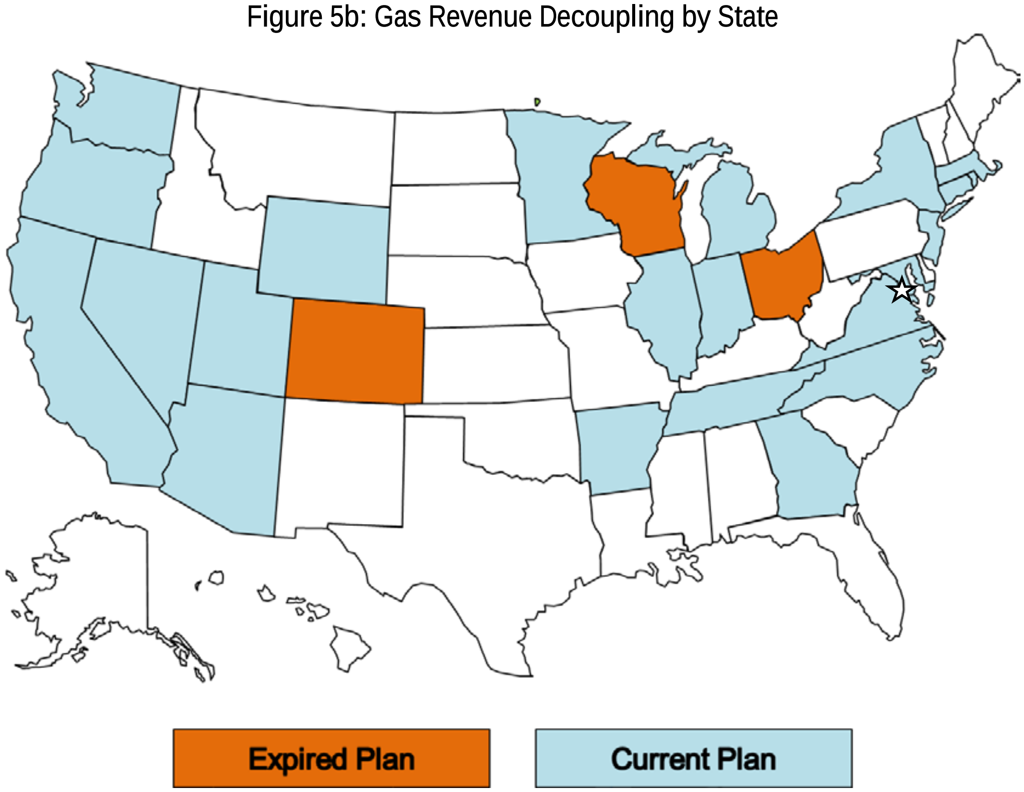


Table 4

Revenue Decoupling Precedents

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
Current					
United States					
AR	Arkansas Oklahoma Gas	Gas	2014-open	No RAM but multiple capital cost trackers	Docket 13-078-U
AR	CenterPoint Energy	Gas	2008-2016	No RAM but multiple capital cost trackers	Dockets 06-161-U, 11-088-U, 12-057-TF, and 13-114-TF
AR	SourceGas Arkansas (Arkansas Western)	Gas	2014-open	No RAM but multiple capital cost trackers	Docket 13-079-U
AZ	Southwest Gas	Gas	2012-open	Customers	Docket G-01551A-10-0458
CA	Bear Valley Electric Service	Electric	2013-2016	Stairstep	Decision 14-11-002
CA	California Pacific Electric	Electric	2013-2015	Indexing	Decision 12-11-030
CA	Pacific Gas & Electric	Gas & Electric	2014-2016	Stairstep	Decision 14-08-032
CA	San Diego Gas & Electric	Gas & Electric	2012-2015	Stairstep	Decision 13-05-010
CA	Southern California Edison	Electric	2012-2014	Hybrid	Decision 12-11-051
CA	Southern California Gas	Gas	2012-2015	Stairstep	Decision 13-05-010
CA	Southwest Gas	Gas	2014-2018	Stairstep	Decision 14-06-028
CT	Connecticut Light & Power	Electric	2014-open	No RAM	Docket 14-05-06
CT	Connecticut Natural Gas	Gas	2014-open	No RAM	Docket 13-06-08
CT	United Illuminating	Electric	2013-open	Stairstep until July 2015, No RAM thereafter	Docket 13-01-19
DC	Potomac Electric Power	Electric	2010-open	Customers	Order 15556
GA	Atmos Energy	Gas	2012-open	No RAM but FRP type mechanism also in effect	Docket 34734
HI	Hawaiian Electric Company	Electric	2011-open	Hybrid	Dockets 2008-0274, 2008-0083, 2013-0141
HI	Hawaiian Electric Light Company	Electric	2012-open	Hybrid	Dockets 2008-0274, 2009-0164, 2013-0141
HI	Maui Electric	Electric	2012-open	Hybrid	Dockets 2008-0274, 2009-0163, 2013-0141
ID	Idaho Power	Electric	2012-open	Customers	Cases IPC-E-11-19, IPC-E-14-17
IL	North Shore Gas	Gas	2012-open	No RAM	Case 11-0280
IL	Peoples Gas Light & Coke	Gas	2012-open	No RAM but broad-based capital cost tracker	Case 11-0281
IN	Citizens Gas	Gas	2007-open	Customers	Cause 42767
IN	Indiana Gas	Gas	2011-2015	Customers	Cause 44019
IN	Indiana Gas	Gas	2016-2019	Customers	Cause 44598
IN	Indiana Natural Gas	Gas	2014-open	Customers	Cause 44453
IN	Vectren Southern Indiana	Gas	2011-2015	Customers	Cause 44019
IN	Vectren Southern Indiana	Gas	2016-2019	Customers	Cause 44598
MA	Bay State Gas	Gas	2015-2018	Revenue per Customer Stairstep	DPU 15-50
MA	Boston-Essex Gas	Gas	2010-open	Customers	DPU 10-55
MA	Colonial Gas	Gas	2010-open	Customers	DPU 10-55
MA	Fitchburg Gas & Electric	Gas	2011-open	Customers	DPU 11-02
MA	Fitchburg Gas & Electric	Electric	2011-open	No RAM	DPU 11-01
MA	Massachusetts Electric	Electric	2010-open	No RAM but broad-based capital cost tracker	DPU 09-39
MA	New England Gas	Gas	2011-open	Customers	DPU 10-114
MA	Western Massachusetts Electric	Electric	2011-open	No RAM	DPU 10-70
MD	Baltimore Gas & Electric	Electric	2008-open	Customers	Letter Orders ML 108069, 108061
MD	Baltimore Gas & Electric	Gas	1998-open	Customers	Case 8780
MD	Chesapeake Utilities	Gas	2006-open	Customers	Order 81054
MD	Columbia Gas of Maryland	Gas	2013-open	Customers	Order 85858
MD	Delmarva Power & Light	Electric	2007-open	Customers	Order 81518
MD	Potomac Electric Power	Electric	2007-open	Customers	Order 81517
MD	Washington Gas Light	Gas	2005-open	Customers	Order 80130
ME	Central Maine Power	Electric	2014-open	Customers	Docket 2013-00168

Table 4 (cont'd)

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
Current (cont'd)					
United States (cont'd)					
MI	Consumers Energy	Gas	2015-open	No RAM	Case U-17643
MI	Michigan Consolidated Gas	Gas	2013-open	No RAM	Case U-16999
MI	Michigan Gas Utilities	Gas	2015-open	No RAM	Case U-17273
MN	CenterPoint Energy	Gas	2015-2018	Customers	GR-13-316
MN	Minnesota Energy Resources	Gas	2013-2016	Customers	GR-10-977
MN	Northern States Power - MN	Electric	2016-2018	Customers	GR-13-868
NC	Piedmont Natural Gas	Gas	2008-open	Customers	Docket G-9, Sub 550
NC	Public Service Co of NC	Gas	2008-open	Customers	Docket G-5, Sub 495
NJ	New Jersey Natural Gas	Gas	2014-open	Customers	Docket GR13030185
NJ	South Jersey Gas	Gas	2014-open	Customers	Docket GR13030185
NV	Southwest Gas	Gas	2009-open	Customers	D-09-04003
NY	Central Hudson G&E	Gas & Electric	2015-2018	Revenue per Customer Stairstep for Gas, Stairstep for Electric	Cases 14-E-0318, 14-G-0319
NY	Consolidated Edison	Gas	2014-2016	Revenue per Customer Stairstep	Case 13-G-0031
NY	Consolidated Edison	Electric	2014-2016	Stairstep	Case 13-E-0030
NY	Corning Natural Gas	Gas	2015-2017	Customers	Case 11-G-0280
NY	Keyspan Energy Delivery - Long Island	Gas	2010-open	Revenue per Customer Stairstep through 2012, Customers After 2012	Case 06-G-1186
NY	Keyspan Energy Delivery New York	Gas	2013-2014	Revenue per Customer Stairstep through 2014, Customers After 2014	Case 12-G-0544
NY	National Fuel Gas	Gas	2013-2015	Customers	Case 13-G-0136
NY	New York State Electric & Gas	Gas	2010-2013	Revenue per Customer Stairstep through 2013, Customers thereafter	Case 09-E-0715
NY	New York State Electric & Gas	Electric	2010-2013	Stairstep through 2013, No RAM thereafter	Case 09-G-0716
NY	Niagara Mohawk	Gas	2013-2016	Optional Revenue per Customer Stairstep	Case 12-G-0202
NY	Niagara Mohawk	Electric	2013-2016	Optional Stairstep	Case 12-E-0201
NY	Orange & Rockland Utilities	Gas	2015-2018	Revenue per Customer Stairstep	Case 14-G-0494
NY	Orange & Rockland Utilities	Electric	2015-2017	Stairstep	Case 14-E-0493
NY	Rochester Gas & Electric	Gas	2010-2013	Revenue per Customer Stairstep through 2013, Customers thereafter	Case 09-E-0717
NY	Rochester Gas & Electric	Electric	2010-2013	Stairstep through 2013, No RAM thereafter	Case 09-G-0718
NY	St. Lawrence Gas	Gas	2010-open	Revenue per Customer Stairstep through 2012, Customers thereafter	Case 08-G-1392
OH	AEP Ohio	Electric	2012-2018	Customers	Cases 11-351-EL-AIR, 13-2385-EL-SSO
OH	Duke Energy Ohio	Electric	2015-open	Customers	Case 14-841-EL-SSO
OR	Cascade Natural Gas	Gas	2013-2015	Customers	Order 13-079
OR	Northwest Natural Gas	Gas	2012-open	Customers	Order 12-408
OR	Portland General Electric	Electric	2014-2016	Customers	Order 13-459
RI	Narragansett Electric	Electric	2012-open	No RAM but broad-based capital cost tracker	Docket 4206
RI	Narragansett Electric	Gas	2012-open	Customers	Docket 4206
TN	Chattanooga Gas	Gas	2013-open	Customers	Docket 09-0183
UT	Questar Gas	Gas	2010-open	Customers	Docket 09-057-16
VA	Columbia Gas of Virginia	Gas	2013-2015	Customers	Case PUE-2012-00013
VA	Virginia Natural Gas	Gas	2013-2016	Customers	Case PUE-2012-00118
VA	Washington Gas Light	Gas	2013-2016	Customers	Case PUE-2012-00138
WA	Avista	Gas & Electric	2015-2019	Customers	Dockets UE-140188 and UG-140189
WA	Puget Sound Energy	Gas & Electric	2013-2016	Revenue per Customer Stairstep	Dockets UE-121697 and UG-121705
WY	Questar Gas	Gas	2012-open	Customers	Docket 30010-113-GR-11
WY	SourceGas Distribution	Gas	2011-open	Customers	Docket 30022-148-GR-10

Table 4 (cont'd)

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
Current (cont'd)					
Canada					
BC	BC Hydro	Electric	2015-2016	Stairstep	Order G-48-14
BC	FortisBC	Electric	2014-2019	Indexing	Order G-139-14
BC	FortisBC Energy	Gas	2014-2019	Indexing	Order G-138-14
BC	Pacific Northern Gas	Gas	2003-open	Customers	N/A
ON	Enbridge Gas Distribution	Gas	2014-2018	Stairstep	EB-2012-0459
ON	Union Gas	Gas	2014-2018	Indexing	EB-2013-0202
Historic					
United States					
AR	Arkansas Oklahoma Gas	Gas	2007-2013	No RAM	Dockets 07-026-U, 07-077-TF
AR	Arkansas Western	Gas	2008-2013	No RAM	Docket 07-078-TF
CA	Bear Valley Electric Service	Electric	2009-2012	Stairstep	Decision 09-10-028
CA	Pacific Gas & Electric	Gas & Electric	1982-1983	Hybrid	Decision 93887
CA	Pacific Gas & Electric	Electric	1984-1985	Hybrid	Decision 83-12-068
CA	Pacific Gas & Electric	Electric	1986-1989	Hybrid	Decision 85-12-076
CA	Pacific Gas & Electric	Electric	1990-1992	Hybrid	Decision 89-12-057
CA	Pacific Gas & Electric	Gas & Electric	1993-1995	Hybrid	Decision 92-12-057
CA	Pacific Gas & Electric	Gas & Electric	2004-2006	Indexing	Decision 04-05-055
CA	Pacific Gas & Electric	Gas & Electric	2007-2010	Stairstep	Decision 07-03-044
CA	Pacific Gas & Electric	Gas & Electric	2011-2013	Stairstep	Decision 11-05-018
CA	Pacific Gas & Electric	Gas	1978-1981	No RAM	Decisions 89316, 91107
CA	PacifiCorp	Electric	1984-1985	Stairstep	Decision 89-09-034
CA	San Diego Gas & Electric	Gas & Electric	1982-1983	Hybrid	Decision 93892
CA	San Diego Gas & Electric	Gas & Electric	1986-1988	Hybrid	Decision 85-12-108
CA	San Diego Gas & Electric	Electric	1989-1993	Hybrid	Decision 89-11-068
CA	San Diego Gas & Electric	Gas & Electric	1994-1999	Hybrid	Decision 94-08-023
CA	San Diego Gas & Electric	Gas & Electric	2005-2007	Indexing	Decision 05-03-025
CA	San Diego Gas & Electric	Gas & Electric	2008-2011	Stairstep	Decision 08-07-046
CA	Southern California Edison	Electric	1983-1984	Hybrid	Decision 82-12-055
CA	Southern California Edison	Electric	1986-1991	Hybrid	Decision 85-12-076
CA	Southern California Edison	Electric	2001-2003	Indexing	Decision 02-04-055
CA	Southern California Edison	Electric	2004-2006	Hybrid	Decision 04-07-022
CA	Southern California Edison	Electric	2006-2008	Hybrid	Decision 06-05-016
CA	Southern California Edison	Electric	2009-2011	Stairstep	Decision 09-03-025
CA	Southern California Gas	Gas	1979-1980	No RAM	Decision 89710
CA	Southern California Gas	Gas	1981-1982	Stairstep	Decision 92497
CA	Southern California Gas	Gas	1983-1984	Hybrid	Decision dated December 8, 1982
CA	Southern California Gas	Gas	1986-1989	Hybrid	Decision 85-12-076
CA	Southern California Gas	Gas	1990-1993	Hybrid	Decision 90-01-016
CA	Southern California Gas	Gas	1998-2002	Indexing	Decision 97-07-054
CA	Southern California Gas	Gas	2005-2007	Indexing	Decision 05-03-025
CA	Southern California Gas	Gas	2008-2011	Stairstep	Decision 08-07-046
CA	Southwest Gas	Gas	2009-2013	Stairstep	Decision 08-11-048
CO	Public Service Company of Colorado	Gas	2008-2011	Customers	Decision C07-0568
CO	Public Service Company of Colorado	Electric	2012-2014	Stairstep	Decision C12-0494
CT	United Illuminating	Electric	2009-2013	Stairstep until 2011/No RAM for 2011 onwards	Docket 08-07-04
FL	Florida Power Corporation	Electric	1995-1997	Customers	Docket 930444
ID	Idaho Power	Electric	2007-2009	Customers	Case IPC-E-04-15
ID	Idaho Power	Electric	2010-2012	Customers	Case IPC-E-09-28
IL	North Shore Gas	Gas	2008-2012	Customers	Case 07-0241
IL	Peoples Gas Light & Coke	Gas	2008-2012	Customers	Case 07-0242
IN	Citizens Gas	Gas	2007-2011	Customers	Cause 42767
IN	Vectren Energy	Gas	2007-2011	Customers	Cause 43046
IN	Vectren Southern Indiana	Gas	2007-2011	Customers	Cause 43046
MA	Bay State Gas	Gas	2009-open	Customers	DPU 09-30
ME	Central Maine Power	Electric	1991-1993	Customers	Docket 90-085
MI	Consumers Energy	Electric	2009-2011	Customers	Case U-15645
MI	Consumers Energy	Gas	2010-2012	Customers	Case U-15986
MI	Detroit Edison	Electric	2010-2011	Customers	Case U-15768
MI	Michigan Consolidated Gas	Gas	2010-2012	Customers	Case U-15985
MI	Michigan Gas Utilities	Gas	2010-2013	Customers	Case U-15990
MI	Upper Peninsula Power	Electric	2010-2011	Customers	Case U-15988
MN	CenterPoint Energy	Gas	2010-2013	Customers	Docket GR-08-1075
MT	Montana Power Company	Electric	1994-1998	Customers	Docket 93.6.24

Table 4 (cont'd)

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
Historic (cont'd)					
United States (cont'd)					
NC	Piedmont Natural Gas	Gas	2005-2008	Customers	Docket G-44 Sub 15
ND	Northern States Power - MN	Electric	2012	Not Applicable, plan only 1 year in duration	Case PU-11-55
NJ	New Jersey Natural Gas	Gas	2007-2010	Customers	Docket GR05121020
NJ	New Jersey Natural Gas	Gas	2010-2013	Customers	Docket GR05121020
NJ	South Jersey Gas	Gas	2007-2010	Customers	Docket GR05121019
NJ	South Jersey Gas	Gas	2010-2013	Customers	Docket GR05121019
NY	Central Hudson G&E	Gas	2009-open	Customers	Case 08-E-0888
NY	Central Hudson G&E	Electric	2009	No RAM	Case 08-E-0887
NY	Central Hudson G&E	Gas & Electric	2010-2013	Revenue per Customer Stairstep for Gas, Stairstep for Electric	Case 09-E-0588
NY	Central Hudson G&E	Gas & Electric	2013-open	Customers for Gas, No RAM for Electric	Case 12-M-0192
NY	Consolidated Edison	Electric	1992-1995	Stairstep	Opinion 92-8
NY	Consolidated Edison	Gas	2007-2010	Stairstep	Case 06-G-1332
NY	Consolidated Edison	Electric	2008-open	No RAM	Case 07-E-0523
NY	Consolidated Edison	Gas	2010-2013	Revenue per Customer Stairstep	Case 09-G-0795
NY	Consolidated Edison	Electric	2010-2013	Stairstep	Case 09-E-0428
NY	Corning Natural Gas	Gas	2012-2015	Revenue per Customer Stairstep	Case 11-G-0280
NY	Keyspan Energy Delivery - New York	Gas	2010-open	Revenue per Customer Stairstep	Case 06-G-1185
NY	Long Island Lighting Company	Electric	1992-1994	Stairstep	Opinion 92-8
NY	National Fuel Gas	Gas	2008-open	Customers	Case 07-G-0141
NY	New York State Electric & Gas	Electric	1993-1995	Stairstep	Opinion 93-22
NY	Niagara Mohawk	Electric	1990-1992	Stairstep	Case 94-E-0098
NY	Niagara Mohawk	Gas	2009-open	Customers	Case 08-G-0609
NY	Niagara Mohawk	Electric	2011-open	No RAM	Case 10-E-0050
NY	Orange & Rockland Utilities	Electric	2012-2015	Stairstep	Case 11-E-0408
NY	Orange & Rockland Utilities	Electric	2011-2012	No RAM	Case 10-E-0362
NY	Orange & Rockland Utilities	Electric	2008-2011	Stairstep	Case 07-E-0949
NY	Orange & Rockland Utilities	Electric	1991-1993	Stairstep	Case 89-E-175
NY	Orange & Rockland Utilities	Gas	2012-2015	Customers	Case 08-G-1398
NY	Orange & Rockland Utilities	Gas	2009-2012	Revenue per Customer Stairstep	Case 08-G-1398
NY	Rochester Gas & Electric	Electric	1993-1996	Stairstep	Opinion 93-19
OH	Duke Energy Ohio	Electric	2012-2014	Customers	Case 11-5905-EL-RDR
OH	Vectren Energy	Gas	2007-2009	Customers	Case 05-1444-GA-UNC
OR	Cascade Natural Gas	Gas	2007-2012	Customers	Order 06-191
OR	Northwest Natural Gas	Gas	2002-2005	Customers	Order 02-634
OR	Northwest Natural Gas	Gas	2005-2009	Customers	Order 05-934
OR	Northwest Natural Gas	Gas	2009-2012	Customers	Order 07-426
OR	PacifiCorp	Electric	1998-2001	Indexing	Order 98-191
OR	Portland General Electric	Electric	1995-1996	Stairstep	Order 95-0322
OR	Portland General Electric	Electric	2009-2010	Customers	Order 09-020
OR	Portland General Electric	Electric	2011-2013	Customers	Order 10-478
TN	Chattanooga Gas	Gas	2010-2013	Customers	Docket 09-0183
UT	Questar Gas	Gas	2006-2010	Customers	Docket 05-057-T01
VA	Virginia Natural Gas	Gas	2009-2012	Customers	Case PUE-2008-00060
VA	Washington Gas Light	Gas	2010-2013	Customers	Case PUE-2009-00064
WA	Avista	Gas	2007-2009	Customers	Docket UG-060518
WA	Avista	Gas	2009-2012	Customers	Docket UG-060518
WA	Avista	Gas	2013-2014	Revenue per Customer Stairstep	Docket UG-120437
WA	Cascade Natural Gas	Gas	2005-2010	Customers	Docket UG-060256
WA	Puget Sound & Power	Electric	1991-1995	Customers	Docket UE-901184-P
WI	Wisconsin Public Service	Gas & Electric	2009-2012	Customers	D-6690-UR-119
WI	Wisconsin Public Service	Gas & Electric	2013	Not Applicable, plan only 1 year in duration	Docket 6690-UR-121
WY	Questar Gas	Gas	2009-2012	Customers	Docket 30010-94-GR-08

Table 4 (cont'd)

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
Historic (cont'd)					
Canada					
BC	BC Gas	Gas	1994-1995	Hybrid	Order G-59-94
BC	BC Gas	Gas	1996-1997	Hybrid	N/A
BC	BC Gas	Gas	1998-2000	Hybrid	Order G-85-97
BC	BC Gas	Gas	2000-2001	Hybrid	Order G-48-00
BC	BC Hydro	Electric	2009-2010	Hybrid	Order G-16-09
BC	BC Hydro	Electric	2011	Not Applicable, plan only 1 year in duration	Order G-180-10
BC	BC Hydro	Electric	2012-2014	Stairstep	Order G-77-12A
BC	FortisBC	Electric	2012-2013	Stairstep	Order G 110-12
BC	Terasen Gas	Gas	2008-2009	Hybrid	Order G-33-07
BC	Terasen Gas	Gas	2004-2007	Hybrid	Order G-51-03
BC	Terasen Gas	Gas	2010-2011	Hybrid	Order G-141-09
BC	Terasen Gas	Gas	2012-2013	Stairstep	Order G-44-12
ON	Enbridge Gas Distribution	Gas	2008-2012	Revenue per Customer Indexing	Docket EB-2007-0615
ON	Union Gas	Gas	2008-2012	Indexing	Docket EB-2007-0606

Fixed/variable pricing relaxes the revenue/usage link with low administrative cost since it requires neither decoupling true ups nor load impact calculations. When average use is declining, base revenue will grow more rapidly with fixed/variable pricing so that rate cases tend to be less frequent even if the decline is largely driven by external forces. Base revenue grows more slowly than under conventional rate designs if average use is rising. The short term disincentive is removed to embrace various DSM initiatives. However, fixed/variable pricing reduces a utility's ability to use usage charges as a tool for promoting DSM. For example, it does not encourage customers with electric vehicles to charge these vehicles at night. Note also that the principle of rate design gradualism often discourages regulators from immediately adopting SFV pricing.

SFV pricing has been used on a large scale by interstate gas transmission companies since the early 1990s. Precedents for fixed/variable pricing in retail ratemaking are listed below on Table 5 and Figure 6. It can be seen that fixed/variable pricing has to date been considerably more common for gas distributors than electric utilities. This again reflects the greater problem of declining average use that gas distributors have faced, and the fact that the decline has been driven largely by external forces. Since our 2013 survey, fixed/variable pricing has been implemented for an electric utility in Oklahoma.

In addition to the precedents listed here, utilities in Wisconsin and several other states have in recent years made sizable steps in the direction of fixed/variable pricing by redesigning rates for small volume customers to raise customer charges and lower volumetric charges substantially. Investor-owned utilities in Canada are typically permitted to raise a much higher portion of their revenue through fixed charges than are utilities in the United States. Most fixed/variable rate designs feature uniform fixed charges within service classes, but gas utilities in Florida, Georgia, and Oklahoma have fixed charges that vary in some fashion with long term consumption patterns.

Figure 6: Fixed/Variable Pricing Precedents by State

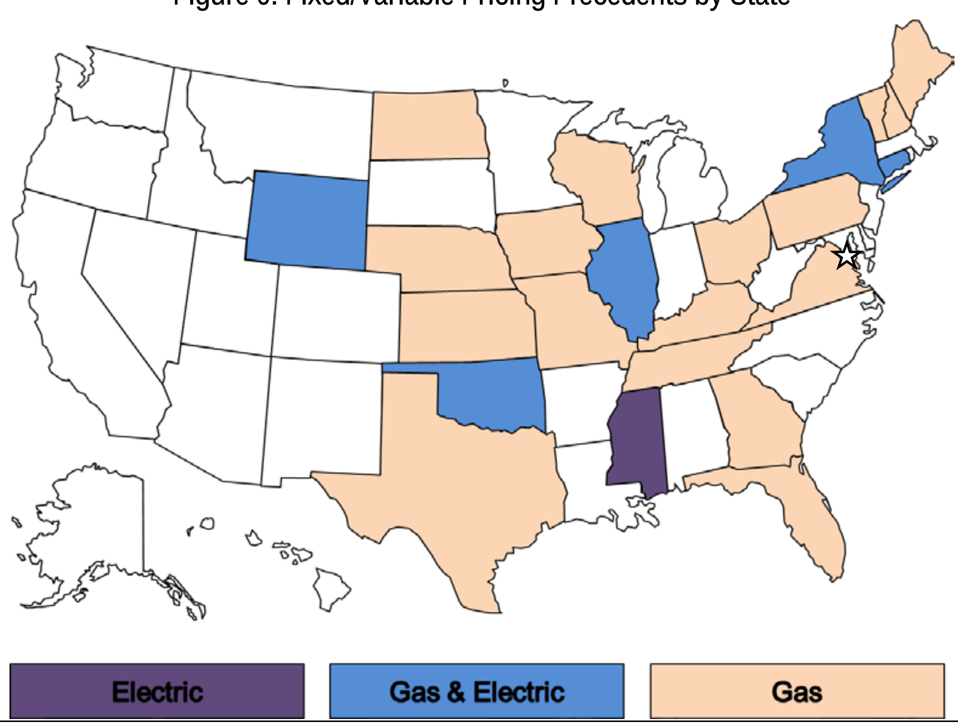


Table 5

Fixed Variable Residential Pricing Precedents[1]

Jurisdiction	Company Name	Services	Years in Place	Case Reference
CT	Connecticut Light & Power	Electric	2007-open	Docket 07-07-01
CT	Connecticut Natural Gas	Gas	2014-open	Docket 13-06-08
CT	United Illuminating	Electric	Occurred over period of years	No specific case
CT	Yankee Gas System	Gas	2011-open	Docket 10-12-02
FL	Peoples Gas System	Gas	2009-open	Docket 080318-GU
GA	Liberty Utilities	Gas	2015-open	Docket 34734
IA	Black Hills Energy	Gas	2009-open	Docket RPU-08-3
IL	Ameren CILCO	Gas	2008-2012	Case 07-0588
IL	Ameren CIPS	Gas	2008-2012	Case 07-0589
IL	Ameren IP	Gas	2008-2012	Case 07-0590
IL	Ameren Illinois	Gas	2012-open	Case 11-0282
IL	Ameren Illinois	Electric	Occurred over period of years	No specific case
IL	Commonwealth Edison	Electric	2011-2013	Case 10-0467
IL	Mt. Carmel Public Utilities	Gas	2013-open	Case 13-0079
IL	North Shore Gas	Gas	2008-open	Case 07-0241
IL	Peoples Gas Light & Coke	Gas	2008-open	Case 07-0242
KS	Atmos Energy	Gas	2010-open	Docket 10-ATMG-495-RTS
KS	Black Hills Energy (formerly Aquila)	Gas	2007-open	Docket 07-AQLG-431-RTS
KS	Kansas Gas Service	Gas	2012-open	Docket 12-KGSG-835-RTS
KY	Atmos Energy	Gas	2014-open	Case 2013-00148
KY	Columbia Gas	Gas	2013-open	Case 2013-00167
KY	Delta Natural Gas	Gas	2007-open	Case 2007-00089
KY	Duke Energy Kentucky	Gas	2010-open	Case 2009-00202
ME	Maine Natural Gas	Gas	Occurred over period of years	Docket 2009-00067
ME	Northern Utilities	Gas	2014-open	Docket 2013-00133
MO	AmerenUE	Gas	2007-open	Case GR-2007-0003
MO	Atmos Energy	Gas	2007-2010	Case GR-2006-0387
MO	Atmos Energy	Gas	2010-open	Case GR-2010-0192
MO	Empire District Gas	Gas	2010-open	Case GR-2009-0434
MO	Laclede Gas	Gas	2002-open	Case GR-2002-356
MO	Missouri Gas Energy	Gas	2007-open	Case GR-2006-0422
MS	Mississippi Power	Electric	Occurred over period of years	No specific case
ND	Xcel Energy	Gas	2005-open	Case PU-04-578
NE	SourceGas Distribution	Gas	2012-open	Docket NG-0067
NH	Liberty Utilities (EnergyNorth Natural Gas)	Gas	Occurred over period of years	No specific case
NH	Northern Utilities	Gas	2014-open	DG 13-086
NY	Central Hudson Gas & Electric	Electric & Gas	Occurred over period of years	No specific case
NY	Consolidated Edison	Electric & Gas	Occurred over period of years	No specific case
NY	Corning Gas	Gas	Occurred over period of years	No specific case
NY	Keyspan Energy Delivery - Long Island	Gas	Occurred over period of years	No specific case
NY	Keyspan Energy Delivery - New York	Gas	Occurred over period of years	No specific case
NY	National Fuel Gas	Gas	Occurred over period of years	No specific case

Table 5 (cont'd)

Jurisdiction	Company Name	Services	Years in Place	Case Reference
NY	New York State Electric & Gas	Electric	Occurred over period of years	No specific case
NY	Niagara Mohawk	Electric & Gas	Occurred over period of years	No specific case
NY	Orange & Rockland	Electric & Gas	Occurred over period of years	No specific case
NY	Rochester Gas & Electric	Electric & Gas	Occurred over period of years	No specific case
OH	Columbia Gas	Gas	2008-open	Case 08-0072-GA-AIR
OH	Dominion East Ohio	Gas	2008-2010	Case 07-830-GA-ALT
OH	Duke Energy Ohio (CG&E)	Gas	2008-open	Case 07-590-GA-ALT
OH	Vectren Energy Delivery of Ohio	Gas	2009-open	Case 07-1080-GA-AIR
OK	Arkansas Oklahoma Gas	Gas	2013-open	Cause PUD 201200236
OK	Centerpoint Energy	Gas	2010-open	Cause PUD 201000030
OK	Oklahoma Natural Gas	Gas	2004-open	Causes PUD 200400610, PUD 201000048, PUD 200900110
OK	Public Service Company of Oklahoma	Electric	2015-open	Cause PUD 201300217
PA	Columbia Gas	Gas	2013-open	Docket R-2012-2321748
TN	Atmos Energy	Gas	2012-open	Docket 12-00064
TN	Piedmont Natural Gas	Gas	2012-open	Docket 11-00144
TX	Atmos Energy - Mid-Tex Division	Gas	Occurred over period of years	No specific case
TX	Atmos Energy - West Texas Division	Gas	Occurred over period of years	No specific case
TX	Centerpoint Energy Houston Division	Gas	Occurred over period of years	No specific case
TX	Centerpoint Energy Beaumont/East Texas Division	Gas	Occurred over period of years	No specific case
VA	Columbia Gas of Virginia	Gas	Occurred over period of years	No specific case
VT	Vermont Gas Systems	Gas	Occurred over period of years	No specific case
WI	Madison Gas & Electric	Gas	2015-open	Docket 3270-UR-120
WI	Wisconsin Public Service	Gas	2015-open	Docket 6690-UR-123
WY	SourceGas Distribution	Gas	2011-open	Docket 30022-148-GR-10
WY	PacifiCorp (d/b/a Rocky Mountain Power)	Electric	2009-open	Docket 20000-333-ER-08

[1] Fixed variable pricing precedents include power and gas distributors that have a customer charge equal to or in excess of $15 (or $20 for vertically integrated electric utilities).

IV. Forward Test Years

General rate cases involve "test years" in which revenue requirements and billing determinants (e.g., the residential delivery volume) are jointly considered in ratesetting. A historical test year ends before the rate case is filed. A forward (a/k/a "fully forecasted") test year ("FTY") begins after the rate case is filed. An FTY typically begins about the time the rate case is expected to end and new rates take effect. Two-year forecasts may be required in this event which span both the year of the rate case and the rate effective year.[4] In between forward and historical test years is the option of a "partially forecasted" test year in which some months of historical data on utility operations are combined with some months of forecasted data. Under this approach, actual data for all months usually become available during the course of the rate case.

Historical test years tend to be uncompensatory when cost is growing faster than billing determinants. Annual rate cases with historical test years can alleviate but not eliminate underearning under these conditions. The effect on credit metrics can be material.[5] Where historical test years are used, there are thus added advantages to implementing other Altreg innovations discussed in this survey.

Forward test years can fully compensate utilities when cost growth exceeds growth in billing determinants. If this imbalance is chronic, however, FTYs do not eliminate the problem of frequent rate cases. It is therefore not unusual for regulators to combine FTYs with other Altreg remedies, such as cost trackers or multiyear rate plans.

Many approaches are used to forecast costs in FTY rate cases. Some companies rely on their budgeting process to make cost projections. Others normalize data for an historical reference period, adjusted for known and measurable changes, and then use indexing and other statistical methods to extend projections. A mixture of forecasting methods is common. For example, index-based forecasting may be used only for O&M expenses.

FTYs were adopted in many jurisdictions during the 1970s and 1980s, when rapid inflation and major plant additions coincided with oil shock-induced slowdowns in the growth of average use. Several additional states have recently moved in the direction of FTYs. Some of these states are in the West, where comparatively rapid economic growth has required more rapid buildout of utility infrastructure.

Current state policies concerning test years are summarized below in Figure 7 and Table 6. In many jurisdictions the use of partially or fully-forecasted test years is not standardized. For example, in some jurisdictions, including Illinois and North Dakota, utilities are allowed to select their type of rate case test year. Test year selection may also be made part of the rate case (e.g., Utah). A few jurisdictions allow forward test years to be used in rate cases or formula rate plans, but not both (e.g., Illinois and Arkansas).

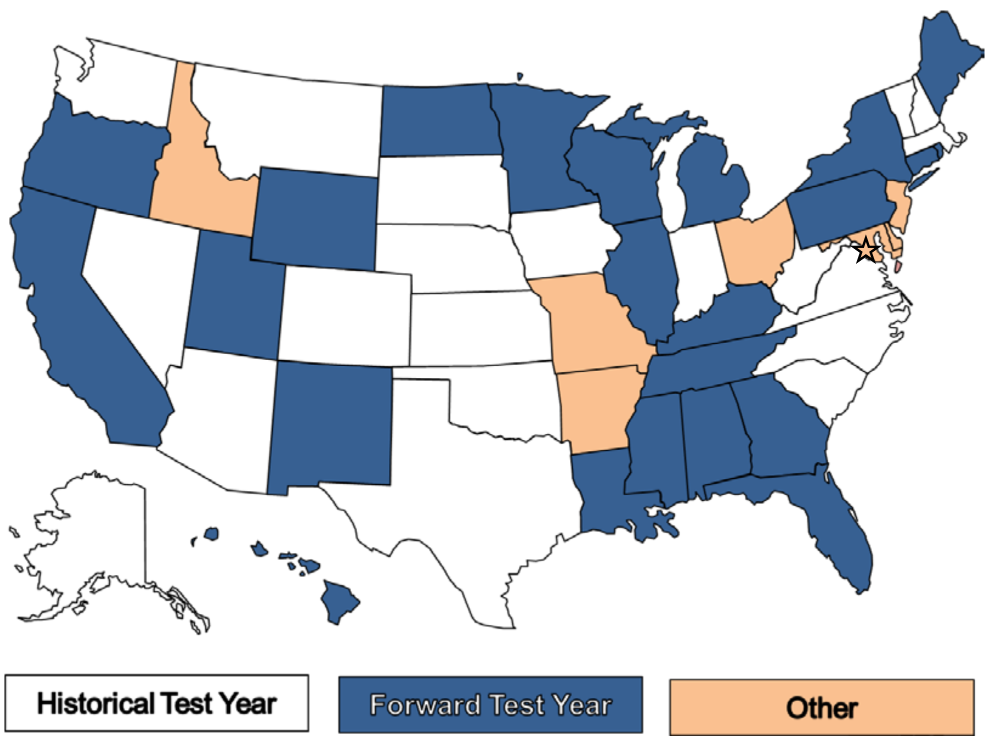
[4] A forward test year can in principle be the rate case year, and thereby not require two-year forecasts. Proposed rates can be established on an interim basis shortly after the filing.

[5] For evidence see "Forward Test Years for US Electric Utilities" by Mark Newton Lowry, David Hovde, Lullit Getachew, and Matt Makos, Edison Electric Institute, 2010.

Because of these complications, we have separated Table 6 into separate sections, specifying where FTYs are commonly used or occasionally used. Figure 7 shows jurisdictions where FTYs are commonly or occasionally used. Jurisdictions where partially-forecasted test years are commonly or occasionally used are in the category titled Other, with the remaining jurisdictions counted as historical test years.

The ranks of US jurisdictions that allow the use of forward test years have swollen and now encompass about half of the total. Since our 2013 survey, electric utilities in Pennsylvania have successfully used FTYs and utilities in Arkansas and Indiana have received legislative authorization for their use.[6] [7] Forward test years are the norm in Canadian regulation.

Figure 7: Test Year Policy by State



[6] In addition, another electric utility in Mississippi was recently permitted to use a forward-looking formula rate plan.
[7] FTYs in Arkansas can only be used in formula rate plans.

Table 6

Test Year Approaches of US Jurisdictions

Jurisdiction	Notes
Fully-Forecasted Test Years Commonly Used (15)	
Alabama	Utilities operate under forward-looking formula rate plans
California	
Connecticut	
FERC	Rate cases use forward test years but some formula rate plans use historical test years
Florida	
Georgia	
Hawaii	
Maine	
Michigan	
Minnesota	
New York	
Oregon	
Rhode Island	
Tennessee	
Wisconsin	
Fully-Forecasted Test Years Occasionally Used (9)	
Illinois	Utilities use various test years including forward test years ("FTYs")
Kentucky	Utilities use various test years including FTYs
Louisiana	Utilities use various test years including FTYs
Mississippi	Both electric utilities operate under forward-looking formula rate plans. Gas formula rate plans rely on historical test years ("HTYs").
New Mexico	A recently passed law allows for use of FTYs, and at least one rate increase based on FTY evidence has been approved
North Dakota	Utilities use various test years including FTYs
Pennsylvania	Partially-forecasted test years have traditionally been the norm. However, a law allowing fully-forecasted test years passed in 2012 and several electric utility rate increases based on FTY evidence have been approved.
Utah	Test year selection is part of the rate case and can be contested. Several recent rate cases have used FTYs.
Wyoming	Rocky Mountain Power has recently used FTYs
Partially-Forecasted Test Years Commonly or Occasionally Used (8)	
Arkansas	Utilities have typically used partially forecasted test years in rate cases. However, a recent bill authorized the use of formula rates with either historical or forecasted test periods.
Delaware	Before restructuring FTY filings were common, but companies have used a mix of HTYs and partially-forecasted test years in recent filings
District of Columbia	PEPCO has filed rate cases using both hybrid and historical test years recently
Idaho	
Maryland	Utilities use various test years excluding FTYs
Missouri	Utilities have the option to file partially-forecasted test years
New Jersey	
Ohio	
Historical Test Years Commonly Used (20)	
Alaska	
Arizona	
Colorado	Utilities have filed FTY evidence. However, no FTY rates have yet been approved but a recent case made extraordinary HTY adjustments.
Indiana	A recently passed law allows for use of FTYs, but no rate increase based on FTY evidence has been approved for an energy utility to date
Iowa	
Kansas	
Massachusetts	
Montana	
Nebraska	Nebraska has no electric IOUs. Gas companies are legally authorized to use FTYs but commonly use HTYs.
Nevada	
New Hampshire	
North Carolina	
Oklahoma	
South Carolina	
South Dakota	
Texas	
Vermont	
Virginia	
Washington	
West Virginia	

V. Multiyear Rate Plans

Multiyear rate plans ("MRPs") are designed to reduce regulatory cost, while increasing the utility incentive for efficient operation. Rate cases are held infrequently, most often at three to five year intervals. Between rate cases, rate escalations are based on a combination of automatic attrition relief mechanisms ("ARMs") and cost trackers. The rate adjustments provided by ARMs are largely "external" in the sense that they give a utility an *allowance* for cost growth rather than reimbursement for its *actual* growth.

The "externalization" of ratemaking that ARMs and rate case moratoria achieve gives utilities more opportunity to profit from improved performance. Benefits of better performance can be shared between the utility and its customers. Performance incentives are strengthened despite streamlined regulation. Lower regulatory cost has special appeal in jurisdictions where numerous utilities must be regulated.

ARMs can cap growth in rates (e.g., customer charges and cents per kWh) or allowed revenue. Rate caps are favored when and where utilities are encouraged to bolster customer use of the grid. Revenue caps are usually combined with revenue decoupling mechanisms, and are often favored where utilities must cope with declining average use and/or policymakers strongly encourage DSM.

Several approaches to ARM design are well-established. These include multiyear cost forecasts, indexing, and hybrids. Indexing escalates rates (or revenue) automatically for inflation and sometimes also for growth in other cost drivers like the number of customers served. A hybrid approach to ARM design was developed in the US that involves indexing of revenue for O&M expenses and forecasts for capital cost revenue.

The indexing approach to ARM design has been more common for UDCs because their cost growth is relatively gradual and predictable. Hybrid and forecasted ARMs have historically been more common for vertically integrated electric utilities because occasional major plant additions have given their cost trajectories more of a "stairstep" pattern. However, this pattern is becoming less common in an era when demand growth is slower and fewer large power plants are under construction. Some VIEUs operating under MRPs have separate ARMs for generation and distribution.

Cost trackers are often used in MRPs to address changes in business conditions that are difficult to address using ARMs. A tracker that recovers a large portion of a utility's capex cost can sometimes permit the company to operate under a multiyear freeze on rates for other non-energy costs. MRPs with "tracker/freeze" provisions for vertically integrated utilities often accord tracker treatment to costs of new or refurbished generating plants.[8] Trackers also address *force majeure* events like severe storms and changes in tax rates that affect costs.

Many MRPs feature earnings sharing mechanisms ("ESMs") that automatically share earnings surpluses and/or deficits that result when the rate of return on equity ("ROE") deviates from its regulated target. Some MRPs feature "off-ramps" that permit plan suspension when earnings are unusually high or low.

[8] A good example is the Generation Base Rate Adjustment in the current MRP of Florida Power & Light.

Plans often feature performance incentive mechanisms that are linked to the utility's service quality. With stronger cost containment incentives, there is a greater need for a link between revenue and service quality. Many MRPs combine revenue decoupling, the tracking of DSM expenses, and performance incentives for DSM. The stronger incentive to contain cost that MRPs provide then becomes a "fourth leg" for the DSM stool.

MRPs have long been used to regulate utilities where market-responsive rates and services are a priority. Infrequent rate cases reduce the regulatory cost of allocating the revenue requirement between a complex and changing mix of market offerings and lessen concerns about cross-subsidization. These benefits of MRPs can be enhanced by designing other plan provisions in ways that insulate core customers from potentially adverse consequences of marketing flexibility.

For example, in the early 1990s, Maine's electric utilities were still vertically integrated and needed flexibility in marketing power to paper and pulp customers, some of whom had cogeneration options. The commission, under the chairmanship of Thomas Welch (a former telecom industry lawyer) approved a succession of price cap plans for Central Maine Power which facilitated marketing flexibility. As a result, the company had more freedom to enter into special contracts. The stronger incentives the company had to offer the right discounts to customers at risk of bypass was acknowledged by the commission when costs were allocated in later rate cases.

MRPs were first widely used in the United States to regulate railroad, oil pipeline, and telecommunications companies. A major attraction was the ability of MRPs to afford utilities flexibility in serving markets with diverse competitive pressures and complex, changing customer needs. US and Canadian precedents for MRPs in the electricity and gas utility industries are indicated in Table 7 and Figures 8a and 8b.[9] In the US, MRPs have traditionally been most common in California and the Northeast. MRPs have been adopted by well-known VIEUs in Florida, North Dakota, and Virginia since our 2012 survey. A number of states have, additionally, experimented with "mini-MRPs" with terms of only two years. The forecast and tracker/freeze approaches to ARM design are most common currently in the US. The Federal Energy Regulatory Commission ("FERC") uses MRPs with index-based ARMs to regulate oil pipelines.

Canada is moving towards MRPs with index-based ARMs for gas and electric power distribution in all four populous provinces. In advanced economies overseas, MRPs are more the rule than the exception for utility regulation. Australia, Britain, and New Zealand are long time practitioners.

[9] Rate freezes without extensive supplemental funding from capital cost trackers are excluded from Table 7 and Figures 8a and 8b.

Figure 8a: Recent US Multiyear Rate Plan Precedents by State

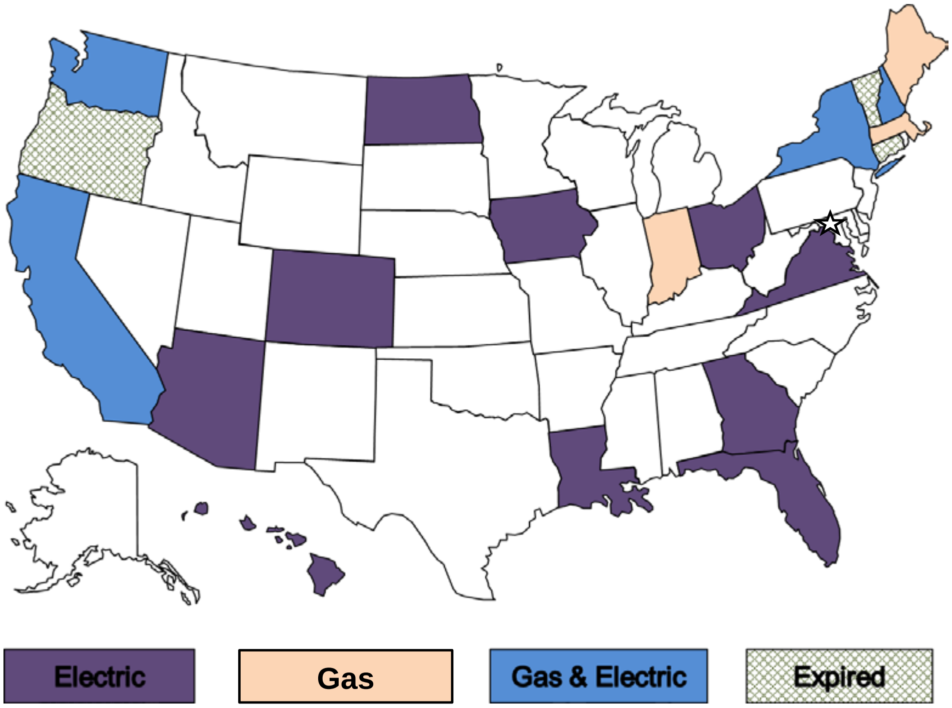


Figure 8b: Recent Canadian Multiyear Rate Plan Precedents by Province

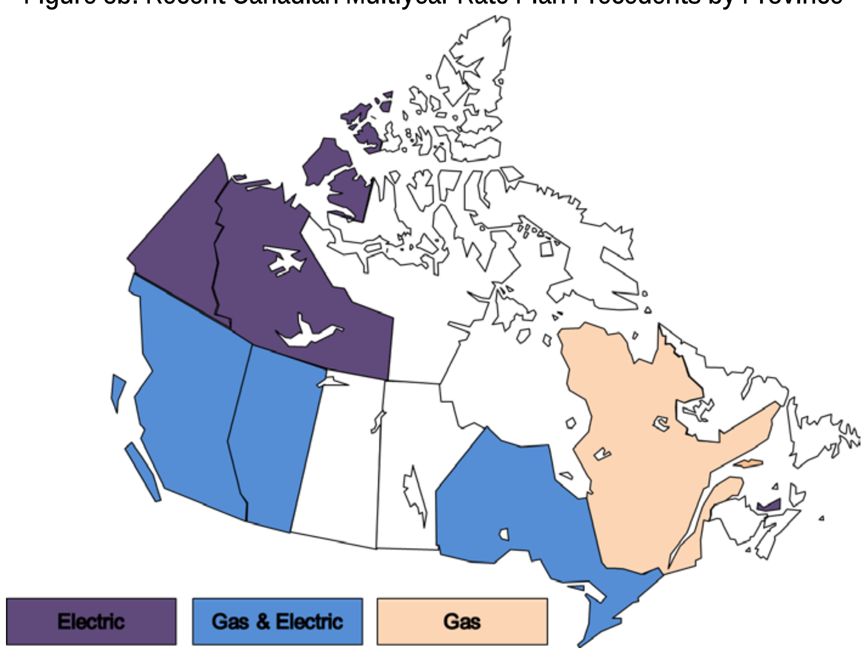


Table 7

Multiyear Rate Plan Precedents [1]

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Current						
United States						
AZ	Arizona Public Service	2012-2016	Bundled power service	Rate Freeze with an adjustment to account for purchase of SCE's share of Four Corners generating facility, additional capital and other cost trackers, LRAM	None	Decision 73183; May 2012
CA	Bear Valley Electric Service	2013-2016	Power distribution	Revenue Cap Stairstep	None	Decision 14-11-002; November 2014
CA	California Pacific Electric	2013-2015	Power distribution	Revenue Cap Index	None	Decision 12-11-030; November 2012
CA	Pacific Gas & Electric	2014-2016	Gas & bundled power service	Revenue Cap Stairstep	None	Decision 14-08-032; August 2014
CA	PacifiCorp	2011-2013, extended through 2016	Bundled power service	Price Cap Index: Rates escalated by Global Insight forecast of CPI, less 0.5% productivity factor; supplemental funding for major plant additions can be requested in annual filings	None	Decision 10-09-010; September 2010
CA	San Diego Gas & Electric	2012-2015	Gas & bundled power service	Revenue Cap Stairstep	None	Decision 13-05-010; May 2013
CA	Southern California Gas	2012-2015	Gas	Revenue Cap Stairstep	None	Decision 13-05-010; May 2013
CA	Southwest Gas	2014-2018	Gas	Revenue Cap Stairstep	None	Decision 14-06-028; June 2014
CO	Public Service of Colorado	2015-2017	Bundled power service	Rate Freeze with multiple capital cost trackers	Sharing of overearnings only up to earnings cap	Decision C15-0292; March 2014
FL	Florida Power & Light	2013-2016	Bundled power service	Rate Freeze with multiple capital and other cost trackers	None	Docket 120015-EI; December 2012
FL	Gulf Power	2014-June 2017	Bundled power service	Price Cap Stairstep through 2015, Rate Freeze beyond	None	Docket 130140-EI; December 2013
FL	Duke Energy Florida (formerly Progress Energy Florida)	2012-2016, extended through 2018	Bundled power service	Rate Freeze with one step plus capital and other cost trackers	None	Dockets 120022-EI and 130208-EI; 2012 and November 2013
FL	Tampa Electric	2013-2017	Bundled power service	Revenue Cap Stairstep	None	Docket 130040-EI
GA	Georgia Power	2014-2016	Bundled power service	Revenue Cap Stairstep	Sharing of overearnings only with deadband	Docket 36989; December 2013
HI	Hawaiian Electric Company	2012-open	Bundled power service	Revenue Cap Hybrid	Sharing of overearnings only without deadband, multiple sharing levels	Dockets 2008-0274 & 2008-0083
HI	Hawaiian Electric Light Company	2013-open	Bundled power service	Revenue Cap Hybrid	Sharing of overearnings only without deadband, multiple sharing levels	Dockets 2008-0274 & 2009-0164
HI	Maui Electric	2013-open	Bundled power service	Revenue Cap Hybrid	Sharing of overearnings only without deadband, multiple sharing levels	Dockets 2008-0274 & 2009-0163
IA	MidAmerican Energy	2014-2017	Bundled power service	Revenue Cap Stairstep for 2014-2016, Rate Freeze for 2017	Sharing of overearnings only with deadband up to earnings cap	RPU-2013-0004
IN	Northern Indiana Public Service Company	2015-2020	Gas	Rate Freeze with capital and other cost trackers, possible reopening in 2017	Earnings cap implemented if company overearns since last rate case or prior 59 months, whichever is less	Cause 43894 and 44403 TDSIC 1 (August 2013 and January 2015)
LA	Cleco Power	2014-2017	Bundled power service	Rate Freeze with capital and other cost trackers	Sharing of overearnings only with deadband up to earnings cap	Docket U-32779; June 2014
MA	Bay State Gas	2015-2018	Gas	Revenue Cap Stairstep for 2015, 2016, Revenue Freeze through October 2018	None	DPU 15-150; October 2015
ME	Summit Natural Gas of Maine	2013-2022	Gas	Price Cap Indexing: 75% of change in GDPPI	None until company has 1,000 or more customers, then sharing of under/overearnings evenly with deadband	Docket 2012-258; January 2013
NH	Northern Utilities	May 2014 - April 2017	Gas	Revenue Cap Stairstep for 2014-2015, Rate Freeze in 2016	Sharing of overearnings only with deadband up to earning cap	DG 13-086; April 2014
NH	Public Service Company of New Hampshire	2010-2015	Power distribution (generation regulated separately)	Revenue Cap Stairstep: Rate increases allowed to account for distribution capital additions in 2010-2013	Sharing of overearnings only with deadband	DE 09-035
NH	Unitil Energy Systems	2011-2016	Power distribution	Revenue Cap Stairstep: Rate increases allowed to account for distribution capital additions in 2011-2013	Sharing of overearnings only with deadband	DE 10-055

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Current (cont'd)						
United States (cont'd)						
NY	Central Hudson Gas & Electric	2015-2018	Gas & power distribution	Revenue Cap Stairstep	Sharing of overearnings with deadband and multiple sharing bands	Cases 14-E-0318, 14-G-0319
NY	Consolidated Edison	2014-2016	Gas	Revenue Cap Stairstep	Sharing of overearnings only with deadband and multiple bands	Case 13-G-0031
NY	Corning Natural Gas	2012-2015	Gas	Revenue Cap Stairstep	Sharing of overearnings only with deadband and multiple bands	Case 11-G-0280
NY	Orange & Rockland Utilities	November 2015-October 2018	Gas	Revenue Cap Stairstep	Sharing of overearnings only with deadband and multiple sharing bands	Case 14-G-0494
ND	Northern States Power - Minnesota	2013-2016	Bundled power service	Revenue Cap Stairstep for 2013-2015, Rate Freeze in 2016	Sharing of overearnings only without deadband, earnings adjusted for effects of weather	Case PU-12-813
OH	First Energy Ohio	2011-2014, later extended to 2016	Power distribution	Rate Freeze supplemented by capital and other cost trackers	Company subject to Significantly Excessive Earnings Test conducted annually	Cases 11-388-EL-SSO, 12-1230-EL-SSO
US	All	2011-2016	Oil pipelines	Price Cap Index: PPI-Finished Goods + 2.65%	None	Docket RM10-25-000; December 2010
VA	Appalachian Power	2014-2017	Bundled power service	Rate Freeze supplemented by capital and other cost trackers	None	Senate Bill 1349
VA	Virginia Electric Power	2015-2019	Bundled power service	Rate Freeze supplemented by capital and other cost trackers	None	Senate Bill 1349
WA	Puget Sound Energy	2013-2016	Gas & bundled power service	Revenue Cap Stairstep	Sharing of overearnings only without deadband, equal sharing between company and customers	Dockets UE-121697 and UG-121705
Canada						
Alberta	Altagas Utilities and ATCO Gas	2013-2017	Gas	Revenue per Customer Indexing: Input price index - 1.16%, + capital cost trackers	None	Decision 2012-237
Alberta	ATCO Electric, EPCOR, Fortis Alberta	2013-2017	Power distribution	Price Cap Index: Input Price Index - 1.16%, + capital cost trackers	None	Decision 2012-237
British Columbia	FortisBC	2014-2018	Bundled power service	Revenue Cap Index: I-Factor - 1.03%, + capital cost tracker for CPCN projects	Symmetric without deadband	Project #3698719, Decision; September 2014
British Columbia	FortisBC Energy	2014-2018	Gas	Revenue Cap Index: I-Factor - 1.1%, + capital cost tracker for CPCN projects	Symmetric without deadband	Project #3698715, Decision; September 2014
Ontario	All unless company opts out	2014-2018	Power distribution	Price Cap Index: Input price index - (0%+stretch); stretch factor reassigned annually, + capital cost tracker option available	None	EB-2010-0379 Report of the Board; November 2013
Ontario	Horizon Utilities	2015-2019	Power distribution	Revenue Cap Stairstep	Sharing of overearnings only without deadband	EB-2014-0002; December 2014
Ontario	Hydro One Networks	2015-2017	Power distribution	Revenue Cap Stairstep	None	EB-2014-0247; March 2015
Ontario	Enbridge Gas Distribution	2014-2018	Gas	Revenue Cap Stairstep	Sharing of overearnings only without deadband	EB-2012-0459, Decision with Reasons; July 2014
Ontario	Union Gas Limited	2014-2018	Gas	Revenue Cap Index: 40% of growth in GDP-IPI	Sharing of overearnings only with deadband, multiple sharing ranges	EB 2013-0202 Decision; October 2013
Prince Edward Island	Maritime Electric	2013-2016	Bundled power service	Price Cap Stairstep: Bill defines rates for each year.	Earnings cap set at allowed ROE, no floor	Bill 26 (2012) Electric Power (Energy Accord Continuation) Amendment Act
Quebec	Gazifere	2011-2015	Gas distribution	Price Cap Index	Sharing of overearnings only without deadband and multiple sharing bands up to earnings cap	D-2010-112; August 2010
Yukon Territory	Yukon Electrical Company, Limited	2013-2015	Bundled power service	Revenue Cap Stairstep	None	Board Order 2014-06; April 2014

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Current (cont'd)						
Great Britain						
Great Britain	All	2013-2021	Gas and power transmission	British-Style Hybrid	Not reviewed	RIIO-T1 Final Proposals, April and December 2012
Great Britain	All	2013-2021	Gas distribution	British-Style Hybrid	Not reviewed	RIIO-GD1 Final Proposals, December 2013
Great Britain	All	2015-2023	Power distribution	British-Style Hybrid	Variances of cost from budgets shared though Information Quality Incentive Mechanism	RIIO-ED1 Final Proposals, December 2014
Australia/New Zealand						
Australia	ActewAGL	2015-2019	Power transmission & distribution	Australian-Style Hybrid	Not reviewed	Final Decision ActewAGL distribution determination 2015-16 to 2018-19; April 2015
Australia	Ausgrid	2015-2019	Power distribution	Australian-Style Hybrid	Not reviewed	Final Decision Ausgrid distribution determination 2015-16 to 2018-19; April 2015
Australia	Directlink	2015-2020	Power transmission	Australian-Style Hybrid	Not reviewed	Final Decision Directlink transmission determination 2015-16 to 2019-20; April 2015
Australia	Endeavour Energy	2015-2019	Power distribution	Australian-Style Hybrid	Not reviewed	Final Decision Endeavour Energy distribution determination 2015-16 to 2018-19; April 2015
Australia	Energex	2015-2020	Power distribution	Australian-Style Hybrid	Not reviewed	Final Decision Energex determination 2015-16 to 2019-20
Australia	Ergon Energy	2015-2020	Power distribution	Australian-Style Hybrid	Not reviewed	Final Decision Ergon Energy determination 2015-16 to 2019-20
Australia	Essential Energy	2015-2019	Power distribution	Australian-Style Hybrid	Not reviewed	Final Decision Essential Energy distribution determination 2015-16 to 2018-19; April 2015
Australia	Jemena Gas Networks	2015-2020	Gas distribution	Australian-Style Hybrid	Not reviewed	Final Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2015−20; June 2015
Australia	SA Power Networks	2015-2020	Power distribution	Australian-Style Hybrid	Not reviewed	Final Decision SA Power Networks determination 2015-16 to 2019-20
Australia	TasNetworks	2015-2019	Power transmission	Australian-Style Hybrid	Not reviewed	Final Decision TasNetworks transmission determination 2015-16 to 2018-19; April 2015
Australia	TransGrid	2015-2018	Power transmission	Australian-Style Hybrid	Not reviewed	Final Decision TransGrid transmission determination 2015-16 to 2017-18; July 2015
Australia	Power & Water	2014-2019	Power transmission & distribution	Australian-Style Hybrid	Not reviewed	2014 Networks Price Determination Final Determination Part-A Statement of Reasons; April 2014
Australia	All Queensland Distributors	2011-2016	Gas distribution	Australian-Style Hybrid	Not reviewed	Access Arrangement Proposal for Qld Gas Network, Final Decision; June 2011
Australia	Energex and Ergon Energy	2010-2015	Power distribution	Australian-Style Hybrid	Not reviewed	Queensland Distribution Determination 2011-11 to 2014-15 (Final Decision)
Australia	Envestra	2011-2016	Gas distribution	Australian-Style Hybrid	Not reviewed	Access Arrangement Proposal for the SA Gas Network, Final Decision; June 2011
Australia	All Victorian Distributors	2013-2017	Gas distribution	Australian-Style Hybrid	Not reviewed	Access Arrangement Final Decision; March 2013

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Current (cont'd)						
Australia/New Zealand (cont'd)						
Australia	CitiPower	2011-2015	Power distribution	Australian-Style Hybrid	Not reviewed	CitiPower Pty Distribution Determination 2011-2015; September 2012
Australia	Powercor	2011-2015	Power distribution	Australian-Style Hybrid	Not reviewed	Powercor Australia Ltd Distribution Determination 2011-2015; October 2012
Australia	Jemena Electricity Networks	2011-2015	Power distribution	Australian-Style Hybrid	Not reviewed	Jemena Electricity Networks (Victoria) Ltd Distribution Determination 2011-2015; September 2012
Australia	SP AusNet	2011-2015	Power distribution	Australian-Style Hybrid	Not reviewed	SPI Electricity Pty Ltd Distribution Determination 2011-2015; August 2013
Australia	United Energy Distribution	2011-2015	Power distribution	Australian-Style Hybrid	Not reviewed	United Energy Distribution Distribution Determination 2011-2015; September 2012
New Zealand	All but Orion Electric	2015-2020	Power distribution	Revenue Cap Index: CPI-0% for most companies	None	Project no. 14.07/14118; November 2014
New Zealand	All	2013-2017	Gas distribution	New Zealand-Style Hybrid	Not reviewed	Project no. 15.01/13199
New Zealand	All	2013-2017	Gas transmission	New Zealand-Style Hybrid	Not reviewed	Project no. 15.01/13199
Historic						
United States						
CA	Bear Valley Electric Service	2009-2012	Power distribution	Revenue Cap Stairstep	None	Decision 09-10-028; October 2009
CA	Pacific Gas & Electric	2011-2013	Gas & bundled power service	Revenue Cap Stairstep	None	Decision 11-05-018; May 2011
CA	Pacific Gas & Electric	2007-2010	Gas & bundled power service	Revenue Cap Stairstep	None	Decision 07-03-044; March 2007
CA	Pacific Gas & Electric	2004-2006	Gas & bundled power service	Revenue Cap Index	None	Decision 04-05-055; May 2004
CA	Pacific Gas & Electric	1993-1995	Gas & bundled power service	Revenue Cap Hybrid	None	Decision 92-12-057; December 1992
CA	Pacific Gas & Electric	1990-1992	Gas & bundled power service	Revenue Cap Hybrid	None	Decision 89-12-057; December 1989
CA	Pacific Gas & Electric	1987-1989	Gas & bundled power service	Revenue Cap Hybrid	None	Decision 86-12-092; December 1986
CA	Pacific Gas & Electric	1984-1986	Gas & bundled power service	Revenue Cap Hybrid	None	Decisions 83-12-068; December 1983 and 85-12-076; December 1985
CA	PacifiCorp	2007-2009, extended to 2010	Bundled power service	Price Cap Index	None	Decisions 06-12-011; December 2006 and 09-04-017; April 2009
CA	PacifiCorp	1994-1996	Bundled power service	Price Cap Index	None	Decision 93-12-106; December 1993
CA	PacifiCorp	1984-1987	Bundled power service	Revenue Cap Hybrid	None	Decisions 84-07-150; July 1984 and 85-12-076; December 1985
CA	San Diego Gas & Electric	2008-2011	Gas & bundled power service	Revenue Cap Stairstep	None	Decision 08-07-046; July 2008
CA	San Diego Gas & Electric	2005-2007	Gas & bundled power service	Revenue Cap Index	Sharing of overearnings only with deadband and multiple sharing bands	Decision 05-03-025; March 2005
CA	San Diego Gas and Electric	1999-2002	Gas & power distribution	Price Cap Index	Sharing of overearnings only above deadband with multiple sharing bands	Decision 99-05-030; May 1999

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Historic (cont'd)						
United States (cont'd)						
CA	San Diego Gas & Electric	1994-1999	Gas & bundled power service	Revenue Cap Hybrid	Sharing of overearnings only with deadband and multiple sharing bands up to an earnings cap	Decision 94-08-023; August 1984
CA	San Diego Gas & Electric	1989-1993	Gas & bundled power service	Revenue Cap Hybrid	None	Decision 88-12-085; December 1988
CA	San Diego Gas & Electric	1986-1988	Gas & bundled power service	Revenue Cap Hybrid	None	Decision 85-12-108; December 1985
CA	Sierra Pacific Power	2009-2011, extended to 2012	Bundled power service	Price Cap Index	None	Decision 09-10-041; October 2009
CA	Sierra Pacific Power	1990-1992	Bundled power service	Revenue Cap Hybrid	None	Decision 90-07-060; July 1990
CA	Southern California Edison	2012-2014	Bundled power service	Revenue Cap Hybrid	None	Decision 12-11-051; November 2012
CA	Southern California Edison	2009-2011	Bundled power service	Revenue Cap Stairstep	None	Decision 09-03-025; March 2009
CA	Southern California Edison	2006-2008	Bundled power service	Revenue Cap Hybrid	None	Decision 06-05-016; May 2006
CA	Southern California Edison	2004-2006	Bundled power service	Revenue Cap Hybrid	None	Decision 04-07-022; July 2004
CA	Southern California Edison	1997-2001	Power distribution	Price Cap Index	Sharing of over/underearnings outside deadband with multiple sharing bands	Decision 96-09-092; September 1996
CA	Southern California Edison	1986-1991	Bundled power service	Revenue Cap Hybrid	None	Decision 85-12-076; December 1985
CA	Southern California Gas	2008-2011	Gas	Revenue Cap Stairstep	None	Decision 08-07-046; July 2008
CA	Southern California Gas	2005-2007	Gas	Revenue Cap Index	Sharing of overearnings only with deadband and multiple sharing bands	Decision 05-03-025; March 2005
CA	Southern California Gas	1998-2003	Gas	Revenue Cap Index	Sharing of over/underearnings outside deadband with multiple sharing bands	Decision 97-07-054; July 1997
CA	Southern California Gas	1990-1993	Gas	Revenue Cap Hybrid	None	Decision 90-01-016; January 1990
CA	Southern California Gas	1985-1989	Gas	Revenue Cap Hybrid	None	1984, 85-12-076; December 1985, and 87-05-027; May 1987
CA	Southwest Gas	2009-2013	Gas	Revenue Cap Stairstep	None	Decision 08-11-048; November 2008
CO	Public Service Company of Colorado	2012-2014	Bundled power service	Revenue Cap Stairstep	Sharing of overearnings only without deadband, multiple sharing bands up to earnings cap	Decision C12-0494
CT	Connecticut Light & Power	2004-2007	Power distribution	Revenue Cap Stairstep	Even sharing of overearning without deadband	Docket 03-07-02
CT	United Illuminating	2006-2008	Power distribution	Revenue Cap Stairstep	Even sharing of overearning without deadband	Docket 05-06-04
FL	Florida Power & Light	2006-2009	Bundled power service	Rate Freeze with exception for new generating facilities after they are in service and multiple capital and other cost trackers	None	Docket 050045-EI
FL	Progress Energy Florida	2006-2009	Bundled power service	Rate Freeze with 1 step to reflect generation brought in-service and multiple capital and other cost trackers	None	Docket 050078-EI
GA	Georgia Power	2011-2013	Bundled power service	Revenue Cap Stairstep: Rate increases permitted for DSM and major generation plant additions	Sharing of overearnings only with deadband	Docket 31958
IA	MidAmerican Energy	2001-2005, extended to 2013	Bundled power service	Rate Freeze with nuclear capital and other cost trackers	Sharing of overearnings only in multiple sharing bands, deadband not applicable due to no allowed ROE	Dockets RPU-01-3 and RPU-2012-0001
LA	Cleco Power	2009-2014	Bundled power service	Rate Freeze with capital cost tracker	Sharing of overearnings only with deadband up to earnings cap	Order U-30689
MA	Bay State Gas	2006-2015, terminated in 2009	Gas distribution	Price Cap Index	75-25 shareholders-ratepayers sharing around deadband	Docket DTE 05-27
MA	Berkshire Gas	February 2002-January 2012	Gas distribution	No adjustment until September 2004, then Price Cap Index	None	Docket D.T.E. 01-56

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Attrition Relief Mechanism	Earnings Sharing Provisions	Case Reference
Historic (cont'd)						
United States (cont'd)						
MA	Boston Gas (I)	1997-2001	Gas distribution	Price Cap Index	75-25 shareholders-ratepayers sharing around deadband	Docket D.P.U. 96-50-C (Phase I); May 1997
MA	Boston Gas (II)	2004-2013, Terminated in 2010	Gas distribution	Price Cap Index	75-25 shareholders-ratepayers sharing around deadband	Docket DTE 03-40
MA	Blackstone Gas	November 1, 2004 - October 31, 2009	Gas distribution	Price Cap Index	Even sharing of earnings above/below deadband	Docket D.T.E. 04-79
MA	Nstar	2006-2012	Power distribution	Price Cap Index	Deadband with 50-50 sharing of over and underearnings	Docket D.T.E. 05-85
ME	Bangor Gas	2000-2009, extended to 2012	Gas distribution	Price Cap Index	Even sharing of overearnings only. No allowed ROE established for company and no determination of a deadband.	Docket 970795; June 1998
ME	Bangor Hydro Electric (I)	1998-2000	Power distribution	Price Cap Index	50/50 sharing around deadband	Docket 97-116; March 1998
ME	Central Maine Power (I)	1995-1999	Bundled power service	Price Cap Index	Even sharing of earnings above/below deadband	Docket 92-345 Phase II; January 1995
ME	Central Maine Power (II)	2001-2007	Power distribution	Price Cap Index	50-50 sharing below deadband	Docket 99-666; November 2000
ME	Central Maine Power (III)	2009-2013	Power distribution	Price Cap Index: GDPPI - 1%, separate capital cost tracker for AMI	50-50 sharing above 11% ROE	Docket 2007-215
ME	Maine Natural Gas	2010-2012	Gas	Revenue Cap Stairstep with steps conditioned on company earnings	None	Docket 2009-67
NY	Brooklyn Union Gas	October 1, 1991 - September 30, 1994	Gas	Revenue Cap Stairstep	Sharing of overearnings only without deadband	Case 90-G-0981, Opinion 91-21; October 1991
NY	Brooklyn Union Gas	October 1, 1994 - September 30, 1997	Gas	Revenue Cap Stairstep	Sharing of overearnings only without deadband and multiple sharing bands	Case 93-G-0941, Opinion 94-22; October 1994
NY	Central Hudson Gas & Electric	2010-2013	Gas & power distribution	Revenue Cap Stairstep	Sharing of overearnings with deadband and multiple sharing bands	Case 09-E-0588
NY	Central Hudson Gas & Electric	July 1, 2006 - June 30, 2009	Gas & power distribution	Price Cap Stairstep	Sharing of overearnings only with deadband, multiple sharing bands up to earnings cap	Case 05-E-0934 & Case 05-G-0935; July 2006
NY	Consolidated Edison	2010-2013	Gas	Revenue Cap Stairstep	Sharing of overearnings only with deadband that varies annually and multiple sharing bands	Case 09-G-0795
NY	Consolidated Edison	2007-2010	Gas	Revenue Cap Stairstep	Even sharing of overearnings only above deadband, sharing threshold adjustable depending on work with DSM program administrator for first year only	Case 06-G-1332
NY	Consolidated Edison	October 1, 1994 - September 30, 1997	Gas	Revenue Cap Stairstep	Even sharing of overeearnings only above deadband	Case 93-G-0996, Opinion 94-2; October 1994
NY	Consolidated Edison	2010-2013	Power distribution	Revenue Cap Stairstep	Sharing of overearnings only above deadband with multiple sharing bands	Case 09-E-0428
NY	Consolidated Edison	April 1, 2005 - March 31, 2008	Power distribution	Price Cap Stairstep	Sharing of overearnings only with multiple bands. No allowed ROE approved.	Case 04-E-0572; March 2005
NY	Consolidated Edison	1992-1995	Bundled power service	Revenue Cap Stairstep	Even sharing of overearnings with varying allowed ROE and no deadband	Opinion 92-8
NY	Keyspan Energy Delivery - Long Island	2010-2012	Gas	Revenue Cap Stairstep	Sharing of overearnings only above deadband with multiple sharing bands, sharing threshold adjustable for good DSM performance	Case 06-G-1185
NY	Keyspan Energy Delivery - New York	2010-2012	Gas	Revenue Cap Stairstep	Sharing of overearnings only above deadband with multiple sharing bands, sharing threshold adjustable for good DSM performance	Case 06-G-1186
NY	Long Island Lighting Company	December 1, 1993- November 30, 1996	Gas	Revenue Cap Stairstep	Even sharing of overearnings only with deadband	Case 93-G-002, Opinion 93-23; December 1993
NY	Long Island Lighting Company	1992-1994	Bundled power service	Revenue Cap Stairstep	Even sharing of overearnings only without deadband	Opinion 92-8

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Attrition Relief Mechanism	Earnings Sharing Provisions	Case Reference
Historic (cont'd)						
United States (cont'd)						
NY	New York State Electric & Gas	2010-2013	Gas & power distribution	Revenue Cap Stairstep	Sharing of overearnings only with deadband that varies annually and multiple sharing bands	Case 09-E-0715
NY	New York State Electric & Gas	August 1, 1995 - July 31, 1998, Years 2 and 3 not implemented due to restructuring	Bundled power service	Revenue Cap Stairstep	Sharing of overearnings only with annually varying deadbands	Case 94-M-0349, Opinion 95-27; September 1995
NY	New York State Electric & Gas	December 1, 1993 - August 31, 1995	Gas & bundled power service	Revenue Cap Stairstep	Even sharing of overearnings only above deadband	Case 92-G-1086, Opinion 93-22; November 1993
NY	Niagara Mohawk	July 1, 1990 - December 31, 1992	Gas & bundled power service	Revenue Cap Stairstep	Sharing of overearnings only without deadband up to earnings cap	Case 29327, Opinion 89-37; June 1991
NY	Orange & Rockland Utilities	2009-2012	Gas	Revenue Cap Stairstep	Sharing of overearnings only beyond deadband and multiple sharing bands	Case 08-G-1398
NY	Orange & Rockland Utilities	November 1, 2006 - October 31, 2009	Gas	Price Cap Stairstep	Sharing of overearnings only beyond deadband and multiple sharing bands	Case 05-G-1494; October 2006
NY	Orange & Rockland Utilities	November 1, 2003- October 31, 2006	Gas	Price Cap Stairstep	Even sharing of overearnings only without deadband	Case 02-G-1553; October 2003
NY	Orange & Rockland Utilities	2012-2015	Power distribution	Revenue Cap Stairstep	Sharing of overearnings only with deadband and multiple bands	Case 11-E-0408
NY	Orange & Rockland Utilities	2008-2011	Power distribution	Revenue Cap Stairstep	Sharing of overearnings only above deadband with multiple sharing bands	Case 07-E-0949
NY	Orange & Rockland Utilities	1991-1993	Bundled power service	Revenue Cap Stairstep	Even sharing of overearnings above deadband	Case 89-E-175
NY	Rochester Gas & Electric	2010-2013	Gas & power distribution	Revenue Cap Stairstep	Sharing of overearnings only with deadband that varies annually and multiple sharing bands	Case 09-E-0717
NY	Rochester Gas & Electric	July 1, 1993 - June 30, 1996	Gas & bundled power service	Revenue Cap Stairstep	Earnings cap only	Case 92-G-0741, Opinion No. 93-19; August 1993
OH	AEP-Ohio	2012-2015	Power distribution	Rate Freeze supplemented by capital and other cost trackers	Company subject to Significantly Excessive Earnings Test conducted annually	Case No. 11-346-EL-SSO; August 2012
OH	Cincinnati Gas & Electric	2009-2011	Power generation	Price Cap Stairstep	Company subject to Significantly Excessive Earnings Test conducted annually	Case 08-920-EL-SSO
OR	PacifiCorp	1998-2001	Power distribution	Revenue Cap Index	Sharing of over/underearning outside deadband in multiple sharing bands	Order No. 98-191
US	All	2006-2011	Oil pipelines	Price Cap Index: PPI-Finished Goods + 1.3%	None	RM05-22-000
US	All	2001-2006	Oil pipelines	Price Cap Index: PPI-Finished Goods + 0%	None	RM00-11-000
US	All	1995-2001	Oil pipelines	Price Cap Index: PPI-Finished Goods - 1%	None	RM93-11-000
VT	Green Mountain Power	2007-2010	Bundled power service	Revenue Cap Stairstep	Earnings cap for overearnings above deadband; Multiple sharing bands for earnings apply if actual ROE below deadband (earnings floor of the deadband also applies)	Docket No. 7176
WA	Puget Sound Energy	1997-2001	Bundled power service	Price Cap Stairstep	None	Docket UE-960195
Australia/New Zealand						
Australia	Jemena Gas Networks	2010-2015	Gas distribution	Australia-Style Hybrid	Not reviewed	Access Arrangement Proposal for NSW Gas Networks, Final Decision; June 2010
Australia	All New South Wales distributors	2009-2014	Power distribution	Australia-Style Hybrid	Not reviewed	New South Wales Distribution Determination 2009-10 to 2013-14 Final Decision
Australia	ElectraNet	2008-2013	Power transmission	Australia-Style Hybrid	Not reviewed	Final Decision; April 2008
Australia	ElectraNet	2003-2008	Power transmission	Australia-Style Hybrid	Not reviewed	File No: C2001/1094
Australia	Powerlink	2007-2012	Power transmission	Australia-Style Hybrid	Not reviewed	Final Decision; June 2007

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Historic (cont'd)						
Australia/New Zealand (cont'd)						
Australia	Powerlink	2002-2007	Power transmission	Australia-Style Hybrid	Not reviewed	File No: 2000/659
Australia	Snowy Mountains	1999-2004 (terminated in 2002 due to merger with Transgrid)	Electric transmission	Australia-Style Hybrid	Not reviewed	File No: C1999/62
Australia	SPI PowerNet	2003-2008	Power transmission	Australia-Style Hybrid	Not reviewed	File No: C2001/1093
Australia	Transend	2009-2014	Power transmission	Australia-Style Hybrid	Not reviewed	Transend Transmission Determination 2009/10-2013/14 (Final Decision)
Australia	Transend	2004-2009	Power transmission	Australia-Style Hybrid	Not reviewed	File No: C2001/1100
Australia	Transgrid	2009-2014	Electric transmission	Australia-Style Hybrid	Not reviewed	Transgrid Transmission Determination 2009/10-2013/14 (Final Decision)
Australia	Transgrid	2004-2009	Power transmission	Australia-Style Hybrid	Not reviewed	File No. M2003/287
Australia	Transgrid	1999-2004	Power transmission	Australia-Style Hybrid	Not reviewed	File No: CG98/118
Australia- New South Wales	Country Energy Gas	2006-2010	Gas distribution	Australia-Style Hybrid	Not reviewed	Revised Access Arrangement for Country Energy Gas Network, Final Decision; November 2005
Australia- New South Wales	AGL Gas Networks	1999-2004	Gas transmission & distribution	Australia-Style Hybrid	Not reviewed	Access Arrangement for AGL Gas Networks Limited, Final Decision; July 2000
Australia - New South Wales	All	2004-2009	Power distribution	Australia-Style Hybrid	Not reviewed	File No: S2004/138
Australia - New South Wales	All	1999-2004	Power distribution	Australia-Style Hybrid	Not reviewed	NEC Determination 99-1
Australia - Northern Territory	Power & Water	2000-2003	Power transmission & distribution	Australia-Style Hybrid	Not reviewed	Revenue Determinations document; June 2000
Australia - Northern Territory	Power & Water	2009-2014	Power transmission & distribution	Price Cap Index: CPI + 0.85%	Not reviewed	Final Determination Networks Pricing: 2009 Regulatory Reset; March 2009
Australia - Northern Territory	Power & Water	2004-2009	Power transmission & distribution	Price Cap Index: CPI - 2%	Not reviewed	Final Determination Networks Pricing: 2004 Regulatory Reset; February 2004
Australia -Victoria	All	2008-2012	Gas distribution	Australia-Style Hybrid	Not reviewed	Gas Access Arragement Review 2008-2012, Final Decision; March 2008
Australia -Victoria	All	2003-2007	Gas distribution	Australia-Style Hybrid	Not reviewed	Review of Gas Access Arrangements, Final Decision; October 2002
Australia -Victoria	All	2006-2010	Power distribution	Australia-Style Hybrid	Not reviewed	Electricity Distribution Price Review 2006-2010 (Final Decision Volume 1)
Australia -Victoria	All	2001-2005	Power distribution	Australia-Style Hybrid	Not reviewed	Electricity Distribution Price Determination 2001-2005 (Final Decision Volume 1)
New Zealand	All	2010-2015	Power distribution	Revenue Cap Index: CPI - 0%	None	Commerce Commission Initial Reset of the Default Price-Quality Path for Electricity Distribution Businesses Decisions Paper; November 2009

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Historic (cont'd)						
Australia/New Zealand (cont'd)						
New Zealand	All	2004-2009	Power distribution	Revenue Cap Index: CPI - 0.86% (Average across firms)	None	Commerce Commission Regulation of Electricity Lines Businesses, Targeted Control Regime, Threshold Decisions; December 2003
Canada						
Alberta	Enmax	2007-2013	Power distribution	Price Cap Index: Input Price Index -1.2%	50-50 for excess earnings above deadband	Decision 2009-035
Alberta	Northwestern Utilities	1999-2002, reopened for 2001-2002	Gas distribution	Revenue Cap Stairstep; at reopener replaced with rate freeze	Sharing of earnings above/below deadband with multiple bands for overearnings; at reopener simplified to 50/50 sharing of overearnings with deadband	Decision U98060; March 1998 and Decision 2000-85; December 2000
Alberta	EPCOR	2002-2005, Terminated 12/31/2003	Power distribution	Price Cap Index	None	City of Edmonton Distribution Tariff Bylaw 12367; August 2000
Northwest Territory	Northland Utilities	2011-2013	Bundled power service	Revenue Cap Stairstep	None	Decision 17-2011; November 2011
Northwest Territory	Northland Utilities (Yellowknife)	2011-2013	Bundled power service	Revenue Cap Stairstep	None	Decision 13-2011; August 2011
Ontario	All Ontario Distributors	2010-2013	Power distribution	Price Cap Index: GDP IPI for Final Domestic Demand - (0.92% to 1.32% depending on company's annual performance in benchmarking studies)	None	EB-2007-0673; July 2008, September 2008, and January 2009
Ontario	All Ontario Distributors	2006-2009	Power distribution	Price Cap Index	None	EB-2006-0089; December 2006
Ontario	All Ontario Distributors	2000-2003	Power distribution	Price Cap Index	50-50 sharing of excess earnings without deadband	RP-1999-0034; January 2000
Ontario	Enbridge Gas Distribution	2008-2012	Gas distribution	Revenue Cap Index: GDP-IPI * 53%	50-50 sharing of excess earnings above deadband	EB-2007-0615; February 2008
Ontario	Union Gas	2008-2012	Gas distribution	Revenue Cap Index: GDP-IPI -1.82%	Sharing of overearnings only with deadband and multiple sharing bands	EB-2007-0606; January 2008
Ontario	Union Gas	2001-2003	Gas distribution	Price Cap Index	50-50 sharing around deadband	RP-1999-0017; July 2001
Great Britain						
Great Britain	All	2008-2013	Gas distribution	British-Style Hybrid	Not reviewed	Review- Final Proposals; Published December 2007
Great Britain	All	2002-2007, extended to 2008	Gas distribution	British-Style Hybrid	Not reviewed	"RPI - X @ 20." Ofgem Publication
Great Britain	All	2007-2012	Gas transmission	British-Style Hybrid	Not reviewed	Transmission Price Control Review; Published December 2006
Great Britain	All	2002-2007	Gas transmission	British-Style Hybrid	Not reviewed	"RPI - X @ 20." Ofgem Publication
Great Britain	All	1998-2002	Gas transmission & distribution	British-Style Hybrid	Not reviewed	Energy Law Journal Volume 23 No. 2 p.444
Great Britain	All	1994-1997	Gas transmission & distribution	British-Style Hybrid	Not reviewed	Energy Law Journal Volume 23 No. 2 p.444
Great Britain	All	1992-1994	Gas transmission & distribution	British-Style Hybrid	Not reviewed	Energy Law Journal Volume 23 No. 2 p.444
England & Wales	All	1995-2000	Power distribution	British-Style Hybrid	Not reviewed	"RPI - X @ 20." Ofgem Publication
Great Britain	All	2010-2015	Power distribution	British-Style Hybrid	Variances of cost from budgets shared though Information Quality Incentive Mechanism	Ofgem Distribution Price Control Review 5
Great Britain	All	2005-2010	Power distribution	British-Style Hybrid	Not reviewed	Ofgem Distribution Price Control Review 4

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Historic (cont'd)						
Great Britain (cont'd)						
Great Britain	All	2000-2005	Power distribution	British-Style Hybrid	Not reviewed	"RPI - X @ 20." Ofgem Publication
England & Wales	National Grid	2001-2006, extended to 2007	Power transmission	British-Style Hybrid	Not reviewed	OECD Reviews of Regulatory Reform
England & Wales	National Grid	1997-2001	Power transmission	British-Style Hybrid	Not reviewed	"RPI - X @ 20." Ofgem Publication
England & Wales	National Grid	1993-1997	Power transmission	British-Style Hybrid	Not reviewed	Energy Law Journal Volume 23 No. 2 p.452
Great Britain	All	2007-2012	Power transmission	British-Style Hybrid	Not reviewed	Transmission Price Control Review; Published December 2006
Scotland	All	2000-2005, extended to 2007	Power transmission	British-Style Hybrid	Not reviewed	"RPI - X @ 20." Ofgem Publication
Scotland	All	1995-2000	Power transmission	British-Style Hybrid	Not reviewed	1995 Report by Monopolies and Mergers Commission

[1] Rate freezes without extensive supplemental funding from capital cost trackers are excluded from this table.

VI. Formula Rates

A cost of service formula rate plan ("FRP") is essentially a wide-scope cost tracker designed to help a utility's revenue track its cost of service. Earnings surpluses or deficits occur when revenue and cost are not balanced. FRPs have earnings true up mechanisms that adjust rates so that earnings variances are reduced or eliminated. Regulatory cost is contained by limiting review of costs and revenues.

The earnings true up mechanism plays a key role in an FRP. Some mechanisms compare the earned ROE to the target ROE and then calculate the rate adjustment needed to reduce the ROE variance. Others adjust rates for the difference between revenue and a pro forma cost of service calculated using a rate of return target. Both approaches can keep the utility whole for the time value of money.

Earning true up mechanisms often include a deadband in which variances don't trigger a rate adjustment. Once the variance exceeds the deadband, however, earnings true up mechanisms in FRPs commonly move the ROE all, or almost all, of the way to its regulated target without sharing earnings variances. This is an important distinction between the earnings true up mechanism of an FRP and the earnings *sharing* mechanisms found in some multiyear rate plans.

Formula rates do not always address major plant additions. In state-regulated FRPs for retail electric services, for instance, major investment programs are generally approved separately through such means as hearings on certificates of public convenience and necessity. The resultant cost is often recovered through a separate tracker.

Mechanisms are sometimes added to an FRP to encourage better operating performance. For example, escalation of revenue that compensates the utility for its O&M expenses may be limited by a formula tied to an inflation index. FRPs in several states that include Illinois and Mississippi contain a number of targeted performance incentive mechanisms.

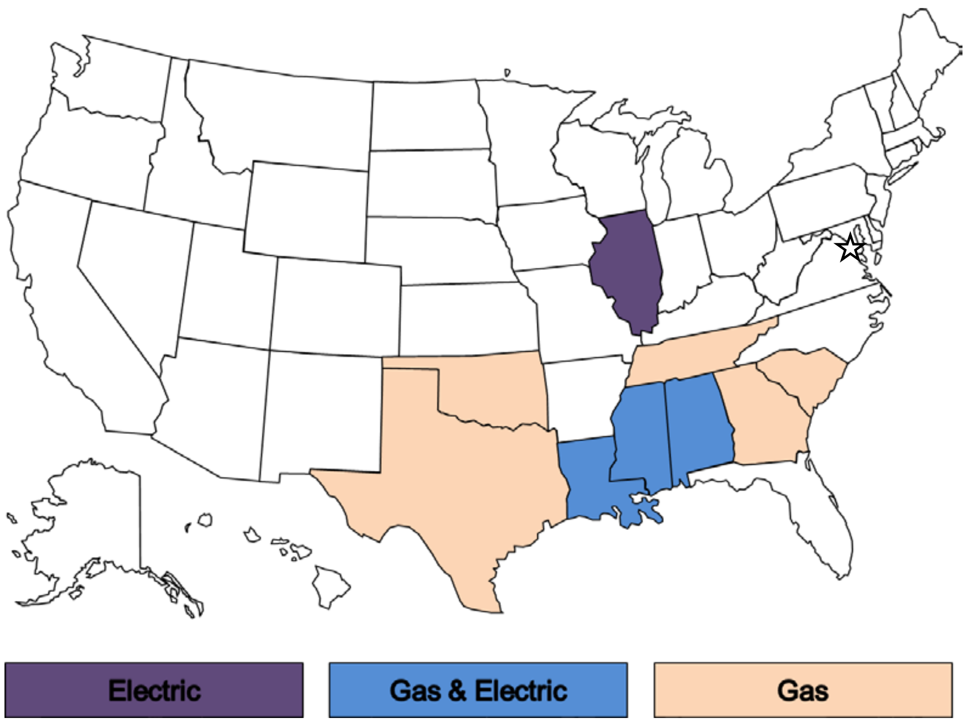
Formula rates have been used at the FERC and its predecessor agency to regulate interstate services of energy utilities for decades. Use of FRPs by the FERC was encouraged in the 1970s and early 1980s by rapid price inflation. Despite slower inflation in recent years, the FERC has made extensive use of formula rates for power transmission in an effort to simplify its daunting regulatory task and facilitate urgently needed investments.

Precedents for retail formula rates, which recover costs of generation and/or distribution, are listed in Table 8 and Figure 9.[10] It can be seen that FRPs for retail utility services are most common in the Southeast and South Central states. Alabama was an early innovator, approving "Rate Stabilization and Equalization"

[10] Some plans labeled as formula rates do not qualify for inclusion in this table and figure based on our definition. These usually take the form of ESMs that may or may not protect the utility from underearning.

plans for Alabama Power and Alabama Gas in the early 1980s.[11] Formula rates are now used to regulate electric utilities in Illinois, some gas and electric utilities in Louisiana and Mississippi, and some gas utilities in Georgia, Oklahoma, South Carolina, Tennessee, and Texas. Most of the recent approvals of formula rates have been for gas distribution, as this is one means to avoid the frequent rate cases that declining average use can trigger. However, formula rates were recently authorized legislatively for electric utilities in Arkansas.

Figure 9: Current Retail Formula Rate Precedents by State



[11] For further discussion of the Alabama FRP experience see Edison Electric Institute, *Case Study of Alabama Rate Stabilization and Equalization Mechanism*, June 2011.

Table 8

Retail Formula Rate Plan Precedents[1]

Jurisdiction	Company Name	Services	Plan Name	Plan Term	Case Reference
Current					
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	2013-open	Dockets 18117 and 18416 (August 2013)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2014-2018	Dockets 18406 and 18328 (December 2013)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2013-2017	Docket 28101 (August 2013)
GA	Atmos Energy	Gas	Georgia Rate Adjustment Mechanism (GRAM)	2012-open	Docket 34764 (December 2011)
IL	Ameren Illinois	Power Distribution	Rate Modernization Action Plan - Pricing (Rate MAP-P)	2011-2017, extended through 2019	Case 12-0001 (September 2012) and Public Act 098-1175
IL	Commonwealth Edison	Power Distribution	Rate Delivery Service Pricing and Performance (Rate DSPP)	2011-2017, extended through 2019	Case 11-0721 (May 2012) and Public Act 098-1175
LA	Atmos Energy - Louisiana Gas Service	Gas	Rate Stabilization Clause	2014-open	Docket U-32987 (June 2014)
LA	Atmos Energy - Trans Louisiana Gas	Gas	Rate Stabilization Clause	2014-open	Docket U-32987 (June 2014)
LA	Southwestern Electric Power	Electric	Formula Rate Plan	2013-2016	Docket U-32220 (July 2014)
MS	Atmos Energy Corp	Gas	Stable/Rate Rider	2011-present	Docket 05-UN-0503 (April 2011)
MS	Centerpoint Energy	Gas	Rate Regulation Adjustment Rider	2014-open	Docket 2014-UN-060 (May 2014)
MS	Entergy Mississippi	Bundled Power Service	Formula Rate Plan 6 (FRP-6)	2015-open	Docket 2014-UN-132 (December 2014)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 5 (PEP-5)	2010-open	Docket 2003-UN-0898 (November 2009)
OK	Centerpoint Energy Arkla	Gas	Performance Based Rate of Change Plan	2010-open	Cause PUD 201000030 (July 2010)
OK	Arkansas Oklahoma Gas	Gas	Performance Based Rate of Change Plan	2013-open	Cause PUD 201200236 (July 2013)
SC	Piedmont Gas	Gas	NA	2005-open	Docket 2005-125-G (September 2005)
SC	South Carolina Electric and Gas	Gas	NA	2005-open	Docket 2005-113-G (October 2005)
TN	Atmos Energy	Gas	Annual Review Mechanism	2015-open	Docket 14-00146 (May 2015)
TX	Centerpoint Energy-Texas Coast Division	Gas	Cost of Service Adjustment Clause	2008-open	Gas Utility Docket 9791 (October 2008)
TX	Atmos Energy-Mid Texas Division	Gas	Rate Review Mechanism	2013-2017	Various Resolutions/Ordinances across cities in service territory, including City of Fort Worth Ordinance 17989-02-2007
TX	Atmos Energy West Texas Division	Gas	Rate Review Mechanism	2014-open	Various Resolutions/Ordinances across cities in service territory including City of Tulia Ordinance 2014-03
TX	Texas Gas Service - Rio Grande Service Area	Gas	Cost of Service Adjustment	2012-open	Various Resolutions/Ordinances across cities in service territory
TX	Texas Gas Service - North Service Area	Gas	Cost of Service Adjustment Tariff	2009-open	Various Resolutions/Ordinances in service territory and Gas Utility Docket 9839 (April 2009)

Table 8 (cont'd)

Jurisdiction	Company Name	Services	Plan Name	Plan Term	Case Reference
Historic					
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	2006-2013	Dockets 18117 and 18416 (October 2005)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	2002-2006	Dockets 18117 and 18416 (March 2002)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1998-2002	Dockets 18117 and 18416 (March 1998)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1990-1998	Dockets 18117 and 18416 (March 1990)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1985-1990	Dockets 18117 and 18416 (June 1985)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1982-1985	Dockets 18117 and 18416 (November 1982)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2008-2014, later changed to 2013	Dockets 18406 and 18328 (December 2007)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2002-2007	Dockets 18046 and 18328 (June 2002)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1996-2001	Dockets 18046 and 18328 (October 1996)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1991-1995	Dockets 18046 and 18328 (December 1990)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1987-1990	Dockets 18046 and 18328 (September 1987)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1985-1987	Dockets 18046 and 18328 (May 1985)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1983-1985	Dockets 18046 and 18328 (January 1983)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2009-2013	Docket 28101 (December 2009)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2005-2009	Docket 28101 (June 2005)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2001-2005	Docket 28101 (June 2002)
LA	Atmos Energy - Louisiana Gas Service	Gas	Rate Stabilization Plan	2006-2014	Docket U-21484 (May 2006)
LA	Atmos Energy - Louisiana Gas Service	Gas	Rate Stabilization Plan	2001-2003	Docket U-21484 (January 2001)
LA	Atmos Energy - Trans Louisiana Gas	Gas	Rate Stabilization Plan	2006-2014	Dockets U-28814 and U-28588 and U-28587(May 2006)
LA	Entergy New Orleans	Electric and Gas	Formula Rate Plan	2010-2012	Docket UD-08-03 (April 2009)
LA	Entergy New Orleans	Electric only	Formula Rate Plan	2004-2006	Docket UD-01-04 (May 2003)
MS	Atmos Energy Corp	Gas	Stable/Rate Rider	2009-2011	Docket 05-UN-0503 (December 2009)
MS	Atmos Energy Corp	Gas	Stable/Rate Rider	2006-2009	Docket 05-UN-0503 (October 2005)
MS	Atmos Energy Corp	Gas	Stable/Rate Rider	1992-2006	Docket 92-UA-0230 (September 1992)
MS	Centerpoint Energy	Gas	Rate Regulation Adjustment Rider	2012-2014	Docket 12-UN-139 (May 2012)

Table 8 (cont'd)

Jurisdiction	Company Name	Services	Plan Name	Plan Term	Case Reference
Historic (cont'd)					
MS	Centerpoint Energy Entex	Gas	Rate Regulation Adjustment Rider	2008-2012	Docket 07-UN-548 (December 2007)
MS	Centerpoint Energy Entex	Gas	Rate Regulation Adjustment Rider	1996-2007	Docket 96-UN-0202 (September 1996)
MS	Entergy Mississippi	Bundled Power Service	Formula Rate Plan 5 (FRP-5)	2010-2014	Docket 2009-UN-388 (March 2010)
MS	Entergy Mississippi	Bundled Power Service	Formula Rate Plan 1 (FRP-1)	1995	Docket 93-UA-0301 (March 1994)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 4A (PEP- 4A)	2009	Docket 06-UN-0511 (January 2009)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 4 (PEP-4)	2004-2009	Docket 03-UN-0898 (May 2004)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 3 (PEP-3)	2002-2004	Docket 01-UN-0826 (October 2002)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 2A (PEP-2A)	2001-2002	Docket 01-UN-0548 (December 2001)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 1A (PEP-1A)	1992-1993	Docket 92-UN-0059 (July 1992)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 1 (PEP-1)	1991-1992	Docket 90-UN-0287 (December 1990)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan	1986-1990	Cause PUD U-4761 (August 1986)
OK	Centerpoint Energy Arkla	Gas	Performance Based Rate of Change Plan	2008-2010	Cause PUD 200800062 (July 2008)
OK	Centerpoint Energy Arkla	Gas	Performance Based Rate of Change Plan	2004-2008	Cause PUD 200400187 (November 2004)
OK	Oklahoma Natural Gas	Gas	Performance Based Rate of Change Plan	2010-2014	Docket 200800348 (April 2009)
TX	Atmos Energy-Mid Texas Division	Gas	Rate Review Mechanism	2008 - varying end dates	Various Resolutions/Ordinances across cities in service territory, including City of Fort Worth Ordinance 17989-02-2008
TX	Atmos Energy West Texas Division	Gas	Rate Review Mechanism	2009 - conclusion of rate case to be filed on or before June 1, 2013	Various Resolutions/Ordinances across cities in service territory
TX	Centerpoint Energy - Beaumont East Texas Gas Division	Gas	Cost of Service Adjustment	2009-2011	Various Resolutions/Ordinances across cities in service territory
TX	Texas Gas Service - Rio Grande Service Area	Gas	Cost of Service Adjustment	2009-2011	Various Resolutions/Ordinances across cities in service territory

[1] Table excludes some mechanisms that do not conform to our FRP definition. Some of these are called formula rate plans.

VII. Marketing Flexibility

This is a new section, added since the last survey. We've added it because we (and EEI) believe that marketing flexibility is a growing, strategic issue for EEI members. Several trends in business conditions are driving the need for more flexibility. The growth of distributed energy resources, for example, is a competitive challenge but also brings new service opportunities related to the development of distributed energy assets (e.g., designing, financing, procuring, building, fueling, and maintaining). Grid modernization is providing new functional capabilities to the grid which also create new service opportunities.[12] Examples include new reliability, network management, and transaction management services. Residential and commercial customers also have a growing interest in plug-in electric vehicles, and all retail customers have shown an interest in green power packages that can be supplied from grid-accessed resources.

New services will tend to be optional services that all customers will not want. Customers must be able to decline them; and if they do, not to incur associated costs. Competitive alternatives will be available for many of these services, and customers may have special needs that are difficult to address with standard tariffs. Thus, utilities will need to be able to respond quickly to the market. They will often be price "takers," as opposed to price "makers."

To date, regulatory precedent allowing investor-owned electric utilities to offer many of these services has been limited. This chapter is, in effect, a place holder for expected future electricity precedent.

Why Electric Utilities Need Marketing Flexibility

Of course, electric utilities have always needed flexibility in some of the markets they serve:

- Utility assets have uses in markets other than those for retail electric services. Most notably, surplus generating capacity of VIEUs can be used for sales in bulk power markets. These markets are competitive and price-volatile. Land in transmission corridors can be well-suited for nurseries. Prices utilities charge in competitive markets like these are largely decontrolled. Margins earned in these markets are shared with customers of retail electric services.
- The demand of large-load retail customers is often sensitive to the rates and other terms of service utilities offer because these customers have power-intensive technologies and/or options to cost-competitively cogenerate or operate at alternative locations, or are economically marginal. Customers of this kind are especially important to vertically integrated utilities. Discounts or special contracts for such customers are traditionally allowed but often require specific approval. Commission reviews of special contracts can take months.

[12] For an overview of modernization, see: EPRI, *The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources*, 2014.

Marketing Flexibility Remedies

Marketing flexibility runs the gamut from greater commission effort to approve new rates and services by traditional means to “light handed” regulation and outright decontrol. Light handed regulation typically takes the form of expedited approval of market offerings. These offerings may be subject to further scrutiny at a later date (e.g., in the next rate case).

Flexibility is most commonly granted for rates and services with certain characteristics. Light handed regulation of optional rates and services, for example, is based on the grounds that customers are protected by their freedom not to take the service, their continued access to service under standard tariffs, and the availability of alternatives in unregulated markets. Optional offerings include tariffs open to all qualifying customers, special contracts, and discretionary value-added services. Decontrol is typically permitted only for offerings to markets where vigorous competition reigns.

Marketing Flexibility Examples: Electric Utilities

Marketing flexibility is not extensive in the electric utility industry today but there are nonetheless notable examples such as the following.

- Four Florida electric utilities have “Commercial/Industrial Service Rider” (“CISR”) tariffs that allow them to negotiate contract service agreements (“CSAs”) that outline discounts on the base energy and/or demand charges for large load customers who can show that they have viable alternatives to utility-provided electric service.[13] The discounted rate must cover the incremental cost of service provision and provide a contribution to fixed costs. CSAs do not need commission approval but the commission has the option to conduct a prudence review of any signed contract.

- Duke Energy offers large North Carolina customers an optional Green Source Rider service. The program allows customers that have added at least 1 MW of new load since June 2012 to apply for an annual amount of renewable energy (and the associated renewable energy certificates) over a specific term (between 3-15 years). Customers may request a particular renewable resource in their application. Duke would then negotiate a purchased power agreement on behalf of the customer or attempt to source the energy from its own assets.

[13] Florida Public Service Commission (2014), Order Approving Commercial/Industrial Service Rider Tariff, Order No. PSC-14-0110-TRF-EI.

Marketing Flexibility in Other Regulated Industries

Regulators and electric utilities considering new forms of marketing flexibility can learn from other utility industries that have experienced technological change, increased competition, and/or complex and changing customer needs. We provide here brief overviews of experience in the telecommunications, gas distribution, gas transmission, and railroad industries.

Telecommunications

Local telephone companies (aka incumbent local exchange carriers or "ILECs") control the traditional distribution networks connecting residences and businesses. The "last mile" services they provide include the interconnection needed for long-distance, data, security, paging, and mobile telephone services as well as local telephone calling. ILECs have in the last 30 years confronted extensive competition, rapid technological change, and new marketing opportunities. Challenges they have faced have many parallels to those emerging for electric utilities.

The Federal Communications Commission (“FCC”) regulates interstate access services of ILECs. Other ILEC services are regulated by state commissions. In the 1980s, ILECs were still regulated using cost-of-service regulation with complex reporting and compensation schemes. This was succeeded by multiyear rate plans, often called "price cap" plans since they capped rate escalation but permitted some discounts to encourage greater system use. Price caps were often escalated using inflation – X formulas where the X factor reflected an estimate of the telecommunication industry productivity trend. Prices were separately capped for several baskets of services. This insulated customers in each service basket from discounts offered to other baskets. Insulation was heightened by the infrequency (or elimination) of rate cases and the common lack of earnings sharing. The FCC instituted price caps for interstate access services of ILECs in the early 1990s. Price caps also became commonplace in state ILEC regulation.

Marketing flexibility for ILECs has been most relevant in the following two areas.

Competition in Traditional Service Markets Some services ILECs offered became subject to mounting competitive pressure that varied with the location where service was offered. For example, by the late 1990s, competitive access providers like MFS were constructing high-speed fiber optic networks connecting office buildings in metropolitan areas. These networks allowed businesses and long-distance carriers to connect to customers while bypassing ILEC data facilities. They could also be used to transmit voice traffic, avoiding ILEC voice access charges. High regulated prices were uncompetitive in high-traffic locations where facilities-based competitors entered the market. For services subject to competitive challenges, price cap plans in many states permitted discounts to standard tariffs within certain bands (e.g., rates could rise by 5% less than the price cap index) and/or subject to pricing floors that discouraged predation and cross-subsidization. In markets where pronounced competition could be demonstrated, ILEC rates were sometimes effectively decontrolled.

Innovative Services Technological change gave rise to innovative new services [e.g., Voicemail, Centrex and high-speed data (e.g., digital subscriber loop or "DSL")] which utilize essential network assets of ILECs and cannot not practically be performed by affiliates.[14] Many of these services were deemed “information” services and were regulated by the FCC. Regulators ultimately permitted ILECs to provide a host of these services and allowed considerable pricing flexibility.

Gas Distribution

Natural gas distributors also need flexibility to address some markets that they serve. Like VIEUs, many large-load customers of gas distributors have price sensitive demands and special needs. Distributors have frequently obtained light handed regulation to respond to these challenges. Nicor Gas, for example, offers a contract service for customers taking delivery near interstate gas pipelines. Contracts are submitted to state regulators for informational purposes and are treated on a proprietary basis. Nicor has similar flexibility to enter into custom contracts with electric power generators. The Company must document to the regulator that revenues from such service exceed the incremental cost of service, thereby ensuring a positive contribution to fixed cost recovery.

Interstate Gas Transmission

Interstate pipeline companies need marketing flexibility for many reasons. Demand for a pipeline’s services can be sensitive to the terms it offers due to competition from other pipelines, dual-fuel capabilities of large volume customers, the extreme variability of need for service, and other special needs. It is difficult to design standard tariffs that meet the needs of all customers. Pipelines also have their own needs, such as an interest in signing anchor shippers to long-term contracts before constructing new facilities. Since 1996, the FERC has engaged in light handed regulation of negotiated pipeline rates to individual customers who have recourse to service under a standard tariff. The FERC gives a quick turnaround to most requests for negotiated contracts. A sizable share of pipeline service is conducted under negotiated rates. A remarkable variety of rate designs have been employed.[15]

Railroads

In the railroad industry, MRPs were permitted under the terms of the Staggers Railroad Act of 1980. Railroads were given a freer hand to respond to competition from truckers, waterborne carriers, and other railroads. The railroads also used marketing flexibility to offer discounts to customers that reduced their cost by assembling their own unit trains and not requesting pickups or deliveries in remote locations.

MRPs are less common today in the railroad and telecom industries. However, marketing flexibility continues under new regulatory systems that share with MRPs the attribute of protecting core customers without linking a carrier’s rates closely to its own cost. Railroads have recently used this flexibility to compete for traffic from new oil field developments.

[14] Centrex service, which provided businesses features like call-waiting, auto attendant, voicemail, 4-digit extension dialing and conference calling, could also be sourced by purchasing or leasing a private branch exchange ("PBX"), a private network platform that enabled these features.

[15] See, for example, Comments of the Interstate Natural Gas Association of America in FERC Docket PLO2-6-000, September 2002.

VIII. Conclusions

Regulation of North American energy utilities is evolving to better meet the needs of utilities and their customers in a rapidly changing world. Innovation continues, while some older forms of Altreg such as multiyear rate plans are having a renaissance.

The variety of Altreg approaches that have been established reflects the varied circumstances of utilities. Some are vertically integrated, while others are more specialized wire companies. Capex needs and trends in average use vary greatly. Regulatory traditions also vary across the US and other advanced industrial countries.

No single Altreg approach is right for every situation. The availability of multiple remedies for the underlying challenges increases the chance that an approach has already been tried that would work well, with some adjustments, in new situations. Numerous precedents for an approach should raise confidence that it makes good sense under fairly common circumstances.

Taken together, the many innovations described in this survey can encourage utilities to achieve compensatory rates of return while making needed investments, improving efficiency, and developing more market-responsive rates and services. Regulation can be streamlined, and utilities can be encouraged to embrace cost-effective DERs. Regulators and stakeholders to regulation across the US should give priority attention to these options and consider which kinds of Altreg might work best in their situation.

Regulatory Research Associates
REGULATORY FOCUS

RRA Topical Special Report November 19, 2013

ALTERNATIVE REGULATION/INCENTIVE PLANS

~ A State-by-State Overview ~

Numerous electric and gas utilities are operating under alternative regulation plans (ARPs), mechanisms that generally provide an opportunity for the utilities to earn returns for shareholders that are above the returns achievable under the traditional framework. These ARPs largely permit the utilities to retain at least a portion of the earnings benefits as an incentive to surpass certain targets, possibly related to: authorized return levels; customer service; merger savings; fuel procurement; off-system sales; plant performance; management efficiency (i.e., overall cost savings); renewable portfolio standards; energy efficiency; or, emissions. If successful, such ARPs can provide tangible benefits to all parties -- customers are provided long-term benefits from lower-cost, more efficient operations, and shareholders are permitted to retain a portion of the benefits achieved from the operation of the plan.

Certain ARPs are "penalty-only" mechanisms, whereby the incentive to the utility is a "penalty avoidance," rather than a retention of operational efficiency benefits. For example, several companies in New York are subject to service quality standards -- failure to achieve these standards may trigger a financial penalty, while surpassing the standards would not trigger any tangible financial reward.

Other ARPs, while not directly providing an opportunity to earn incentives, represent a departure from traditional regulatory practices and methods, and generally streamline the process or provide enhanced certainty. For example, a formula-based rate plan generally allows a utility to operate freely within a range of reasonableness with respect to predetermined levels for earned return on equity and service quality. Operating outside of this range may trigger a rate adjustment. Additionally, certain states permit the utilities to reflect incremental plant investment in rate base and to recover the operating costs of newly completed plant without going through a full general rate case. Such rate changes provide for improved cash flow and possibly earnings through reduced regulatory lag.

This Regulatory Study provides a state-by-state/company-by-company overview of various ARPs that are currently in place for the major U.S. investor-owned electric and gas utilities. The tables that begin on pages 2 and 11 (and footnotes on page 20) provide a listing of 14 different types of ARPs that are in place -- to the extent that we are aware -- for each major utility within each jurisdiction. For purposes of this study, we define these ARPs as follows:

Table I

1) *Formula-Based Rates* refer to plans in which a utility's rates may be adjusted automatically in the event the company earns a return that is outside an authorized range. This column also reflects rate plans that include automatic rate adjustments based upon changes in an inflation measure such as the Consumer Price index or Gross Domestic Product-price Index, less a productivity offset;

2) *Price Freeze/Cap* plans include rate case moratoriums that prohibit utilities from filing new rate proceedings, intervenors from seeking earnings investigations, and/or the commission from authorizing base rate adjustments prior to a predetermined date. Such plans may not specify any restrictions on earnings, and as a result, any achieved cost savings are retained by the company. This column also includes multi-year rate plans, whereby a utility is permitted to implement a predetermined annual rate change over the course of the plan -- these types of plans generally include earnings sharing mechanisms;

3) *Earnings Sharing* mechanisms permit a utility to retain at least a portion of actual earnings that are in excess of the return allowed in the company's last rate case -- we note that under traditional regulation, a utility that earns in excess of its authorized equity return may become the subject of an earnings investigation. Earnings sharing mechanisms are often included in multi-year rate plans under which deviations from benchmark returns or revenue levels are shared by ratepayers and stockholders;

4) *Formula-Based ROE* plans are those in which a company's authorized return on equity is periodically reset based upon, for example, changes in long-term utility bond yields. While not considered an incentive provision, a commission's use of formula-based ROEs may reduce the investor uncertainty associated with

(Text continued on page 24.)

30 Montgomery Street, Jersey City, NJ 07302 • Phone 201.433.5507 • Fax 201.433.6138 • rra@snl.com

Table I -- Alternative Regulation Plans (Types 1-7)

State/ Company	Ultimate Parent Ticker	Type of Service	Type of Alternative Regulation: Formula-Based Rates	Price Freeze/Cap	Earnings Sharing	Formula-Based ROE	Rate Base Additions	Svc. Qual./ Mgt. Perf.	Merger Savings
ALABAMA									
Alabama Power	SO	Elec.	✓	--	--	--	✓	--	--
Alabama Gas	EGN	Gas	✓	--	--	--	--	--	--
Mobile Gas	SRE	Gas	✓	--	--	--	--	--	--
ALASKA									
Alaska Electric Light & Power	--	Elec.	--	--	--	--	--	--	--
Enstar Natural Gas	--	Gas	--	--	--	--	--	--	--
ARIZONA									
Arizona Public Service	PNW	Elec.	--	✓	--	--	--	--	--
Southwest Gas	SWX	Gas	--	✓	--	--	--	--	--
Tucson Electric Power	UNS	Elec.	--	--	--	--	--	--	--
UNS Electric	UNS	Elec.	--	--	--	--	--	--	--
UNS Gas	UNS	Gas	--	--	--	--	--	--	--
ARKANSAS									
Arkansas Oklahoma Gas	--	Gas	--	--	--	--	--	--	--
CenterPoint Energy Resources	CNP	Gas	--	--	--	--	✓	--	--
Entergy Arkansas	ETR	Elec.	--	--	--	--	✓	--	--
Oklahoma Gas & Electric	OGE	Elec.	--	--	--	--	--	--	--
SourceGas Arkansas	--	Gas	--	--	--	--	--	--	--
Southwestern Electric Power	AEP	Elec.	--	--	--	--	✓	--	--
CALIFORNIA									
Pacific Gas & Electric	PCG	Elec.	--	✓*	--	✓	✓	--	--
Pacific Gas & Electric	PCG	Gas	--	✓*	--	✓	--	--	--
San Diego Gas & Electric	SRE	Elec.	--	✓*	--	✓	--	--	--
San Diego Gas & Electric	SRE	Gas	--	✓*	--	✓	--	--	--
Southern California Edison	EIX	Elec.	--	✓*	--	✓	--	--	--
Southern California Gas	SRE	Gas	--	✓*	--	✓	--	--	--
Southwest Gas	SWX	Gas	--	✓*	--	✓	--	--	--
COLORADO									
Black Hills Colorado Electric	BKH	Elec.	--	--	--	--	✓	--	--
Public Service Co. of Colorado	XEL	Elec.	--	✓	✓	--	✓	--	--
Public Service Co. of Colorado	XEL	Gas	--	--	--	--	✓	--	--
SourceGas Distribution	--	Gas	--	--	--	--	--	--	--
CONNECTICUT									
Connecticut Lt. & Pwr.	NU	Elec.	--	✓	✓	--	--	--	--
Conn. Natural Gas	UIL	Gas	--	--	--	--	--*	--	--
Southern Conn. Gas	UIL	Gas	--	--	--	--	--*	--	--
United Illuminating	UIL	Elec.	--	--	✓	--	--	--	--
Yankee Gas Service	NU	Gas	--	--	--	--	--*	--	--

State/ Company	Ultimate Parent Ticker	Type of Service	Type of Alternative Regulation: Formula-Based Rates	Price Freeze/Cap	Earnings Sharing	Formula-Based ROE	Rate Base Additions	Svc. Qual./ Mgt. Perf.	Merger Savings
DELAWARE									
Chesapeake Utilities	CPK	Gas	--	--	--	--	--	--	--
Delmarva Power & Light	POM	Elec.	--	--	--	--	--*	--	--
Delmarva Power & Light	POM	Gas	--	✓	--	--	--	--	--
DISTRICT OF COLUMBIA									
Potomac Electric Power	POM	Elec.	--	--	--	--	--	--	--
Washington Gas Light	WGL	Gas	--	--	--	--	--	--	--
FLORIDA									
Florida Power & Light	NEE	Elec.	--	✓	--	--	✓	--	--
Florida Power	DUK	Elec.	--	✓	--	--	✓	--	--
Florida Public Utilities	CPK	Elec.	--	--	--	--	--	--	--
Florida Public Utilities	CPK	Gas	--	--	--	--	✓	--	--
Gulf Power	SO	Elec.	--	--	--	--	--	--	--
Peoples Gas System	TE	Gas	--	--	--	--	✓	--	--
Pivotal Utility Holdings	GAS	Gas	--	--	--	--	--	--	--
Tampa Electric	TE	Elec.	--	✓	--	--	✓	--	--
GEORGIA									
Atlanta Gas Light	GAS	Gas	--	--	--	--	✓	--	✓
Georgia Power	SO	Elec.	--	✓	✓	--	✓	--	--
Liberty Energy (Georgia)	--	Gas	✓	--	--	--	--	--	--
HAWAII									
Hawaiian Electric	HE	Elec.	--	--	✓	--	✓	--	--
Hawaii Electric Light	HE	Elec.	--	✓	✓	--	✓	--	--
Maui Electric	HE	Elec.	--	--	✓	--	✓	--	--
IDAHO									
Avista Corp.	AVA	Elec.	--	✓	--	--	--	--	--
Avista Corp.	AVA	Gas	--	✓	--	--	--	--	--
Idaho Power	IDA	Elec.	--	--	✓	--	--	--	--
PacifiCorp	BRK	Elec.	--	✓	--	--	--	--	--
ILLINOIS									
Ameren Illinois	AEE	Elec.	✓	--	✓	✓	--	✓	--
Ameren Illinois	AEE	Gas	--	--	--	--	--*	--	--
Commonwealth Edison	EXC	Elec.	✓	--	✓	✓	--	✓	--
MidAmerican Energy	BRK.A	Elec.	--	--	--	--	--	--	--
MidAmerican Energy	BRK.A	Gas	--	--	--	--	--	--	--
North Shore Gas	TEG	Gas	--	--	--	--	--	--	--
Northern Illinois Gas	GAS	Gas	--	✓	--	--	--*	--	--
Peoples Gas Light & Coke	TEG	Gas	--	--	--	--	--*	--	--

State/ Company	Ultimate Parent Ticker	Type of Service	Type of Alternative Regulation						
			Formula-Based Rates	Price Freeze/Cap	Earnings Sharing	Formula-Based ROE	Rate Base Additions	Svc. Qual./ Mgt. Perf.	Merger Savings
INDIANA									
Duke Energy Indiana	DUK	Elec.	--	✓	--	--	✓*	--	--
Indiana Gas	VVC	Gas	--	--	--	--	--*	--	--
Indiana Michigan Power	AEP	Elec.	--	--	--	--	✓*	--	--
Indianapolis Power & Light	AES	Elec.	--	--	--	--	✓*	--	--
Northern Indiana Public Service	NI	Elec.	--	--	--	--	✓*	--	--
Northern Indiana Public Service	NI	Gas	--	--	--	--	--*	--	--
Southern Indiana Gas & Electric	VVC	Elec.	--	--	--	--	--*	--	--
Southern Indiana Gas & Electric	VVC	Gas	--	--	--	--	--*	--	--
IOWA									
Black Hills Iowa Gas Utility	BKH	Gas	--	--	--	--	--	--*	--
Interstate Power & Light	LNT	Elec.	--	✓	--	--	--	--*	--
Interstate Power & Light	LNT	Gas	--	--	--	--	--	--*	--
MidAmerican Energy	BRK.A	Elec.	--	✓	✓	--	--	--*	--
MidAmerican Energy	BRK.A	Gas	--	--	--	--	--	--*	--
KANSAS									
Atmos Energy	ATO	Gas	--	--	--	--	✓*	--	--
Black Hills/Kansas Gas Utility	BKH	Gas	--	--	--	--	✓*	✓	✓
Empire District Electric	EDE	Elec.	--	--	--	--	✓*	--	--
Kansas City Power & Light	GXP	Elec.	--	--	--	--	✓*	✓	--
Kansas Gas & Electric	WR	Elec.	--	--	--	--	✓*	--	✓
ONEOK	OKE	Gas	--	--	--	--	✓*	--	--
Westar Energy	WR	Elec.	--	--	--	--	✓*	--	✓
KENTUCKY									
Atmos Energy	ATO	Gas	--	--	--	--	✓	--	--
Columbia Gas of Kentucky	NI	Gas	--	--	--	--	✓	--	--
Delta Natural Gas	DGAS	Gas	--	--	--	--	✓	--	--
Duke Energy Kentucky	DUK	Elec.	--	--	--	--	--	--	--
Duke Energy Kentucky	DUK	Gas	--	--	--	--	--	--	--
Kentucky Power	AEP	Elec.	--	--	--	--	✓	--	--
Kentucky Utilities	PPL	Elec.	--	--	--	--	✓	--	--
Louisville Gas & Electric	PPL	Elec.	--	--	--	--	✓	--	--
Louisville Gas & Electric	PPL	Gas	--	--	--	--	--	--	--
LOUISIANA-NOCC									
Entergy New Orleans	ETR	Elec.	--	--	--	--	--	--	--
Entergy New Orleans	ETR	Gas	--	--	--	--	--	--	--
LOUISIANA PSC									
Atmos Energy	ATO	Gas	✓	--	✓	--	--	--	✓
CenterPoint Energy Resources	CNP	Gas	✓	--	✓	--	--	--	--
Cleco Power	CNL	Elec.	✓	--	✓	--	--	--	--
Entergy Gulf States Louisiana	ETR	Elec.	--	--	--	--	--	--	--
Entergy Gulf States Louisiana	ETR	Gas	✓	--	✓	--	--	--	--
Entergy Louisiana	ETR	Elec.	--	--	--	--	--	--	--
Southwestern Electric Power	AEP	Elec.	✓	✓	✓	--	--	--	--

State/ Company	Ultimate Parent Ticker	Type of Service	Type of Alternative Regulation: Formula-Based Rates	Price Freeze/Cap	Earnings Sharing	Formula-Based ROE	Rate Base Additions	Svc. Qual./ Mgt. Perf.	Merger Savings
MAINE									
Bangor Hydro-Electric	--	Elec.	--	--	--	--	--	--	--
Central Maine Power	--	Elec.	✓	--	✓	--	--	--*	--
Maine Public Service	--	Elec.	--	--	--	--	--	--	--
Northern Utilities	UTL	Gas	--	✓	--	--	--	--	--
MARYLAND									
Baltimore Gas & Electric	EXC	Elec.	--	--	--	--	--	--	--
Baltimore Gas & Electric	EXC	Gas	--	--	--	--	--*	--	--
Columbia Gas of Maryland	NI	Gas	--	--	--	--	--*	--	--
Delmarva Power & Light	POM	Elec.	--	--	--	--	--	--	--
Potomac Edison	FE	Elec.	--	--	--	--	--	--	--
Potomac Electric Power	POM	Elec.	--	--	--	--	--	--	--
Washington Gas Light	WGL	Gas	--	--	--	--	--*	--	--
MASSACHUSETTS									
Bay State Gas	NI	Gas	--	--	--	--	✓	✓	--
Boston/Colonial/Essex Gas	NGG	Gas	--	--	--	--	✓	✓	--
Fitchburg Gas & Electric	UTL	Elec.	--	--	--	--	--	✓	--
Fitchburg Gas & Electric	UTL	Gas	--	--	--	--	--	✓	--
Massachusetts Electric	NGG	Elec.	--	--	✓	--	✓	✓	--
New England Gas	ETE	Gas	--	--	--	--	✓	✓	--
NSTAR Electric	NU	Elec.	--	✓	--	--	--	✓	--
NSTAR Gas	NU	Gas	--	✓	--	--	--	✓	--
Western Mass. Electric	NU	Elec.	--	✓	--	--	--	✓	--
MICHIGAN									
Consumers Energy	CMS	Elec.	--	--	--	--	--	--	--
Consumers Energy	CMS	Gas	--	--	--	--	--	--	--
DTE Electric	DTE	Elec.	--	--	--	--	--	--	--
DTE Gas	DTE	Gas	--	--	--	--	✓	--	--
Indiana Michigan Power	AEP	Elec.	--	--	--	--	--	--	--
Michigan Gas Utilities	TEG	Gas	--	--	--	--	--	--	--
SEMCO Energy Gas	--	Gas	--	--	--	--	--	--	--
Upper Peninsula Power	TEG	Elec.	--	✓	--	--	--	--	--
Wisconsin Electric Power	WEC	Elec.	--	--	--	--	--	--	--
MINNESOTA									
Minnesota Power	ALE	Elec.	--	--	--	--	--	--	--
CenterPoint Energy Resources	CNP	Gas	--	--	--	--	--	--	--
Interstate Power & Light	LNT	Elec.	--	--	--	--	--	--	--
Minnesota Energy Resources	TEG	Gas	--	--	--	--	--	--	--
Northern States Power-Minnesota	XEL	Elec.	--	--	--	--	--	--	--
Northern States Power-Minnesota	XEL	Gas	--	--	--	--	--	--	--
Otter Tail Power	OTTR	Elec.	--	--	--	--	--	--	--

State/ Company	Ultimate Parent Ticker	Type of Service	Type of Alternative Regulation						
			Formula-Based Rates	Price Freeze/Cap	Earnings Sharing	Formula-Based ROE	Rate Base Additions	Svc. Qual./ Mgt. Perf.	Merger Savings
MISSISSIPPI									
Atmos Energy	ATO	Gas	✓	--	--	✓	--	✓	--
Entergy Mississippi	ETR	Elec.	✓	--	--	✓	✓	✓	--
Mississippi Power	SO	Elec.	✓	--	--	✓	--	✓	--
MISSOURI									
Empire District Electric	EDE	Elec.	--	✓	--	--	--*	--	--
Empire District Gas	EDE	Gas	--	--	--	--	--*	--	--
Kansas City Power & Light	GXP	Elec.	--	--	--	--	--*	--	--
KCP&L Greater Missouri Operations	GXP	Elec.	--	--	--	--	--*	--	--
Laclede Gas	LG	Gas	--	--	--	--	✓	--	--
Liberty Energy (Midstates)	--	Gas	--	--	--	--	✓	--	--
Missouri Gas Energy	ETE	Gas	--	--	--	--	✓	--	--
Union Electric	AEE	Elec.	--	--	--	--	--*	--	--
Union Electric	AEE	Gas	--	--	--	--	✓	--	--
MONTANA									
MDU Resources	MDU	Elec.	--	--	--	--	--	--	--
MDU Resources	MDU	Gas	--	--	--	--	--	--	--
Northwestern Energy	NWE	Elec.	--	--	--	--	--	--	--
Northwestern Energy	NWE	Gas	--	--	--	--	--	--	--
NEBRASKA									
Black Hills Nebraska Gas	BKH	Gas	--	--	--	--	--	--	--
Northwestern Energy	NWE	Gas	--	--	--	--	--	--	--
SourceGas Distribution	--	Gas	--	--	--	--	--	--	--
NEVADA									
Nevada Power	NVE	Elec.	--	--	--	--	✓*	--	--
Sierra Pacific Power	NVE	Elec.	--	--	--	--	✓*	--	--
Sierra Pacific Power	NVE	Gas	--*	--*	--*	--	--	--	--
Southwest Gas	SWX	Gas	--*	--*	--*	--	--	--	--
NEW HAMPSHIRE									
EnergyNorth Natural Gas	NGG	Gas	--	✓	--*	--	--	--	✓
Granite State Electric	NGG	Elec.	--	--	--	--	--	--	--
Northern Utilities	UTL	Gas	--	--	--	--	--	--	--
Public Service Co. of New Hampshire	NU	Elec.	--	✓	✓	--	--	--	--
Unitil Energy Systems	UTL	Elec.	--	✓	✓	--	--	--	--
NEW JERSEY									
Atlantic City Electric	POM	Elec.	--	--	--	--	✓	--	--
Jersey Central Power & Light	FE	Elec.	--	--	--	--	✓	--	--
New Jersey Natural Gas	NJR	Gas	--	--	--	--	✓	--	--
Pivotal Utility Holdings	GAS	Gas	--	--	--	--	✓	--	--
Public Service Electric & Gas	PEG	Elec.	--	--	--	--	✓	--	--
Public Service Electric & Gas	PEG	Gas	--	--	--	--	✓	--	--
Rockland Electric	ED	Elec.	--	--	--	--	✓	--	--
South Jersey Gas	SJI	Gas	--	--	--	--	✓	--	--

State/ Company	Ultimate Parent Ticker	Type of Service	Type of Alternative Regulation						
			Formula-Based Rates	Price Freeze/Cap	Earnings Sharing	Formula-Based ROE	Rate Base Additions	Svc. Qual./ Mgt. Perf.	Merger Savings
NEW MEXICO									
El Paso Electric	EE	Elec.	--	--	--	--	--	--	--
New Mexico Gas	--	Gas	--	--	--	--	--	--	--
Public Service Co. of New Mexico	PNM	Elec.	--	--	--	--	--	--	--
Southwestern Public Service	XEL	Elec.	--	✓	--	--	--	--	--
NEW YORK									
Brooklyn Union Gas	NGG	Gas	--	✓	✓	--	--	--*	--
Central Hudson Gas & Electric	CHG	Elec.	--	✓	✓	--	--	--*	--
Central Hudson Gas & Electric	CHG	Gas	--	✓	✓	--	--	--*	--
Consolidated Edison of New York	ED	Elec.	--	--	✓	--	--	--*	--
Consolidated Edison of New York	ED	Gas	--	--	✓	--	--	--*	--
Consolidated Edison of New York	ED	Steam	--	--	✓	--	--	--*	--
KeySpan Gas East	NGG	Gas	--	--	✓	--	--	--*	--
National Fuel Gas Distribution	NFG	Gas	--	--	--	--	--	--	--
New York State Electric & Gas	--	Elec.	--	✓	✓	--	--	--*	--
New York State Electric & Gas	--	Gas	--	✓	✓	--	--	--*	--
Niagara Mohawk Power	NGG	Elec.	--	✓	✓	--	--	--*	--
Niagara Mohawk Power	NGG	Gas	--	✓	✓	--	--	--*	--
Orange & Rockland Utilities	ED	Elec.	--	✓	✓	--	--	--*	--
Orange & Rockland Utilities	ED	Gas	--	--	✓	--	--	--*	--
Rochester Gas & Electric	--	Elec.	--	✓	✓	--	--	--*	--
Rochester Gas & Electric	--	Gas	--	✓	✓	--	--	--*	--
NORTH CAROLINA									
Carolina Power & Light	DUK	Elec.	--	--	--	--	--	--	--
Duke Energy Carolinas	DUK	Elec.	--	✓	--	--	--	--	--
Piedmont Natural Gas	PNY	Gas	--	--	--	--	--	--	--
Public Service Co. of North Carolina	SCG	Gas	--	--	--	--	--	--	--
Virginia Electric & Power	D	Elec.	--	--	--	--	--	--	--
NORTH DAKOTA									
MDU Resources	MDU	Elec.	--	--	--	--	--	--	--
MDU Resources	MDU	Gas	--	--	--	--	--	--	--
Northern States Power-Minnesota	XEL	Elec.	--	--	--	--	--	--	--
Northern States Power-Minnesota	XEL	Gas	--	--	--	--	--	--	--
Otter Tail Power	OTTR	Elec.	--	--	--	--	--	--	--
OHIO									
Cleveland Electric Illuminating	FE	Elec.	--	✓*	✓*	--	✓	--	--
Columbia Gas	NI	Gas	--	--	--	--	✓	--	--
Dayton Power & Light	DPL	Elec.	--	--	✓*	--	✓	--	--
Duke Energy Ohio	DUK	Elec.	--	--	✓*	--	--	--	--
Duke Energy Ohio	DUK	Gas	--	--	--	--	✓	--	--
East Ohio Gas	D	Gas	--	--	--	--	✓	--	--
Ohio Edison	FE	Elec.	--	✓*	✓*	--	✓	--	--
Ohio Power	AEP	Elec.	--	✓*	✓*	--	✓	--	--
Toledo Edison	FE	Elec.	--	✓*	✓*	--	✓	--	--
Vectren Energy Delivery of Ohio	VVC	Gas	--	--	--	--	✓	--	--

State/ Company	Ultimate Parent Ticker	Type of Service	Type of Alternative Regulation						
			Formula-Based Rates	Price Freeze/Cap	Earnings Sharing	Formula-Based ROE	Rate Base Additions	Svc. Qual./ Mgt. Perf.	Merger Savings
OKLAHOMA									
CenterPoint Energy Resources	CNP	Gas	✓	--	✓	--	--	--	--
Oklahoma Gas & Electric	OGE	Elec.	--	--	--	--	✓	--	--
ONEOK	OKE	Gas	✓	--	✓	--	--	--	--
Public Service Oklahoma	AEP	Elec.	--	--	--	--	✓	--	--
OREGON									
Avista Corp.	AVA	Gas	--	--	--	--	--	--	--
Cascade Natural Gas	MDU	Gas	--	--	--	--	--	--	--
Idaho Power	IDA	Elec.	--	--	--	--	✓*	--	--
Northwest Natural Gas	NWN	Gas	--	--	--	--	✓	--	--
PacifiCorp	BRK.A	Elec.	--	--	--	--	✓*	--	--
Portland General Electric	POR	Elec.	--	--	--	--	✓*	--	--
PENNSYLVANIA									
Columbia Gas of Pennsylvania	NI	Gas	--	--	--	--	✓*	--	--
Duquesne Light	--	Elec.	--	--	--	--	--*	--	--
Equitable Gas	EQT	Gas	--	--	--	--	✓*	--	--
Metropolitan Edison	FE	Elec.	--	--	--	--	--*	--	--
National Fuel Gas Distribution	NFG	Gas	--	--	--	--	--*	--	--
PECO Energy	EXC	Elec.	--	--	--	--	--*	--	--
PECO Energy	EXC	Gas	--	--	--	--	✓*	--	--
Pennsylvania Electric	FE	Elec.	--	--	--	--	--*	--	--
Pennsylvania Power	FE	Elec.	--	--	--	--	--*	--	--
Peoples Natural Gas	--	Gas	--	--	--	--	✓*	--	--
PPL Electric Utilities	PPL	Elec.	--	--	--	--	✓*	--	--
UGI Central Penn Gas	UGI	Gas	--	--	--	--	--*	--	--
UGI Penn Natural Gas	UGI	Gas	--	--	--	--	--*	--	--
West Penn Power	FE	Elec.	--	--	--	--	--*	--	--
UGI Utilities	UGI	Elec.	--	--	--	--	--*	--	--
UGI Utilities	UGI	Gas	--	--	--	--	--*	--	--
RHODE ISLAND									
Narragansett Electric	--	Elec.	--	--	✓	--	✓	--	--
Narragansett Electric	--	Gas	--	--	✓	--	✓	--	--
SOUTH CAROLINA									
Carolina Power & Light	DUK	Elec.	--	--	--	--	--	--	--
Duke Energy Carolinas	DUK	Elec.	--	✓	--	--	--	--	--
Piedmont Natural Gas	PNY	Gas	✓	--	--	--	--	--	--
South Carolina Electric & Gas	SCG	Elec.	--	✓	--	--	✓	--	--
South Carolina Electric & Gas	SCG	Gas	✓	--	--	--	--	--	--
SOUTH DAKOTA									
Black Hills Power	BKH	Elec.	--	--	--	--	--	--	--
Northern States Power-Minnesota	XEL	Elec.	--	✓	--	--	--	--	--
Northwestern Energy	NWE	Gas	--	--	--	--	--	--	--

State/ Company	Ultimate Parent Ticker	Type of Service	Type of Alternative Regulation						
			Formula-Based Rates	Price Freeze/Cap	Earnings Sharing	Formula-Based ROE	Rate Base Additions	Svc. Qual./ Mgt. Perf.	Merger Savings
TENNESSEE									
Atmos Energy	ATO	Gas	--	--	--	--	--	--	--
Chattanooga Gas	GAS	Gas	--	--	--	--	--	--	--
Kingsport Power	AEP	Elec.	--	--	--	--	--	--	--
Piedmont Natural Gas	PNY	Gas	--	--	--	--	--	--	--
TEXAS PUC									
AEP Texas Central	AEP	Elec.	--	--	--	--	✓*	--	--
AEP Texas North	AEP	Elec.	--	--	--	--	✓*	--	--
CenterPoint Energy Houston Electric	CNP	Elec.	--	--	--	--	✓*	--	--
Cross Texas Transmission	--	Elec.	--	--	--	--	✓*	--	--
El Paso Electric	EE	Elec.	--	--	--	--	✓*	--	--
Electric Transmission of Texas	BRK.A/AEP	Elec.	--	--	--	--	✓*	--	--
Entergy Texas	ETR	Elec.	--	--	--	--	✓*	--	--
Lone Star Transmission	NEE	Elec.	--	--	--	--	✓*	--	--
Oncor Electric Delivery	--	Elec.	--	--	--	--	✓*	--	--
Southwestern Electric Power	AEP	Elec.	--	--	--	--	✓*	--	--
Southwestern Public Service	XEL	Elec.	--	✓	--	--	✓*	--	--
Texas-New Mexico Power	PNM	Elec.	--	--	--	--	✓*	--	--
Wind Energy Transmission of Texas	--	Elec.	--	--	--	--	✓*	--	--
TEXAS RRC									
Atmos Energy	ATO	Gas	--	--	--	--	✓	--	--
CenterPoint Energy Resources	CNP	Gas	--	--	--	--	✓	--	--
Texas Gas Service	OKE	Gas	--	--	--	--	--	--	--
UTAH									
PacifiCorp	BRK.A	Elec.	--	✓	--	--	--	--	--
Questar	STR	Gas	--	--	--	--	✓	--	--
VERMONT									
Green Mountain Power	--	Elec.	✓	✓	✓	✓	--	✓	--
Vermont Gas Systems	--	Gas	✓	✓	✓	✓	--	--	--
VIRGINIA									
Appalachian Power	AEP	Elec.	--	--	✓	✓	✓	✓	--
Columbia Gas of Virginia	NI	Gas	--	--	--	--	✓	--	--
Kentucky Utilities	PPL	Elec.	--	--	--	--	--	--	--
Virginia Electric & Power	D	Elec.	--	✓*	✓	✓	✓	✓	--
Virginia Natural Gas	GAS	Gas	--	--	--	--	✓	--	--
Washington Gas Light	WGL	Gas	--	--	--	--	✓	--	--

State/ Company	Ultimate Parent Ticker	Type of Service	Type of Alternative Regulation						
			Formula-Based Rates	Price Freeze/Cap	Earnings Sharing	Formula-Based ROE	Rate Base Additions	Svc. Qual./ Mgt. Perf.	Merger Savings
WASHINGTON									
Avista Corp.	AVA	Elec.	--	✓	--	--	--	--	--
Avista Corp.	AVA	Gas	--	✓	--	--	--*	--	--
Cascade Natural Gas	MDU	Gas	--	--	--	--	✓*	--	--
Northwest Natural Gas	NWN	Gas	--	--	--	--	--*	--	--
PacifiCorp	BRK.A	Elec.	--	--	--	--	--	--	--
Puget Sound Energy	--	Elec.	--	✓*	✓*	--	✓	--	--
Puget Sound Energy	--	Gas	--	✓*	✓*	--	--*	--	--
WEST VIRGINIA									
Appalachian Power	AEP	Elec.	--	--	--	--	✓	--	--
Hope Gas	D	Gas	--	--	--	--	--	--	--
Monongahela Power	FE	Elec.	--	--	--	--	✓	--	--
Mountaineer Gas	--	Gas	--	--	--	--	--	--	--
Potomac Edison	FE	Elec.	--	--	--	--	✓	--	--
Wheeling Power	AEP	Elec.	--	--	--	--	✓	--	--
WISCONSIN									
Madison Gas & Electric	MGEE	Elec.	--	✓	--	--	--*	--	--
Madison Gas & Electric	MGEE	Gas	--	✓	--	--	--*	--	--
Northern States Power-Wisconsin	XEL	Elec.	--	--	--	--	--*	--	--
Northern States Power-Wisconsin	XEL	Gas	--	--	--	--	--*	--	--
Wisconsin Electric Power	WEC	Elec.	--	✓	--	--	--*	--	--
Wisconsin Electric Power	WEC	Gas	--	✓	--	--	--*	--	--
Wisconsin Gas	WEC	Gas	--	✓	--	--	--*	--	--
Wisconsin Power & Light	LNT	Elec.	--	✓	✓	--	--*	--	--
Wisconsin Power & Light	LNT	Gas	--	✓	✓	--	--*	--	--
Wisconsin Public Service	TEG	Elec.	--	--	--	--	--*	--	--
Wisconsin Public Service	TEG	Gas	--	--	--	--	--*	--	--
WYOMING									
Cheyenne Light Fuel & Power	BKH	Elec.	--	--	--	--	✓	--	--
Cheyenne Light Fuel & Power	BKH	Gas	--	--	--	--	--	--	--
MDU Resources	MDU	Elec.	--	--	--	--	--	--	--
PacifiCorp	BRK	Elec.	--	✓	--	--	--	--	--
SourceGas Distribution	--	Gas	--	--	--	--	--	--	--

* See footnotes for further information.

As of 11/18/13
Source: SNL Energy/RRA

Table II -- Alternative Regulation Plans (Types 8-14)

State/ Company	Ultimate Parent Ticker	Type of Service	Type of Alternative Regulation: Fuel & Power Procurement	Capacity Rel./OSS	Plant Performance	Renewables	DSM/Energy Efficiency	Emissions	Energy Trading
ALABAMA									
Alabama Power	SO	Elec.	--	--	--	--	--	--	--
Alabama Gas	EGN	Gas	--	--	--	--	--	--	--
Mobile Gas	SRE	Gas	--	--	--	--	--	--	--
ALASKA									
Alaska Electric Light & Power	--	Elec.	--	--	--	--	--	--	--
Enstar Natural Gas	--	Gas	--	--	--	--	--	--	--
ARIZONA									
Arizona Public Service	PNW	Elec.	--	--	--	--	✓	--	--
Southwest Gas	SWX	Gas	--	--	--	--	--	--	--
Tucson Electric Power	UNS	Elec.	--	--	--	--	✓	--	--
UNS Electric	UNS	Elec.	--	--	--	--	✓	--	--
UNS Gas	UNS	Gas	--	--	--	--	--	--	--
ARKANSAS									
Arkansas Oklahoma Gas	--	Gas	--	--	--	--	✓	--	--
CenterPoint Energy Resources	CNP	Gas	--	--	--	--	✓	--	--
Entergy Arkansas	ETR	Elec.	--	--	--	--	✓	--	--
Oklahoma Gas & Electric	OGE	Elec.	--	--	--	--	✓	--	--
SourceGas Arkansas	--	Gas	--	--	--	--	✓	--	--
Southwestern Electric Power	AEP	Elec.	--	--	--	--	✓	--	--
CALIFORNIA									
Pacific Gas & Electric	PCG	Elec.	--	--	--	--	✓	--	--
Pacific Gas & Electric	PCG	Gas	✓	--	--	--	✓	--	--
San Diego Gas & Electric	SRE	Elec.	--	--	--	--	✓	--	--
San Diego Gas & Electric	SRE	Gas	✓	--	--	--	✓	--	--
Southern California Edison	EIX	Elec.	--	--	--	--	✓	--	--
Southern California Gas	SRE	Gas	✓	--	--	--	✓	--	--
Southwest Gas	SWX	Gas	--	--	--	--	--	--	--
COLORADO									
Black Hills Colorado Electric	BKH	Elec.	--	✓	--	--*	✓	--	--
Public Service Co. of Colorado	XEL	Elec.	--	✓	--	✓*	✓	--	✓
Public Service Co. of Colorado	XEL	Gas	--	--	--	--*	--	--	--
SourceGas Distribution	--	Gas	--	--	--	--*	--	--	--
CONNECTICUT									
Connecticut Lt. & Pwr.	NU	Elec.	--	--	--	--	✓	--	--
Conn. Natural Gas	UIL	Gas	--	✓	--	--	✓	--	--
Southern Conn. Gas	UIL	Gas	--	✓	--	--	✓	--	--
United Illuminating	UIL	Elec.	--	--	--	✓*	✓	--	--
Yankee Gas Service	NU	Gas	--	✓	--	--	✓	--	--

	Ultimate		Type of Alternative Regulation						
State/ Company	Parent Ticker	Type of Service	Fuel & Power Procurement	Capacity Rel./OSS	Plant Performance	Renewables	DSM/Energy Efficiency	Emissions	Energy Trading
DELAWARE									
Chesapeake Utilities	CPK	Gas	--	--	--	--	--	--	--
Delmarva Power & Light	POM	Elec.	--	--	--	--	--	--	--
Delmarva Power & Light	POM	Gas	--	✓	--	--	--	--	--
DISTRICT OF COLUMBIA									
Potomac Electric Power	POM	Elec.	--	--	--	--	--	--	--
Washington Gas Light	WGL	Gas	--	--	--	--	--	--	--
FLORIDA									
Florida Power & Light	NEE	Elec.	✓	✓	✓	--	✓	--	--
Florida Power	DUK	Elec.	--	✓	✓	--	✓	--	--
Florida Public Utilities	CPK	Elec.	--	--	--	--	✓	--	--
Florida Public Utilities	CPK	Gas	--	--	--	--	✓	--	--
Gulf Power	SO	Elec.	--	✓	✓	--	✓	--	--
Peoples Gas System	TE	Gas	--	--	--	--	✓	--	--
Pivotal Utility Holdings	GAS	Gas	--	--	--	--	✓	--	--
Tampa Electric	TE	Elec.	--	✓	✓	--	✓	--	--
GEORGIA									
Atlanta Gas Light	GAS	Gas	--	--	--	--	--	--	--
Georgia Power	SO	Elec.	--	--	--	--	✓	--	--
Liberty Energy (Georgia)	--	Gas	--	--	--	--	--	--	--
HAWAII									
Hawaiian Electric	HE	Elec.	--	--	--	--	✓	--	--
Hawaii Electric Light	HE	Elec.	--	--	--	--	✓	--	--
Maui Electric	HE	Elec.	--	--	--	--	✓	--	--
IDAHO									
Avista Corp.	AVA	Elec.	✓	--	--	--	--	--	--
Avista Corp.	AVA	Gas	--	--	--	--	--	--	--
Idaho Power	IDA	Elec.	✓	--	--	--	--	✓	--
PacifiCorp	BRK	Elec.	✓	--	--	--	--	--	--
ILLINOIS									
Ameren Illinois	AEE	Elec.	--	--	--	--	--	--	--
Ameren Illinois	AEE	Gas	--	--	--	--	--	--	--
Commonwealth Edison	EXC	Elec.	--	--	--	--	--	--	--
MidAmerican Energy	BRK.A	Elec.	--	--	--	--	--	--	--
MidAmerican Energy	BRK.A	Gas	--	--	--	--	--	--	--
North Shore Gas	TEG	Gas	--	--	--	--	✓	--	--
Northern Illinois Gas	GAS	Gas	--	--	--	--	--	--	--
Peoples Gas Light & Coke	TEG	Gas	--	--	--	--	✓	--	--

State/ Company	Ultimate Parent Ticker	Type of Service	Type of Alternative Regulation: Fuel & Power Procurement	Capacity Rel./OSS	Plant Performance	Renewables	DSM/Energy Efficiency	Emissions	Energy Trading
INDIANA									
Duke Energy Indiana	DUK	Elec.	--	✓	--	--*	✓	--	--
Indiana Gas	VVC	Gas	--	--	--	--	✓	--	--
Indiana Michigan Power	AEP	Elec.	--	✓	--	--*	✓	--	--
Indianapolis Power & Light	AES	Elec.	--	--	--	--*	✓	--	--
Northern Indiana Public Service	NI	Elec.	--	✓	--	--*	✓	--	--
Northern Indiana Public Service	NI	Gas	✓	✓	--	--	✓	--	--
Southern Indiana Gas & Electric	VVC	Elec.	--	✓	--	--*	✓	--	--
Southern Indiana Gas & Electric	VVC	Gas	--	--	--	--	✓	--	--
IOWA									
Black Hills Iowa Gas Utility	BKH	Gas	--	--	--	--	--	--	--
Interstate Power & Light	LNT	Elec.	--	--	--	--	--	--	--
Interstate Power & Light	LNT	Gas	--	✓	--	--	--	--	--
MidAmerican Energy	BRK.A	Elec.	--	--	--	--	--	--	--
MidAmerican Energy	BRK.A	Gas	✓	✓	--	--	--	--	--
KANSAS									
Atmos Energy	ATO	Gas	--*	✓	--	--*	--*	--	--
Black Hills/Kansas Gas Utility	BKH	Gas	--*	✓	--	--*	--*	--	--
Empire District Electric	EDE	Elec.	--	--	--	--*	--*	--	--
Kansas City Power & Light	GXP	Elec.	--	--	--	--*	--*	--	--
Kansas Gas & Electric	WR	Elec.	--	--	--	--*	--*	--	--
ONEOK	OKE	Gas	--*	✓	--	--*	--*	--	--
Westar Energy	WR	Elec.	--	--	--	--*	--*	--	--
KENTUCKY									
Atmos Energy	ATO	Gas	✓	✓	--	--	✓	--	--
Columbia Gas of Kentucky	NI	Gas	✓	✓	--	--	✓	--	--
Delta Natural Gas	DGAS	Gas	--	--	--	--	✓	--	--
Duke Energy Kentucky	DUK	Elec.	--	✓	--	--	--	--	--
Duke Energy Kentucky	DUK	Gas	--	--	--	--	✓	--	--
Kentucky Power	AEP	Elec.	--	✓	--	--	--	--	--
Kentucky Utilities	PPL	Elec.	--	--	--	--	--	--	--
Louisville Gas & Electric	PPL	Elec.	--	--	--	--	--	--	--
Louisville Gas & Electric	PPL	Gas	✓	✓	--	--	✓	--	--
LOUISIANA-NOCC									
Entergy New Orleans	ETR	Elec.	--	--	--	--	--	--	--
Entergy New Orleans	ETR	Gas	--	--	--	--	--	--	--
LOUISIANA PSC									
Atmos Energy	ATO	Gas	--	--	--	--	--	--	--
CenterPoint Energy Resources	CNP	Gas	--	--	--	--	--	--	--
Cleco Power	CNL	Elec.	--	--	--	--	--	--	--
Entergy Gulf States Louisiana	ETR	Elec.	--	--	✓*	--	--	--	--
Entergy Gulf States Louisiana	ETR	Gas	--	--	--	--	--	--	--
Entergy Louisiana	ETR	Elec.	--	--	--	--	--	--	--
Southwestern Electric Power	AEP	Elec.	--	✓	--	--	--	--	--

State/ Company	Ultimate Parent Ticker	Type of Service	Type of Alternative Regulation: Fuel & Power Procurement	Capacity Rel./OSS	Plant Performance	Renewables	DSM/Energy Efficiency	Emissions	Energy Trading
MAINE									
Bangor Hydro-Electric	--	Elec.	--	--	--	--	--	--	--
Central Maine Power	--	Elec.	--	--	--	--	--	--	--
Maine Public Service	--	Elec.	--	--	--	--	--	--	--
Northern Utilities	UTL	Gas	--	--	--	--	--	--	--
MARYLAND									
Baltimore Gas & Electric	EXC	Elec.	--	--	--	--	--	--	--
Baltimore Gas & Electric	EXC	Gas	✓	✓	--	--	--	--	--
Columbia Gas of Maryland	NI	Gas	✓	✓	--	--	--	--	--
Delmarva Power & Light	POM	Elec.	--	--	--	--	--	--	--
Potomac Edison	FE	Elec.	--	--	--	--	--	--	--
Potomac Electric Power	POM	Elec.	--	--	--	--	--	--	--
Washington Gas Light	WGL	Gas	--	✓	--	--	--	--	--
MASSACHUSETTS									
Bay State Gas	NI	Gas	--	✓	--	--	✓	--	--
Boston/Colonial/Essex Gas	NGG	Gas	--	✓	--	--	✓	--	--
Fitchburg Gas & Electric	UTL	Elec.	--	--	--	--	✓	--	--
Fitchburg Gas & Electric	UTL	Gas	--	✓	--	--	✓	--	--
Massachusetts Electric	NGG	Elec.	--	--	--	--	✓	--	--
New England Gas	ETE	Gas	--	✓	--	--	✓	--	--
NSTAR Electric	NU	Elec.	--	--	--	--	✓	--	--
NSTAR Gas	NU	Gas	--	✓	--	--	✓	--	--
Western Mass. Electric	NU	Elec.	--	--	--	--	✓	--	--
MICHIGAN									
Consumers Energy	CMS	Elec.	--	--	--	--	✓	--	--
Consumers Energy	CMS	Gas	--	--	--	--	✓	--	--
DTE Electric	DTE	Elec.	--	--	--	--	✓	--	--
DTE Gas	DTE	Gas	--	--	--	--	✓	--	--
Indiana Michigan Power	AEP	Elec.	--	--	--	--	✓	--	--
Michigan Gas Utilities	TEG	Gas	--	--	--	--	✓	--	--
SEMCO Energy Gas	--	Gas	--	--	--	--	✓	--	--
Upper Peninsula Power	TEG	Elec.	--	--	--	--	✓	--	--
Wisconsin Electric Power	WEC	Elec.	--	--	--	--	✓	--	--
MINNESOTA									
Minnesota Power	ALE	Elec.	--	--	--	--	✓	--*	--
CenterPoint Energy Resources	CNP	Gas	--	--	--	--	✓	--*	--
Interstate Power & Light	LNT	Elec.	--	--	--	--	✓	--*	--
Minnesota Energy Resources	TEG	Gas	--	--	--	--	✓	--*	--
Northern States Power-Minnesota	XEL	Elec.	--	--	--	--	✓	--*	--
Northern States Power-Minnesota	XEL	Gas	--	--	--	--	✓	--*	--
Otter Tail Power	OTTR	Elec.	--	--	--	--	✓	--*	--

State/ Company	Ultimate Parent Ticker	Type of Service	Type of Alternative Regulation: Fuel & Power Procurement	Capacity Rel./OSS	Plant Performance	Renewables	DSM/Energy Efficiency	Emissions	Energy Trading
MISSISSIPPI									
Atmos Energy	ATO	Gas	--	--	--	--	--	--	--
Entergy Mississippi	ETR	Elec.	--	--	--	--	--	--	--
Mississippi Power	SO	Elec.	--	--	--	--	--	--	--
MISSOURI									
Empire District Electric	EDE	Elec.	✓	✓	--	--	--*	✓	--
Empire District Gas	EDE	Gas	--	--	--	--	--	--	--
Kansas City Power & Light	GXP	Elec.	--	--	--	--	--*	--	--
KCP&L Greater Missouri Operations	GXP	Elec.	✓	✓	--	--	✓*	✓	--
Laclede Gas	LG	Gas	✓	✓	--	--	--	--	--
Liberty Energy (Midstates)	--	Gas	--	--	--	--	--	--	--
Missouri Gas Energy	ETE	Gas	--	✓	--	--	--	--	--
Union Electric	AEE	Elec.	✓	✓	--	--	✓*	✓	--
Union Electric	AEE	Gas	--	--	--	--	--	--	--
MONTANA									
MDU Resources	MDU	Elec.	✓	✓	--	--	--*	--	--
MDU Resources	MDU	Gas	--	--	--	--	--*	--	--
Northwestern Energy	NWE	Elec.	--	--	--	--	--*	--	--
Northwestern Energy	NWE	Gas	--	--	--	--	--*	--	--
NEBRASKA									
Black Hills Nebraska Gas	BKH	Gas	--	--	--	--	--	--	--
Northwestern Energy	NWE	Gas	--	--	--	--	--	--	--
SourceGas Distribution	--	Gas	--	--	--	--	--	--	--
NEVADA									
Nevada Power	NVE	Elec.	--	--	--	--	✓	--	--
Sierra Pacific Power	NVE	Elec.	--	--	--	--	✓	--	--
Sierra Pacific Power	NVE	Gas	--	--	--	--	✓	--	--
Southwest Gas	SWX	Gas	--	--	--	--	✓	--	--
NEW HAMPSHIRE									
EnergyNorth Natural Gas	NGG	Gas	--	--	--	--	✓	--	--
Granite State Electric	NGG	Elec.	--	--	--	--	✓	--	--
Northern Utilities	UTL	Gas	--	--	--	--	✓	--	--
Public Service Co. of New Hampshire	NU	Elec.	--	--	--	--	✓	--	--
Unitil Energy Systems	UTL	Elec.	--	--	--	--	✓	--	--
NEW JERSEY									
Atlantic City Electric	POM	Elec.	--	--	--	--	--	--	--
Jersey Central Power & Light	FE	Elec.	--	--	--	--	--	--	--
New Jersey Natural Gas	NJR	Gas	✓	✓	--	--	--	--	--
Pivotal Utility Holdings	GAS	Gas	✓	--	--	--	--	--	--
Public Service Electric & Gas	PEG	Elec.	--	--	--	--	--	--	--
Public Service Electric & Gas	PEG	Gas	--	✓	--	--	--	--	--
Rockland Electric	ED	Elec.	--	--	--	--	--	--	--
South Jersey Gas	SJI	Gas	✓	✓	--	--	--	--	--

State/ Company	Ultimate Parent Ticker	Type of Service	Type of Alternative Regulation: Fuel & Power Procurement	Capacity Rel./OSS	Plant Performance	Renewables	DSM/Energy Efficiency	Emissions	Energy Trading
NEW MEXICO									
El Paso Electric	EE	Elec.	✓	✓	--	--	--	--	--
New Mexico Gas	--	Gas	--	--	--	--	--	--	--
Public Service Co. of New Mexico	PNM	Elec.	--	--	--	--	--	--	--
Southwestern Public Service	XEL	Elec.	--	✓	--	--	--	--	--
NEW YORK									
Brooklyn Union Gas	NGG	Gas	--	--	--	--	✓	--	--
Central Hudson Gas & Electric	CHG	Elec.	--	--	--	--	✓	--	--
Central Hudson Gas & Electric	CHG	Gas	--	--	--	--	✓	--	--
Consolidated Edison of New York	ED	Elec.	--	--	--	--	✓	--	--
Consolidated Edison of New York	ED	Gas	--	--	--	--	✓	--	--
Consolidated Edison of New York	ED	Steam	--	--	--	--	✓	--	--
KeySpan Gas East	NGG	Gas	--	--	--	--	✓	--	--
National Fuel Gas Distribution	NFG	Gas	--	--	--	--	✓	--	--
New York State Electric & Gas	--	Elec.	--	--	--	--	✓	--	--
New York State Electric & Gas	--	Gas	--	--	--	--	✓	--	--
Niagara Mohawk Power	NGG	Elec.	--	--	--	--	✓	--	--
Niagara Mohawk Power	NGG	Gas	--	--	--	--	✓	--	--
Orange & Rockland Utilities	ED	Elec.	--	--	--	--	✓	--	--
Orange & Rockland Utilities	ED	Gas	--	--	--	--	✓	--	--
Rochester Gas & Electric	--	Elec.	--	--	--	--	✓	--	--
Rochester Gas & Electric	--	Gas	--	--	--	--	✓	--	--
NORTH CAROLINA									
Carolina Power & Light	DUK	Elec.	--	--	--	--	--	--	--
Duke Energy Carolinas	DUK	Elec.	--	--	--	--	--	--	--
Piedmont Natural Gas	PNY	Gas	--	--	--	--	--	--	--
Public Service Co. of North Carolina	SCG	Gas	--	--	--	--	--	--	--
Virginia Electric & Power	D	Elec.	--	--	--	--	--	--	--
NORTH DAKOTA									
MDU Resources	MDU	Elec.	--	--	--	--	--	--	--
MDU Resources	MDU	Gas	--	--	--	--	--	--	--
Northern States Power-Minnesota	XEL	Elec.	--	✓	--	✓	--	--	✓
Northern States Power-Minnesota	XEL	Gas	--	--	--	--	--	--	--
Otter Tail Power	OTTR	Elec.	--	✓	--	--	--	--	--
OHIO									
Cleveland Electric Illuminating	FE	Elec.	--	--	--	--	✓	--	--
Columbia Gas	NI	Gas	--	--	--	--	--	--	--
Dayton Power & Light	DPL	Elec.	--	--	--	--	✓	--	--
Duke Energy Ohio	DUK	Elec.	--	--	--	--	✓	--	--
Duke Energy Ohio	DUK	Gas	--	--	--	--	--	--	--
East Ohio Gas	D	Gas	--	--	--	--	--	--	--
Ohio Edison	FE	Elec.	--	--	--	--	✓	--	--
Ohio Power	AEP	Elec.	--	--	--	--	✓	--	--
Toledo Edison	FE	Elec.	--	--	--	--	✓	--	--
Vectren Energy Delivery of Ohio	VVC	Gas	--	--	--	--	--	--	--

State/ Company	Ultimate Parent Ticker	Type of Service	Type of Alternative Regulation: Fuel & Power Procurement	Capacity Rel./OSS	Plant Performance	Renewables	DSM/Energy Efficiency	Emissions	Energy Trading
OKLAHOMA									
CenterPoint Energy Resources	CNP	Gas	--	--	--	--	✓	--	--
Oklahoma Gas & Electric	OGE	Elec.	--	--	--	--	✓	--	--
ONEOK	OKE	Gas	--	--	--	--	✓	--	--
Public Service Oklahoma	AEP	Elec.	--	✓	--	--	✓	--	--
OREGON									
Avista Corp.	AVA	Gas	✓	--	--	--	--	--	--
Cascade Natural Gas	MDU	Gas	✓	--	--	--	--	--	--
Idaho Power	IDA	Elec.	--	--	--	--	--	--	--
Northwest Natural Gas	NWN	Gas	✓	✓	--	--	--	--	--
PacifiCorp	BRK.A	Elec.	--	--	--	--	--	--	--
Portland General Electric	POR	Elec.	✓	--	--	--	--	--	--
PENNSYLVANIA									
Columbia Gas of Pennsylvania	NI	Gas	--	✓	--	--	--	--	--
Duquesne Light	--	Elec.	--	--	--	--	--	--	--
Equitable Gas	EQT	Gas	--	✓	--	--	--	--	✓*
Metropolitan Edison	FE	Elec.	--	--	--	--	--	--	--
National Fuel Gas Distribution	NFG	Gas	--	--	--	--	--	--	--
PECO Energy	EXC	Elec.	--	--	--	--	--	--	--
PECO Energy	EXC	Gas	--	✓	--	--	--	--	✓*
Pennsylvania Electric	FE	Elec.	--	--	--	--	--	--	--
Pennsylvania Power	FE	Elec.	--	--	--	--	--	--	--
Peoples Natural Gas	--	Gas	--	✓	--	--	--	--	✓*
PPL Electric Utilities	PPL	Elec.	--	--	--	--	--	--	--
UGI Central Penn Gas	UGI	Gas	--	--	--	--	--	--	--
UGI Penn Natural Gas	UGI	Gas	--	--	--	--	--	--	--
West Penn Power	FE	Elec.	--	--	--	--	--	--	--
UGI Utilities	UGI	Elec.	--	--	--	--	--	--	--
UGI Utilities	UGI	Gas	--	--	--	--	--	--	--
RHODE ISLAND									
Narragansett Electric	--	Elec.	--	--	--	✓*	✓	--	--
Narragansett Electric	--	Gas	--	--	--	--	✓	--	--
SOUTH CAROLINA									
Carolina Power & Light	DUK	Elec.	--	--	--	--	✓	--	--
Duke Energy Carolinas	DUK	Elec.	--	--	--	--	✓	--	--
Piedmont Natural Gas	PNY	Gas	--	--	--	--	--	--	--
South Carolina Electric & Gas	SCG	Elec.	--	--	--	--	✓	--	--
South Carolina Electric & Gas	SCG	Gas	--	--	--	--	--	--	--
SOUTH DAKOTA									
Black Hills Power	BKH	Elec.	--	✓	--	✓	--	✓	--
Northern States Power-Minnesota	XEL	Elec.	--	✓	--	--	--	--	✓
Northwestern Energy	NWE	Gas	--	--	--	--	--	--	--

State/ Company	Ultimate Parent Ticker	Type of Service	Type of Alternative Regulation: Fuel & Power Procurement	Capacity Rel./OSS	Plant Performance	Renewables	DSM/Energy Efficiency	Emissions	Energy Trading
TENNESSEE									
Atmos Energy	ATO	Gas	✓	✓	--	--	--	--	--
Chattanooga Gas	GAS	Gas	--	--	--	--	--	--	--
Kingsport Power	AEP	Elec.	--	--	--	--	--	--	--
Piedmont Natural Gas	PNY	Gas	--	✓	--	--	--	--	--
TEXAS PUC									
AEP Texas Central	AEP	Elec.	--	--	--	--	✓	--	--
AEP Texas North	AEP	Elec.	--	--	--	--	✓	--	--
CenterPoint Energy Houston Electric	CNP	Elec.	--	--	--	--	✓	--	--
Cross Texas Transmission	--	Elec.	--	--	--	--	--	--	--
El Paso Electric	EE	Elec.	--	--	--	--	✓	--	--
Electric Transmission of Texas	BRK.A/AEP	Elec.	--	--	--	--	--	--	--
Entergy Texas	ETR	Elec.	--	--	--	--	✓	--	--
Lone Star Transmission	NEE	Elec.	--	--	--	--	--	--	--
Oncor Electric Delivery	--	Elec.	--	--	--	--	✓	--	--
Southwestern Electric Power	AEP	Elec.	--	--	--	--	✓	--	--
Southwestern Public Service	XEL	Elec.	--	--	--	--	✓	--	✓
Texas-New Mexico Power	PNM	Elec.	--	--	--	--	✓	--	--
Wind Energy Transmission of Texas	--	Elec.	--	--	--	--	--	--	--
TEXAS RRC									
Atmos Energy	ATO	Gas	--	--	--	--	--	--	--
CenterPoint Energy Resources	CNP	Gas	--	--	--	--	--	--	--
Texas Gas Service	OKE	Gas	--	--	--	--	--	--	--
UTAH									
PacifiCorp	BRK.A	Elec.	✓	--	--	--	--	--	--
Questar	STR	Gas	--	✓	--	--	--	--	--
VERMONT									
Green Mountain Power	--	Elec.	--	--	--	--	--	--	--
Vermont Gas Systems	--	Gas	--	--	--	--	--	--	--
VIRGINIA									
Appalachian Power	AEP	Elec.	--	✓	--	✓*	--	--	--
Columbia Gas of Virginia	NI	Gas	--	--	--	--	✓	--	--
Kentucky Utilities	PPL	Elec.	--	✓	--	--	--	--	--
Virginia Electric & Power	D	Elec.	--	✓	--	✓*	--	--	--
Virginia Natural Gas	GAS	Gas	✓	--	--	--	--	--	--
Washington Gas Light	WGL	Gas	--	--	--	--	✓	--	✓

	Ultimate		Type of Alternative Regulation						
State/ Company	Parent Ticker	Type of Service	Fuel & Power Procurement	Capacity Rel./OSS	Plant Performance	Renewables	DSM/Energy Efficiency	Emissions	Energy Trading
WASHINGTON									
Avista Corp.	AVA	Elec.	✓	--	--	--	--*	--	--
Avista Corp.	AVA	Gas	--	--	--	--	--*	--	--
Cascade Natural Gas	MDU	Gas	--	--	--	--	--*	--	--
Northwest Natural Gas	NWN	Gas	--	--	--	--	--*	--	--
PacifiCorp	BRK.A	Elec.	--	--	--	--	--*	--	--
Puget Sound Energy	--	Elec.	✓	--	--	--	--*	--	--
Puget Sound Energy	--	Gas	--	--	--	--	--*	--	--
WEST VIRGINIA									
Appalachian Power	AEP	Elec.	--	--	--	--*	--	--	--
Hope Gas	D	Gas	--	--	--	--	--	--	--
Monongahela Power	FE	Elec.	--	--	--	--*	--	--	--
Mountaineer Gas	--	Gas	--	--	--	--	--	--	--
Potomac Edison	FE	Elec.	--	--	--	--*	--	--	--
Wheeling Power	AEP	Elec.	--	--	--	--*	--	--	--
WISCONSIN									
Madison Gas & Electric	MGEE	Elec.	✓	--	--	--	--	--	--
Madison Gas & Electric	MGEE	Gas	--	--	--	--	--	--	--
Northern States Power-Wisconsin	XEL	Elec.	✓	--	--	--	--	--	--
Northern States Power-Wisconsin	XEL	Gas	--	--	--	--	--	--	--
Wisconsin Electric Power	WEC	Elec.	✓	--	--	--	--	--	--
Wisconsin Electric Power	WEC	Gas	--	--	--	--	--	--	--
Wisconsin Gas	WEC	Gas	--	--	--	--	--	--	--
Wisconsin Power & Light	LNT	Elec.	✓	--	--	--	--	--	--
Wisconsin Power & Light	LNT	Gas	--	--	--	--	--	--	--
Wisconsin Public Service	TEG	Elec.	✓	--	--	--	--	--	--
Wisconsin Public Service	TEG	Gas	--	--	--	--	--	--	--
WYOMING									
Cheyenne Light Fuel & Power	BKH	Elec.	✓	--	--	✓	--	--	--
Cheyenne Light Fuel & Power	BKH	Gas	✓	--	--	--	--	--	--
MDU Resources	MDU	Elec.	--	--	--	--	--	--	--
PacifiCorp	BRK	Elec.	✓	--	--	--	--	--	--
SourceGas Distribution	--	Gas	✓	--	--	--	--	--	--

* See footnotes for further information.

As of 11/18/13
Source: SNL Energy/RRA

FOOTNOTES

California

Price Freeze/Cap--The state's major electric and gas utilities typically file general base rate cases every three years. The California PUC usually authorizes a rate change for the test year, and also authorizes additional "attrition" rate changes for each of the two years following the test year.

Colorado

Renewables--Electric utilities are permitted to earn rate-of-return premiums on eligible renewable energy resource investments that provide "net economic benefits" to customers. Public Service Company of Colorado allocates to ratepayers 10% of proprietary trading margin, which includes margin from the sale of renewable energy credits.

Connecticut

Rate Base Additions--In accordance with the directives outlined in the Governor's Comprehensive Energy Strategy and state law, the PURA is to establish a mechanism to provide for the gas utilities to recover the costs associated with prudent capital expenditures in a timely manner outside of a rate case proceeding. A proceeding is pending.

Renewables--Under United Illuminating’s (UI's) "renewable connections program" (RCP), approved by the Connecticut PURA on Oct. 23, 2013, the company is permitted to develop up to 10 MW of renewable generation for recovery on a cost-of-service basis. UI is permitted to earn an equity return on its RCP investment that is above the return authorized on its distribution investment.

Delaware

Rate Base Additions--In the context of a November 2012 electric rate case decision for Delmarva Power & Light, the Delaware PSC directed the parties to discuss regulatory mechanisms to reduce regulatory lag associated with the company's planned infrastructure investments. On Oct. 2, 2013, the company filed for approval of a forward-looking multi-year (2014 through 2017) rate plan.

Illinois

Rate Base Additions--In July 2013, Senate Bill 2266 was enacted, allowing the Illinois Commerce Commission to approve the use of adjustment clauses for the natural gas local distribution companies (LDCs) for the recovery of costs associated with certain infrastructure investments. The law applies to the largest LDCs, namely Ameren Illinois, Peoples Gas Light and Coke, and Northern Illinois Gas.

Indiana

Rate Base Additions--Environmental cost recovery riders are in place for Duke Energy Indiana (DEI), Indiana Michigan Power, Indianapolis Power & Light, and Northern Indiana Public Service. DEI is permitted to recover certain costs associated with the Edwardsport integrated gasification combined-cycle plant through a rider. Separately, legislation enacted in April 2013 permits the Indiana Utility Regulatory Commission to authorize the utilities to implement a transmission, distribution, and storage system improvement charge rider to facilitate recovery of the costs associated with certain electric and gas infrastructure expansion projects.

Renewables--State statutes provide for a voluntary renewable portfolio standard that specifies that any electric utility that meets certain thresholds may be permitted to earn an incentive of up to 50 basis points above the utility's authorized equity return. No such returns have been authorized to date.

Iowa

Service Quality/Management Performance--The Iowa Utilities Board has occasionally adopted return-on-equity premiums (or imposed penalties) on a case-by-case basis related to management efficiency, but has not done so in recent years.

Kansas

Rate Base Additions--"Abbreviated" rate cases are statutorily authorized to be filed by the utilities, within 12 months of a KCC rate order in the utility's most recent base rate proceeding. Such filings may reflect rate base additions and related operating expenses, and must incorporate all of the regulatory procedures, principles, and rate-of-return parameters established by the Commission in the previous base rate order. Statutes also permit the local gas distribution companies to request KCC approval of a gas system reliability surcharge mechanism to recover the costs associated with distribution system replacement projects between base rate proceedings. The KCC is authorized to permit an electric utility to earn an ROE premium on nuclear pre-construction costs. No such premiums have been requested to date.

Fuel & Power Procurement--KCC rules allow the local gas distribution companies to retain a portion of gas cost savings relative to a benchmark, through their purchased gas adjustment mechanisms. However, no such proposals have been filed.

Renewables/DSM/Energy Efficiency--By law, the KCC can authorize an energy company to earn up to a 200-basis-point return on equity premium on investments associated with the generation of energy from renewable resources, conservation, or energy efficiency. No such premiums have been requested to date.

Louisiana PSC

Plant Performance--As part of a plan adopted by the Louisiana PSC in 1992 for EGS' River Bend Unit 1, a portion of that plant became a "deregulated asset," from which EGS' ratepayers purchase electricity at a rate based upon an assumed annual River Bend capacity factor of 68%. EGS, therefore, benefits to the extent the capacity factor exceeds 68%.

Maine

Service Quality/Management Performance--Central Maine Power is operating under an alternative regulation plan that provides for a service quality penalty of up to $5 million in any year if the company fails to achieve certain baselines. There is no incentive for exceeding the baseline.

Maryland

Rate Base Additions—Legislation enacted in 2013 permits the Maryland PSC to authorize gas utilities to implement monthly surcharges to recover costs associated with approved accelerated infrastructure replacement programs. No such riders have yet been approved, but cases are pending for Baltimore Gas & Electric, Columbia Gas of Maryland, and Washington Gas.

Minnesota

Emissions--State law permits the Minnesota PUC to approve cost-recovery riders that include performance-based incentives for mercury emissions reductions in excess of 90%. To date, no incentives have been requested.

Missouri

Rate Base Additions--The Missouri PSC is permitted to approve the use of environmental cost recovery mechanisms for the electric utilities; however, none of the utilities currently have such a mechanism in place.

DSM/Energy Efficiency--The electric utilities may request riders for energy efficiency that include incentive provisions. Plans are in place for Union Electric and KCP&L Greater Missouri Operations.

Montana

DSM/Energy Efficiency--State statutes allow the Montana PSC to approve up to a 200-basis-point return-on-equity premium for demand-side management program investments. To date, no such premium has been requested.

Nevada

Formula-Based Rates/Price Freeze/Cap/Earnings Sharing--While legislation permits the Nevada PUC to implement broad-based alternative regulation plans (presumably formula-based rate plans) for gas utilities, no such plans are currently in place.

Rate Base Additions--The PUC's integrated resource planning rules permit the approval of incentive mechanisms for facilities designated as "critical." Under the rules, the PUC may designate a project as critical if it protects reliability, promotes supply diversity or develops renewable resources. For such a project, the utility may be awarded: (1) an enhanced return on equity of up to 500 basis points on the designated critical facility over the life of the facility; (2) a cash return on construction work in progress associated with the facility; and/or, (3) the deferral of costs incurred to construct the facility. Over the years, the PUC has designated several facilities owned by Nevada Power and Sierra Pacific Power as critical.

New Hampshire

Earnings Sharing--For EnergyNorth Natural Gas, an earnings sharing mechanism is to be implemented beginning in August 2017, under which the company is to share equally with ratepayers any incremental earnings above its authorized return on equity.

New York

Service Quality/Management Performance--Most of the major utilities are operating under regulatory plans that include the potential for penalties (but no incentives) related to service quality and customer service.

Ohio

Price Freeze/ Cap--Cleveland Electric Illuminating, Ohio Edison, and Toledo Edison are operating under an Electric Security Plan (ESP) that includes an overall freeze on base distribution rates through June 1, 2016. Revenue-neutral rate design changes are permitted. Ohio Power is operating under an ESP that includes a three-year freeze on base (non-fuel) generation rates until May 31, 2015, when such rates are to be established through a competitive bid process.

Earnings Sharing--Each ESP for the electric utilities includes a Significantly Excessive Earnings Test (SEET). Under the SEET, the Ohio PUC is required to determine if the ESP would provide the utility with a return on equity that is "significantly in excess of the return on common equity likely to be earned by publicly traded companies, including utilities that face comparable business and financial risk." If the PUC determines that the utility is earning an excessive return, it would be permitted to terminate the ESP. Excess earnings would be refunded to customers. For each utility, the SEET's ROE threshold generally has been set at level that is well above the prevailing industry average of authorized ROEs nationwide.

Oregon

Rate Base Additions--Renewable resources adjustment clauses are utilized for the state's electric utilities to earn a return of and on prudently incurred costs associated with meeting the state's renewable energy standards. The mechanism allows for cost recovery, without filing a general rate case, of renewable resources that are expected to be placed into service in the current year.

Pennsylvania

Rate Base Additions--In 2012, legislation was enacted allowing the Pennsylvania PUC to approve automatic adjustment clauses to recognize, between general rate cases, utility investments in certain infrastructure projects. Distribution System Improvement Charges have been approved for Columbia Gas of Pennsylvania, Equitable Gas, PECO Energy, Peoples Natural Gas, and PPL Electric Utilities' gas businesses.

Energy Trading--Certain of the state's gas utilities are permitted to retain a portion of the net savings associated with their gas-commodity-cost-hedging programs.

Rhode Island

Renewables--Legislation enacted in 2009 requires electric distribution companies to enter into long-term contracts with renewable energy facilities and also provides for electric distribution utilities to receive an incentive payment from customers equal to 2.75% of the annual contract payments to the renewable energy suppliers.

Texas PUC

Rate Base Additions--Pursuant to 2011, legislation, the Texas PUC may approve periodic distribution cost recovery factors (DCRFs) for both vertically integrated and transmission and distribution-only electric utilities. Adjustments under the mechanism are to be limited to once per year, with no more than four adjustments permitted between comprehensive base rate cases. The PUC may prohibit a utility from implementing a rate change under the mechanism if the Commission determines that the utility is earning in excess of its authorized return prior to the adjustment. Amounts approved for recovery under the DCRF are to be rolled into base rates in the utility's subsequent rate case, subject to a prudence review. None of the utilities are operating under a DCRF. However, mechanisms are in place for recognition of transmission and smart-1grid investments.

Virginia

Price Freeze/Cap—Pursuant to a settlement reached in Virginia Electric & Power's (VEPCO's) 2009 biennial earnings review, the company's base rates may not change prior to Dec. 1, 2013. The company's 2013 biennial review is pending, and any rate change approved in that proceeding will become effective Jan. 1, 2014. Rate changes have been permitted through various adjustment clause mechanisms.

Renewables—Both VEPCO's and Appalachian Power Company's (APCO's) currently authorized ROEs include 50-basis-point ROE premiums for meeting the state's voluntary renewable portfolio targets, as permitted by state law enacted in 2007. However, legislation enacted in 2012, repealed this provision of state law. Consequently, these premiums will not be included in the prospective ROEs ultimately approved in VEPCO's pending biennial earnings review, or in APCO's biennial review that is to commence by March 31, 2014.

Washington

Price Freeze/Cap/Earnings Sharing--A rate plan is in place for Puget Sound Energy (PSE) that is to provide for annual increases in allowed revenue per customer through at least March 2016, and possibly through March 2017. The rate plan is comprised of a "series of predetermined annual increases in…allowed revenues intended to afford the Company the ability to avoid the need to file a general rate case over the next two to three years." Under the plan, PSE's allowed delivery revenue per customer is to increase annually each Jan. 1 by 3% for electric and by 2.2% for gas. PSE is to share equally with ratepayers incremental earnings above a 7.77% overall return. During the plan, PSE cannot file a general rate case prior to April 1, 2015 and must file one no later than April 1, 2016.

Rate Base Additions--On Dec. 31, 2012, the WUTC issued a policy statement calling for gas LDCs to file a pipe replacement program by June 1, 2013 (the plans have since been approved for the 2013-2015 period), and outlining conditions for cost recovery between rate cases. The WUTC indicated that it would approve a pipeline replacement cost recovery mechanism (CRM) to allow for a return of and return on specific eligible investments between rate cases. The CRM would be in effect for four years, after which a general rate case filing would be required in order to incorporate the investment into base rates and adjust the CRM. A company may include a request for a CRM in its June 1, 2013 pipeline replacement program, or on June 1 of any subsequent year. The utility is to propose a cap for annual expenditures recoverable through the CRM, based on a percent of rate base, percent of revenues, or total expenditures. The WUTC adopted a CRM for Cascade Natural Gas; the state's other gas utilities did not seek a CRM.

DSM/Energy Efficiency--State statutes permit the Washington Utilities and Transportation Commission (WUTC) to grant financial incentives, e.g., a 200-basis-point adder to a company's authorized ROE for a period of at least seven years, but not more than 30 years, on investments in distributed generation and certain energy efficiency measures. State law also permits the WUTC to consider whether incentives should be provided to electric investor-owned utilities for exceeding their conservation targets. In 2010, the WUTC issued a policy statement indicating that it would consider conservation incentives for both electric and gas utilities. However, no such incentives have been approved.

West Virginia

Renewables—State law allows the West Virginia PSC to approve incentives for prudent investments made to comply with the state's renewable portfolio standards, but to our knowledge no such incentives have been approved to date.

Wisconsin

Rate Base Additions--At times, the PSC has authorized the utilities to file limited-issue reopeners of previously completed base rate cases instead of full rate cases. The reopeners provide for recognition of certain specified investments and/or expenses, and do not involve the re-determination of rate of return.

(Continued from p. 1)

the determination of the allowed return on equity in a rate case, and may reduce the time it takes for a rate case to be adjudicated;

5) *Rate Base Additions* refers to mechanisms that provide for rate recognition of a utility's capital investment and possibly the associated operating expenses outside of a general rate case. Certain of these mechanisms allow for construction work in progress to be effectively included in rate base, while others reflect only completed plant and associated operating expenses. In some instances, ROE premiums are included;

6) *Service Quality/Management Performance* includes those plans in which at least a portion of the benefits from management efficiencies or achieving service quality goals are retained by shareholders (penalty-only plans are referenced in the table footnotes);

7) *Merger Savings* refers to plans under which regulated utilities that have been involved in mergers are currently permitted to retain a portion of the associated synergy savings. A utility's retention of merger savings tends to be a temporary benefit, given that the company's reduced cost-of-service is often reflected in its next general rate case;

Table II

8) *Fuel & Power Procurement* incentive plans are designed to minimize electric fuel costs and purchased power expenses, as well as gas commodity costs. Such plans may provide for the utilities to absorb or retain a portion of the difference between the actual cost of fuel/energy and a pre-determined benchmark;

9) *Capacity Release/Off-System Sales* incentive plans permit gas/electric utilities to retain at least a portion of the revenues from such activities. Under a capacity release incentive plan, a gas distribution utility may retain a portion of the revenue generated from the sale of unneeded pipeline capacity that the company had previously reserved for its distribution customers. Similarly for an electric utility, the company may be permitted to retain the margins from the wholesale sale of power that the company had intended to sell at the retail level, but was not ultimately required to serve native-load customers;

10) *Plant Performance* refers to plans under which companies are rewarded or penalized based upon the operation of their generating facilities (either nuclear or fossil-fueled). Metrics used to determine eligibility for incentives may include unit availability, capacity factor, or heat rate;

11) *Renewables* refers to incentive provisions allowing an electric utility that meets or exceeds certain renewables thresholds with respect to the amount of power provided from resources classified as renewables to earn a premium return on equity on the related investment. Additionally, utilities may also be permitted to retain a portion of the net proceeds from the sale of renewable energy credits;

12) *Demand-Side Management/Energy Efficiency* refers to frameworks under which utilities are permitted to retain a portion of savings associated with energy efficiency programs. Additionally, these frameworks can involve the authorization of bonus returns on certain demand-side management program investments;

13) *Emissions* incentive plans generally permit utilities to retain a portion of the net proceeds related to the sale of surplus emissions allowances or earn an incentive return on equity on emissions-control equipment; and,

14) *Energy Trading* incentive plans generally involve a utility's retention of a portion of the net savings associated with commodity-cost hedging programs or trading margin from assets that are not owned by the utility.

The following statistics may be of interest: 15 individual electric or gas utilities in six jurisdictions utilize formula-based rate plans; 63 utilities in 29 jurisdictions are operating under rate freezes or rate caps; and, 54 utilities in 18 states are subject to earnings-sharing mechanisms. Additionally, 103 utilities have riders in place to periodically reflect in rates incremental capital investment. We also note that incentives related to fuel and/or purchased power expense are in place for 41 utilities in 18 jurisdictions. It appears that there are no ARPs in effect in four jurisdictions (Alaska, District of Columbia, New Orleans City Council, and Nebraska).

Further detail regarding the information in this report can be found in RRA's Commission Profile for each of the jurisdictions listed in the table (a link to each Profile is provided in Tables I and II). The following profile sections are particularly useful: Alternative Regulation, Return on Equity, Renewable Energy, Adjustment Clauses, Merger Activity, Emissions Requirements, and Integrated Resource Planning.

Regulatory Agency Abbreviations

ACC - Arizona Corporation Commission

ARC - Alaska Regulatory Commission

BPU - Board of Public Utilities (New Jersey)

DPU - Department of Public Utilities (Massachusetts)

ICC - Illinois Commerce Commission

IUB - Iowa Utilities Board

KCC - Kansas Corporation Commission

NCUC - North Carolina Utilities Commission

NOCC - New Orleans City Council

OCC - Oklahoma Corporation Commission

PRC - Public Regulation Commission (New Mexico)

PSB - Public Service Board (Vermont)

PSC - Public Service Commission

PUC - Public Utility(ies) Commission

PURA - Public Utilities Regulatory Authority (Connecticut)

RRC - Railroad Commission (Texas)

SCC - State Corporation Commission (Virginia)

TRA - Tennessee Regulatory Authority

URC - Utility Regulatory Commission (Indiana)

WUTC - Washington Utilities and Transportation Commission

Rob Schain
Jim Davis
Katerina Dimitratos
Russell Ernst
Lillian Federico
Lisa Fontanella
Dennis Sperduto

American Gas Association

9/15/2016

State Infrastructure Replacement Activity

State	Activity	Relevant Documents
Alabama	• In 1995, the Alabama PSC approved the Cast Iron Main Replacement Factor as part of Mobile Gas' general rate case. The program recovers the annual revenue requirement level of depreciation, taxes and return associated with cast iron main replacements. The tracking mechanism is applied to all rate classes and is updated annually for incremental investment in cast iron main replacements. • Mobile Gas and Alabama Gas presently utilize a Rate Stabilization and Equalization Plan.	Docket No. 24794
Arkansas	• In 1988, CenterPoint received approval from the Arkansas PSC for a Gas Main Replacement Program (GMRP) which provided for a tracker to be applied to the replacement of bare steel and cast iron mains and associated services. In 1992, the program was modified to include recovery of capital investment (depreciation) and was expanded to include all cast iron gas main and related services. At that time it was also renamed the Cast Iron Main Replacement Program (CIGMRP). In 2002, the program was modified again to include bare steel and associated services, and was renamed the Main Replacement Program (MRP). • On July 9, 2012, in Docket No. 12-045-TF, the Arkansas PSC authorized CenterPoint Energy to include as eligible for expedited replacement steel mains that do not have a cathodic protection system (unprotected steel main) along with any associated services. These mains were deemed eligible for cost recovery under CenterPoint's Main Replacement Program Rider (Rider MRP). • On July 7, 2014, the Arkansas Public Service Commission adopted a settlement in SourceGas Arkansas' (SGA) base rate proceeding. The approved settlement allows SGA to implement a main replacement program (MRP) rider and an at risk meter relocation program rider. The primary purpose of the MRP Rider is to support the expedited replacement of Subject Mains and Associated Services. Eligible mains and services under the MRP are: o 1) Bare steel mains; o 2) Coated steel mains that are not cathodically protected; and o 3) Mains that are the subject of an advisory issued by a federal or state agency and which the Company has determined to be in unsatisfactory condition. • On July 25, 2014, the Arkansas Public Service	Dockets 06-161-U and 10-108-U (CenterPoint) Docket No. 13-079-U (SourceGas Arkansas) Docket No. 13-078-U (Arkansas Oklahoma Gas) Docket No. 12-045-TF (CenterPoint MRP)

	Commission adopted a settlement in Arkansas Oklahoma Gas' base rate proceeding. The approved settlement also allowed for the implementation of a system safety and enhancement rider (SSER). The SSER will provide AOG with the opportunity to earn the Commission approved rate of return on investments made in replacing aging infrastructure. The SSER is designed to prioritize the replacement of the riskiest pipe in the system each year, but at a rate which has minimal impact on customers' bills. Mains covered under the SSER are: o 1) Bare steel mains; o 2) Any mains associated with the replacement of low pressure systems (AOG's tariff defines a low pressure system as one that is composed of distribution mains operated at less than or equal to 12 ounces of pressure); and o 3) Mains that are the subject of an advisory issued by a federal or Arkansas state agency and which the Company has determined to be in unsatisfactory condition.	
Arizona	• In January 2012, the Arizona Corporation Commission granted Southwest Gas approval to implement a Customer Owner Yard Line (COYL) program as part of its general rate case settlement. The program is designed to facilitate leak surveying and, when required, replacement of customer yard lines. The program includes a cost recovery component whereby Southwest Gas defers the actual COYL capital costs and files an annual application requesting authority from the Arizona CC to implement a per therm surcharge rate to recover the revenue requirement on the deferred COYL costs.	Docket No. G-01551A-10-0458 (Southwest Gas)
California	• In December 2010, San Diego Gas & Electric filed a request with the California PUC for a gas base rate increase. In its filing, the utility also proposes a post-test-year ratemaking mechanism for the three-year period 2013 through 2015, under which the company's revenue requirement would be adjusted to reflect increases in capital-related and other expenses. The CPUC approved the mechanism in May 2013. • In December 2010, Southern California Gas filed a request with the CPUC for a gas base rate increase. As part of that filing, the utility proposes a post-test-year ratemaking mechanism for the three year period 2013-2015, which under the company's revenue requirement would be adjusted to reflect increases in capital-related and other expenses. The company did not request specific rate increases under the mechanism. The CPUC approved the mechanism in May 2013. • As part of its 2013 GRC in California, Southwest Gas (Southwest) proposed an Infrastructure Reliability and Replacement Adjustment Mechanism (IRRAM) that is designed to facilitate and complement projects involving the enhancement and replacement of gas infrastructure. • In June of 2014, southwest received approval for an	A1012005 (San Diego Gas & Electric) A1012006 (Southern California Gas) A1212024 (Southwest Gas)

	IRRAM mechanism. Southwest's approved IRRAM, applies to infrastructure replacement and other non-revenue producing infrastructure projects. The PUC will allow SWG to assess a surcharge to collect the first year IRRAM budget of $232,665 in Southern California, $48,345 in Northern California, and $58,942 in South Lake Tahoe. The first phase of this program will be limited to surveying leaks on Customer Owned Yard Lines (COYL) on school properties. • Southwest will also continue with its Early Vintage Plastic Pipe (EEVP) replacement plan, which it began in 2007. Southwest had proposed to accelerate this program in order to complete replacement of the replacement of Aldyl-A pipe by 2018, however, the Commission denied this proposal. The company will adhere to its current EEVP schedule, which is due to be completed in 2026.	
Colorado	• In September 2011, Public Service Company of Colorado received approval from the Colorado PUC to implement a pipeline system integrity adjustment tracker to recover costs associated with reliability improvements and compliance with certain federal safety regulations. • SourceGas has Rate Schedules for natural gas service that are subject to a System Safety and Integrity Rider ("SSIR") designed to collect Eligible System Safety and Integrity Costs. Eligible project cost include: o Projects in accordance with Code of Federal Regulations ("CFR") Title 49 (Transportation), Part 192 (Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards), Subpart O (Gas Transmission Pipeline Integrity Management), including projects in accordance with the Company's transmission integrity management program ("TIMP") and projects in accordance with State enforcement of Subpart O and the Company's TIMP; o Projects in accordance with CFR Title 49 (Transportation), Part 192 (Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards), Subpart P (Gas Distribution Pipeline Integrity Management), including projects in accordance with the Company's distribution integrity management program ("DIMP") and projects in accordance with State enforcement of Subpart P and the Company's DIMP; and o Projects in accordance with final rules and regulations of the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") that becomes effective on or after the filing date of the application requesting approval of the SSIR. • The SSIR rate will be subject to annual changes to be effective on January 1 of each year for a period of four years from the first effective date, after which period of time the Company's SSIR Tariff will expire unless the SSIR Tariff is reinstated upon consideration of the Public	Docket No. 10AL-963G Docket No. 15AL-0135G (Xcel) 15AL-0299G (Atmos)

	Utilities Commission of the State of Colorado (the "Commission") of an application filed by the Company no later than six months prior to the expiration date. The SSIR Tariff to be applied to each Rate Schedule is as set forth on the statement of effective rates, charges and fees, Sheet Nos. 8 through 10 of the Rocky Mountain Tariff. • In its March 2015 rate filing, Xcel Energy requested (in addition to its base rate increase) a cumulative increase of $42.9 million attributable to the extension and modification of the pipeline system integrity adjustment, spread out over three years. This mechanism was extended through 2018 on January 27, 2016. • On September 23, 2015, Atmos Energy filed a settlement signed by Commission Staff, the Office of Consumer Counsel, and Energy Outreach Colorado in with the Public Utilities Commission of Colorado in which the settling parties agreed to allow Atmos to separately recover system safety integrity costs through a System Safety and Integrity Rider (SSIR). • Projects eligible for recovery through the SSIR will include high and moderate risk integrity projects that are (a) identified by the Company and approved on a preliminary basis by the Commission based on filing made on or before February 1, 2016 (for 2016 Projects) and on or before each November 1 thereafter (for 2017 and beyond Projects), (b) implemented in consultation with the Staff of the Commission and the Office of Consumer Counsel, and (c) ultimately approved for inclusion in the SSIR by the Commission through a filing made on or before February 1, 2016 (for 2016 Projects) and each November 1 thereafter (for 2017 and beyond Projects). Such SSIR Projects shall be consistent with the Company's compliance with federal and state regulatory requirements including, but not limited to, 49 CFR Part 192, final rules and regulations of the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) and the Environmental Protection Agency (EPA) that become effective on or after the effective date of the SSIR. • The SSIR will be implemented for an initial three year term, from January 1, 2016, through December 31, 2018, and will recover capital investments made between September 1, 2015, and December 31, 2018, that are associated with integrity projects. Atmos will have the right to seek an extension of the initial three-year term in a future filing. This proposal was approved on November 4, 2015.	
Connecticut	• In a June 2011 order, the Public Utilities Regulatory Authority (PURA) approved Yankee Gas' proposal to increase its capital spending on cast iron and bare steel replacement by approximately $13 million in Rate Year 1, and approximately $25 million in Rate Year2. Yankee plans to maintain this $40 million capital spending level (i.e., $15 million authorized in 06-12-02PH01 plus an incremental $25 million) in each subsequent year. The Commission found that this level of spending was	Docket No13-06-08 Docket No 10-12-02 (Yankee Gas)

	reasonable to adequately provide for the integrity of Yankee's pipeline system and it anticipates that this level of replacement will reflect the improvement required by the DIMP regulations. • On January 22, 2014 the Public Utilities Regulatory Authority (PURA) approved a Distribution Integrity Management Program (DIMP) mechanism that allows recovery of the revenue requirement for main replacement activity between rate applications. Additionally, the PURA approved a schedule and budget for system integrity projects that target needed replacement of cast iron mains, bare steel mains and bare steel services.	
District of Columbia	• In February 2012, WGL filed a rate case with the DC PSC in which it proposed to expand its existing pipe replacement program (originally approved in 2007). In the filing, WGL proposes a 5-year accelerated pipeline replacement program and a surcharge recovery of $119 million to be invested in replacement infrastructure. The DC PSC ruled, in part, on this case in May 2013. It denied WGL's request to implement the initial 5 year phase of its Accelerated Pipeline Replacement Program. A decision on WGL's request to recover the costs of its Accelerated Pipeline Replacement Program in a Plant Recovery Adjustment was deferred until a later date. • The DC PSC conditionally approved WGL's program on March 31, 2014. WGL has since received full approval to implement the first five years of a 40-year Accelerated Pipe Replacement Plan (APRP). The APRP is designed to reduce risk and enhance safety by replacing aging, corroded or leaking pipe in the natural gas distribution system. • WGL will spend $110M during this period. The APRP is divided into multiple "programs", three of which were approved in this first phase: o $40 million to replace an undetermined number of bare and/or unprotected service replacements. o $32.5 million to replace 18 miles of bare and unprotected steel main and an undetermined number of services. o $37.5 million to replace 20 miles of cast iron mains.	Case No. 1093
Florida	• On August 14, 2012, the Florida Public Service Commission approved a Gas Reliability Infrastructure Program (GRIP) for Florida Public Utilities Company (FPU) and its partner company, Central Florida Gas (CFG). Under the program, the two providers plan to replace more than 350 miles of pipeline over the next ten years. At that time the Commission approved the same program for Chesapeake Utilities. • Also on August 14, 2012, the Florida PSC approved a GI Cast Iron/Bare Steel Replacement Rider for TECO Peoples Gas Systems. Under that program, TECO is expected to invest approximately $8 million and over the course of ten years will replace 150 miles of cast iron	Docket No. 120036-GU (GRIP for FPU/CFG and Chesapeake Utilities) Docket No. 110320-GI (GI Replacement Rider for TECO) Florida PSC News Release (8/14/2012) Docket No. 150116-GU Florida City Gas

	and 400 miles of bare steel pipeline, comprising about 4 percent of the company's system. • On September 15, 2015, the Florida Public Service Commission (PSC) issued an order approving Florida City Gas' (FCG) request to implement the Safety, Access, and Facility Enhancement (SAFE) program that is to replace aging pipes to improve system safety and reliability, FCG's SAFE program encompasses a 10-year, $105 million project that is to relocate and replace 254.3 miles of 4-inch and smaller mains and associated facilities from rear property easements to the street front. The relocation and replacement program will remove most of the utility's 61.3 miles of unprotected steel mains and improve service reliability, safety, and facility access. Expenditures for the first full calendar-year of the program will not exceed $9.5 million. • Recovery of the revenue requirement associated with the SAFE program, including a return on the investment, depreciation, ad valorem taxes, income taxes, and noticing expenses will be effectuated through a surcharge mechanism. The cost to remove the facilities identified in the SAFE program will not be recovered through the surcharge; rather, they will be recovered through the cost of removal component in FCG's existing depreciation rates.	
Georgia	• In 1998, AGL Resources began a 15 year Pipeline Replacement Program (PRP), which, at the time, was reviewed annually by the Georgia PSC—the PSC reviewed the utility's infrastructure replacement expenses from the previous year and then approved a new surcharge amount. Later, the commission agreed to a fixed dollar amount of expense to be recovered in rates over the remaining 7 years of the program. • In 2009, the Georgia PSC approved the expanding of the PRP to include investments for infrastructure expansion. PRP is now included as part of the Strategic Infrastructure Development and Enhancement (STRIDE) Program for AGL Resources. STRIDE provides for a rider on customer bills that will allow AGL to recover costs associated with both traditional infrastructure replacement, as well as infrastructure expansion relating to customer growth and economic development. • In 2000, Liberty Utilities (then Atmos) received approval to implement a pipe replacement surcharge for its Georgia customers. • In September of 2013, AGL received approval to replace 756 miles of vintage plastic pipe over 4 years.	Docket Nos. 8516 & 29950 (Approving Georgia STRIDE Program) Docket No. 12509-U (Atmos – now Liberty)
Illinois	• In May 2013, the Illinois General Assembly passed the Natural Gas Consumer, Safety and Reliability Act (SB 2266). The legislation will allow utilities to make incremental investments in infrastructure upgrades and recover those costs through a rider on customer bills. The rider/surcharge is to be regularly reviewed by the ICC. In addition, the measure requires utilities to file annual plans with the ICC detailing performance	Natural Gas Consumer, Safety and Reliability Act (Passed by legislature 5/28/13, Signed by Governor Quinn 7/5/13, Public Act 98-0057) Case Number: 14-0292

	improvements and reporting on progress. Performance improvements may include decreases in time to respond to gas emergency calls and/or preventing damage caused by utility or contractor error. • The Illinois Commerce Commission has authorized a cost recovery mechanism for the work, known as the rider qualified infrastructure program, that went into effect January 1, 2014 and sunsets after 2023. The rider enables Peoples to recover its costs with only a one-month cash flow lag, eliminating the regulatory lag between rate cases, and allows the company to earn a return on investment based on the cost of capital established in the most recent rate case. • Peoples had been replacing roughly 45 miles of cast iron and ductile iron main with modern polyethylene pipes annually, but in 2011 the utility ramped up the replacement program, aiming to tackle nearly 2,000 miles of gas pipe, or 40% of the company's system, over two decades. • On April 7, 2014, Nicor Gas filed for its infrastructure replacement surcharge with the ICC. Nicor's plan calls for approximately $171 million in spending in each of the three years beginning in 2015. Entitled the Qualifying Infrastructure Plant (QIP) tariff, this surcharge will allow NICOR to replace hundreds of miles of aging distribution lines and thousands of natural gas services. The company also plans to upgrade gas transmission and storage systems and refurbish regulating stations. This application was approved on July 30, 2014. This plan will allow the company to replace approximately 125 miles of gas mains and 15,000 natural gas service lines. The following projects are eligible for recovery under the QIP: 1) Replacing cast iron main and related services; 2) Replacing non-cast iron main, which may include wrought iron, ductile iron, unprotected coated steel, unprotected bare steel, pre-1973 DuPont Aldyl "A" polyethylene, polyvinylchloride ("PVC") plastic, or other vintage materials, and related services; 3) Replacing copper services; 4) Replacing high-pressure transmission pipelines and associated facilities; and 5) Replacing and/or installing regulator stations, regulators, valves, and associated facilities. • In August of 2014, Ameren Illinois announced its plan for a 10-year, $400 million overhaul of its natural gas distribution in central and southern Illinois. When the project is completed, up to 350 miles of steel pipe will be replaced with polyethylene pipe. The project includes upgrades to 70 stations that regulate gas from interstate pipelines and adding over 450,000 so-called 'smart meters.' • On January 6, 2015, the ICC approved a QIP rider for Ameren Illinois.	Nicor Gas Case Number 14-0573 Ameren Illinois QIP

Indiana	• In 2013, the state legislature passed a bill that allowed for gas utilities to apply for a cost recovery tracker for infrastructure upgrades and extensions; under the legislation, utilities may propose a 7 year infrastructure plan to the IURC, and, if considered reasonable, the utility may recover its investment in a timely manner through a tracker on the customer's bill. • In 2008, Indiana Gas (Vectren Corp.) received approval to implement a tracking mechanism that allows the utility to defer expenses associated with investments in infrastructure and replacement projects. • In 2006, Southern Indiana Gas and Electric Company (Vectren Corp.) received approval of a tracking mechanism for recovery of an accelerated bare steel and cast iron pipeline replacement program. • NIPSCO field its 7 year plan with the IURC on October 3, 2013. Among the projects which NIPSCO will pursue over the next seven years: installing 80 miles of transmission pipeline and adding automated valves ($280 million); eliminating bare steel gas mains and replacing them with low pressure systems ($61 million); and retrofitting lines for in-line inspection ($46 million).This plan was approved on April 30, 2014. • Vectren filed its 7 year plan with the IURC on November 26, 2013. The plan includes the replacement of 800 miles of bare steel and cast iron distribution mains with new mains in the 13,000-mile network in Vectren North, inspecting and upgrading its pipelines, and the expansion of gas delivery infrastructure to rural areas, which call for an estimated $650 million investment. The company will also replace 300 miles of bare steel and cast iron distribution mains with new mains in the 3,200-mile network of Vectren South, which call for an estimated $215 million investment. The costs will be recovered through a fixed charge to be included in residential customers' monthly bills. Gas bills will not be adjusted for these expenditures until 2015, with modest increases in adjustments up to 2021. The IURC approved this plan on August 27, 2014. • On March 30, 2016, the Indiana Utility Regulatory Commission approved gas infrastructure modernization projects representing $890 million in investments supported by recovery mechanisms for Vectren as part of the company's third update to its initial 7 year plan.	Indiana SB 560 (Became Public Law No. 133-2013 on 5/1/2013) Case No. 43298 (Indiana Gas) Case No. 43112 (Southern Indiana Gas and Electric Company) Cause Number 44403 (NIPSCO) Cause number 44429 (Vectren)
Iowa	• In October 2011, the Iowa Utilities Board adopted a rule that allows the state's natural gas utilities to implement either of two types of automatic adjustment mechanisms for recovery of a limited number of capital infrastructure investments outside of a general rate case, including those that are required by government mandates or are required by state or federal pipeline safety mandates. To date no utility has implemented either of the two types of mechanisms for cost recovery. • Effective April 25, 2013, the Iowa Utilities Board has	Docket No. RMU-2011-0002 (October 2011) Docket No. RPU 2002-0004 (April 2013)

	approved tariffs implementing a capital infrastructure investment automatic adjustment mechanism. • Black Hills utilizes this rider.	
Kansas	• In 2006, the Kansas State Legislature passed the Gas Safety and Reliability Policy Act, which approved the implementation of a gas system reliability surcharge (GSRS) between 0.5% and 10% of revenues to recover new infrastructure replacement costs not already included in rates; Atmos, Black Hills, and Kansas Gas Service utilize the surcharge. • GSRS balances are rolled into base rates in its next rate case. GSRS riders may be used for up to five years (or up to six years under certain circumstances) and the utilities must file new rate cases if their riders are to remain in place. GSRS rate changes may not be requested more frequently than every 12 months. Annualized GSRS revenues may not exceed 10% of the utility's base revenue level, as approved in its most recent rate case. GSRS rate changes are not permitted if they are less than 0.5% of the utility's base revenue level, or $1 million, whichever is lower. • On March 12, 2015, the Kansas Corporation Commission opened the General Investigation Regarding the Acceleration of Replacement of Natural Gas Pipelines Constructed of Obsolete Materials. In the Order Opening General Investigation, Staff reported that after meetings with Kansas natural gas utilities and Commission work studies, they had developed a framework with eleven parameters for a pipeline replacement program that could be uniformly applied to Kansas natural gas utilities. This proceeding is presently pending. • In its August 2015 rate filing, Atmos Energy proposed to implement a system integrity program (SIP) rider that would allow the company to accelerate the replacement of certain obsolete components of its distribution system. The SIP rider, which would be in place for a five-year pilot term and would be updated on a quarterly basis, is intended to address the "capital investment lag" associated with the GSRS and a $0.40 per customer, per month statutory cost recovery cap that applies to the GSRS. This proposal was rejected on March 17, 2016.	K.S.A 66-2201 through K.S.A 66-204 (Gas Safety Reliability Policy Act) Docket No. 16-ATMG-079-RTS (Atmos) Docket No. 15-GIMG-343-GIG
Kentucky	• In 2005, pursuant to passage of KY HB 440, Kentucky created a new section in the Kentucky Revised Code titled “Recovery of Costs for Investments in Natural Gas Pipeline Replacement Programs,” which allows the commission to approve the recovery of costs for investment in natural gas pipeline replacement programs which are not recovered in the existing rates of a regulated utility; Atmos, Columbia Kentucky, Delta Natural Gas, and Duke Energy Kentucky utilize such programs.	KRS 278.509 Case No. 2009-00141 (Columbia Gas of Kentucky) Case No. 2009-00354 (Atmos) Case No. 2005-00042 (Duke Energy Kentucky)

		Case No. 2010-00116 (Delta Natural Gas)
Louisiana	• CenterPoint utilizes a rate stabilization program (Rider RSP) to change its rates annually to reflect higher capital investment (rate base) and higher O&M costs relating to pipeline safety and other factors. • Under this program, for each twelve month period ended June 30, a determination shall be made pursuant to this Rider RSP as to whether the Company's revenue should be increased, decreased or left unchanged. If it is determined that the revenue should be increased or decreased, the natural gas rate schedules incorporating this Rider RSP will be adjusted accordingly. • On June 6, 2014, Atmos Energy received approval to establish a regulatory asset using an accounting deferral to recover significant increases in the amount of investment made for the replacement of its aging infrastructure. The mechanism will be reviewed annually as part of the Rate Stabilization Clause (RSC) filing. • In January of 2015, Entergy Gulf States received permission to start replacing many of the old pipes that carry natural gas in Baton Rouge. In the first phase, Entergy is replacing about 25 miles of cast iron pipe, then another two miles of bare steel, Another 72 miles of vintage plastic will be replaced in phase three. The Louisiana Public Service Commission, voted 3-1 to approve a special rider to pay for the work.	CenterPoint Rider RSP Docket U-32987 (Atmos) U-32682 (Entergy Gulf States)
Maine	• In 2011, the Maine Public Utilities Commission authorized Northern Utilities to implement a limited, one year, incremental step adjustment of $0.9 million effective 5/1/2012 to reflect investments made under the company's Cast Iron Replacement Program (CIRP); Initially the utility had sought a targeted infrastructure replacement adjustment (TIRA) tracker to reflect incremental CIRP investments; The Commission did not approve a permanent tracker, instead opting for the more limited mechanism for one year. • On December 17, 2013, the Maine Public Utilities Commission ("MPUC"), during its public deliberations, voted unanimously to approve a Settlement and Stipulation ("Stipulation") in Docket No. 2013-00133, the base rate proceeding for the Maine division of Northern Utilities, Inc. Unitil Corporation's natural gas distribution utility subsidiary. • The Stipulation included a Targeted Infrastructure Replacement Adjustment ("TIRA") rate mechanism, which will provide for annual adjustments to distribution base rates in future years to recover costs associated with the Unitil's investments in specified operational and safety-related infrastructure replacement and reliability upgrade projects to its natural gas distribution system. The TIRA will have an initial term of four (4) years, and applies to investments made in eligible facilities in each	Docket No. 2011-92 Docket No. 2013-00133

	of the calendar years 2013, 2014, 2015, and 2016.	
Maryland	• On February 22, 2013, the Maryland General Assembly passed SB 8, legislation that allows a gas company to recover costs associated with infrastructure replacement projects through a gas infrastructure replacement surcharge on customer bills. The bill specifies how the pretax rate of return is calculated and adjusted and what it includes, and states that it is the intent of the General Assembly to accelerate infrastructure improvements by establishing this mechanism for gas companies to recover reasonable and prudent costs of infrastructure replacement. • As of November 7, 2013, Washington Gas Light, Baltimore Gas and Electric and Columbia Gas of Maryland had all filed for approval of their STRIDE plans with the Maryland PSC. • On January 29, 2014, The Maryland PSC approved the first phase of Baltimore Gas and Electric's (BGE) $400 million, 30-year gas STRIDE Plan. BGE's plan targets five specific areas for improvement, including bare steel mains, cast iron mains and bare steel services. It calls for the replacement of the company's 42 miles of bare steel mains within 15 years and 1,292 miles of cast iron mains within 30 years. • On January 31, The Maryland PSC the Maryland Public Service Commission (PSC) rejected Columbia Gas of Maryland's (CGM's) proposed STRIDE plan and associated rider mechanism, finding that the plan failed to meet certain statutory requirements. In addition, the PSC found that the STRIDE plan would not improve safety and reliability in the gas distribution system, because the plan "does not keep pace" with the company's current replacement rate of aging mains and services and would thus decelerate its infrastructure replacement activity. The Commission noted that it may approve a gas infrastructure replacement plan in accordance with state law if it finds the proposed investments and estimated costs of eligible projects to be: reasonable and prudent; and, designed to improve public safety or infrastructure reliability. The PSC directed CGM to submit an amended application addressing the issues within 60 days; the Commission indicated that it would consider an amended application on an expedited basis. • On May 6, 2014, the Public Service Commission of Maryland (MDPSC) issued an Order conditionally approving Washington Gas' amended accelerated pipeline replacement plan, commonly referred to as STRIDE, which will accelerate natural gas infrastructure upgrades and replacement projects. The plan will also provide current cost recovery for the company, reduce greenhouse gas emissions and costs to utility customers. Washington Gas has accepted the conditions and will be able to recover eligible infrastructure replacements costs for projects initiated after January 1, 2014, that are not included in current base rates. The STRIDE surcharge	Maryland SB 8 (Enrolled 5/2/2013, MD Chapter No. 161) Case No. 9331 Case No. 9332 Case No. 9335

	will not exceed $2.00 per month for residential customers. Washington Gas will provide the MDPSC with an updated list of planned STRIDE projects for 2014 by June 5, 2014. Audits will be performed following each program year. • On August 18, 2014 the Maryland Public Service Commission (PSC) conditionally approved Columbia Gas of Maryland's (CGM's) proposed infrastructure replacement and improvement plan (IRIP) and an associated annually-adjusted rider (IRIS). CGM accepted the conditions and the IRIS surcharge will begin recovery of the forecasted $8.9 million of eligible investment. The IRIS mechanism covers investments made from January 1st through December 31st of each year. Audits will be performed following each program year.	
Massachusetts	• Several of the state's utilities utilize a Targeted Infrastructure Reinvestment Factor (TIRF) for cost recovery of infrastructure replacement: o Columbia Gas of Massachusetts received approval for its TIRF in 2009. The TIRF allows for the recovery of the revenue requirement associated with bare steal capital additions for the previous calendar year o National Grid companies Boston Gas, Essex Gas and Colonial Gas received approval for a TIRF as part of a 2010 general rate case. The TIRFs provide for the recovery of costs associated with the accelerated replacement of gas mains and the companies are allowed to surcharge customers up to 1% of total revenue o New England Gas (Now Liberty Utilities) received authorization to implement a TIRF to provide recovery of incremental expenditures associated with reinforcing the system and meeting public safety goals • On February 28, 2014, the Massachusetts Department of Public Utilities issued an order in Columbia Gas of Massachusetts' (Columbia) rate case (DPU 13-75) which allowed Columbia to increase the annual cap on amounts collected under the TIRF mechanism from 1% to 3.75% of distribution revenues. • Governor Deval Patrick signed H. 4164 into law on June 26, 2014. The bill provides for the following: o Civil penalties for violations of federal pipeline safety regulations; o Uniform natural gas leak classification for all gas companies; o Grade 1 leaks defined as representing an existing or probably hazard to persons or property and requiring immediate action; o Grade 2 leaks defined as non-hazardous to persons or property at time of detecting but justifies scheduled repair based on future hazard; Requires company to replace the main within 1 year from date of leak classification; o Grad 3 leaks defined as non-hazardous to persons or property and can be reasonably	Docket No. DPU 09-30 (Columbia Gas of Massachusetts) Docket No. DPU 10-55 (National Grid) Docket No. DPU 10-114 (New England Gas) Docket No. DPU 13-75 (Columbia Gas of Massachusetts) H 4164 DPU 14-130 Unitil GSEP DPU 14-131 Berkshire Gas GSEP DPU 14-132 National Grid GSEP DPU 14-133 Liberty Utilities GSEP DPU 14-134 Columbia Gas of Massachusetts GSEP DPU 14-135 NSTAR Gas GSEP

	expected to remain non-hazardous; Requires utilities to reevaluate during scheduled surveys or within 12 months until the main is replaced;
	o Prioritization of pipeline repairs in school zones
	o Cost recovery for eligible infrastructure replacement programs;
	o Eligible plans shall include, but not be limited to, the following:
	  o Eligible infrastructure replacement of mains, services and meter sets composed of non-cathodically protected steel, cast iron and wrought iron prioritized to implement the federal DIMP plan annually submitted to the department
	  o Anticipated timeline for the completion of each project—timelines should include a target end date of either not more than 20 years or a reasonable target end date considering the allowable recovery cap established
	  o Estimated cost of each project
	  o Rate change requests
	  o Customer costs/benefits under the plan
	o An expansion component which permits the DPU to authorize gas utilities to design and offer programs to customers which will increase the availability, affordability and feasibility of natural gas service for new customers;
	o A direction for the DPU to issue a report addressing the prevalence of natural gas leaks in the natural gas system including estimates for the number of Grade 1, 2 and 3 leaks and estimates for lost and unaccounted for gas and methane emissions.
	
	• Pursuant to H. 4164 (now G.L. c. 164, § 145), National Grid, Unitil, NSTAR Gas, Columbia Gas of Massachusetts, Liberty Utilities and Berkshire Gas all filed Gas System Enhancement Program Plans (GSEP) for 2015 on October 31, 2014. These plans were approved on April 30, 2015.
	
	• These plans will allow for the removal of all cast iron and bare steel mains to be eliminated in 20 years for National Grid, Unitil, Columbia Gas of Massachusetts, Liberty Utilities and Berkshire Gas and 25 years for NSTAR Gas.	

Michigan	• In January 2011, the Michigan PSC adopted a settlement that establishes a main replacement program rider. The mechanism will enable SEMCO Energy to recover the incremental capital-related costs associated with the accelerated removal and replacement of cast iron and unprotected steel service lines and mains. The program expires in 5 years unless extended by order or new rate case. • In June 2012, the Commission approved a settlement in a Consumers Energy gas rate case that will fund a main replacement program at $56 million annually until the program is reviewed and spending is reset by the Commission in a general rate proceeding. • In May 2013, the Commission approved an expanded main replacement program proposed by SEMCO Energy Gas Company that will double the amount spent annually on the program and double the miles of main replaced annually. Coupled with its existing program, SEMCO will replace 40.6 miles of high-risk main annually. This will allow SEMCO to accelerate the installation of excess flow valves at the homes of its customers, helping to protect customers in case of a service line leak. • On April 16, 2013, the Michigan PSC approved an expanded gas main replacement program (MRP) and a pipeline integrity program, and the recovery of the costs of those programs, as well as the ongoing meter move-out program, through an infrastructure recovery mechanism (IRM) for DTE Gas Company. This order allowed the company to accelerate its annual pace of main replacement from 30 miles to 66 miles per year. • On January 13, 2015, the Michigan Public Service Commission (PSC) adopted a settlement in a Consumers Energy (CE) gas base rate case. The settlement provides for an Enhanced Infrastructure Replacement Program (EIRP). The EIRP is a twenty-five year incremental investment program to upgrade natural gas infrastructure, including approximately 540 miles of cast iron pipe. The EIRP is based on transmission and distribution integrity management principles intended to eliminate cast iron pipe and other high-risk components as identified through existing federal and state code requirements. CE projects that it will spend about $75 million per year under the EIRP. • On June 3, 2015, The Michigan Public Service Commission (MPSC) approved a settlement agreement that authorized SEMCO Energy Gas Company to extend its natural gas main replacement program (MRP) and increase its MRP surcharge, effective with the next full billing cycle. The surcharge will continue until the earlier of either the establishment of base rates in a future contested case addressing the MRP through self-implementation or Commission order, or May 30, 2020. • Under the terms of the settlement, the parties agreed that SEMCO will: o continue to annually replace 26 miles of main	Docket No. U-16169 (SEMCO) Docket No U-16999 (DTE) Docket No. U-16855 (Consumers) Case No. U-17643 (Consumers EIRP) Case No. U-17701 (DTE) Case No. U-17824 (SEMCO)

	through the MRP and 14.6 miles under the base program, for a total of 40.6 miles of main from 2016 through 2020; o spend on average approximately $10.1 million annually for a total of $50.5 million on main replacement for 2016 through 2020; o not file any further requests for expansion, continuation, or modification of the MRP surcharge outside of a general rate case, unless there is a change in the law addressing infrastructure replacement programs; and o File an MRP planning report and MRP performance report by March 31 of each year for that year's main replacement spending. • On November 12, 2014, DTE Gas filed an application with the Michigan PSC to further improve the overall safety and reliability of the DTE Gas distribution system by revising its Main Replacement Program ("MRP" or "Program") to increase MRP capital expenditures by $46.9 million annually in 2016 and 2017 and increase the Infrastructure Recovery Mechanism ("IRM") surcharge to recover the capital costs associated with the Program. This program would accelerate the company's pace of replacement to approximately 120 miles per year. (Case No. Case No. U-17701). • On November 23, 2015, the Michigan Public Service Commission (PSC) issued a decision that modified DTE's proposal and authorized the company to expand its Main Replacement Program in 2016 by $15.6 million above the previously-approved spending levels, and to increase spending in 2017 by $31.4 million above previously-approved spending levels, contingent upon 2016 targets being met. • Additionally, the PSC directed its Staff to meet with DTE prior to July 1, 2016, to reassess the utility's target mileage for 2016 main replacement. In reassessing the target mileage for 2016, Staff is to consider all relevant information and documents provided by the company, the authorized increase for 2016, and the fact the utility exceeded mileage targets and completed more main replacement than expected under the current MR program to date. The PSC also determined that the parties should reassess 2017 targets in a similar manner prior to July 1, 2017, and that authorization of the 2017 spending increase is subject to reduction back to 2016 levels if 2016 targets are not substantially completed.	
Minnesota	• In May 2013, the Minnesota legislature passed an Omnibus jobs, economic development, housing, commerce and energy bill which included a rider for the recovery of gas utility infrastructure costs. Under the legislation, a gas utility may submit a gas infrastructure project plan report and a petition for cost recover. Upon receiving those items, the Minnesota Public Utilities Commission may approve a rider provided that the costs included for recovery through the rate schedule are prudently incurred and achieve gas facility improvements at the lowest reasonable and prudent cost to ratepayers.	Minnesota H.F. 279 (As enrolled, 5/23/2013) Docket No. 14-336 (Xcel)

	• In August of 2014, Xcel Energy stated in a regulatory filing that it intends to spend $15 million in 2015 on pipeline safety improvements, which is roughly a twofold increase over past levels. In future years, the company envisions even larger safety-related investments, peaking in 2019 at more than $50 million. Should the Minnesota Public Utilities Commission approve the 2015 investment, it would increase customers' bills 3.5 percent in January, about $2 per month for a typical customer, the company said. Future investments could bring more increases, though they would need separate regulatory approval. • On January 27, 2015, The Commission approved Xcel's proposed GUIC rider, rate-adjustment factors, and tariff sheets with the following modifications: o A rate of return calculated using the capital structure and cost of debt from Xcel's electric rate case, Docket No. E-002/GR-13-868, and the cost of equity from its last natural-gas rate case, Docket No. G-002/GR-09-1153; o A rate design that allocates the 2015 revenue requirement to Xcel's customer classes in the same manner as revenues were apportioned in the Company's February 28, 2011 compliance filing in its last natural-gas rate case; and o An effective date of the date of this order, with final rate-adjustment factors calculated to recover the 2015 revenue requirement over the remaining months of 2015. • The Commission also determined that sixty days in advance of its next annual GUIC filing, Xcel shall submit information on what it believes the appropriate rate of return should be for the coming year. Lastly, in the initial filing in its next natural-gas rate case, Xcel must submit detailed schedules, any necessary supporting documentation, and an explanation of all O&M costs that were being recovered in the rider and are now included in the test year for recovery in base rates.	
Mississippi	• CenterPoint utilizes a rate stabilization mechanism (RRA Plan) to change its rates annually to reflect higher capital investment (rate base) and higher O&M costs relating to pipeline safety and other factors. • For each twelve-month period ending December 31, a Commission determination shall be made pursuant to this RRA Plan as to whether the Company's revenue should be increased, decreased or left unchanged. • On September 8, 2015, the Mississippi Public Service Commission approved a stipulation which approved Atmos Energy's proposal to establish a long term system integrity plan and accelerate an investment program to make its system safer and ensure full compliance with federal (DOT/PHMSA) pipeline safety directives. ' • The docket involved a comprehensive review of Atmos Energy's planned system integrity spending over the next 10 years and projected rate impact.	CenterPoint RRA Plan Docket No. 2015-UN-049 (Atmos SIP)

	• Among the key provisions approved: o A rigorous annual review of Atmos Energy's proposed system integrity projects for the next fiscal year and annual rate impact, including o Project spending o Project objective and regulatory requirement being met o Start and completion dates o Historical spending analysis o Project analysis including safety benefit/alternatives considered/engineering support o Annual summary of operational metrics/savings/safety reports o A rolling five-year capital spending plan update including estimated rate impacts o Rate recovery though a combination of fixed and volumetric rates o Estimated impact of the first year of implementation (begins November 2016) is \$0.85/month per residential customer	
Missouri	• Missouri established an Infrastructure Replacement Surcharge (ISRS) mechanism as part of a revision to Missouri Statute 393.1009-105. The ISRS allows rates of a gas utility to be adjusted twice per year to provide for the recovery of costs of eligible infrastructure replacements. Companies that utilize the ISRS must file a rate case at least every 3 years; Ameren, Liberty Utilities, Laclede and Missouri Gas Energy use an ISRS mechanism. • The Missouri Legislature had considered legislation that would modify the provisions outlined above. SB 240 would have required the PSC to specify the annual amount of net write-off incurred by a gas corporation, after which the company would be allowed to recover 90% of the increase in net write offs from customers. The legislation would have also modified the provisions above by extending the amount of time in which a company must come in for a rate case to be eligible for the ISRS from three years to five years. It would have also increased the amount a utility may recover through ISRS from 10% of the company's base revenue level to 13%. This legislation was vetoed by Governor Nixon on July 9, 2013. • In January of 2014, Laclede Gas filed for a \$7.4 million increase in its ISRS, revenues to recover investments in replacement of distribution pipelines over the previous 13 months. Laclede proposed to spend \$7.1 million annually from the new charge to fund roughly 68 miles of gas main replacements. This request was approved on April 3, 2014.	Missouri Statute 393.1009-1015 Missouri SB 240 (Final Passage on 5/9/13; Governor Nixon vetoed this legislation on 7/9/13)

Nebraska	• In 2009, Nebraska established an Infrastructure System Replacement Surcharge (ISRS) as part of revisions to Nebraska Statutes 66-1865, 66-1866 and 66-1867. The ISRS allows the rates of a gas utility to be adjusted twice per year to provide for the recovery of costs of eligible infrastructure replacements. Companies that utilize the ISRS must file a rate case at least every 5 years. • SourceGas and Black Hills currently utilize these riders.	NRS 66-1865, 66-1866, 66-1867
Nevada	• As part of its GRC in 2011, Southwest Gas proposed a Gas Infrastructure Recovery Mechanism (GIR) that would have allowed the utility to invest in incremental non-revenue producing projects and collect on an annual basis the revenue requirement associated therewith. The GIR was not approved as part of the rate case; however, the Commission opened a rulemaking to develop regulations to facilitate the implementation of a GIR-type of recovery mechanism. Pursuant to the rulemaking, Southwest Gas is proposed a mechanism to allow the capital cost of qualifying investments to be deferred, and the associated revenue requirement recovered on an interim basis until its next general rate case. • On January 8, 2014, the Nevada Public Utilities Commission approved regulations establishing an application process for accelerated recovery of eligible costs associated with replacing natural gas pipelines to address safety and reliability concerns that are incurred by operators in between general rate cases.	Docket No. 11-03029 (2011 GRC) Docket Nos. 12-04005 and 12-02019
New Hampshire	• Energy North (now Liberty Utilities) established a Cast Iron Bare Steel (CIBS) Replacement Program as part of the National Grid/KeySpan merger settlement agreement approved by the Commission in Order No. 24,777 on July 12, 2007, in Docket No. DG 06-107. • In, 2009 National Grid (now Liberty Utilities) proposed to modify its annual CIBS rate adjustment mechanism to include public works projects and to eliminate the $0.5 million annual threshold required prior to cost recovery. In a March 2011 settlement, the New Hampshire PUC called for the CIBS rate adjustment mechanism, as it was originally structured, to remain in effect.	Docket No. DG 10-1017
New Jersey	• In 2009, the New Jersey Board of Public Utilities approved accelerated infrastructure programs for five of the seven major utilities that had filed such plans. In total, the plans provide that the utilities will invest $956 million in incremental infrastructure and energy efficiency programs over the following two years, and the costs of the various programs were to be recovered through various, separate adjustment mechanisms (see below). o New Jersey Natural Gas: In 2009, New Jersey Natural Gas received approval to invest $71 million in new infrastructure and system upgrades, which it completed in 2011. In 2011, the utility was granted approval for an additional $60 million. The recovery mechanism is not a traditional tracker or surcharge—the utility is	Docket No. GO09010052 (New Jersey Natural Gas) Docket No. GO09010053 (Elizabethtown Gas) Docket No. GO09010050 (PSE&G) Docket Nos GR09110907, GR10100765, GO1100632 (South Jersey Gas) PSEG Energy Strong Order

<table>
<tr>
<td></td>
<td>
recovering the costs through adjustments to base rates

Elizabethtown Gas: The utility implemented the Utilities Infrastructure Enhancement Program in 2009, which includes both the costs of replacing cast iron pipes and investments in specified new main extensions. The recovery mechanism was through a surcharge. In 2011, the utility was granted approval for the extension of the program through 2012, and the recovery mechanism continued to be a surcharge until October 2011 when the surcharge rolled into base rates
PSE&G: In 2009, the utility received approval for an infrastructure investment program. The recovery mechanism, the Capital Adjustment Charge (CAC), is a deferral account that is adjusted each January based on forecasted program expenditures.
South Jersey Gas: In 2009, South Jersey Gas received approval for its Capital Investment Recovery Tracker (CIRT) mechanism. The program has gone through several revisions in the last several years (CIRT-I, CIRT-II, CIRT-III)

In October of 2012, New Jersey Natural Gas received approval from the New Jersey Board of Public Utilities (BPU) to implement its Safety Acceleration and Facility Enhancement (SAFE) program. Through SAFE, NJNG will replace 276 miles, or approximately 50 percent, of the cast iron and unprotected steel mains and associated services in its delivery system over the next four years.
In August 2013, Elizabethtown Gas received unanimous approval from the New Jersey BPU to implement its Accelerated Infrastructure Replacement (AIR) program. The agreement will enable Elizabethtown Gas to invest up to $115 million over a four-year period to enhance the safety, reliability and integrity of the utility’s distribution system. Under the terms, Elizabethtown Gas will file a rate case no later than September 1, 2016 at which time the AIR program costs will be subject to review. During the AIR program, Elizabethtown Gas will accrue Allowance for Funds Used During Construction (AFUDC) related to project expenditures during the construction period, and accrue associated carrying costs from the time the project is placed in service until the time its costs are recovered through base rates. This program allows the company to replace approximately 30 miles of year of cast and bare steel mains per year.
In the aftermath of Hurricane Sandy, Public Service Electric & Gas Co (PSEG) has proposed a multi-billion dollar network hardening plan to improve resiliency and allow its electric delivery system to recover more quickly after damaging events. Had it been approved as PSEG proposed, the program, referred to as Energy Strong, would have allowed PSEG to will invest $1.1 billion into gas service system upgrades over a 10-year period to proactively protect and strengthen its systems against increasingly frequent severe weather.

</td>
<td>
Docket No. GO12070693 (Elizabethtown Gas AIR Order)

Docket No. GR13090828 (New Jersey Natural Gas RISE Order)

Docket No. GR13009814 (South Jersey Gas SHARP Order)
</td>
</tr>
</table>

	• On May 21, 2014 the New Jersey BPU adopted a settlement approving PSEG's Energy Strong infrastructure improvement program and related surcharge mechanisms. PSEG will improve its natural gas infrastructure over a three-year period. Under the now-approved settlement, over the next three years PSEG is to expend on natural gas investments: $350 million to replace and modernize 250 miles of low-pressure cast iron gas mains in or near flood areas and $50 million to protect five natural gas metering stations and a liquefied natural gas station affected by Hurricane Sandy or located in flood zones. • On July 23, 2014, the New Jersey Board of Public Utilities (BPU) approved New Jersey Natural Gas' (NJNG's) New Jersey Reinvestment in System Enhancements (NJ RISE) infrastructure program. The NJ RISE program is comprised of multiple investments over a five-year time frame of $102.5 million in gas distribution storm hardening and mitigation projects. The BPU also authorized an annual adjustment mechanism for this program. This mechanism covers program costs incurred through July 31, 2015. A base rate case must be filed no later than November 15, 2015. All costs incurred after July 31, 2015 will be addressed in the base rate proceeding. • Also on July 23, 2014, the BPU approved the Elizabethtown Natural Gas Distribution Utilities Reinforcement Effort (ENDURE) program, under which the company was authorized to invest approximately $15 million over a one-year period from January 1, 2014 to December 31, 2014 in its natural gas infrastructure to prevent damage from future major storm events, and to improve communication during and after weather-related emergencies. Elizabethtown Gas proposed to defer the costs of the program, with recovery of the ENDURE program-related deferrals to be determined in a base rate case to be filed in 2016. • On August 20, 2014, the New Jersey Board of Public Utilities approved the South Jersey Gas's $103.5 million storm hardening and reliability program (SHARP) to improve its infrastructure in advance of significant weather events. SHARP, which is expected to be completed in the next three years, will replace roughly 93 miles of natural gas mains and approximately 11,100 associated services. Program costs will be recovered through annual adjustments to South Jersey Gas base rates on October 1st of each year of the program. There will be no immediate impact to customer bills. • On March 2, 2015, PSE&G filed a proposal with the New Jersey Board of Public Utilities to invest $1.6 billion over the next five years to proactively modernize its gas systems. PSEG's Gas System Modernization Program would include replacing an average of approximately 160 miles of cast iron and unprotected steel gas mains, and about 11,000 unprotected steel service lines to homes and businesses per year, over the five year period of the program.	

	• On September 15, 2015, PSE&G announced a $905 million settlement in principle with the staff of the New Jersey Board of Public Utilities (BPU) and the New Jersey Division of Rate Counsel to expedite the replacement of aging gas pipelines. The settlement will enable the company to replace up to 510 miles of gas mains and 38,000 service lines over the three-year period. • Under the agreement, PSE&G will earn a return on equity of 9.75 percent on $650 million of investment based on an accelerated recovery mechanism, and will seek to recover the remaining $255 million in a base rate case, to be filed no later than November 1, 2017. This agreement was approved on November 16, 2015. • On September 23, 2015, Elizabethtown Gas Co. filed a plan a 10-year, $1.1 billion infrastructure program with the BPU. The program aims to replace 630 miles of aging cast iron, steel and copper pipelines. • The proposed Safety, Modernization and Reliability Tariff plan intends to eliminate all aging pipelines, along with 240 regulator stations associated with the utility's low-pressure distribution system, by 2027,and also includes the installation of excess flow valves on all new service lines, and the transferring of gas meters to the outside of homes and businesses. This matter is presently pending. • On February 29, 2016, South Jersey Gas (SJG) filed a petition with the New Jersey Board of Public Utilities seeking to continue its Accelerated Infrastructure Replacement Program (AIRP) for a period of seven years with a total program investment of $500 million. The proposed program will be referred to as AIRP II. Under the AIRP II program, SJG would continue its Distribution Integrity Management Program-based approach to addressing the most significant threats on its distribution system and would replace and retire a significant portion of the vintage and most leak prone mains and services in its distribution system. The company's targets for replacement include: o All remaining cast iron and unprotected bare steel mains and associated services; o The most leak prone coated steel mains that are 2" in diameter or less and associated services; and o Other pipe materials and sizes found within replacement grids that would be logical and necessary to complete the modernization of the grid • Approval of AIRP II would enable the company to continue enhancing the reliability and safety of its gas distribution system in a cost effective manner, achieve increased operational efficiencies and continue the employment benefits that have been created by its previous and existing main replacements programs. SJG proposes to recover the capital investment costs and expenses of the AIRP II program through annual base	

	rate adjustments. The company's first AIRP II rate adjustment filing would be made on April 1, 2017 and there would be no rate adjustment or customer bill impact from the AIRP II program until October 1, 2017. This matter is presently pending. • On September 23, the New Jersey Board of Public Utilities (BPU) adopted a settlement in New Jersey Natural Gas Company's (NJNG) base rate case. As part of the decision, the BPU granted a five-year extension on the utility's Safety and Facilities Enhancement program (SAFE). The SAFE program is a $200 million pipeline replacement effort to modernize NJNG's distribution system. The program allows NJNG to earn an allowance on its invested capital used in construction and request rate increases for spending in annual filings. These annual filings will consider the rate impacts associated with program spending of $157.5 million over its term.	
New York	• Corning Natural Gas has had a limited pipeline replacement cost recovery mechanism since 2006. • National Grid Long Island has had a limited infrastructure replacement tracker program since 2008. The program allows the utility to track only the costs of new or replacement infrastructure that are necessitated by city and state construction projects; National Grid NYC has a similar infrastructure replacement tracker that covers only those costs that are necessitated by city and state construction projects. • National Grid (NYC) uses a risk based prioritization model to identify and rank segments of Leak Prone Pipe (LPP) to be removed from service. The Company will target LPP removal from service of 85 miles in CY 2013 and CY 2014, with a minimum of 40 miles during each calendar year, including at least 10 miles per year outside of City/State Construction-driven work. The Company will incur a negative revenue adjustment of 8 basis points should it fail to remove from service a minimum of 40 miles of LPP in each of CY 2013 and CY 2014 or a cumulative two year total of 85 miles of LPP by the end of CY 2014. • On September 10, 2010, The New York PSC approved a leak prone replacement schedule for New York State Electric and Gas (NYSEG) and Rochester Gas and Electric (RGE). The schedule requires that NYSEG replace a minimum of 24 miles of leak prone main per year and a minimum of 1200 leak prone services per year. RGE shall be required to replace 24 miles of leak prone main per year and 1000 services. • National Grid Niagara Mohawk has had a limited pipeline replacement cost recovery mechanism since 2008. The limited program was scheduled to run for 5 years. • National Grid Niagara Mohawk uses a risk based prioritization model to identify and rank segments of Leak Prone Pipe (LPP) to be removed from service. The Company will target LPP removal of 35 miles in CY13, 40 miles in CY14 and 45 miles in CY15. The Company	Docket No. 08-G-1137 (Corning Natural Gas) Docket No. 09-G-0716/ 09-G-0718 (NYSEG and RGE) Docket No. 06-M-0878 (National Grid Long Island, National Grid NYC, National Grid Niagara Mohawk) Docket No. 13-G-0031 (Con Ed) Docket No. 13-G-0136 National Fuel Docket No. 12-G-0202 (National Grid NIMO) Docket No. 12-G-0544 (National Grid NYC) Docket No. 14-G-0319 (Central Hudson) Docket No. 15-G-0151 (Commission Acceleration Proceeding) Docket No. 15-G-0284 (RGE and NYSEG) Docket No. 14-G-0494 (Orange and Rockland) Docket No. 16-G-0061 (Con Ed RSM) Docket No. 16-0059 (National Grid Brooklyn

		will incur a negative revenue adjustment of 8 basis points should it fail to remove from service a minimum of 35 miles in CY13 and 35 miles in CY14 or a cumulative three-year total of 120 miles by the end of CY15. • On May 8, 2014, The New York PSC authorized a leak-prone pipe (LPP) removal plan for National Fuel Gas Distribution Corp. The Company will continue to use its risk based prioritization model to identify and rank segments of LPP to be removed from service. The Company will target removal from service of a cumulative total of leak prone pipe of 190 miles over CY 2014 and CY 2015, with a minimum of 90 miles removed in each year. • In February 2014, the New York PSC approved a multi-year Joint Proposal (JP) that resolved all issues in Consolidated Edison's (Con Ed) gas delivery rate proceeding. The JP provided for the following gas related expenditures relating to storm hardening which will allow Con Ed to modernize its system at an accelerated pace: o Rate Year 1: $524.2 million of which $5.021 million will go toward storm hardening; o Rate Year 2: $586 million of which $36.459 million will go toward storm hardening; o Rate Year 3: $627 million of which $56.942 will go towards storm hardening • Con Ed has approximately 1,100 miles of cast iron and bare steel pipe in their inventory in the state, and they replaced approximately 13-20 miles per year over the last four years. Under the new program outlined above, the company will replace 60 miles in 2014, 65 miles in 2015, and 70 miles in 2016. • In June of 2014, National Grid petitioned the Public Service Commission to accelerate the replacement of leak prone pipe on Long Island. On December 11, 2014, The PSC ordered the company to accelerate the annual pace of this program to 77.5 miles in 2015 and 95 miles in 2016 to improve public safety and system performance. • In its 2014 rate case, Orange and Rockland proposed to expand its current gas infrastructure replacement program so as to remove a total of 100,000 feet of main annually. In order to eliminate all low pressure mains in six years, the Company proposes to replace annually a minimum of 10,000 feet of low pressure mains. Orange and Rockland also proposes to replace an additional 500 bare steel services annually, as part of the Company's ten year program to remove all bare steel services in its service territory. • On October 15, 2015 the New York Public Service Commission (PSC) adopted a multi-year Joint Proposal (JP) in Orange and Rockland Utilities' (ORU) gas rate proceeding. The approved JP establishes funding for the removal of 21 miles, 22 miles, and 23 miles of leak prone pipe in RY1, RY2, and RY3, respectively, with	and Long Island)

	annual reporting by O&R on the status of its leak prone pipe replacement efforts. The JP also allows a negative revenue adjustment if the Company fails to replace at least 20 miles of leak prone pipe in any calendar year. The JP recommends a total negative revenue adjustment of up to eight basis points, rather than continuation of the current level of six basis points, which was initially recommended by Staff in its pre-filed testimony. • The approved JP also provides for an incentive mechanism for incremental replacement of leak prone pipe above the amounts provided for in base rates. This mechanism will allow for a positive revenue adjustment equivalent to two basis points for each whole incremental mile of leak prone main replaced in any calendar year above the targets provided for in base rates, up to a 10 basis point cap. ORU could recover the cumulative incremental revenue requirement for such costs through the Reliability Surcharge Mechanism, provided the company had also met its other targets for net plant under the approved agreement. • In a February 2015 Joint Proposal, Central Hudson Gas and Electric proposed a leak prone pipe replacement program that would allow for up to $1.4 million in deferred costs for every mile over 13 miles in 2016, up to $1.5 million for every mile over 14 miles in 2017, and up to $1.6 million for every mile above 15 miles in 2018. For the avoidance of doubt, the Company is expressly authorized to include Leak Prone Pipe eliminations (abandonment, disuse or any other method that terminates use of the Leak Prone Pipe while still serving the customer) in this deferral mechanism. • In the event the Company replaces or eliminates Leak Prone Pipe in excess of its mileage target in any calendar year, for each mile in excess of the applicable target, the Company shall receive a positive revenue adjustment of 2 basis points per additional mile, capped at a maximum of 5 miles (10 basis points) per calendar year, which the Company will defer for future recovery. This proposal was approved on June 17, 2015. • On April 17, 2015, The New York PSC issued an order instituting a proceeding to implement a cost recovery mechanism to further accelerate the replacement of leak prone pipe. The Commission's stated goal will be to reduce the statewide average replacement timeline to 20 years. This matter is presently pending. • On May 20, 2015, RGE and NYSEG filed rate cases in which the combined companies proposed an acceleration of leak prone gas main removal. The Companies propose to increase the leak prone main replacement target from 24 miles in 2016 to 26 miles in 2017, and to 28 miles each year thereafter. The combined annual cost is estimated to be approximately $27 million in 2017. Based on the increased miles, the Companies estimate that it will take approximately 11 years (a two year acceleration), beginning in 2016 to replace all of their leak prone gas mains. This proposal	

	was approved on n June 22, 2016. • In its January 29, 2016 rate filing, Con Ed proposed a Reliability Surcharge Mechanism (RSM). Under the RSM, beginning February 1, 2018, the company's Monthly Rate Adjustment would recover the cumulative net plant carrying costs and associated O&M costs for any capital expenditures associated with main replacement above the levels established in the Company's base delivery rates and installed since base rates were last reset. Carrying costs, including associated O&M costs, would be recovered through the RSM over the twelve-month period beginning February immediately following the end of each Rate Year until the Company's base delivery rates are reset. Both the allowed revenue requirement associated with the cost of main replacement as well as the targeted mileage of main replacement must be exceeded on a cumulative basis for any costs to be recovered through the RSM. • Any over- or under-collections for each period, including interest at the Commission's Other Customer Capital Rate, will be reconciled and included in a subsequent RSM. The RSM is applicable to Firm Sales Customers taking service under SC Nos. 1, 2, 3 and 13, applicable Riders and equivalent firm transportation service under SC No. 9. • ConEd's proposal also seeks to increase base gas rates by $154 million, including $77 million for infrastructure investments to support a significant acceleration of the replacement of cast iron and unprotected steel gas mains. The company is currently replacing, on average, approximately 65 miles of gas main per year. The company is proposing to ramp up that goal to 100 miles annually, reducing the time of total system replacement from over 30 years to 20 years. The proposed rate plan also would continue the company's monthly inspections of its gas delivery system. This matter is presently pending. • In its January 29, 2016 rate filing for its Brooklyn and Long Island service territories (KEDNY and KEDLI, respectively), National Grid outlined a proposal targeting the replacement of more than 300 miles of Leak Prone Pipe (LPP) over a five-year period (2017 through 2021). In recognition of the unprecedented incremental work associated with the company's accelerated main replacement targets, and to allow the company to begin recovering the actual costs of the accelerated replacement of LPP as the work is completed, the Company proposed a Gas Safety and Reliability Surcharge under which the Company would be allowed to recover a return on investment, depreciation expense and related O&M expense (i.e., disconnects and reconnects) associated with prudent investment in LPP replacement incremental to the level funded in base rates. Provided the Company exhausts its rate allowance for LPP replacements, incremental investment in LPP above the base level of 50 miles in any calendar year, in an amount not to exceed the company's average cost of main replacement for comparable pipe materials, sizes,	

	strata (e.g., pavement, grass) and working conditions, would be included in the Gas Safety and Reliability Surcharge. • Additionally, with regard to the LPP performance metric, KEDNY and KEDLI propose a negative revenue adjustment of eight pre-tax basis points if they fail to remove their Base LPP Targets of an average of 50 miles per year and 115 miles per year, respectively, over the next three years. The targets would have annual and cumulative targets similar to KEDNY's current LPP metric in Colander years (CY) 2013 and 2014. That is, KEDNY would incur a negative revenue adjustment in each year for failure to replace a minimum of 45 miles in CYs 2017 and 2018, and a minimum cumulative three-year total of 150 miles for CYs 2017 to 2019. KEDLI would incur a negative revenue adjustment in each year for failure to replace a minimum of 105 miles in CYs 2017 and 2018, and a minimum cumulative three-year total of 345 miles for CYs 2017 to 2019. Any replacement miles recovered through the Gas Safety and Reliability surcharge would not count toward the cumulative CY 2019 target. The proposal is presently pending.	
North Carolina	• In May 2013, the North Carolina General Assembly passed legislation that will authorize the NC PUC to adopt, implement, modify or eliminate a rate adjustment mechanism for natural gas local distribution company rates so that the utility can recover the prudently incurred costs associated with complying with federal gas pipeline safety requirements; Piedmont Natural Gas Company has applied for a tracker in accordance with this legislation as part of its recent rate filing. • In December of 2013, the NC PUC permitted Piedmont Natural Gas to implement an integrity management rider (IMR) that allows the company to track and recover future capital expenditures it expects to incur to comply with federal pipeline safety and integrity requirements outside of a general rate case. IMR filings are to occur annually, each November, to reflect costs incurred through the previous October, and the revised rates are to become effective the following February. • In March of 2015, Senator Robert Rucho (R) introduced Senate Bill 434, which would permit the NC PUC to adopt, implement, modify, or eliminate a rate adjustment mechanism to enable the company to recover the reasonable and prudently incurred capital investment and associated costs of complying with federal gas pipeline safety requirements, including a return based on the company's then authorized return. Costs incurred for routine maintenance, repair, and replacement of system components shall not be included in a rate adjustment mechanism authorized under this legislation. The Commission shall adopt, implement, modify, or eliminate a rate adjustment mechanism authorized under this section only upon a finding by the Commission that the mechanism is in the public interest. The Commission may eliminate or modify any rate adjustment mechanism authorized pursuant to this section upon a finding that it	NC H 119 (Signed by Governor 5/17/13) Docket No. G-9, Sub 631 (Piedmont) Senate Bill 434 (died)

	is not in the public interest. This bill died at the end of the legislative session.	
Ohio	• In its 2008 base rate case, Columbia Gas of Ohio received approval for its Infrastructure Replacement Program (IRP) tracker. The IRP was authorized for an initial five year period, and no rate case is required. The approved 25-year plan called for $2.7 billion to replace approximately 4,100 miles of bare steel, cast and wrought iron and copper pipelines. • In 2011, in Case No. 11-55-15-ALT, the Commission approved a stipulation that Columbia may continue its Rider IRP mechanism to reflect IRP investments made through December 31, 2017. However, should Columbia file a base rate case with new rates effective before December 31, 2017, as part of any such rate case, interested parties may challenge any aspect of the IRP and the Commission may, as a result of such challenge, or on its own initiative, revise Columbia's IRP prior to December 31,2017. • This stipulation also expanded the scope of the AMRP component of Columbia's IRP to expressly include first generation plastic pipe or Aldyl-A plastic pipe when such pipe is associated with priority pipe in replacement projects. For each calendar year of the IRP, the footage of such first generation plastic pipe and Aldyl-A plastic pipe that may be included in Rider IRP may not exceed five percent of the total AMRP program footage for that same calendar year. • In its 2008 rate case, Dominion East Ohio received initial approval for its Pipeline Infrastructure Replacement (PIR) tracker program. In 2011, the utility filed a motion to modify the program due to an increase in the identified scope and in response to recent national concern about pipeline safety, which PUCO approved in August 2011. • Duke Energy has had an accelerated main replacement tracker in place since 2000. All customers, except interruptible transportation customers, are assessed a monthly charge in addition to the customer charge component of their applicable rate schedule. • In 2009, the Commission approved the establishment of a tracking mechanism for Vectren Energy Delivery of Ohio that allows the recovery of costs associated with an accelerated bare steel and cast iron pipeline replacement program. • In 2011 Dominion East Ohio (DEO) received Commission approval to further accelerate its replacement activities. PUCO authorized a modified program for another 5 years or until DEO's next rate case. This approval raised the annual adjustment cap	Case No. 08-72-GA-AIR (Columbia Gas of Ohio) Case No. 09-458-GA-RDR (Dominion East Ohio) Case No. 01-1228-GA-AIR (Duke Energy) Case No. 07-1080-GA-AIR (Vectren Ohio) Case No. 11-5515-GA-ALT (Columbia Gas) Case No. 11-3238-GA-RDR (Dominion) 15-0362-GA-ALT (Dominion)

	on the company's rider mechanism. • On February 9, 2015 Dominion East Ohio filed a notice of intent for approval of an alternative rate plan which would extend and increase its investment in pipeline replacement (Docket No. 15-0362-GA-ALT). On September 15, 2016, The Public Utilities Commission of Ohio (PUCO) authorized the continuance of Dominion's pipeline infrastructure replacement program through 2021. PUCO also approved an increase in the yearly spending for the replacement program from $160 million to $180 million in 2017, $200 million in 2018, and a 3% increase per year thereafter.	
Oklahoma	• CenterPoint utilizes a rate stabilization mechanism (Rider PBRC) to change its rates annually to reflect higher capital investment (rate base) and higher O&M costs relating to pipeline safety and other factors. • For each twelve-month period ended December 31, a Commission determination shall be made pursuant to this PBRC Plan as to whether the Company's revenue should be increased, decreased or left unchanged.	CenterPoint Rider PBRC
Oregon	• In the settlement of Avista's 2010 rate case, the Oregon Public Utility Commission provided for deferred accounting treatment for two capital additions: the second phase of the Roseburg Reinforcement Project and the Medford Integrity Management Pipe Replacement Project. A subsequent incremental rate adjustment was made on June 1, 2012 to recover the costs of the projects. • NW Natural has a tracker that recovers the cost of the acceleration of bare steel pipe replacement, transmission pipeline integrity costs and distribution pipeline integrity costs. • On October 21, 2014, NW Natural filed Advice No. 14-23 with an effective date of March 1, 2015. Subsequently, NW Natural filed on February 6, 2015, to extend the effective date to April 1, 2015. The filing requests that Northwest Natural's SIP Recovery Mechanism be extended beyond its sunset date of October 31, 2014. On March 3, 2015, NW Natural filed a supplement to Advice No. 14-23. The purpose of this supplemental filing is to add language requiring that SIP costs be subject to an earnings test. • NW Natural noted in its filing that the regulatory component of the SIP program consists of the ability to update NW Natural's rate base on an annual basis to reflect certain system safety investments. The SIP is comprised of three distinct programs: the Bare Steel Program, the Transmission Integrity Management Program (TIMP), and the Distribution Integrity Management Program (DIMP). On March 10, 2015, Staff recommended that the Commission suspend Northwest Natural's Advice No. 14-23, its request to continue Schedule 177, the System Integrity Program Recovery Mechanism, and open an investigation. The Commission adopted Staff's recommendation and	Docket No. UG-201 (Avista) Docket No. UG-177 (NW Natural) UM 1722 (PUC Investigation Into Recovery of Safety Costs)

	opened an Investigation into Recovery of Safety Costs by Natural Gas Utilities on March 25, 2015.	
Pennsylvania	• In February 2012, the Pennsylvania General Assembly passed HB 1244, legislation that amended Title 66 (Public Utilities) of the Pennsylvania Consolidated Statutes to provide an additional mechanism for distribution systems (gas, electric, water, wastewater) to recover costs related to the repair, improvement and replacement of eligible property. Under the amended law, the PA PUC may approve the establishment of a distribution system improvement charge (DSIC) to provide for the timely recovery of reasonable and prudent costs incurred by a utility to repair, improve or replace eligible infrastructure. • On March 14, 2013, The Pennsylvania Public Utility Commission approved the Distribution System Improvement Charge (DSIC) of Columbia Gas of Pennsylvania. Columbia anticipates completing the replacement of cast iron and bare steel mains in approximately 17 years, or by the end of 2029. • On April 4, 2013, The Pennsylvania Public Utility Commission approved the DSIC of Philadelphia Gas Works. PGW also received approval of its long-term infrastructure improvement plans (LTIIP) to accelerate its replacement of 8 inch and smaller cast iron main inventory (totaling 1,200 miles) by 17 years, and accelerating the replacement of all 12 inch and 30 inch high pressure cast iron main by more than 60 years. Without the LTIIP, PGW removed 18 miles of cast iron main as part of its baseline main replacement program. The approved LTIIP allows PGW to remove cast iron main from inventory at a rate of approximately 25 miles per year. • On May 9, 2013, The Pennsylvania Public Utility Commission approved the DSIC plan of PECO. • PECO will modernize all of the cast iron and bare steel mains in its gas system within approximately 34 years. This represents a significant acceleration over the 85-year replacement plan that existed prior to acceleration. All bare steel services will be modernized within 10 years versus the 22 year replacement period that existed prior to acceleration. • On May 23, 2013, The Pennsylvania Public Utility Commission approved the DSIC plans of Peoples Natural Gas and Peoples TWP. • Beginning in 2012, Peoples TWP commenced its SMP program to replace all of its unprotected bare steel and some cathodically-protected steel gas mains – a total of roughly 948 miles of pipeline – over a twenty year period, the early years of which have been described and incorporated in PTWP's LTIIP addressed in the Commission's order approving its DSIC and LTIIP.	Pennsylvania HB 1294 (Original legislation) Pennsylvania Consolidated Statute: Title 66, Chapter 13B, Section 1353 Docket No. P-2012-2338282 (Columbia Gas of PA) Docket No. P-2013-2347340 (PECO) Docket No. P-2013-2342745 (Equitable Gas) Docket No. P-2012-2337737 (PGW) Docket No. P-2013-2344595 (Peoples TWP) Docket No. P-2013-2344596 (Peoples Natural Gas) Docket No. P-2013-2342745 (Equitable Gas) Docket No. P-2013-2398835 (UGI Utilities) Docket No. P-2013-2397056 (UGI Penn Natural Gas)

	• Beginning in 2011, Peoples commenced its SMP program to replace all of its cast iron, unprotected bare steel, and some cathodically-protected steel gas mains – a total of roughly 2,300 miles of pipeline – over a twenty year period, the early years of which have been described and incorporated in Peoples' LTIIP addressed in the Commission's order approving its DSIC and LTIIP. • On July 16, 2013, The Pennsylvania Public Utility Commission approved the DSIC plan of Equitable Gas Co. • At the time of the approval of its DSIC and LTIIP, Equitable operated approximately 41 miles of cast iron distribution mainlines. In 2012, Equitable began to accelerate the replacement of small diameter cast iron. The Commission's order approving its DSIC and LTIIP will allow for the removal of all such pipe from Equitable's distribution system by 2017. During the same time period, Equitable intends to accelerate the replacement of larger diameter cast iron distribution mainline. • This LTIIP will allow Equitable to replace all small diameter (<12 in.) cast iron distribution mains (9.8 miles), 11.4 miles of large diameter (>12 in.) cast iron distribution mains, 49.7 miles of bare steel and wrought iron distribution mains and 28.7 miles of bare steel and wrought iron gathering mains through calendar year 2017. • On December 12, 2013, UGI Central Penn Gas filed for approval of a DSIC and DSIC Tariff. • On December 12, 2013, UGI Penn Natural Gas filed for approval of a DSIC and DSIC Tariff. • UGI-PNG plans to retire or replace all in-service cast iron mains over the period of 14 years and all bare steel mains over the period of 30 years beginning in March 2013. • On July 9, 2014, The Pennsylvania Public Utility Commission approved UGI Utilities Inc.'s $256 million long-term infrastructure improvement plan. UGI's five-year plan puts the utility on track to replace its cast-iron mains within 14 years and its bare-steel mains within 30 years of March 2013. As of 2013, UGI had roughly 2,118 miles of steel and 316 miles of iron distribution main, along with 603 miles of steel service lines. UGI also plans to replace gas service lines in conjunction with the mains to which they are connected, the PUC noted in a news release. • On September 11, 2014, the Pennsylvania Public Utility Commission (PUC) approved the long-term infrastructure improvement plans, or LTIIP, of UGI Penn Natural Gas Inc. (UGI-PNG) and UGI Central Penn Gas Inc. (UGI-CPG). In its order, the PUC also approved the companies' plans to implement the distribution system improvement charges, or DSIC. Under the LTIIP, each of the UGI Corp. subsidiaries are allowed to replace an	

	average of 17 miles of pipeline per year in a five-year period. UGI-PNG plans to spend nearly $23 million per year, while UGI-CPG plans to spend almost $14 million per year, on pipeline replacements, service line improvements and safety device installations over the five-year period. • In February of 2015, PECO filed a request with the Pennsylvania Public Utility Commission (PUC) for approval to accelerate the modernization of the company's natural gas distribution system. PECO's plan would increase the company's Long-Term Infrastructure Improvement Plan from $34 million per year to $61 million per year. Under the proposed plan, replacement of natural gas main would increase from about 30 miles per year to more than 50 miles per year by 2018. Bare steel service line replacement would remain at about 4,000 lines per year. This would accelerate the replacement of existing cast iron, bare steel, wrought iron and ductile iron gas main and bare steel service line from 34 years to 22 years. This plan was approved on May 7, 2015. • On July 8, 2015 the Pennsylvania Public Utility Commission (PUC) issued orders finalizing previously approved distribution system improvement charge (DSIC) mechanisms for UGI Penn Natural Gas (UGI-PNG) Gas and UGI Central Penn Gas (UGI-CGP). • This decision relates back to the PUC's September 2014 orders approving Long Term Infrastructure Improvement Plans (LTIIPs) and related DSICs for UGI-PNG and UGI-CPG, subject to subsequent review of certain issues. Pursuant to a 2012 settlement resolving an investigation into a gas pipeline explosion in Allentown, the companies were not permitted to implement adjustments under the DSIC until April 2015. • Under its approved LTIIP, UGI-PNG is to expend roughly $23 million annually on pipeline replacements (average of 17 miles per year), service line improvements, and safety device installations over the five-year term of the plan. Additionally, UGI-CPG, the company is to expend roughly $14 million annually on pipeline replacements (average of 17 miles per year), service line improvements, and safety device installations over the five-year term of its plan. • On September 3, 2015, the Pennsylvania Public Utility Commission voted 5-0 to approve PECO Energy Co.'s plan to implement a distribution system improvement charge for its gas operations. • On January 28, 2016, the Pennsylvania Public Utility Commission (PUC) voted to help Philadelphia Gas Works (PGW) fund faster pipeline replacement work. The commissioners unanimously approved an increase to the utility's distribution system improvement charge, or DSIC, raising the cap from 5% of the company's billed revenues to 7.5%. PGW will have to track and account for all its distribution system improvement charge, or DSIC, spending using a designated accounting	

	mechanism, earmarking all unspent DSIC money for future infrastructure spending or refunds to customers, if necessary, according to the PUC decision. This increase would allow PGW to spend about $33 million annually on its main replacement program, which would cut the projected timeline to replace the company's aging gas mains to 48 years. • On March 10, 2016, the Pennsylvania Public Utility Commission issued an order approving Peoples Natural Gas' (Peoples) Second Revised Long Term Infrastructure Improvement Plan. The newly-approved plan will allow Peoples to implement the following changes: o Shift its replacement focus towards urban projects in order to more effectively target pipeline replacements for higher risk projects located in the higher population areas of its system; o Deploy automated meter reading technology; o Undertake various upgrades and improvements to M&R stations and related M&R equipment; o Expand the replacement of bare steel and other at-risk customer-owned service lines. • In addition, Peoples received approval to establish a Construction Division with in-house employees and construction crews that would perform 100% of capital related construction work at Peoples, the Equitable Division and its sister company – Peoples TWP, LLC. The Construction Division's scope of work will include design, planning, construction, and restoration. Peoples maintains that the move to an in-house staffed Construction Division will further improve the quality of capital work by reducing the cycle time of "planning to restoration" and improving the efficiency and operating costs of all construction activities. The transition to a full Construction Division is expected to be a two-year process that will continue through 2016. • By the end of 2016, the Construction Division will be staffed with superintendents, managers, supervisors, technicians and engineers, as well as approximately 300 field employees that will be located throughout the company's service territories to handle all construction and restoration work. Approximately 220 of these field employees (including field inspectors) will be assigned to 45 construction crews, and the remaining field employees (approximately 80) will be responsible for restoration work. While the Construction Division employees will be dedicated to performing capital work, they will be made available, on a limited basis, to support Operations and Maintenance (O&M) work activities, such as emergencies and overtime call outs, in order to ensure that all operations activities are done in the most cost-efficient manner. Should this occur, their time would be properly tracked and charged as an O&M expense. • On March 18, 2016 Columbia Gas of Pennsylvania (CGP) filed with the Pennsylvania Public Utility Commission (PUC) for gas distribution base rate	

	increase. CGP indicated that the rate increase is intended to allow the company to collect the revenue requirement associated with investments made under the company's accelerated pipeline replacement program. The company expended $152 million on infrastructure investments in 2015, and estimates that is will spend $162 million on infrastructure modernization in 2016. Over the years 2016 through 2020, Columbia estimates its total capital spending will be $958 million. The filing also reflects increases in operation and maintenance expenses associated with the facilities upgrades. This matter is presently pending. • On June 30, 2016, The Pennsylvania Public Utility Commission (PUC) approved the modified long-term infrastructure improvement plans (LTIIPs) for Peoples Natural Gas, UGI Utilities Inc. - Gas, UGI Penn Natural Gas Inc. and Central Penn Gas Inc. • The approved, revised LTIIP for Peoples Natural Gas replaces the currently approved, separate LTIIPs of the Peoples Division and the Equitable Division (previously Equitable Gas Company) of the Peoples Natural Gas Co. Peoples' Revised LTIIP is a five-year plan that builds off of, and expands upon, the previously-approved LTIIPs for the Peoples and Equitable Divisions. Peoples has replaced all known cast iron pipelines in its system, and plans to address accelerated replacement of the 37 miles of known cast iron pipelines acquired through its formation of the Equitable Division. Peoples proposes to replace all bare steel and cast iron pipelines over an approximately 20-year period. • In its revised LTIIP, Peoples indicates it will replace all at-risk customer-owned service lines, which is an update from its original LTIIP where the company said it planned to pressure test customer-owned service lines prior to replacement. Peoples provides natural gas service to approximately 640,000 residential, commercial, and industrial customers in all or portions of 17 Southwestern Pennsylvania Counties. • In a separate action, the Commission voted to approve the modified LTIIPs for UGI Gas, UGI Penn Natural Gas and UGI Central Penn Gas. Each of the UGI Companies' modified LTIIPs are five-year plans, spanning the years 2014-2018. The LTIIPs detail accelerated infrastructure improvements that are intended to enhance system resiliency. The instant petitions do not propose to change or extend the term of the current LTIIPs. Rather, the instant petitions propose to increase the amount of infrastructure spending over that of the currently effective LTIIPs by more than 20 percent. The UGI Companies as a group propose spending more than 50 percent additional capital in the final three years of their LTIIPs compared to the original projections.	
Rhode Island	• In 2010, the Rhode Island General Assembly passed legislation to amend Chapter 39-1 of the Rhode Island General Laws to allow the Rhode Island PUC to approve revenue decoupling and infrastructure investment tracking mechanisms.	Rhode Island General Laws: Title 39, Chapter 39-1, Section 39-1-27.7.1 Docket No. 4474

	• As a result of this legislation, National Grid utilizes an Infrastructure Safety and Reliability Plan (ISR) which replaced its existing Accelerated Replacement Program (ARP). This program began April 2011 and funds both replacement of leak prone mains and bare steel, high pressure services. The plan also includes funds for system reliability, mandated programs and special projects and includes a fully-reconciling rate mechanism designed to recover actual and anticipated capital investments as reflected in the approved ISR spending plan. • In its FY 2015 Gas Infrastructure Safety and Reliability Plan (ISR) (Docket No. 4474), the Commission authorized the company to target 70 miles of main per year, which would reduce the time frame for removal of leak prone pipe to approximately 20 years. The company had replaced 50 miles in FY 2014.	(National Grid)
South Carolina	• In 2005, South Carolina passed the Natural Gas Rate Stabilization Act (RSA), which was designed to reduce fluctuations in customer rates by allowing for more efficient recovery of the costs regulated utilities incur in expanding, improving and maintaining natural gas service infrastructure. • In lieu of a general rate case, Piedmont Natural gas and SCE&G have filed annual base rate updates since 2005 pursuant to the RSA. The annual rate update enables the Company to earn a return on actual plant investments made thru the prior March 31st.	Natural Gas Rate Stabilization Act
Tennessee	• In April 2013, Tennessee enacted legislation which provides for alternative regulatory methods to allow for public utility rate reviews and cost recovery for investments in infrastructure replacement and expansion in lieu of a general rate case. In particular, the measure allows the Tennessee Regulatory Authority (TRA) to approve cost recovery mechanisms to recoup operational expenses and/or capital costs associated with infrastructure replacement that is necessary to comply with federal and state safety requirements and/or ensuring reliability. • Piedmont Gas utilizes this rider. • In May of 2015, Atmos Energy received approval from the Tennessee Regulatory Authority to implement an Annual Review Mechanism, which will allow the company to adjust its rates annually to reflect higher capital investment and higher O&M costs relating to infrastructure replacement and other factors.	Public Chapter No. 245 (HB 191) Docket No. 1400146 (Atmos Energy)
Texas	• In 2003, the Texas Legislature passed SB 1271 which established the Texas Gas Reliability Infrastructure Program (GRIP). • GRIP allows a gas utility that has filed a rate case within the previous two years to file a tariff or rate schedule that provides for an interim adjustment in its monthly	Senate Bill 1271, Establishing the Gas Reliability Infrastructure Program 16 TAC Chapter 8-Pipeline Safety

	customer charge or initial block rate in order to recover the cost of investment changes, which could include the replacement of aging infrastructure or expansion of infrastructure. • In 2011, the Texas Railroad Commission adopted a comprehensive pipeline safety rule that requires all state natural gas distribution companies to survey their pipeline distribution systems for the greatest potential threats for failure and make replacements. The rule allows for the recovery of costs of such programs via a deferral mechanism. • Atmos Energy, CenterPoint Energy and Texas Gas Service utilize portions of these mechanisms. • On August 25, 2015 the Texas Railroad Commission (RRC) adopted a settlement in CenterPoint Energy's base rate case. The agreement provides that a 10% ROE with a 54.5% equity capital structure is to be used for prospective adjustments under any interim rate adjustment mechanisms that recognize new capital investment, including the company's Gas Reliability Infrastructure Program.	Regulations (2011)
Utah	• In 2010, the Utah Public Service Commission authorized Questar Gas to implement a three-year pilot Infrastructure Replacement Adjustment (IRA) mechanism to track and recover the costs associated with the replacement of high pressure natural gas feeder lines between rate cases.	Docket No. 09-057-16
Virginia	• In 2010, Virginia enacted the SAVE (Steps to Advance Virginia's Energy Plan) Act. The law allows utilities to petition the Virginia State Corporation Commission for a separate rider to recover a return on certain investments, including natural gas facility replacement projects that enhance safety and reliability, or have the potential to reduce greenhouse gas emissions by reducing system integrity risks; Atmos Energy, Columbia Gas Virginia, Virginia Natural Gas and Washington Gas utilize the rider. • On November 28, 2011, The Virginia State Corporation Commission approved the SAVE plan and rider of Columbia Gas of Virginia. The plan permits Columbia to spend $20 million each year with the flexibility to vary this amount up to 5% above or below the projected level of plan investment in any year. The approved plan runs through December 31, 2016. • On July 25, 2014 The Virginia State Corporation Commission authorized Virginia Natural Gas to recover costs associated with the replacement of up to $105 million of infrastructure during the five-year term (2012-2016) of its SAVE Plan. The Company intends to spend up to $25 million annually with the total investment over the five-year term of the SAVE Plan capped at $105 million. Costs are recovered through a rider ("Rider E" or "SAVE Rider") on customers 'bills as authorized by the SAVE Act.	Code of Virginia: 56-603, 56-604 (Implementation of SAVE Act) PUE-2010-000871 (Washington Gas) PUE-2012-00096 (Washington Gas) PUE-2015-00017 (Washington Gas) PUE-2012-00012 (Virginia Natural Gas) PUE-2011-00049 (Columbia Gas of Virginia)

	• On February 6, 2015 Washington Gas Light Company (WGL) filed an application with the Commission for approval of amendments to its SAVE Plan, which the Commission first approved in Case No. PUE-2010-000871 ("Approved SAVE Plan") and modified in its Order Approving Amended SAVE Plan in Case No . PUE-2012-00096. In this Application for an amended SAVE Plan, WGL proposed to increase its Virginia SAVE Plan expenditures for the period January 1, 2015, to December 31, 2017 ("Period") by approximately $75.2 million, for a total of $194 .4 million for the Period, for the expansion of the scope of certain of its approved SAVE Plan programs and implementation of new programs. This plan was approved on June 5, 2015. • WGL plans to expand its pre-1975 Plastic Service Replacements program, and the Copper Service Replacement program to include all services in each of these categories. The Company also proposed to add two new distribution system replacement programs. o Program 8 - a Meter Set Survey and Remediation Program - will address the replacement of piping if certain conditions are discovered during the meter set survey, the replacement of shallow main that is occasionally discovered, and the replacement of gauge lines for medium pressure main-line valves. o Program 9 – a Meter Set Survey Technology Implementation Program - will automate the Company's manual processes by constructing- a data model and technology solution that will provide integration with a range of work management systems, document management systems, and mapping systems. o This filing also calls for the approval of an additional one 1 per year of bare steel replacement on top of the company's currently-approved 25 mile per year pace and .7 miles per year of cast iron replacement on top of the company's current 13.3 mile per year pace. • In December of 2015, Virginia Natural Gas asked the State Corporation Commission to approve a plan to further accelerate its replacement of aging infrastructure. Since 2012, the company has installed 155 miles of new main line and more than 9,000 new service lines to customers, replacing aging connections, and expects to finish work on another nine miles of main line and 600 service lines by the end of the year. The proposed plan aims to replace the final 23 miles of cast iron pipe in the company's system, as well as 293 miles of bare steel main. If approved, this proposal would authorize the company to invest $30 million in 2016 and $35 million a year from 2017 to 2021, up to a maximum of $210 million. • On March 17, 2016, The Virginia State Corporation	

	Commission (SCC) approved an expansion of Virginia Natural Gas' (VNG) infrastructure modernization program. Under the newly-approved plan, VNG plans to invest \$30 million in its Steps to Advance Virginia's Energy (SAVE) program in 2016 and up to \$35 million annually after that to replace more than 200 miles of aging pipeline infrastructure through 2021. Since 2012, Virginia Natural Gas has invested about \$82 million in replacing more than 160 miles of pipeline with modern materials. • The SCC stated that it would require VNG to provide a list of completed projects during the preceding calendar year, a list of planned projects for the current calendar year and details about what the projects address. This list is to be filed annually in January.	
Washington	• In December 2012, the Washington UTC issued a policy statement aiming to enhance safety and modernize and update the state's pipeline system. • In November 2013, the UTC approved the the plans of Avista Corporation, Puget Sound Energy Inc., Cascade Natural Gas Corporation and Northwest Natural Gas Company. The plans involve the replacement of hundreds of miles of older "elevated risk" pipes with plastic pipe. • As an incentive, the UTC permitted these utilities to recover costs annually instead of waiting for future formal rate proceedings. The companies are also required to update their modernization plans every two years.	Docket No. PG-120715 (12/31/2012)
West Virginia	• In its January 2015 base rate filing, Mountaineer Gas proposed an infrastructure replacement program to increase reliability and enhance safety by enabling the more timely cost recovery for eligible infrastructure improvements. The proposed program would cover investments to eliminate bare steel mains and services with the highest leakage rates and other infrastructure replacements. This enhanced investment will accelerate overall safety and reliability improvements by reducing system integrity risks due to corrosion, equipment failures, material failures, and the impact of natural forces, and it will reduce customer service outages through replacement of higher-risk pipeline segments. Investment currently in rate base (or that would be included in rate base in this rate case), or that would increase revenue by directly connecting new customers to the system, would be ineligible. • The program would be funded through a rate mechanism, which would be implemented beginning on January 1, 2017, and the Company would commit to invest at least \$12,800,000 in qualifying infrastructure replacement each year for the succeeding three years. The Company wishes to formalize this program under the Commission's direction and to accelerate its investment in this important component of its system. • On February 3, 2015, the West Virginia Senator Charles Trump (R) filed SB 390. This bill provides that natural	SB 390 Docket No. 15-0003-G-42T (Mountaineer Gas) Docket No. 15-1600-G-390P (Dominion Hope) Docket No. 15-1256-6-390P (Mountaineer IREP)

	gas utilities may file with the commission, an application for a multi-year comprehensive plan for infrastructure replacements, upgrades and extensions. Subject to commission review and approval, a plan may be amended and updated by the natural gas utility as circumstances warrant. • Following commission approval of its infrastructure program, a natural gas utility shall place into effect rates that include an increment that recovers the allowance for return, related income taxes, depreciation and property tax expenses associated with the natural gas utility's estimated infrastructure program investments for the upcoming year, net of contributions to recovery of those incremental costs provided by new customers served by the infrastructure program investments, if any, ("incremental cost recovery increment"). In each year subsequent to the order approving the infrastructure program and an incremental cost recovery increment, the natural gas utility shall file a petition with the commission setting forth a new proposed incremental cost recovery increment based on investments to be made in the subsequent year, plus any under-recovery or minus any over-recovery of actual incremental costs attributable to the infrastructure program investments, for the preceding year. This bill was signed into law on March 24, 2015 and will take effect on June 11, 2015. • On September 30, 2015, Dominion Hope Gas filed for approval of its Pipeline Replacement and Expansion Program (PREP). PREP is consistent with SB 390's objectives of replacing, upgrading, extending and expanding the Company's natural gas pipeline infrastructure to provide continued and enhanced, efficient, safe and reliable gas service to its current base, including to new customer bases in unserved or underserved areas of West Virginia. • PREP features two separate replacement initiatives. The first is a 50-year program to accomplish the following goals: o Replace bare steel distribution mains; o Replace unprotected, ineffectively coated steel distribution mains; o Replace unprotected bare steel services; o Enhance or upgrade system facilities; and o Replace aged gas measurement and regulation equipment • The second replacement initiative is the company's proposal to prospectively replace existing gas sales service customer' piping (CSP) if it is found to be bare steel in the course of associated mainline replacements or when the time comes in the future to replace that customer-owned CSP due to its age or condition. • Costs associated with PREP would be eligible for recovery through an annual rate surcharge. • On July 31, 2015, Mountaineer Gas Company (MGC) filed for approval of an Infrastructure Replacement and	

	Expansion Program (IREP). On October 9, 2015, the parties in this proceeding filed a Joint Stipulation and Agreement for Settlement (Joint Stipulation). In the Joint Stipulation, the parties recommended that the Commission authorize a total 2016 revenue increase of $565,758, using the customer class allocation determined in above-referenced rate proceeding. The IREP rate component for IS and LGS customers will also be expressed as a fixed customer charge, as opposed of the volumetric calculation that MGC had proposed in its IREP Application. The parties asserted that this change would not affect other rate schedules. The parties also agreed that the IREP rate component would not apply to customers who receive service under one or more special contracts filed with the Commission. The Commission approved the Joint Stipulation on December 23, 2015. • On February 4, 2016, the West Virginia Public Service Commission approved a Joint Stipulation and Agreement for Settlement that provides for a Pipeline Replacement and Expansion Program (PREP) and a PREP cost recovery component to the base rates of Hope Gas (Dominion Hope). The Commission modified the Joint Stipulation as it relates to the filing of quarterly reports as part of a pilot program. The approved Stipulation reflects the parties' agreement to a 2016 projected PREP capital investment of approximately $20.5 million. The approved agreement allows Dominion Hope to collect a total 2016 revenue increase of $862,014 using the customer class allocations and rate of return on equity determined in Dominion Hope's last base rate proceeding. The company's initial filing separated proposed projects into 3 categories. Categories 1 and 3 were approved. • Category 1 projects -- The largest category of proposed capital investment, these projects will replace and upgrade aged infrastructure, including distribution mains, service lines and appurtenant facilities. When individual PREP projects are completed Dominion Hope will prepare a work order package that contains the same information that was approved in the Mountaineer SB 390 proceeding: the materials used (type and amount), unit prices, work force used (internal or contracted), total project cost, construction period and duration, project in-service date and related details. These packages will be available to Commission Staff and the Consumer Advocate Division for auditing purposes. • The Commission also approved the parties request for approval of a three-year pilot program in which Category 3 projects - Dominion Hope's repair, replacement and installation of customer service piping. These projects will also be included in the capital investment for PREP cost recovery. The pilot program will begin March 1, 2016, and end December 31, 2018.	
Wyoming	• On August 4, 2016, the Wyoming Public Service Commission approved a Pipeline Safety and Integrity Mechanisms (PSIM) for Black Hills Energy (BHE). The PSIM will allow BHE to recover its investment for nine specific projects utilizing the PSIM and would increase its	DOCKET NO. 30003-66-GA-15

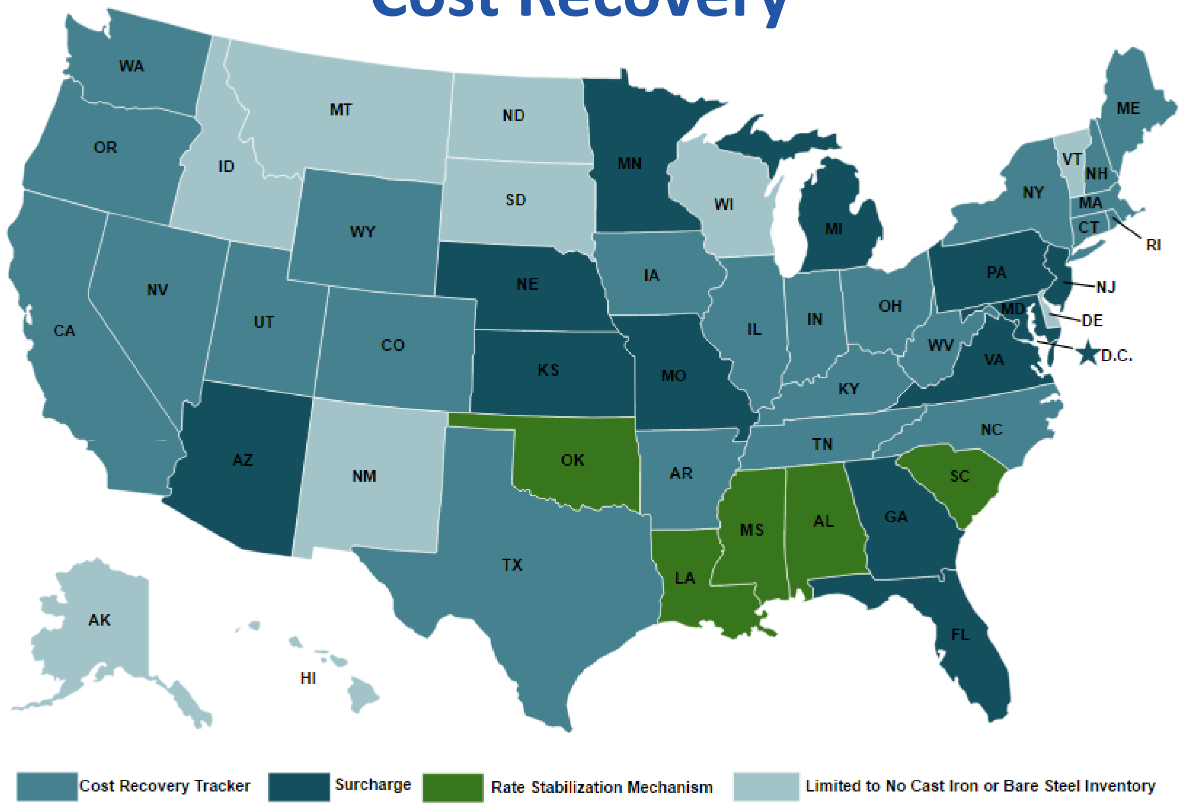
	natural gas utility revenue by $42,511 for the period of August 1, 2016, through March 31, 2017. • The PSIM is designed to recover the PSIM Revenue Requirement associated with the investments in pipeline infrastructure approved in Docket Nos. 30003-62-GA-14 and 30005-187-GA. Until such time as these infrastructure investments are included in base rates, but no later than March 31, 2021, PSIM costs will be recovered from customers using a PSIM charge applied to all customers' monthly bills. The PSIM will be calculated annually using the actual and forecasted capital costs and operating expenses for the just ending calendar year and forecasted Dth billing determinants by customer class, except for the calculation to be used to determine the first PSIM rates effective with usage on or after August 1, 2016. • The Company will make a PSIM filing with the Commission annually by December 31st of each year. The PSIM filings will: 1) reflect the additional investment in pipeline replacement costs that have been, or that are anticipated to be completed, during the current year; 2) true-up to actual costs the investment costs and related revenue requirement from the amount in the previous year's PSIM, and 3) true-up the revenue collected from customers to the amount, reflecting the prior year's trued-up investment. The PSIM applies to all natural gas rate schedules for all classes of service authorized by the Wyoming Public Service Commission	

Innovative Rates, Non-Volumetric Rates, and Tracking Mechanisms: Current List

As of December 2016

American Gas Association

States with Accelerated Infrastructure Cost Recovery



Utilities with Full Infrastructure Cost Recovery Mechanisms

1. AL – Alabama Gas Company
2. AL – Mobile Gas Service
3. AR – Arkansas Oklahoma Gas
4. AR -- SourceGas
5. AR – CenterPoint Energy
6. CA – San Diego Gas and Electric
7. CA – Southern California Gas
8. CA – Southwest Gas
9. CO – Public Service Co. of Colorado
10. CO – Atmos Energy
11. CO -- SourceGas
12. CT – Connecticut Natural Gas
13. DC – Washington Gas
14. FL – Chesapeake Utilities
15. FL – Florida Public Utilities Company
16. FL – Florida City Gas
17. FL – TECO Peoples Gas
18. GA – Atlanta Gas Light
19. GA – Liberty Utilities
20. IL – Ameren Illinois
21. IL – NICOR Gas
22. IL – Peoples Gas
23. IN – Vectren North Indiana Gas
24. IN – Vectren South SIGECO
25. IN – NIPSCO
26. KS – Atmos Energy
27. KS – Black Hills
28. KS – Kansas Gas Service
29. KY – Atmos Energy
30. KY – Columbia Gas of Kentucky
31. KY – Delta Natural Gas
32. KY – Duke Energy Kentucky
33. LA – CenterPoint Energy
34. LA – Entergy Gulf States
35. MA—Berkshire Gas
36. MA – Columbia Gas of Massachusetts
37. MA – National Grid Massachusetts
38. MA – Eversource Energy
39. MA – Liberty Utilities
40. MA—Unitil
41. MD – Baltimore Gas and Electric
42. MD – Columbia Gas of Maryland
43. MD – Washington Gas
44. MI – Consumers Energy
45. MI – DTE
46. MI – SEMCO Energy
47. MN – Xcel Energy
48. MO – Ameren Missouri
49. MO – Liberty Utilities
50. MO – Laclede Gas
51. MO – Missouri Gas Energy
52. MS – Atmos Energy
53. MS – CenterPoint Energy
54. NC – Piedmont Natural Gas
55. NC – Public Service of North Carolina
56. NH – Liberty Utilities
57. NJ – New Jersey Natural
58. NJ – Elizabethtown Gas
59. NJ – Public Service Electric and Gas
60. NJ – South Jersey Gas
61. NV – Southwest Gas
62. OH – Columbia Gas of Ohio
63. OH – Dominion East Ohio
64. OH – Duke Energy
65. OH – Vectren Ohio
66. OK – CenterPoint Energy
67. OR – Avista Corp.
68. OR – NW Natural
69. PA – Columbia Gas of Pennsylvania
70. PA – Equitable Gas
71. PA – Peoples Gas Company
72. PA – Peoples TWP
73. PA – UGI Central Penn Gas
74. PA – UGI Penn Natural Gas
75. PA – PECO
76. PA – Philadelphia Gas Works
77. RI – National Grid Narragansett Gas
78. SC – Piedmont Natural Gas
79. SC – South Carolina Electric and Gas
80. TN – Atmos Energy
81. TN – Piedmont Natural Gas
82. TX – Atmos Energy
83. TX – CenterPoint Energy
84. TX – Texas Gas Service
85. UT – Questar Gas
86. VA – Atmos Energy
87. VA – Columbia Gas of Virginia
88. VA – Virginia Natural Gas
89. VA – Washington Gas
90. WA – Avista Corporation
91. WA – Puget Sound Energy, Inc.
92. WA – Cascade Natural Gas Company
93. WA – Northwest Natural Gas Company
94. WV – Mountaineer Gas Company
95. WV- Dominion Hope
96. WY– Black Hills

Limited and Pending Infrastructure Mechanisms

LIMITED – 3 States

1. AZ – Southwest Gas
2. ME – Northern Utilities
3. NY – Consolidated Edison
4. NY – Corning Natural Gas
5. NY – National Grid NYC
6. NY – National Grid Long Island
7. NY – National Grid Niagara Mohawk
8. NY – Orange and Rockland

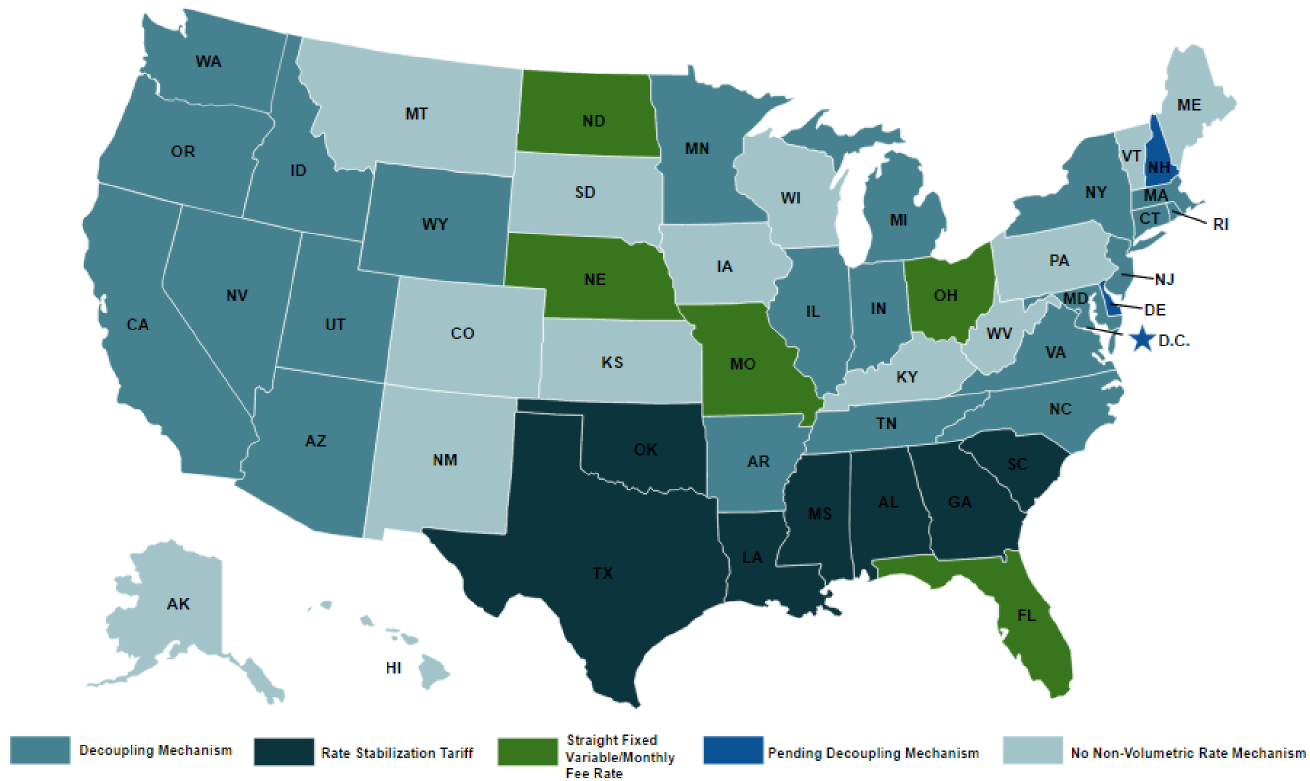
PENDING – 3 States

1. KS – All utilities
2. NJ – Elizabethtown Gas
3. NY – Consolidated Edison
4. NY – All utilities

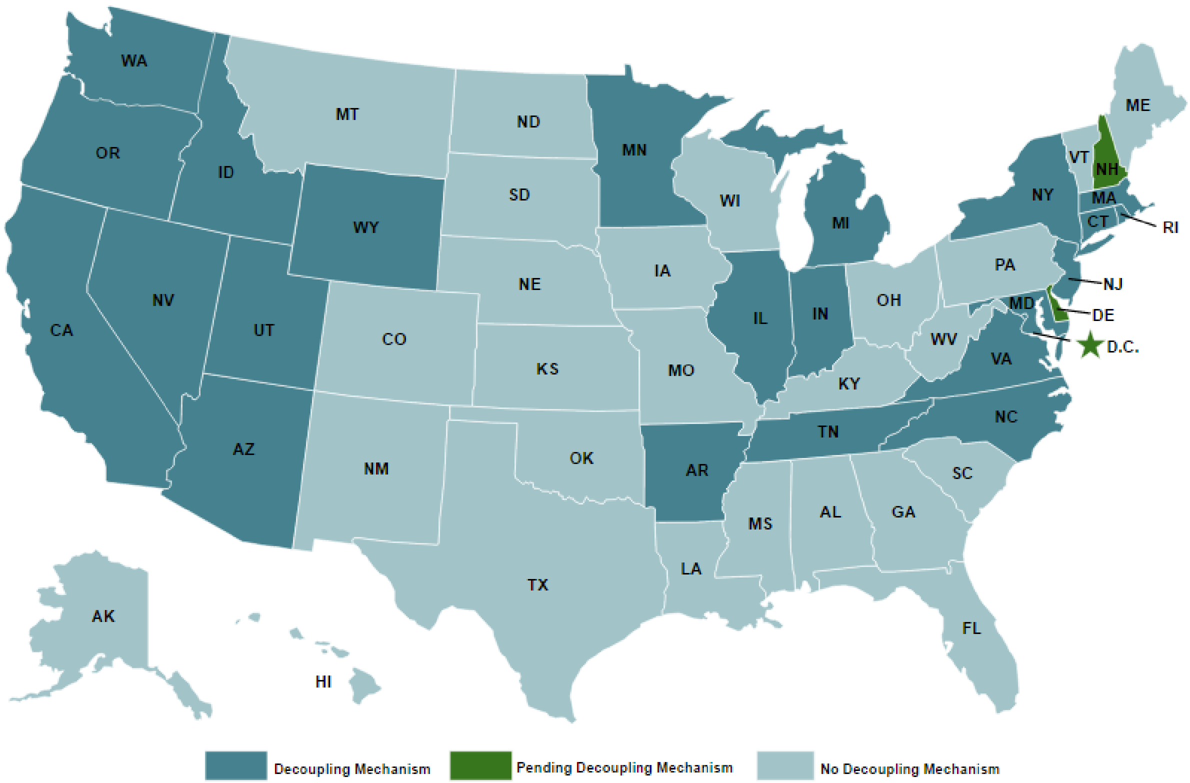
GENERIC RULINGS OR LEGISLATION – 3 States

1. Iowa – All utilities may apply
2. Nebraska – All utilities may apply
3. West Virginia – All utilities may apply

States with Non-Volumetric Rate Designs



Current Status of Decoupling Mechanisms



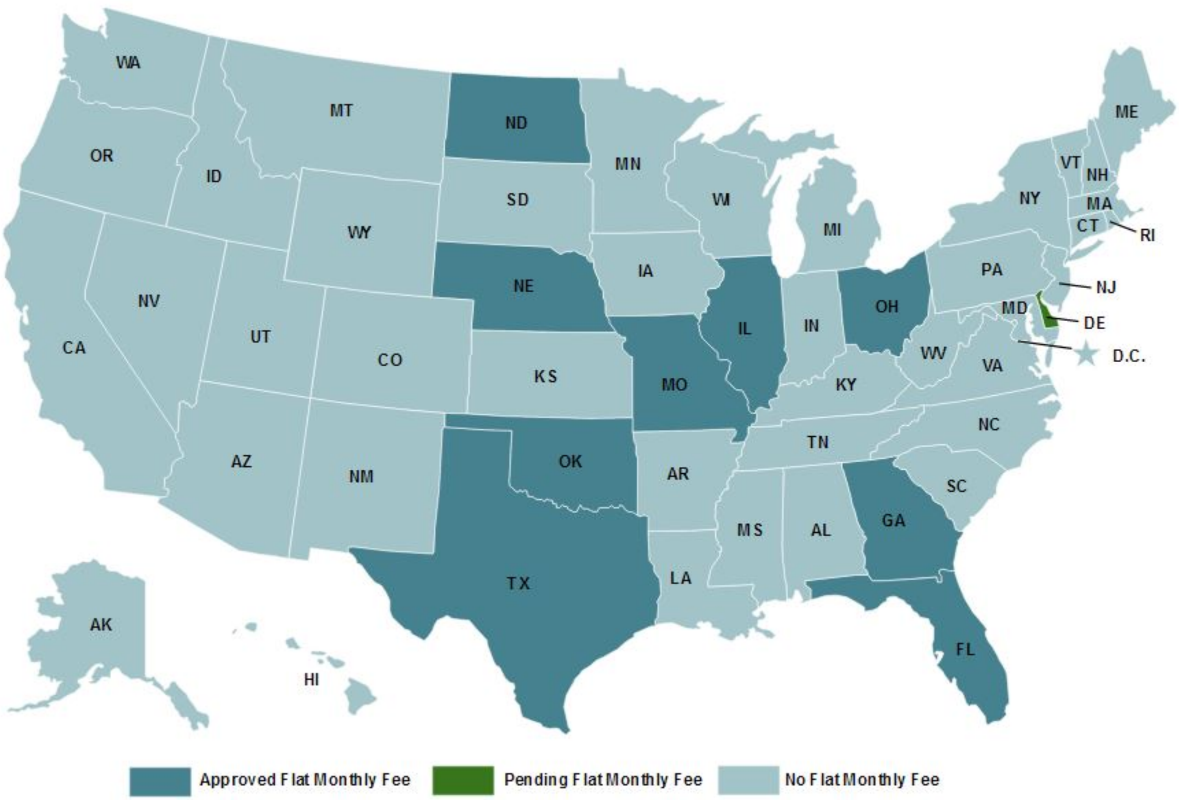
Utilities with Approved Decoupling Mechanisms

1. AR – Arkansas Oklahoma Gas
2. AR – SourceGas
3. AR – CenterPoint Energy
4. AZ – Southwest Gas
5. AZ – UNS Gas
6. CA – Pacific Gas and Electric
7. CA – San Diego Gas and Electric
8. CA – Southern California Gas
9. CA – Southwest Gas
10. CT – Connecticut Natural Gas
11. GA – Liberty Utilities
12. ID – Avista
13. IL – Ameren Illinois
14. IL – Peoples Gas
15. IL – North Shore Gas
16. IN- Citizens Energy Group
17. IN – Vectren North Indiana Gas
18. IN – Vectren South SIGECO
19. MA – Columbia Gas of Massachusetts
20. MA – Fitchburg Gas and Electric
21. MA – National Grid Massachusetts
22. MA – Eversource Energy
23. MA – Liberty Utilities
24. MD – Baltimore Gas and Electric
25. MD – Columbia Gas of Maryland
26. MD – Washington Gas
27. MI—Consumers Energy
28. MI – DTE
29. MN – CenterPoint Energy
30. MN – Minnesota Energy Resources
31. NC – Piedmont Natural Gas
32. NC – Public Service Company of North Carolina
33. NJ – New Jersey Natural Gas
34. NJ – South Jersey Gas
35. NV – Southwest Gas
36. NY – Corning Natural Gas
37. NY – National Grid NYC
38. NY – National Grid Long Island
39. NY – National Grid Niagara Mohawk
40. NY – National Fuel Distribution
41. NY – New York State Electric and Gas
42. NY – Orange and Rockland
43. NY – Rochester Gas and Electric
44. NY – Central Hudson Gas and Electric
45. OR – Avista Corp.
46. OR – Cascade Natural Gas
47. OR – Northwest Natural Gas
48. RI – National Grid Narragansett
49. TN – Chattanooga Gas
50. UT – Questar Gas
51. VA – Columbia Gas of Virginia
52. VA – Virginia Natural Gas
53. VA – Washington Gas
54. WA – Avista Corp.
55. WA – Cascade Natural Gas
56. WA – Puget Sound Energy
57. WY – SourceGas
58. WY – Questar Gas

Pending Mechanisms

1. DC – Washington Gas
2. DE – Delmarva Power and Light
3. ID – Intermountain Gas
4. MI – Consumers Energy
5. NH – Passed Legislation
6. VA – Washington Gas

Current Status of Flat Monthly Fee Rate Designs (SFV)



Utilities with Flat Monthly Fee Rate Designs (SFV)

Approved SFV

1. GA – Atlanta Gas Light – Individually determined monthly demand charge
2. MO – Missouri Gas Energy – Flat monthly fee
3. ND – Montana-Dakota Utilities
4. ND – Xcel Energy – Flat monthly fee
5. OH – Columbia Gas of Ohio – Flat monthly fee
6. OH – Dominion East Ohio – Flat monthly fee
7. OH – Duke Energy – Flat monthly fee
8. OH – Vectren Ohio – Flat monthly fee

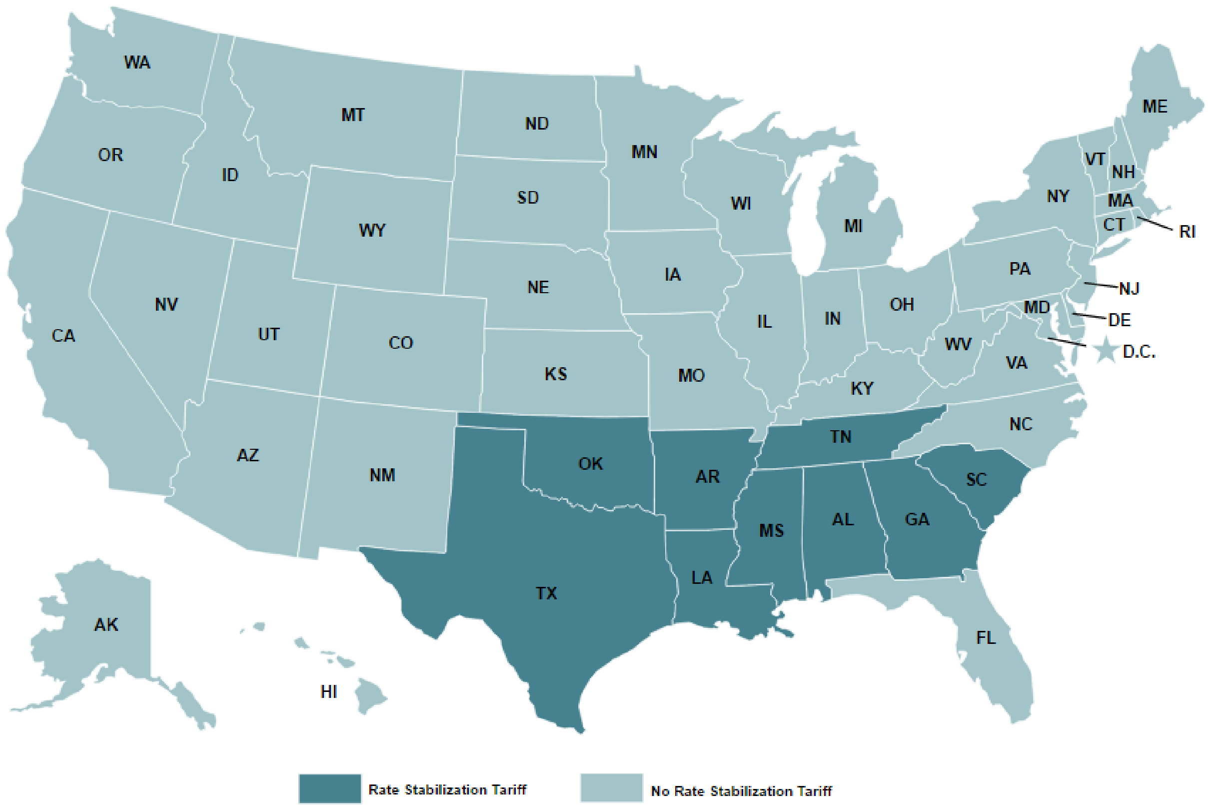
Similar to SFV

1. FL – TECO Peoples Gas – Three-tier monthly charge plus a small variable charge
2. IL - Ameren Illinois – 80% revenue for Residential and Small GS Customers per flat fee plus small variable charge
3. IL – Nicor Gas – Flat fee plus a small variable charge
4. MO – Ameren – Modified rate blocks for Residential Service customers
5. MO – Liberty Utilities – Flat fee plus a small variable charge
6. MO – Laclede Gas – Modified rate blocks
7. NE – Black Hills – Declining rate blocks
8. NE – SourceGas – Modified rate blocks
9. OK – Oklahoma Natural Gas – Two-tier plan – Offers customers a choice
10. TX – Texas Gas Service – Flat fee up to 200 ccf/month

Pending

1. DE – Delmarva Power and Light

Current Status of Rate Stabilization Tariffs



Current Status of Rate Stabilization Tariffs

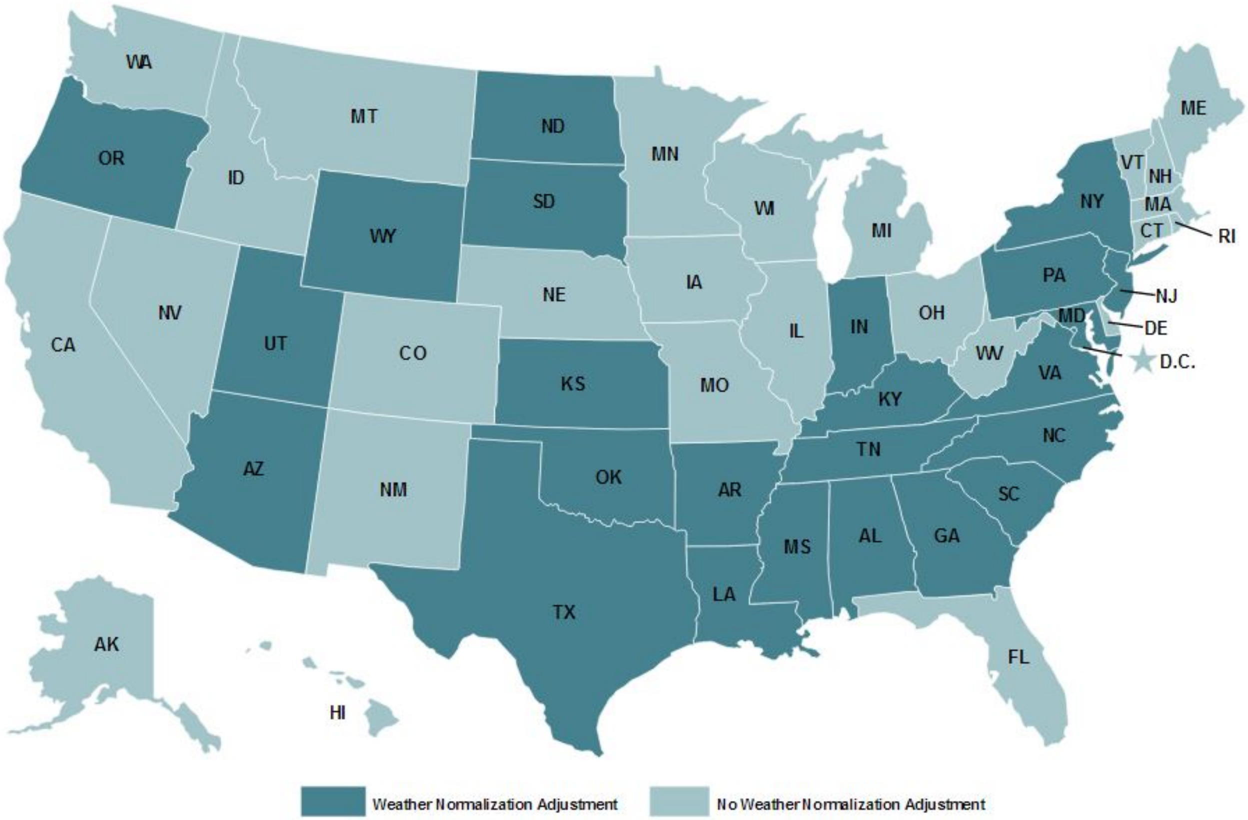
Approved

1. AL – Alabama Gas
2. AL – Mobile Gas
3. AR – CenterPoint Energy
4. GA – Liberty Utilities
5. LA – Atmos Energy
6. LA – CenterPoint Energy
7. LA – Entergy
8. MS – Atmos Energy
9. MS – CenterPoint Energy
10. OK – CenterPoint Energy
11. OK – Oklahoma Natural Gas
12. SC – Piedmont Natural Gas
13. SC – South Carolina Electric and Gas
14. TN – Atmos Energy
15. TX – Atmos Energy

Authorized by Legislation

1. Arkansas

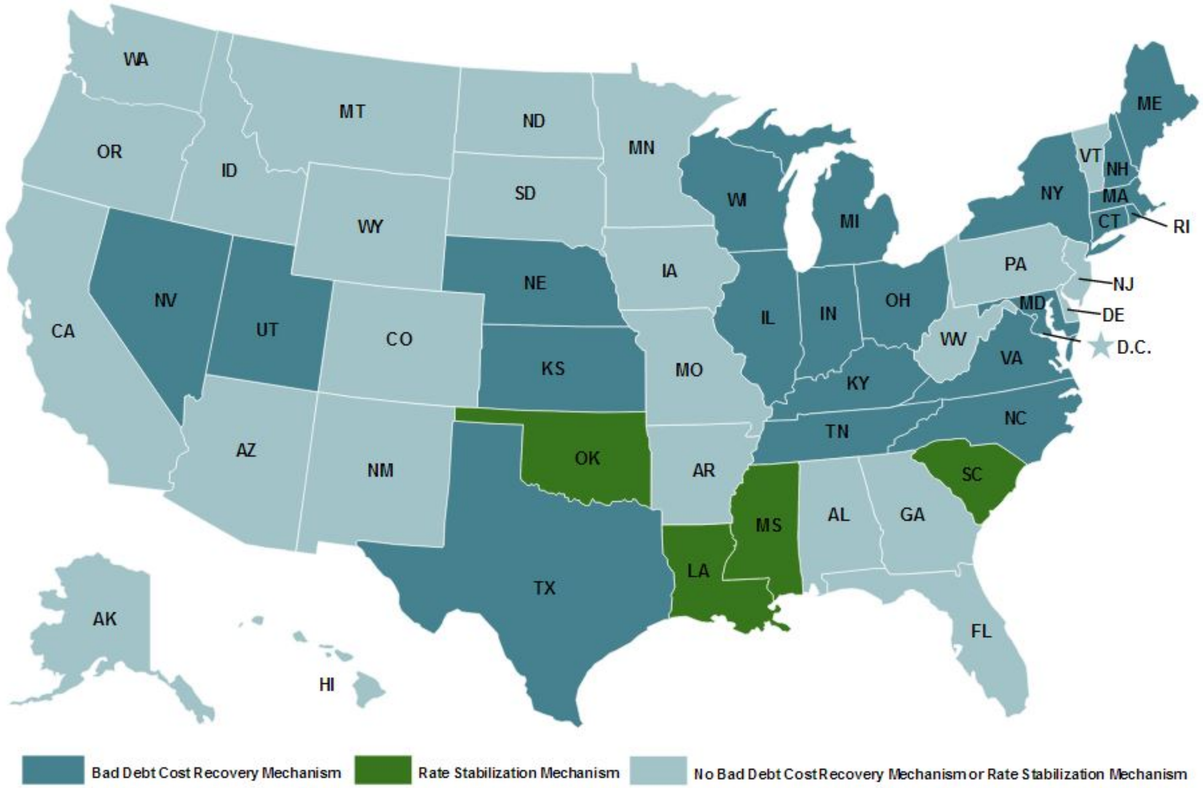
Current Status of Weather Normalization Adjustments



Utilities with Approved Weather Normalization Adjustments

1. AZ – Southwest Gas
2. AL – Alabama Gas
3. AL – Mobile Gas
4. AR – SourceGas
5. AR – CenterPoint Energy
6. GA – Liberty Utilities
7. IN – Citizens Energy Group
8. IN – Vectren North Indiana Gas
9. IN – Vectren South SIGECO
10. KS – Atmos Energy
11. KS – Black Hills
12. KS – Kansas Gas Service
13. KY – Atmos Energy
14. KY – Columbia Gas of Kentucky
15. KY – Delta Natural Gas
16. KY – Louisville Gas and Electric
17. LA – Atmos – Louisiana Gas Service
18. LA – Atmos – Trans Louisiana
19. LA – CenterPoint Energy
20. MD – Chesapeake Utilities
21. MD – Columbia Gas of Maryland
22. MS – Atmos Energy
23. MS – CenterPoint Energy
24. ND – Montana-Dakota Utilities
25. NJ – Elizabethtown Gas
26. NJ – New Jersey Natural Gas
27. NJ – Public Service Electric and Gas
28. NY – Central Hudson Gas and Electric
29. NY – Consolidated Edison
30. NY – National Fuel Gas Distribution
31. NY – National Grid Long Island
32. NY – National Grid Niagara Mohawk
33. NY – National Grid NYC
34. NY – New York State Electric and Gas
35. NY – Orange and Rockland Utilities
36. NY – Rochester Gas and Electric
37. OK – CenterPoint Energy
38. OK – Oklahoma Natural Gas
39. OR – Northwest Natural Gas
40. PA – Columbia Gas of Pennsylvania
41. PA – Philadelphia Gas Works
42. SC – Piedmont Natural Gas
43. SC – South Carolina Electric and Gas
44. SD – Montana-Dakota Utilities
45. TN – Atmos Energy
46. TN – Chattanooga Gas
47. TN – Piedmont Natural Gas
48. TX – Atmos Energy
49. TX – Texas Gas Service
50. UT – Questar Gas
51. VA – Atmos Energy
52. VA – City of Richmond Dept. of Public Utilities
53. VA – Columbia Gas of Virginia
54. VA – Roanoke Natural Gas
55. VA – Southwestern Virginia Natural Gas
56. VA – Virginia Natural Gas
57. VA – Washington Gas

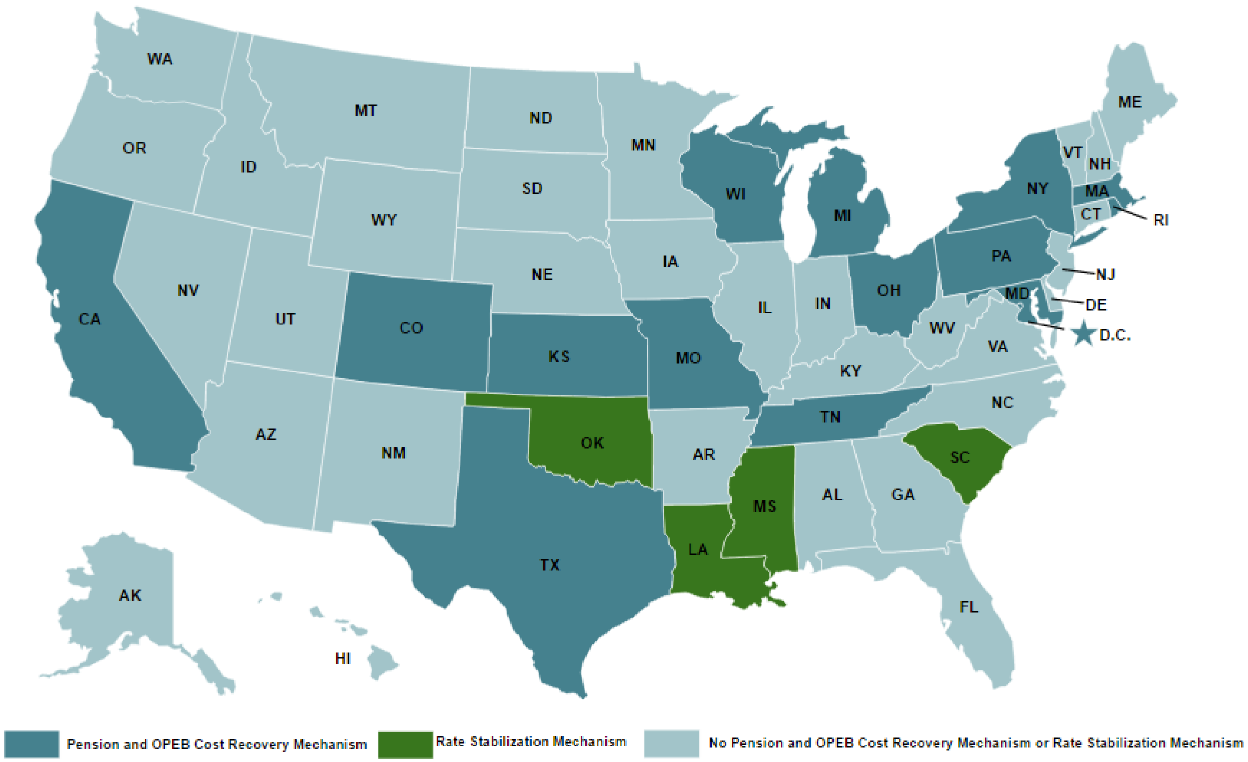
Current Status of Bad Debt Cost Recovery



Utilities with Bad Debt Cost Recovery

1. CT – Connecticut Natural Gas
2. CT – Southern Connecticut Natural Gas
3. CT – Yankee Gas
4. DC – Washington Gas
5. IL – Ameren Illinois
6. IL – Peoples Gas
7. IL – North Shore Gas
8. IL – Nicor Gas
9. IN – Citizens Energy Group
10. IN - NIPSCO
11. IN – Vectren North Indiana Gas
12. IN – Vectren South SIGECO
13. KS – Atmos Energy
14. KS – Black Hills
15. KS – Kansas Gas Service
16. KY – Atmos Energy
17. KY – Columbia Gas of Kentucky
18. KY – Delta Natural Gas
19. KY – Duke Energy
20. LA – CenterPoint Energy
21. MA – Columbia Gas of Massachusetts
22. MA – National Grid
23. MA – NSTAR Gas
24. MD – Baltimore Gas and Electric
25. MD – Washington Gas
26. ME – Northern Utilities
27. MI – DTE
28. MI – Michigan Gas Utilities
29. MS – CenterPoint Energy
30. NC – Piedmont Natural Gas
31. NE – Black Hills
32. NE – SourceGas
33. NH – Liberty Utilities
34. NH – Northern Utilities
35. NV – Southwest Gas
36. NY – Central Hudson Gas and Electric
37. NY – Consolidated Edison
38. NY – National Fuel Gas Distribution
39. NY – National Grid Long Island
40. NY – National Grid Niagara Mohawk
41. NY – National Grid NYC
42. NY – New York State Electric and Gas
43. NY – Orange and Rockland Utilities
44. OH – Columbia Gas of Ohio
45. OH – Dominion East Ohio
46. OH – Eastern Natural Gas
47. OH – Pike Natural Gas
48. OH – Vectren Energy Delivery of Ohio
49. OK – CenterPoint Energy
50. OK – Oklahoma Natural Gas
51. RI – National Grid
52. SC – Piedmont Natural Gas
53. SC – South Carolina Electric and Gas
54. TN – Atmos Energy
55. TN – Chattanooga Gas
56. TN – Piedmont Natural Gas
57. TX – Atmos Energy
58. TX – Texas Gas Service
59. UT – Questar Gas
60. VA – Washington Gas
61. VA – Atmos Energy
62. VA – Columbia Gas of Virginia
63. VA – Virginia Natural Gas
64. WI – Wisconsin Gas

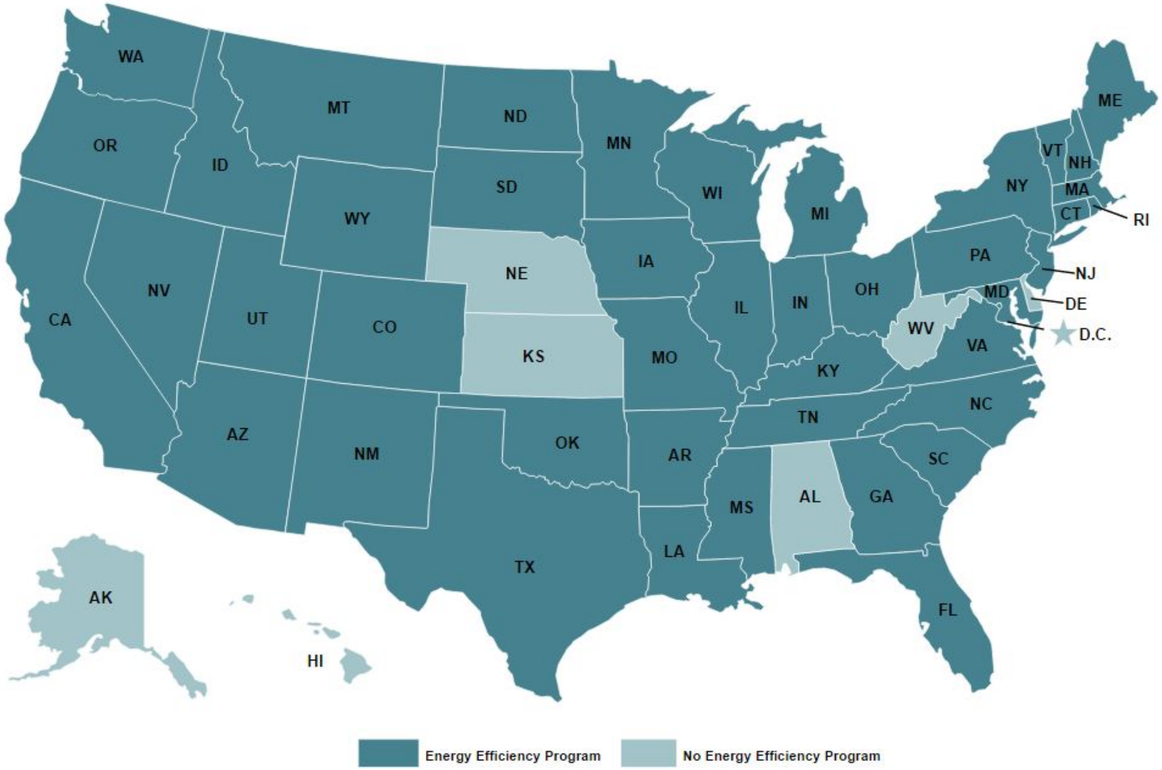
Current Status of Pension and OPEB Cost Recovery



Utilities with Pension and OPEB Cost Recovery

1. CA – San Diego Gas and Electric
2. CA – Southern California Gas
3. CO – Public Service Company of CO (Xcel)
4. DC – Washington Gas
5. KS – Atmos Energy
6. KS- Black Hills
7. KS – Kansas Gas Service
8. LA – Atmos Energy
9. LA – CenterPoint Energy
10. MA – Columbia Gas of Massachusetts
11. MA – Fitchburg Gas and Electric Light Co.
12. MA – National Grid
13. MA – NSTAR Gas Co.
14. MD – Baltimore Gas and Electric Co.
15. MI – DTE
16. MO – Ameren Missouri
17. MO – Laclede Gas
18. MO – Missouri Gas Energy
19. MS – Atmos Energy
20. MS – CenterPoint Energy
21. NY – Central Hudson Gas and Electric
22. NY – Consolidated Edison
23. NY – Orange and Rockland Utilities
24. NY – National Grid NYC
25. OH – Columbia Gas of Ohio
26. OK – CenterPoint Energy
27. OK – Oklahoma Natural Gas
28. PA – Philadelphia Gas Works
29. RI – National Grid
30. SC –Piedmont Natural Gas
31. SC – South Carolina Electric and Gas
32. TN – Piedmont Natural Gas
33. TX – Atmos Energy
34. TX – CenterPoint Energy
35. WI – Wisconsin Power and Light

Current Status of Natural Gas Energy Efficiency Programs



Utilities with Natural Gas Energy Efficiency Programs

1. AR – Arkansas Oklahoma Gas
2. AR – SourceGas
3. AR – CenterPoint Energy
4. AZ – Southwest Gas
5. CA – Pacific Gas and Electric
6. CA – San Diego Gas and Electric
7. CA – Southern California Gas
8. CA – Southwest Gas
9. CO – Atmos Energy
10. CO – Black Hills Energy
11. CO – Colorado Natural Gas
12. CO – SourceGas
13. CO – Public Service Co. of Colorado
14. CT – Connecticut Natural Gas
15. CT – Southern Connecticut Natural Gas
16. CT – Yankee Gas Service
17. FL – TECO Peoples Gas
18. GA – Atlanta Gas Light
19. IA – Liberty Utilities
20. IA – Black Hills Energy
21. IA – Interstate Power and Light
22. IA – MidAmerican Energy
23. IN – Citizens Energy Group
24. IN – NIPSCO
25. IN – Vectren North Indiana Gas
26. IN – Vectren South SIGECO
27. ID – Avista Utilities
28. ID – Intermountain Gas
29. IL – Ameren Illinois
30. IL – MidAmerican Energy
31. IL – Nicor Gas
32. IL – North Shore Gas
33. IL – Peoples Gas
34. KY – Atmos Energy
35. KY – Columbia Gas of Kentucky
36. KY – Delta Natural Gas
37. KY – Duke Energy Kentucky
38. KY – Louisville Gas and Electric
39. LA – Atmos Energy
40. LA – CenterPoint Energy
41. MA – Columbia Gas of Massachusetts
42. MA – Berkshire Gas
43. MA – Fitchburg Gas and Electric Light
44. MA – Liberty Utilities
45. MA – National Grid Massachusetts
46. MA – NSTAR Gas and Electric
47. MD – Baltimore Gas and Electric
48. MD – Columbia Gas of Maryland
49. MD – Washington Gas
50. ME – Northern Utilities
51. MI – Consumers Energy
52. MI – DTE
53. MI – Michigan Gas Utilities
54. MN – CenterPoint Energy
55. MN – Great Plains Natural Gas
56. MN – Interstate Power and Light
57. MN – Minnesota Energy Resources
58. MN – Xcel Energy
59. MO – Ameren
60. MO – Liberty Utilities
61. MO – Empire Natural Gas
62. MO – Laclede Gas
63. MO – Missouri Gas Energy
64. MS – Atmos Energy
65. MS – CenterPoint Energy
66. MT – Montana-Dakota Utilities
67. NC – Piedmont Natural Gas
68. NC – Public Service Co. of NC
69. ND – Montana-Dakota Utilities
70. NH – Liberty Utilities
71. NH – Northern Utilities
72. NJ – Elizabethtown Gas
73. NJ – New Jersey Natural Gas
74. NJ – Public Service Electric and Gas
75. NJ – South Jersey Gas
76. NM – New Mexico Gas
77. NV – NV Energy
78. NV – Southwest Gas
79. NY – Central Hudson Gas and Electric
80. NY – Consolidated Edison
81. NY – National Fuel Gas
82. NY – National Grid NY
83. NY – National Grid Long Island
84. NY – National Grid Niagara Mohawk
85. NY – Orange and Rockland Utilities
86. NY – St. Lawrence Gas
87. OH – Columbia Gas of Ohio
88. OH – Dominion East Ohio
89. OH – Duke Energy
90. OH – Vectren Energy Delivery of Ohio

Utilities with Natural Gas Energy Efficiency Programs (Cont.)

91. OK – CenterPoint Energy
92. OK – Oklahoma Natural Gas
93. OR – Avista Utilities
94. OR – Cascade Natural Gas
95. OR – Northwest Natural Gas
96. PA – Columbia Gas of Pennsylvania
97. PA – Equitable Gas
98. PA – PECO
99. PA – Peoples Natural Gas
100. PA – Philadelphia Gas Works
101. PA – UGI Central Penn Gas
102. PA – UGI Penn Natural Gas
103. PA – UGI Utilities
104. RI – National Grid
105. SC – Piedmont Natural Gas
106. SC – South Carolina Electric and Gas
107. SD – MidAmerican Energy
108. SD – Montana-Dakota Utilities
109. TN – Chattanooga Gas
110. TX – Atmos Energy
111. TX – Texas Gas Service
112. UT – Questar Gas
111. VA – Columbia Gas of Virginia
112. VA – Virginia Natural Gas
113. VA – Washington Gas
114. VT – Vermont Gas Systems
115. WA – Avista Utilities
116. WA – Cascade Natural Gas
117. WA – Northwest Natural Gas
118. WA – Puget Sound Energy
119. WI – City Gas
120. WI – Madison Gas And Electric
121. WI – Midwest Natural Gas
122. WI – St. Croix Valley Natural Gas
123. WI – Superior Water, Light and Power
124. WI – We Energies
125. WI – Wisconsin Light and Power
126. WI – Wisconsin Public Service
127. WI – Xcel Energy
128. WY – Montana-Dakota Utilities
129. WY – Questar Gas

PUC 3-8

Request:

Of the eighteen companies listed in Schedule RBH-10 that have an infrastructure or capital investment mechanism, please explain how that adjustment clause operates, and specifically, identifying how many allow the utility to receive a return on the forecasted plant in service rather than a return after it is demonstrated the asset has been put in service. Which of these has a mechanism that allows the utility to adjust plant in service for purposes of earning an immediate return in between base rate cases?

Response:

Please see the Company's response to PUC 3-7. Mr. Hevert's expectation is that mechanisms designed to allow for recovery of capital project additions would provide for the timely recovery of the revenue requirement associated with the category of capital projects included in the mechanism, including a return on the investment, as well as depreciation and property-tax expense. The question regarding whether the mechanism operates to recover the revenue requirement associated with forecasted plant in service rather than actual plant in service is not determinable without a very thorough, detailed review of each jurisdictional mechanism.

Mr. Hevert is aware that, in Massachusetts, capital cost recovery mechanisms are in place for both gas and electric companies. For gas companies, investment associated with the replacement of leak-prone mains and services is allowed through the Gas System Enhancement Program on a forecast basis. Conversely, for electric companies, recovery for capital investment is allowed after the plant is placed in service.

PUC 3-9

Request:

What percent of the Company's distribution revenues is subject to a tracker mechanism, including, but not limited to, Infrastructure, Safety, and Reliability, pensions, and property tax?

Response:

Please see Attachment PUC 3-9, which contains information for Narragansett Electric on page 1 and Narragansett Gas on page 2.

Prepared by or under the supervision of: Robert Hevert, Scott M. McCabe, and Ann E. Leary

The Narragansett Electric Company
Electric Revenue

Section 1: Calculations

	PUC 3-9		
(1)	Total Distribution Revenue	Section 2, Ln (10)	$302,140,301
(2)	Revenue in Line (1) Under a Reconciling Mechanism	Sum Section 2, Lns (3) thru (7)	$44,716,291
(3)	% of Distribution Revenue Under a Reconciling Mechanism	Section 1, Ln (2) ÷ Section 1, Ln (1)	15%
	PUC 3-10		
(4)	Total Distribution and Renewable Distribution Revenue	Section 2, Ln (10) + Section 2, Ln (14)	$342,148,159
(5)	Revenue in Line (4) Under a Reconciling Mechanism	Section 1, Ln (2) + Section 2, Ln (14)	$84,724,149
(6)	% of Total Distribution and Renewable Distribution Revenue Under a Reconciling Mechanism	Section 1, Ln (5) ÷ Section 1, Ln (4)	25%
	PUC 3-11		
(7)	Total Revenue	Section 2, Ln (22)	$906,848,280
(8)	Revenue in Line (7) Under a Reconciling Mechanism	Ln (5) + Section 2, Ln (18) + Section 2, Ln (20)	$614,634,724
(9)	Tracker % of Total Billings	Section 1, Ln (8) ÷ Section 1, Ln (7)	68%

Section 2: Categorization of Revenue

		Reference to Schedule MAL-2-ELEC (a)		Test Year Ended June 30, 2017 (b)
	Distribution Revenue			
(1)	Customer	Col (a), Ln 2		$56,691,544
(2)	Distribution	Col (a), Ln 3		$181,979,904
(3)	Revenue Decoupling Mechanism Adjustment	Col (a), Ln 4		$2,933,071
(4)	Infrastructure, Safety and Reliability Capital	Col (a), Ln 7		$18,366,740
(5)	Infrastructure, Safety and Reliability O&M	Col (a), Ln 26		$8,360,493
(6)	Pension Adjustment Factor	Col (a), Ln 31		$4,724,675
(7)	Standard Offer Service Admininstrive Cost Factor	Col (a), Ln 25		$10,331,312
(8)	Storm Fund Replenishment Factor	Col (a), Ln 32		$0
(9)	Other Distribution Revenue	Col (a), Sum Lns 14 thru 21		$18,752,562
(10)	**Total Distribution Revenue**		Sum, Section 2, Lns (1) thru (9)	$302,140,301
	Renewable Distribution Revenue			
(11)	Net Metering Surcharge	Col (a), Ln 35		$3,283,480
(12)	Long Term Contracting Renewable Energy Recovery	Col (a), Ln 34		$34,690,580
(13)	RE Growth	Col (a), Ln 33		$2,033,798
(14)	**Total Renewable Distribution Revenue**		Sum, Section 2, Lns (11) thru (13)	$40,007,858
	Other Delivery Revenue			
(15)	CTC (Transition)	Col (a), Ln 28		$978,140
(16)	Transmission	Col (a), Ln 27		$181,281,258
(17)	Energy Efficiency	Col (a), Ln 30		$78,518,199
(18)	**Total Other Delivery Revenue**		Sum, Section 2, Lns (15) thru (17)	$260,777,597
(19)	**Total Delivery Revenue**		Section 2, Lns (10) + (14) + (18)	$602,925,756
	Commodity Revenue			
(20)	Commodity	Col (a), Ln 29		$269,132,978
(21)	GET	Col (a), Ln 28		$34,789,546
(22)	**Total Revenue**		Section 2, Lns (19) + (20) + (21)	$906,848,280

The Narragansett Electric Company
Gas Revenue

Section 1: Calculations

	PUC 3-9		
(1)	Total Distribution Revenue	Section 2, Ln (12)	$203,559,174
(2)	Revenue in Line (1) Under a Reconciling Mechanism	Section 2, Ln (11)	$31,264,074
(3)	% of Distribution Revenue Under a Reconciling Mechanism	Section 1, Ln (2) ÷ Section 1, Ln (1)	15%
	PUC 3-11		
(4)	Total Revenue	Section 2, Ln (21)	$377,158,225
	Revenue in Line (4) Under a Reconciling Mechanism		
(5)	Total DAC Revenue	Section 2, Ln (11)	$31,264,074
(6)	Energy Efficiency (EE) Revenue	Section 2, Ln (13)	$27,861,870
(7)	Total Commodity Revenue	Section 2, Ln (17)	$124,409,502
(8)	Sub-Total Reconciling Mechanism	Sum, Section 1, Lns (5) thru (7)	$183,535,446
(9)	% of Total Revenue Under a Reconciling Mechanism	Section 1, Ln (8) ÷ Section 1, Ln (4)	49%

Section 2: Categorization of Revenue

		Reference to Schedule MAL-2-GAS (a)		Test Year Ended June 30, 2017 (b)
	Distribution Revenue			
	Base Distribution Rate Revenue			
(1)	Firm Base Tariff Revenue	Col (a), Ln 1 + Ln 5		$170,464,302
(2)	Other Service Revenue	Col (a), Ln 6 + Ln 14		$247,144
(3)	Non Firm Revenue	Ln 16, Col (a) + Col (b)		$1,388,117
(4)	Sub-Total		Sum, Section 2, Lns (1) thru (3)	$172,099,564
(5)	Miscellaneous Other Revenue	Col (a), Ln 28, 30, 32		$195,536
	Distribution Adjustment Charge (DAC) Revenues			
(6)	ISR Revenue		Company Data	$34,584,672
(7)	Pension Revenues		Company Data	($2,330,171)
(8)	Revenue Decoupling Adjustment (RDA) Revenues		Company Data	($3,650,570)
(9)	Uncollectible Revenues		Company Data	$1,094,109
(10)	Other DAC Revenues		Company Data	$1,566,034
(11)	Total DAC Revenue	Col (a), Ln 10	Sum, Section 2, Lns (6) thru (10)	$31,264,074
(12)	**Total Distribution Revenue**		Section 2, Lns (4) + (5) + (11)	$203,559,174
(13)	Energy Efficiency (EE) Revenue	Col (a), Ln 11		$27,861,870
(14)	**Total Delivery Revenue**		Section 2, Lns (12) + (13)	$231,421,044
	Commodity Revenue			
(15)	Gas Cost Recovery (GCR) Revenue	Col (a), Ln 9		$123,331,582
(16)	Non Firm Gas Cost Revenue	Col (b), -Ln 16		$1,077,919
(17)	**Total Commodity Revenue**		Section 2, Lns (15) + (16)	$124,409,502
(18)	Total Billed Revenue		Section 2, Lns (14) + (17)	$355,830,546
	Other			
(19)	Gross Earnings Tax	Col (a), Ln 39		$10,722,138
(20)	Accounting Accruals and Adjustments		Section 2, Lns (21) - (18) - (19)	$10,605,542
(21)	Total Revenue	Col (a), Ln 58	Section 2, Lns (16) - (18)	$377,158,225

PUC 3-10

Request:

What percentage of the Company's distribution and renewable distribution charge revenues are subject to tracker mechanisms, including the above and, Long Term Contracting for Renewable Energy Recovery Factor & Reconciliation, Net Metering Reconciliation, and Renewable Energy Growth Program related charges?

Response:

Please see Attachment PUC 3-9 provided in the Company's response to PUC 3-9.

Prepared by or under the supervision of: Robert Hevert, Scott M. McCabe, and Ann E. Leary

PUC 3-11

Request:

What percentage of the Company's overall revenues are subject to tracker mechanism, including all mechanisms in 3-7 and 3-8 plus transmission, standard offer service, and the renewable energy standard?

Response:

Please see Attachment PUC 3-9 provided in the Company's response to PUC 3-9.

Prepared by or under the supervision of: Robert Hevert, Scott M. McCabe, and Ann E. Leary

PUC 3-12

Request:

What percentage of the Company's overall distribution revenues were funded through the Infrastructure, Safety, and Reliability Plan in each of the last five years?

Response:

Please see Attachment PUC 3-12, which contains information for electric on page 1 and gas on page 2.

Prepared by or under the supervision of: Robert Hevert, Scott M. McCabe, and Ann E. Leary

The Narragansett Electric Company
Electric ISR Revenue

		Calendar Year				Test Year Ended
		2013	2014	2015	2016	June 30, 2017
		(a)	(b)	(c)	(d)	(e)
	PUC 3-12					
(1)	Total Distribution Revenue	$266,857,875	$281,361,246	$278,473,143	$283,406,899	$302,140,301
(2)	ISR Revenue	$12,150,440	$10,975,925	$17,292,173	$27,605,314	$26,727,233
(3)	% of Distribution Revenue Recovered through ISR	4.6%	3.9%	6.2%	9.7%	8.8%
	PUC 3-13					
(4)	Total Revenue	$916,714,127	$1,002,323,174	$1,025,718,009	$908,227,918	$906,848,280
(5)	ISR Revenue	$12,150,440	$10,975,925	$17,292,173	$27,605,314	$26,727,233
(6)	% of Total Revenue Recovered through ISR	1.3%	1.1%	1.7%	3.0%	2.9%

(1) Col (a) thru (d): Company Billing System; Col (e): Attachment PUC 3-9, page 1, Section 1, Line (1)
(2) Company Billing System
(3) Line (2) ÷ Line (1)
(4) Col (a) thru (d): FERC Form 1, Page 115, line 2; Col (e): Attachment PUC 3-9, page 1, Section 1, Line (7)
(5) Line (2)
(6) Line (5) ÷ Line (4)

The Narragansett Electric Company
Gas ISR Revenue

		Calendar Year				Test Year Ended
		2013	2014	2015	2016	June 30, 2017
		(a)	(b)	(c)	(d)	(e)
	PUC 3-12					
(1)	Total Distribution Revenue	$176,362,419	$189,015,400	$180,889,296	$180,469,852	$203,559,174
(2)	ISR Revenue	$2,675,880	$2,426,876	$11,268,009	$24,444,435	$34,451,270
(3)	% of Distribution Revenue Recovered through ISR	1.5%	1.3%	6.2%	13.5%	16.9%
	PUC 3-13					
(4)	Total Revenue	$408,298,581	$437,421,301	$414,505,973	$360,886,083	$377,158,225
(5)	ISR Revenue	$2,675,880	$2,426,876	$11,268,009	$24,444,435	$34,451,270
(6)	% of Total Revenue Recovered through ISR	0.7%	0.6%	2.7%	6.8%	9.1%

(1) Col (a) thru (d): Company Billing System; Col (e): Attachment PUC 3-9, page 2, Section 1, Line (1)
(2) Company Billing System
(3) Line (2) ÷ Line (1)
(4) Col (a) thru (d): FERC Form 1, Page 115, line 2; Col (e): Attachment PUC 3-9, page 2, Section 1, Line (4)
(5) Line (2)
(6) Line (5) ÷ Line (4)

PUC 3-13

Request:

For each of the past five years, please provide the percentage of revenues funded through the Infrastructure, Safety, and Reliability Plan.

Response:

Please see Attachment PUC 3-12 provided in the Company's response to PUC 3-12.

Prepared by or under the supervision of: Robert Hevert, Scott M. McCabe, and Ann E. Leary

PUC 3-14

Request:

Referencing Mr. Hevert's testimony on page 15, lines 16-17, he criticizes the discounted cash flow method on the basis that "a fundamental assumption of the Constant Growth DCF model is that current market conditions will continue into the future in perpetuity." How is this criticism relevant to the fact that National Grid has filed for increases to its base distribution rates in 2010, 2013, and now in 2017?

Response:

The Company understands this question to be taking note of the fact that the Constant Growth Discounted Cash Flow (DCF) methodology rests on the fundamental assumption that current market conditions will continue into the future in perpetuity, and to be asserting the proposition that this assumption should not be a concern where the Company is filing for base-rate changes on a relatively short-term cycle, i.e., every three to five years. More specifically, the question appears to ask whether the filing of relatively frequent rate cases would address any biases that might arise from the use of the DCF method, in particular its inherent assumption that current market conditions will remain constant over the long term.

As an initial matter, please note that Mr. Hevert's statements are not a criticism of the Constant Growth DCF model in general. As Mr. Hevert notes on page 8 of his Direct Testimony, the model is widely accepted in regulatory proceedings as one of several methods to assess the Return on Equity (ROE). Rather, as indicated by the question, Mr. Hevert's concern is that the model rests on the fundamental assumption that current market conditions will continue, unchanged, in perpetuity. For various reasons (see also Appendix A to Mr. Hevert's Direct Testimony), recent market conditions are highly unusual and susceptible to substantial change, even in the near-term. Therefore, Mr. Hevert's concern centers around the fact that relying exclusively on a model that assumes constant market conditions is likely to misstate the Company's Cost of Equity, even in the near-term.

In the context of a base-rate proceeding, estimating the Cost of Equity requires, by definition, forward-looking models to assess investors' expectations and return requirements. Recent market conditions are the product of unusual intervention by the Federal Reserve, and those conditions cannot reasonably be assumed to persist in the future when, for example, the Federal Reserve now is actively working to "normalize" monetary policy. Mr. Hevert's recommendation simply is that, given the unique nature of recent capital markets and investors' views that those conditions are likely to change in the near-term, and knowing that the Constant Growth DCF model rests squarely on the proposition that today's market conditions will *not* change, ever, it is necessary for the Public Utilities Commission to supplement its traditional approach to setting the ROE by taking broader factors into account rather than adhering strictly to the mathematical result produced by the traditional DCF model.

The fact that the Company may submit an application for a change in base distribution rates within the next few years is not a reason to dismiss the concern that the DCF approach is likely to understate the Cost of Equity in this case, where market conditions are highly unusual and susceptible to substantial change. Rather, the concern regarding model's underlying assumptions, and the incompatibility of those assumptions with current market conditions is fundamentally relevant to this case. For example, as discussed in the Company's response to PUC 3-15, under today's market conditions, some analysts may conclude that the output of the Constant Growth DCF model indicates that relatively high utility stock prices are caused by relatively lower levels of perceived risk among utility investors, thereby driving a lower required ROE. As noted in Appendix A to Mr. Hevert's Direct Testimony, market-based data indicates we cannot conclude that recent utility valuations are due to a fundamental change in investors' risk perceptions. Rather, recent utility valuation levels likely have been the result of a "reach for yield" that sometimes occurs during periods of low Treasury yields. Historically, in periods during which utility valuation ratios were "stretched" relative to historical levels because of investors' reach for yield, those valuations subsequently moved back toward their long-term average. That is, they did not remain constant as the Constant Growth DCF model requires.

Lastly, it is telling that recently authorized ROEs for electric utilities are well above the Constant Growth DCF model results (as noted on page 36 of Mr. Hevert's Direct Testimony, of 1,522 cases since 1980, only five included an authorized ROE below 9.00 percent). That difference strongly suggests other regulatory commissions recognize that no one model is most reliable under all circumstances, and that the ability to maintain the credit profile needed for capital-intensive utilities to attract capital at reasonable cost rates depends on reasonable regulatory outcomes. A return set solely on the basis of the Constant Growth DCF method would fall far from those available to other utilities, and would significantly diminish the Company's ability to compete for the capital needed to provide safe and reliable utility service.

In summary, the Public Utilities Commission should be seeking to set base rates that appropriately recover the Company's cost of providing safe and reliable service to customers, including a fair and reasonable return on capital invested in utility operations. Given the circumstances underlying the current capital market, resting exclusively on the DCF model will not achieve that result.

Prepared by or under the supervision of: Robert B. Hevert

PUC 3-15

Request:

How does the recent uncharacteristic increases in the stock market affect the assumptions and models discussed by Mr. Hevert?

Response:

The recent increases in market valuations have produced lower dividend yields, and therefore lower Constant Growth Discounted Cash Flow (DCF) results. As Mr. Hevert explains in his pre-filed direct testimony, because the cost of equity does not necessarily lend itself to a strict mathematical solution, those results must be interpreted in the context of the model's assumptions and the current market environment.

The Constant Growth DCF model relies on fundamental assumptions that are inconsistent with the current market. When actual market conditions deviate from the model's fundamental assumptions, the model's results become unreliable. As noted on page 13 of Mr. Hevert's direct testimony, under today's market conditions, some analysts may conclude that the output of the Constant Growth DCF model indicates that the relatively high level of utility stock prices in the marketplace is caused by relatively lower levels of perceived risk among utility investors, thereby driving a lower indicated return on equity. However, recent utility valuation levels likely have been the result of a "reach for yield" that sometimes occurs during periods of low Treasury yields. Historically, in periods during which utility valuation ratios were "stretched" relative to historical levels because of investors' "reach for yield," those valuations subsequently moved back toward their long-term average.

Because the Constant Growth DCF model assumes current valuation ratios (for example, price to earnings) will remain constant in perpetuity, the potential for changing ratios calls into question the reliability of the model's results.

Prepared by or under the supervision of: Robert Hevert

PUC 3-16

Request:

How does the fact that The Narragansett Electric Company is part of a larger company that includes a service company, unregulated, and regulated entities impact Mr. Hevert's assessment of The Narragansett Electric Company's risk?

Response:

The fact that The Narragansett Electric Company is part of a larger company that encompasses a service company, as well as unregulated and regulated entities has *no impact* on Mr. Hevert's assessment of The Narragansett Electric Company's risk. The focus of Mr. Hevert's analysis is to estimate the cost of equity for The Narragansett Electric Company, which is an indirect, wholly-owned subsidiary of National Grid. Mr. Hevert has conducted this analysis for the Company on a standalone basis, so that the operations of any other entities within the National Grid corporate organization are not considered in the analysis.

Prepared by or under the supervision of: Robert Hevert

PUC 3-17

Request:

Referencing Mr. Hevert's testimony at page 67, he quotes Standard & Poor's. In light of this quote, how does Mr. Hevert believe the Infrastructure, Safety, and Reliability mechanism is viewed by Standard & Poor's?

Response:

In Mr. Hevert's experience, cost-recovery mechanisms such as the Company's Infrastructure, Safety, and Reliability mechanism are generally viewed as credit supportive by rating agencies, all else remaining equal. These types of mechanisms address incremental capital requirements that would otherwise diminish cash flows and put downward pressure on credit metrics. In that respect, infrastructure mechanisms may be seen as credit supportive, but not necessarily credit enhancing.

Please note that even after the implementation of the Company's mechanisms, Standard and Poor's noted the regulatory environment in Rhode Island as "less credit-supportive" (see, Standard & Poor's, *Narragansett Electric Company*, September 26, 2011, at 2-3).

Although Moody's noted the Rhode Island regulatory environment as "generally supportive," Moody's also noted that it viewed Rhode Island as "tougher than in some other states" (see Moody's Investors Service, *Narragansett Electric Company*, August 9, 2016, at 3).

PUC 3-18

Request:

How many state jurisdictions have adopted the Bond Yield Risk Premium methodology in the last five years?

Response:

In Mr. Hevert's experience, regulatory jurisdictions do not generally "adopt" and strictly adhere to a particular method for setting the Return on Equity (ROE). Rather, regulatory commissions routinely review and consider multiple methods in determining the authorized ROE and apply their judgment in assessing the analytical results. However, Mr. Hevert is aware that the Bond Yield Risk Premium approach is an accepted method in Oklahoma, Missouri, and Vermont. Further, the Bond Yield Risk Premium approach is one of the methods used by Mississippi to calculate the return on equity in Formula Rate Plans (referred to as the "Regression Analysis"). He is also aware that the Risk Premium approach has been presented in prior rate cases by state regulatory commission staff in Arkansas, Virginia, and Texas.

Prepared by or under the supervision of: Robert Hevert

PUC 3-19

Request:

How many state jurisdictions have adopted the ECAPM methodology in the last five years?

Response:

In Mr. Hevert's experience, regulatory jurisdictions do not generally "adopt" and strictly adhere to a particular method for setting the return on equity (ROE). Instead, regulatory commissions routinely review and consider multiple methods in determining the authorized ROE and apply their judgment in assessing the analytical results. However, Mr. Hevert is aware that the ECAPM (sometimes referred to as the "zero-beta" Capital Asset Pricing Model) has been accepted in prior rate cases in Alaska, Mississippi, New York, and the Province of Alberta, Canada. Mr. Hevert is also aware that the ECAPM has been presented in prior rate cases by state regulatory commission staff in Maryland and Nevada, as well as by the Department of Commerce in Minnesota.

Prepared by or under the supervision of: Robert Hevert

PUC 3-20

Request:

How many state jurisdictions have adopted the Multi-Stage DCF – Terminal P/E Method in the last five years?

Response:

In Mr. Hevert's experience, regulatory jurisdictions do not generally "adopt" and strictly adhere to a particular method for setting the Return on Equity (ROE). Instead, regulatory commissions routinely review and consider multiple methods in determining the authorized ROE and apply their judgment in assessing the analytical results. However, Mr. Hevert is aware that the Multi-Stage DCF approach has been accepted in Colorado, Illinois, Missouri, and Oklahoma. The Massachusetts Department of Public Utilities relies on several models to set the ROE range, and has found the Multi-Stage DCF model to be logical and reasonable, and to provide a credible basis, along with other models, for determining the ROE. A form of the Multi-Stage DCF model also has been presented in prior rate cases by state regulatory commission staff in Arizona and Texas. Mr. Hevert also is aware that the Kansas Corporation Commission and the Maryland Public Service Commission staff have presented a two-stage DCF model.

Prepared by or under the supervision of: Robert Hevert

PUC 3-21

Request:

Referencing Mr. Gredder's testimony on page 12, why does Narragansett Electric expect that manufacturing employment will return to its longer-term negative direction?

Response:

The projections for the economic indicators used in the models are summarized on Schedule JFG-3. For manufacturing employment, Schedule JFG-3 shows that, after some positive growth in the years 2013 through 2018, the projections in year 2019 and in subsequent years are negative. This is consistent with the long-term ten-year average growth rate of negative 2.1 percent (-2.1%) annually. These projections come directly from Moody's, a well-known industry-accepted forecasting service for economic data.

Prepared by or under the supervision of: Joseph Gredder

PUC 3-22

Request:

How are residential heating deliveries identified where there is no electric heating rate?

Response:

The Company's customer billing system has indicators that allow for identification of electric heating accounts, which are used to identify electric residential heating deliveries for purposes of developing the forecast.

Prepared by or under the supervision of: Joseph Gredder

PUC 3-23

Request:

Referencing Mr. Gredder's testimony on page 33, lines 21-22, there appears to be an error in the testimony "Narragansett expects that commercial deliveries after distributed energy resources reductions will decline from 3,572.0 GWh in the Test Year to 3,619.5 GWh in the Rate Year." What is the correction?

Response:

This sentence and the ones that follow it should read as follows: "Narragansett expects that commercial deliveries after distributed energy resources reductions will increase from 3,572.0 GWh in the Test Year to 3,619.5 GWh in the Rate Year. Narragansett Electric then expects deliveries to be 3,603.1 GWh for Data Year 1 and 3,610.1 GWh for Data Year 2. These values represent increases of 1.3 percent between the Test Year and Rate Year, 0.9 percent by Data Year 1, and 1.1 percent by Data Year 2. Overall, future flat growth of 0.0 percent per year for the Rate Year and the Data Years is generally consistent with the five- and ten-year historical growth rates of -0.1 percent each".

Future years 2019, 2020, and 2021 are expected to average 0.0 percent growth versus the current year 2018 (based on the years as defined from September to August). The five-year historical growth of -0.1 percent is defined as years 2013 to 2018 and the ten-year historical growth is defined as years 2008 to 2018 for this comparison (see Schedule JFG-17).

Prepared by or under the supervision of: Joseph Gredder

PUC 3-24

Request:

How do heating degree days affect gas non-heating customers?

Response:

Heating degree days can affect usage of natural gas by non-heating customers in either of two ways: physical or behavioral. Non-heating applications of natural gas include water heating.

To the extent that increases in heating degree days imply colder temperatures, and colder temperatures cause the ground to become colder, gas use to heat hot water will be higher when the ground is colder in the heating season than in the non-heating season when the ground is warmer.

Customer use of natural gas for non-heating applications (e.g., water heating or cooking) can also increase during the heating season, as customers spend more time indoors than during the non-heating season. Cooking can also be an indirect method of spaceheating during the heating season.

Prepared by or under the supervision of: Theodore E. Poe, Jr.

PUC 3-25

Request:

Referencing Mr. Isberg's testimony on page 101, please explain why the Home Energy Monitoring demonstration project is being proposed through the rate case and not through energy efficiency?

Response:

The Home Energy Monitoring demonstration project proposed through the rate case represents a distinct initiative from the Residential Home Energy Monitoring pilot included in the Company's proposed Annual Energy Efficiency Plan for 2018 (2018 EE Plan) in Docket No. 4755, targeting a distinct customer demographic and aiming to validate a different hypothesis.

The Residential Home Energy Monitoring Pilot included in the proposed electric budget in the 2018 EE Plan will be targeted towards past participants in energy efficiency programs, with a goal of identifying whether the customer-facing technology being deployed can support the achievement of sustained and/or incremental energy consumption reduction benefits from these customers over time.

The demonstration project proposed through the rate case will be targeted specifically towards income-eligible customers, and will be designed to inform whether the provision of enhanced customer visibility into home energy usage can drive improved bill payment performance, and reduced Company expense in the form of reduced collections activity, arrearages, service terminations, and write-downs.

Prepared by or under the supervision of: John Isberg

PUC 3-26

Request:

Referencing Mr. Isberg's testimony on page 101, please explain why the "high bill likelihood" communications messaging is being proposed through the rate case and not through energy efficiency.

Response:

The "high bill likelihood" communications messaging proposed in the rate case represents a specific application of a broader technology that is currently in use in the implementation of energy efficiency programs, but will be refined and targeted to a subset of the Company's residential customers served through income eligible electric and gas tariffs.

In the context of the Company's proposed Customer Affordability Program, this messaging will be customized for income-eligible customers, and will be deployed with a goal of not only driving reduced energy consumption among alerted customers, but also to support the goal of improved bill payment performance from these customers through providing early notification of elevated likelihood of an increased customer utility bill relative to previous months.

It should also be noted that the "high bill likelihood" communications messaging highlighted in the rate case does not include any incremental cost proposals – the Company currently believes and intends to support this functionality through existing tools and capabilities, at no incremental cost.

Prepared by or under the supervision of: John Isberg

PUC 3-27

Request:

Referencing Mr. Isberg's testimony on page 101, please explain why the personalization tools in the Customer Contact Center are being proposed through the rate case and not through energy efficiency.

Response:

The Customer Contact Center Personalization tools proposed through the rate case are not limited to energy efficiency initiatives, but rather are intended to support a broader set of services and offerings that are above and beyond those outlined in the Annual Energy Efficiency Plan for 2018 for income-eligible customers.

These proposed tools will be designed to aid Customer Service Representatives when explaining the Company's services and offerings as follows:

- Communicate the comprehensive suite of services and offerings available to income-eligible customers, including income-eligible discount rates, budget billing plans, arrearage management, other deferred payment agreement plans for customers in arrearages, and no-cost energy efficiency services and products;

- Encourage customer adoption of all of the existing services and offerings; and

- Convey the benefits of the Company's services and offerings as a way to help low and moderate income customers manage the affordability of energy, and reduce the potential impacts of volatility associated with their monthly energy spend.

Prepared by or under the supervision of: John Isberg

PUC 3-28

Request:

Mr. Isberg has provided one job description for the Consumer Advocates. His testimony, however, references two Consumer Advocates and one Senior Consumer Advocate. What is the difference? What is the salary and benefits level of each separate position? How will the Consumer Advocate costs be allocated between gas and electric?

Response:

Senior Consumer Advocates are anticipated to have a similar set of job responsibilities and functions as Consumer Advocates; however, the Senior Consumer Advocate role would be open to advocates with a more substantial work history, such as a longer history of driving demonstrated benefits for income-eligible customers either in a utility setting or in other social service and advocacy settings. Relative to Consumer Advocates, Senior Consumer Advocates would be expected to handle more complex income-eligible customer situations, manage larger and more complex relationships with external partners (*e.g.*, Community Action Program agencies or other social service organizations) through which the Company would anticipate partnering in the delivery of services to the income-eligible community in Rhode Island. Senior Consumer Advocates will take a more proactive role in identifying and executing on new outreach and engagement strategies and channels for working with income-eligible customers, and are expected to work directly with local assistance agencies to provide coordination and scheduling for Customer Assistance Expos as well as other community agency interactions. In addition to the external facing tasks, Senior Consumer Advocates would also be expected to take a more visible role internally at the Company, in both reporting on progress against Customer Affordability Program goals as well as in advocating for new and different approaches to serving the income eligible community in Rhode Island.

The costs of the Consumer Advocates will be allocated 50/50 between Narragansett Gas and Narragansett Electric. Please see Attachment PUC 3-28 for a breakdown of the salary and benefits level of each separate position.

Prepared by or under the supervision of: John Isberg

Customer Affordability Program Consumer Advocates Labor Budget

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
(1)					Consumer Advocate		Senior Consumer Advocate	
(2)					Base Salary =	$74,639	Base Salary =	$99,327
(3)	Labor Burdens				Overhead	Calculated	Overhead	Calculated
(4)				Average	Rates	Overheads	Rates	Overheads
(5)	National Grid USA Service Company	B0022	401K Match Burden Thrift	6.75%	6.75%	$5,038	6.75%	$6,705
(6)		B0021	Group Insurance	1.00%	1.00%	$746	1.00%	$993
(7)		B0020	Healthcare	15.75%	15.75%	$11,756	15.75%	$15,644
(8)		B0005	Other Post Employment FAS 112 Benefits	0.50%	0	$0	0	$0
(9)		B0003	Other Post Retirement FAS 106 OPEB	4.25%	0	$0	0	$0
(10)		B0010	Payroll Taxes Burden	10.00%	10%	$7,464	10.00%	$9,933
(11)		B0001	Pension Burden	21.00%	0	$0	0	$0
(12)		B0040	Time Not Worked	17.25%	0	$0	0	$0
(13)		B0030	Variable Pay Management Incentive Comp	20.25%	20.25%	$15,114	20.25%	$20,114
(14)		B0031	Variable pay Non Management Gainsharing	3.75%	0	$0	0	$0
(15)		B0050	Workers' Compensation Burden	0.50%	0.5%	$373	0.5%	$497
(16)	National Grid USA Service Company Total			112%	54%	$40,492	54%	$53,885
(17)	Salary					$74,639		$99,327
(18)	Unit Labor and Overhead Costs					$115,131		$153,212

Total for 3 Full-Time Equivalents $383,473

PUC 3-29

Request:

In Mr. Isberg's testimony at page 108, he states that "[l]andlords of facilities servicing income-eligible customers will also be a focus [of the customer outreach and education] because, as property owners and manager, they are often responsible for instituting energy efficiency programs." How does this program differ from income eligible programs in energy efficiency? If energy efficiency is the focus of the outreach to landlords, why is it included in the rate case and not in energy efficiency?

Response:

The specific customer outreach and education campaign referenced in the rate case is not limited to energy efficiency offerings, but rather is intended to educate landlords about the Company's broader suite of services and offerings as a channel to reach their renters. This education and outreach campaign will focus on the Company's offerings that are intended to help income-eligible customers manage the affordability and volatility of their monthly energy spend (i.e., rates and arrearages programs) as well as energy efficiency programs and behavior-specific measures.

The Company believes that there are efficiencies of both scale and scope in promoting multiple offers and programs to customers when these offers support similar themes. In this case, that equates to helping customers to reduce energy usage through energy efficiency measures, which supports both themes of increased affordability for customers as well as reductions in weather-driven volatility in spend.

In the specific example cited in the rate case testimony, the Company believes that landlords can be an effective channel through which to engage income-eligible customers who happen to be renters on both this broader theme of supporting customer affordability as well as around specific energy efficiency measures and programs.

Prepared by or under the supervision of: John Isberg

PUC 3-30

Request:

Please identify the FTE positions funded through the Gas Infrastructure, Safety, and Reliability (Gas ISR) Plan.

Response:

There are 16 FTE positions funded through the Gas Infrastructure, Safety, and Reliability Plan (Gas ISR Factor),and the job title for all 16 of those FTE positions is "Meter Service Technician".

Commencing on September 1, 2018, these 16 positions will be recovered in base distribution rates and will cease being recovered through the Gas ISR Factor.

Prepared by or under the supervision of: Melissa Little

PUC 3-31

Request:

Are the positions currently funded through the Gas ISR Plan being moved into this general rate case for cost recovery purposes and out of the Gas ISR Plan budget for FY 2019 starting in September 2018?

Response:

Yes. The 16 Meter Service Technician positions currently funded through the Gas Infrastructure, Safety, and Reliability (ISR) Plan will cease to be recovered through the Gas ISR factors effective September 1, 2018 and will instead be recovered through base distribution rates effective September 1, 2018.

Prepared by or under the supervision of: Melissa Little

PUC 3-32

Request:

How many positions are currently funded through the Renewable Energy Growth program budget? Will those positions be moved out of the Renewable Energy Growth program budget and associated recovery factor effective September 1, 2018?

Response:

Please see Attachment PUC 3-32 for the positions funded through the Renewable Energy Growth Program budget. This information is the same as that provided on Page 4 of Schedule ASC-2 of the Company's 2017 Renewable Energy Growth Program Factor filing in Docket No. 4707.

These positions will be moved out of the Renewable Energy Growth Program budget and associated recovery factor, and will instead be recovered through base distribution rates effective September 1, 2018. Please note that the current version of the revenue requirement for Narragansett Electric does not include the Renewable Energy Growth Program's test year labor and associated benefits, as the Company inadvertently removed the expense from the cost of service as a normalizing adjustment to Other Benefits on Schedule MAL-30, Page 6, Line 17(c). However, the Company will eliminate this adjustment in the next revision of the cost of service for Narragansett Electric, thereby seeking recovery of the Renewable Energy Growth Program labor and associated benefits through base distribution rates.

Prepared by or under the supervision of: Melissa Little

Renewable Energy Growth Program
Estimated Administrative Costs
for the Program Year Ending March 31, 2018

	Summary of Estimated Annual Administrative Expenses	
(1)	Billing System Modifications - Revenue Requirement of Capitalized Costs	$106,618
(2)	Billing System Modifications - O&M Budget Estimate for Additional Modifications	$120,000
(3)	Incremental Labor Resources (1)	$705,273
(4)	Estimated SolarWise Program Implementation/Support Costs	$92,300
(5)	Training on Solar PV Safety and Common Installation Violations	$4,925
(6)	DG Board Expense	$68,000
(7)	DG Installation Quality QA Studies	$190,000
(8)	Revenue Requirement - Meter Investment	$27,051
(9)	Estimated Remuneration	$131,364
(10)	Total	$1,445,531

(1) Schedule ASC-4A, Page 1, sum of Lines (13) through (24)
(2) Estimated O&M budget for billing system modifications required to implement new Shared Solar/Community Net Metering Project classes
(3) Footnote (1) Below
(4) Budget Estimate
(5) 5 hour training course recommended by OER
(6) Docket 4604, Order No. 22765
(7) Docket 4536-B, Order No. 22180; $125,000 approved budget, less $75,000 already invoiced and paid in 2016 Program Year + $140,000 additional budget request for Round 2 Study provided by OER
(8) Schedule ASC-4B, Pg. 1, Line (5), Column (c)
(9) Page 1, Line (1) x 1.75%
(10) Sum of Lines (1) through (9)

		Accounts Processing	Customer Solutions	Customer Solutions	DG Customer Facilitator	Interconnection Consultant	FCM Administration	Energy Procurement	Total
	(1) Detail of Incremental Labor Resources	1	1	2	1	1	1	1	8
(1)	Full Time Employees	$31,699	$71,000	$71,000	$115,000	$85,000	$80,000	$103,646	
(2)	Average Salary	100.00%	50.00%	100.00%	60.00%	50.00%	14.06%	80.00%	
(3)	Percent Dedicated to RE Growth	$31,699	$35,500	$142,000	$69,000	$42,500	$11,250	$82,917	$414,866
(4)	Annual Labor Expense	70.00%	70.00%	70.00%	70.00%	70.00%	70.00%	70.00%	
(5)	Overhead rate	$53,889	$60,350	$241,400	$117,300	$72,250	$19,125	$140,959	$705,273
(6)	Total Annual Incremental Expense								

(1) Estimated
(2) Estimated
(3) Estimated
(4) Line (2) x Line (3)
(5) Company Labor Overheads, excluding pension & PBOP
(6) Line (4) x (1 + Line (5))

PUC 3-33

Request:

How many Dig Safe requests have been made for each of the past five years?

Response:

Please see the table below for the requested information:

Year	**Number of Requests**
2013	54,714
2014	61,384
2015	60,509
2016	63,541
2017*	52,910

*Through 12/15/2017

Prepared by or under the supervision of: Alfred Amaral

PUC 3-34

Request:

How many times in each of the past five years has a third party damaged gas infrastructure?

Response:

Please see the table below for the requested information:

Year	**Number of Excavation Damages**
2013	109
2014	87
2015	127
2016	94
2017*	103

*Through 12/15/2017

Prepared by or under the supervision of: Alfred Amaral

PUC 3-35

Request:

Please provide the annual cost for each of the past five years of outsourcing the work associated with the marking of the location of underground facilities. What is the projected cost to bring this work back in-house in the Rate Year? Please itemize the cost to bring the work in-house.

Response:

Prior to November 2017, the work associated with marking the location of underground facilities was outsourced to On Target in all but five cities and towns.[1] The annual outsourcing cost and the projected cost to bring the previously outsourced work in-house is described below.

Annual Outsourcing Costs (5 years)

2013 - $339,486
2014 - $385,779
2015 - $433,950
2016 - $463,115
2017 - $280,353 (through October – work was brought back in house November 2017)

Projected Cost for the Rate Year to Bring the Outsourced Work In-House

$764,939

The projected cost is based on a unit cost analysis of the mark-out work that was done in-house during the Test Year. The unit cost contains only straight time (ST) and overtime (OT) labor to get a Total Labor Cost.

ST $239,333.81+ OT $158,290.50 = $397,624.31 (Total Labor)

The Total Labor Cost is then divided by the ticket counts of the work that was done in-house to obtain the unit cost, resulting in an average cost to perform one ticket in-house.

$397,624.31 / 8377 = $47.47 (Unit Cost)

The unit cost number is then multiplied by the number of tickets performed by the outsourced contractor during the Test Year. This is the projected cost of doing the work that is currently outsourced, by in-house workers.

---

[1] In-house crews were responsible for mark-outs in Barrington, Bristol, Warren, Providence, and East Providence.

$47.47 X 24,834 tickets = $1,178,870 (projected cost)

Subtracting the total invoices paid to the contractor during that time yields the projected increased cost for the Rate Year assuming the same ticket count as was experienced in the Test Year. The actual cost will vary based on the actual ticket count experience in the Rate Year.

$1,178,870 - $413,931 (invoice total) = $764,939 (projected increase in cost)

Prepared by or under the supervision of: Alfred Amaral III

PUC 3-37

Request:

For each of the past five years (at March 31), please provide the number of employees who worked directly for the Rhode Island jurisdiction, the number associated with electric, the number associated with gas, and the average number of vacancies.

Response:

Please see Attachment PUC 3-37 for the number of employees who worked directly for the Rhode Island jurisdiction as of March 31 of the past five years and for the monthly average number of vacancies for the past five years. Please note that the 2014 - 2017 data is for the fiscal year. 2013 data is for the calendar year as data is not available for the entire fiscal year.

Prepared by or under the supervision of: Alfred Amaral III and Raymond Rosario

The Narragansett Electric Company
Headcounts as of March 31

	2013	2014	2015	2016	2017
Management Electric	37.0	38.0	41.0	43.0	43.0
Management Gas	10.0	15.0	15.0	13.0	13.0
Union Electric	374.0	385.0	379.0	367.0	375.0
Union Gas	301.0	308.0	332.0	336.0	328.0

The Narragansett Electric Company
Average Monthly Vacancies by Fiscal Year

	2013*	2014	2015	2016	2017
Management Electric	1.3	0.9	1.7	1.3	0.8
Management Gas	0.4	1.0	0.6	0.3	0.1
Union Electric	7.3	9.4	10.9	8.8	5.8
Union Gas	6.9	4.3	3.8	3.9	2.8

*Average is based on calendar year data; fiscal year data is not available.

PUC 3-38

Request:

The Company is requesting funding for new positions to replace aging workers who may retire. The Rosario joint testimony states on page 13 that the Company needs to take steps to hire workers to replace the retiring workers. How many are expected to retire in the next 4 years? Will the positions of the retired workers be filled after they retire?

Response:

Please see the charts below for the projected retirements for the next four years. In addition, please see pages 29-30 of the joint pre-filed direct testimony of Company Witnesses Raymond J. Rosario, Jr., Alfred Amaral III, and Ryan M. Constable and Schedule OPEX-1 for additional information on retirements over the next five years. Because training for many positions is required in advance of retirement, the Company expects to have already filled the positions before current workers retire.

Rhode Island Electric M&C, CMS	July 17 Active FTEs	Retirement Projection									
		Jul 17-18	Jul 18-19	Jul 19-20	Jul 20-21 (4 yr projection)	Jul 20-21 (5 yr projection in testimony)	Jul 22-23	Jul 23-24	Jul 24-25	Jul 25-26	Jul 26-27
Electric Overhead Worker	159	1	4	7	11	16	22	28	35	42	48
Electric Underground Worker	32	1	1	2	3	4	5	6	7	9	10
Electric Substation Worker	43	0	1	2	3	4	6	8	10	12	14
Electric Protection & Telecom Worker	27	1	2	2	3	4	6	7	8	9	11
Rhode Island CMS Electric	67	2	4	7	10	13	15	18	20	22	24

Rhode Island Gas M&C, CMS	July 17 Active FTEs	Retirement Projection									
		Jul 17-18	Jul 18-19	Jul 19-20	Jul 20-21 (4 yr projection)	Jul 20-21 (5 yr projection in testimony)	Jul 22-23	Jul 23-24	Jul 24-25	Jul 25-26	Jul 26-27
Gas M&C (all job families)	141	5	8	13	18	21	26	31	34	38	42
Rhode Island CMS Gas	144	4	8	11	14	17	22	25	28	32	37

Prepared by or under the supervision of: Raymond Rosario and Alfred Amaral

PUC 3-39

Request:

Has the Company filed a one-year rate case or a multi-year rate plan? If it has filed a multi-year rate plan, please provide all parameters of the proposal, not just the data year expense.

Response:

The Company has filed a one-year rate case. The Company has presented Data Year 1 and Data Year 2 cost of service in its filing to potentially aid in any settlement discussions among the parties to the case.

Prepared by or under the supervision of: Melissa Little

PUC 3-40

Request:

How will small cell attachments to streetlights be billed?

Response:

The Company would bill electric service for small cell attachments to unmetered Company-owned street and area lighting equipment (where street and area lighting service is provided on rate classes S-06, S-10, and S-14) pursuant to the Unmetered Service provision of Rate C-06, Small C&I Rate. Please see Book 16 of 17 of the Company's November 27, 2017 filing, Schedule PP-4-ELEC, Bates page 17, and Schedule PP-5-ELEC, Bates page 129.

The ability to attach any fixtures or devices to customer-owned street and area lighting equipment (where electric service is provided on rate class S-05) is governed by the "Agreement for Customer-Owned Street and Area Lighting Attachments," provided as Attachment PUC 3-40.

Specifically, on page 26 of Attachment PUC 3-40, Section 12.3 of the agreement, "Assignment of Rights," the ability to attach fixtures or devices to customer-owned street and area lighting equipment is prohibited unless the Company consents to such attachment, as follows:

> 12.3 Pole and Structure space licensed to Customer hereunder is for Customer's exclusive use only and is licensed to Customer for the sole purpose of permitting Customer to place or retain existing Attachments. Customer shall not lease, sublicense, share with, convey, or resell to others any such space or rights granted hereunder. Customer shall not allow a third party, including affiliates, to place attachments or any other equipment anywhere on Attachments, upon Poles or within Structures, including, without limitation, the space on Poles or within Structures licensed to Customer for Customer's Attachments, without the prior written consent of Company.

If the Company provides such prior written consent, the Company would bill electric service to small cell attachments on Rate C-06 as unmetered service.

Prepared by or under the supervision of: Scott M. McCabe nationalgrid

AGREEMENT

FOR

CUSTOMER-OWNED
STREET AND AREA LIGHTING
ATTACHMENTS

BETWEEN

The Narragansett Electric Company
d/b/a National Grid
(COMPANY)

AND

Customer Name
(CUSTOMER)

DATED: Month __, 2017

TABLE OF CONTENTS

THIS AGREEMENT FOR CUSTOMER-OWNED STREET AND AREA LIGHTING ATTACHMENTS ("Agreement"), is made this ____ day of Month, 2017, by and between The Narragansett Electric Company, a corporation organized and existing under the laws of Rhode Island, having its principal office at 280 Melrose Street, Providence, Rhode Island, 02907 (hereinafter referred to as the "Company") and the [City/Town Name/Fire District Name/Regional School District Name/Municipal Water Utility Board Name/Kent County Water Authority/Rhode Island Commerce Corporation/Quonset Development Corporation/Rhode Island Airport Corporation/Narragansett Bay Commission/State of Rhode Island], a [describe corporate entity] organized and existing under the laws of Rhode Island, having its principal office at Street Address, City/Town, Rhode Island Zip Code, (hereinafter referred to as the "Customer").

W I T N E S S E T H

WHEREAS, Customer is a [municipal government/government entity/quasi-government entity/state government entity] and shall own, operate and maintain street and area lighting equipment to provide street and area lighting within Customer's jurisdiction; and

WHEREAS, Customer has purchased street and area lighting Facilities attached upon Poles and/or located within Structures [pursuant to/consistent with the requirements described in] R.I.G.L. § 39-30-1, *et seq.*, and desires to retain and/or make Attachments upon the Poles (which are either Jointly Owned or solely owned by the Company) or within Structures of Company; and

WHEREAS, Company agrees to permit, to the extent it is legally permitted and/or required, the continued existence and new placement of Attachments upon Poles and/or within Structures in a specified geographic area subject to the terms of this Agreement, provided that such use of the space upon Poles and within Structures will not interfere with Company's service requirements and obligations or the use of the Poles and Structures by others in accordance with R.I.G.L. § 39-30-1, *et seq.;* and

WHEREAS, the Company and Customer agree to minimize or eliminate the applications of Attachments, except those necessary for electrical connection of Customer Facilities, as designated in this Agreement, by separating existing Facilities at the time of any Material Change (as defined below) to establish clear and distinct ownership delineation, electric distribution and lighting system separation and demarcation as well as operations and maintenance independence;

NOW THEREFORE, in consideration of the mutual covenants, terms and conditions herein contained, the parties do hereby mutually covenant and agree as follows:

1.0 **DEFINITIONS**

Whenever used in this Agreement with initial capitalization, the following terms shall have the following meanings:

"Agreement of Sale" shall mean the agreement pursuant to which Company sold and Customer purchased the Facilities subject to this Agreement.

"Attachment" shall mean (i) the Facilities, including without limitation any luminaire, supporting bracket, and/or wire, conductor, circuitry or other equipment, owned by Customer, existing or proposed to be placed on a Pole and connected to the distribution system at the Connection Point to be used for sole purpose of providing street and/or area lighting, and (ii) the Facilities, including without limitation, any wire, cable, and other hardware, equipment, apparatus, or device, owned by Customer, existing or proposed to exist in or upon Structures connected to the distribution system at the Connection Point for the sole purpose of delivering electrical energy to Customer owned luminaire(s) used to provide street and/or area lighting within Customer's jurisdiction.

"Conduit" shall mean a Structure containing one or more Ducts.

"Company Requirements" shall mean the Company's policies, procedures, practices, guidelines and standards which the Company has made available to the Customer.

"Connection Point" shall mean where the Attachment is energized from the Electric Distribution System.

"Duct" shall mean a single enclosed raceway or pipe in which wires or cables are enclosed.

"Electric Distribution System" shall mean the overhead and underground infrastructure owned by the Company which includes, but is not limited to, circuitry, structures and equipment to support the delivery of energy between 120v and 34.5 kV.

"Facility" or "Facilities" shall mean components or equipment owned by the Customer which were either purchased from the Company or are proposed by the Customer having the sole purpose and function to provide outdoor illumination of streets or areas including the associated support infrastructure and electrical circuitry compliant with applicable regulations, codes or policies.

"Field/Office Survey" shall mean the Company's on-site audit and/or office asset/mapping record review of each individual Pole and/or Structure upon or within which the Customer proposes to (i) make a new Attachment(s), (ii) relocate an existing Attachment(s), or

(iii) materially change an existing Attachment, in accordance with this Agreement to evaluate the structural, electrical, operational and safety requirements including ingress or egress conditions to be in compliance with applicable laws, regulations, codes and Company Requirements.

"Identification Labels" shall mean markings, tags, decals, signage or other displays that indicate ownership, location or asset reference and functional attributes of the Facilities.

"Joint Owner" shall mean a person, firm, or corporation sharing an ownership interest in a Pole, Structure and/or related ancillary equipment with Company.

"Joint User" shall mean any other utility, excluding the Customer, which shall now or hereafter have established the right to use specific Poles and/or Structures.

"Make-Ready Work" shall mean the work to be performed by the Company, identified through the Field/Office Survey, required to safely accommodate Customer's proposed actions for the Attachments.

"Material Change", "Materially Change" or "Materially Changed" shall mean any alteration, modification or replacement made to the existing Facilities that changes its characteristics associated with the licensed specifications or description, mode of operation or maintenance, physical attributes, use of Poles and/or Structures by Company or Other Customers, attributes related to billing, and/or financial reporting considered as a capital investment..

"OSHA" shall mean the Occupational Safety and Health Act, 29 CFR 1910.269, as it may be amended from time to time as administered by the Occupational Safety and Health Administration within the U.S. Department of Labor.

"Other Customer" shall mean any entity, excluding Customer and any Joint User, to whom or which the Company has granted, or hereafter grants, the right or license of attaching equipment or facilities upon Poles and/or within Structures.

"Pole" shall mean any vertically oriented utility structure constructed predominately of treated wood, including metal, composites and concrete used to support electrical conductors and other utility equipment necessary to facilitate the operation of an Electric Distribution System owned by Company and used for Attachments.

"PUC" shall mean the Rhode Island Public Utilities Commission.

"Qualified Electrical Worker" shall mean any worker, electrical worker, contractor or other designated individual having successfully achieved a specified minimum level of training and/or experience including, but not limited to all applicable federal, state, and local work rules and Company Requirements, including compliance with OSHA 29 CFR 1910.269 as it may be amended from time to time.

"Removal Rights" shall refer to the rights pursuant to this Agreement or to applicable laws granting Company certain legal rights and/or recourse to request or perform the removal of certain Attachments.

"Structure" or "Structures" shall mean, but not be limited to, the Ducts, Conduits, vaults, manholes, handholes, foundations, standards and other utility equipment or infrastructure necessary to facilitate the operation of an underground Electric Distribution System or underground sourced street and/or area light(s) owned by Company and used for Attachments.

2.0 SCOPE OF AGREEMENT

2.1 Subject to the provisions of this Agreement, Company hereby provides to Customer, revocable, nonexclusive licenses authorizing Attachments to Poles and/or within Structures within the jurisdiction of the Customer, for the purpose of providing street and/or area lighting as described in this Agreement. The license(s) shall;

(i) authorize the Customer to utilize a space, point, area or location on a Pole or within a Structure for an Attachment as designated and specified by the Company,

(ii) provide definition of individual Facilities through the designation of a unique identification reference,

(iii) utilize the identification reference as the individual license reference, and

(iv) represent Facilities for the purpose of inventory and billing administration.

This Agreement shall govern with respect to licenses issued to Customer's existing or future Attachments. The application for licenses or listing of current licenses shall be in the form attached hereto as APPENDIX II, Form A-1 (Application for Street and Area Lighting Attachment License) and A-2 (Application for Street and Area Lighting Attachment License Detail), respectively.

2.2 No use, however extended, of Poles and Structures or the payment of any fees or charges by Customer as required by R.I.G.L. § 39-30-1, *et seq.* or under this Agreement shall create or vest in Customer any ownership or property rights in such Poles and Structures. Customer's rights herein shall be and remain a license.

2.3 Nothing contained in this Agreement shall be construed to compel Company to construct, retain, extend, place or maintain any Pole or Structure or other facilities not needed for Company's own service requirements. In the event the Company is the sole owner of a Pole, and no longer requires the use of such Pole, and the Customer has been notified to remove its Attachment, the Customer may request to purchase the Pole from the Company and the Company hereby agrees to sell its interest in such Pole for its unamortized balance of the original installation cost. In the event the Company jointly owns a pole, and Company and Joint Owner no longer require the use of such pole, and the Customer has been notified to remove its Attachment, the Customer may request to purchase the pole from the Company and Company hereby agrees to sell its interest in such pole, for its unamortized balance of the original installation cost, provided that either: (a) the Customer provides Company with evidence that

Customer has purchased or will concurrently purchase the Joint Owner's interest in such Pole, or (b) the Customer provides Company notice of Joint Owner's written consent to Company's sale of Company's interest in such pole.

2.4 Nothing contained in this Agreement shall be construed as a limitation, restriction, or prohibition against Company with respect to its obligation to provide electric distribution service to Attachments pursuant to Company's tariffs, or to any agreement(s) and arrangement(s) that Company has heretofore entered into, or may in the future enter into with Other Customers, not party to this Agreement, regarding the Poles and Structures. The rights of the Customer shall at all times be subject to any such existing and future agreement(s) or arrangement(s) between Company and any Joint Owner(s), Joint User(s) or Other Customers of Poles and/or Structures. Nothing contained in this Agreement shall be construed to grant, and Company makes no representations or warranties with respect to, and is not purporting to provide, any third party or Joint Owner attachment rights, licenses or consents for or in connection with the Attachments.

2.5 The Company shall assign to Customer the non-exclusive right, in common with the Company and others entitled thereto, to maintain and operate the Facilities purchased from the Company [pursuant to/consistent with the requirements described in] R.I.G.L. § 39-30-1, *et seq.* under any existing easement, license, grant of location or other agreement associated with such Facilities, to the extent assignable and allowed by such easements, licenses, grants of location or other agreements without any warranties or representations whatsoever. Customer is solely responsible to verify and confirm that it has the necessary rights pursuant to the assignment in this Section, and to obtain from the necessary parties the necessary and appropriate attachment rights, including, without limitation, obtaining rights from the owners or Joint Owners of the applicable Poles, Structures or other assets to which the Attachments are or will be attached.

2.6 Nothing contained in this Agreement shall be construed to grant any rights to Customer to include any wired or wireless hardware, equipment, apparatus, or device that is not a functional part of any Attachment authorized by Company under the terms of this Agreement. Any request made by the Customer to the Company for rights to attach facilities or equipment other than the Facilities or proposed Attachments shall be authorized by Company under the terms of a separate agreement.

2.7 No license granted under this Agreement shall extend to any Poles and/or Structures where the placement of Attachments would result in a forfeiture of the rights of Company or Joint Users, Other Customers, or all, to occupy the property on which such Poles and Structures are located. If placement of Customer's Attachments would result in a forfeiture of the rights of Company or Joint Users, Other Customer, or both, to occupy such property, Customer agrees to remove its Attachments forthwith; and Customer agrees to pay Company or

Joint Users, Other Customers, or both, all losses, damages, and costs incurred as a result thereof.

3.0 <u>ATTACHMENT REQUIREMENTS</u>

3.1 Specifications

3.1.1 All Attachments and all related operation and maintenance functions performed by the Customer or its contractor(s) or agents(s) shall comply with this Agreement and the requirements under Article 7.0.

3.1.2 In the event that Customer seeks to convert, replace or otherwise use a lighting or illumination source other than those provided in Company's applicable tariff, or operate such Facilities in a manner other than as stated in Company's applicable tariff ("Non-Compliant Facilities"), Company shall be under no obligation to permit or provide service to such Non-Compliant Facilities. Should Company elect, in its sole discretion, to accommodate such Non-Compliant Facilities, a separate agreement shall be executed and such agreement shall be subject to applicable regulatory consent or approval prior to application.

3.1.3 In the event the Company, in its sole reasonable judgment, determines that an Attachment does not comply with the provisions of this Agreement and that the existing physical and/or operational conditions of such Attachment is an emergency, threatens the safety of persons or property of third parties or the Company, and/or interferes with the Electric Distribution System or performance of Company's or others' service obligations, within fifteen (15) days following written notification by the Company as required under Article 15.0. Customer shall, at its sole cost and expense, remedy the condition which may include, but not be limited to, the relocation, reorientation, transfer or de-energizing of the Attachment as deemed acceptable by the Company, and, upon completion, provide written notification to the Company specifying the remedy action taken.

3.1.4 Company may, upon fifteen (15) days written notice to Customer and the unsuccessful implementation of other remedies or the continued operation of the Attachment, as stated in Article 15.0, proceed to exercise its Removal Rights in accordance Article 17.0. In such case, the Company may take timely action to remove the Attachment(s) or perform such other work as determined necessary or advisable in the sole discretion of the Company to alleviate the non-conformance or emergency condition(s). All work performed by the Company shall be at the cost and expense of the Customer and without any liability incurred by the Company to Customer for loss of service and/or damage or injury to Attachments without prior notice, written or otherwise to Customer.

3.1.5 Customer acknowledges that the unmetered service provided to Facilities under appropriate tariffs is only applicable to Customers and, therefore, only permits Facilities within an underground residential distribution (URD) area, as designated by the

Company, to be placed on a Customer's bill account as opposed to the Facilities placed on a bill account in the name of a developer, association or other third party.

3.2 Electrical System Ownership, Separation and Disconnection

3.2.1 The Company owns the Electric Distribution System including the Connection Point and the Customer shall own the street and area lighting equipment from the Connection Point to the applicable luminaire. To the extent there is any uncertainty, conflict or unique circumstance with respect to ownership or the Connection Point, the Company shall, in its sole discretion, determine the applicable ownership demarcation point with respect to Facilities and Electric Distribution System equipment.

3.2.2 Customer shall install within Attachment circuitry a Company approved physical disconnect device to function as a means of electrical separation between Company's and Customer's electrical systems. An "in-line fuse" assembly or other form of disconnect device may also provide a level of electrical system protection. The disconnect device shall be located as close in proximity to the energizing source or Connection Point as feasibly practical and be readily accessible to both Company and Customer. The disconnect device shall, at a minimum, create separation of the Customer's energized conductor, however, the Company recommends a dual pole disconnect device to create separation of the Customer's energized circuit. The installation of these disconnect devices by the Customer shall occur during each application of circuit maintenance, circuit or other Material Change and/or prior to each Company connection or reconnection. All existing Attachments shall be so equipped within ten (10) years following execution of this Agreement.

3.2.3 Joint use of Duct by Customer for new Facilities shall not be permitted. Such facilities (i.e. street lighting cables) and other systems (i.e. wired fire alarm monitoring, traffic control, or surveillance systems) must exist prior to this Agreement.

3.2.4 The installation of Facilities such as splice boxes and coiled cables within Structures is discouraged but may be permitted provided that the Customer obtains written specific authorization from the Company and such Facilities are compliant with Article 5.0. Where splice boxes are allowed by the Company, cable slack shall be installed by the Customer to allow the Facility to be lifted clear of the Structure to allow for Company or other facility maintenance and splicing.

3.3 Facility Labels

3.3.1 Customer shall remove, or otherwise permanently cover or mask all existing labeling designations of Company ownership found on any Facilities, and shall place, or request to be placed by Company as Make-Ready Work, ownership Identification Labels as set forth under APPENDIX II, Form E (Identification of Ownership Labels) on Facilities. This ownership labeling shall include, but not be limited to, cables located within or in close proximity to Structures and Customer handholes containing circuit disconnect devices. Attachments that exist upon Poles and/or within Structures as of the date of this Agreement are to have ownership Identification Labels installed at such time when maintenance, repair, replacement, relocation or a Material Change of such Attachment is performed but not to exceed a period of ten (10) years.

3.3.2 For the identification of the type of light source and associated wattage, or lumen output, Customer shall maintain applicable National Electric Manufacturers Association (NEMA) or other industry standard labeling upon each luminaire, in a clear and legible condition.

3.3.3 Customer shall utilize and preserve an appropriate means of individual Attachment location identification (i.e. numbering system) to maintain a unique reference which shall be clear, legible, comprehensive and visible from the street side of the Facilities. Customer may choose to use the pre-existing Company location numbering system. At the end of each calendar quarter, the Customer shall provide to the Company an inventory list that identifies any Facilities on which a new identification reference per luminaire location has been assigned and its corresponding street address.

4.0 ATTACHMENT LICENSE PROCESS

4.1 License Application

4.1.1 The Customer shall provide Company a written notification of all proposed actions including, but not limited to, installation, replacement, reorientation, relocation, Material Changes or removal associated with the proposed or existing Attachment(s) utilizing the forms in APPENDIX II, Forms A-1 (Application for Street and Area Lighting Attachment License) and A-2 (Application for Street and Area Lighting Attachment License Detail). The Company shall perform an assessment and provide a response to the application based upon the proposed action(s), description and engineering/construction detail provided.

4.1.2 Proposed new underground sourced Attachments or modifications of existing Attachments for the purpose of Material Change of the Facilities, within or upon Structures will not be authorized. Only applications for electrical connection(s) associated with new or Materially Changed Facilities external of underground Structures will be considered. Authorized Attachments will comply with designated Company standards to facilitate appropriate ingress/egress of Facilities to Structures and assure compatibility of Facilities for the purpose of connections to Electric Distribution System.

4.1.3 The Company will make commercially reasonable efforts to accommodate Customer's request for a Street and Area Lighting Attachment License. However, Company may, in its sole discretion, refuse to grant a Street and Area Lighting Attachment License or refuse authorization for the relocation, reconfiguration, Material Change or replacement of existing Attachments when Company reasonably determines that conditions including, but not limited to, the following exist:

(i) The proposed Attachment threatens the safe operation of Electric Distribution System,

(ii) Pole or Structure may not be replaced by the Company to accommodate Customer's proposed Attachment,

(iii) The existing Facilities on the Pole or within the Structure may not be rearranged to accommodate the proposed Attachment changes, or

(iv) The proposed Attachments will negatively impact other customer services provided by Company.

The list of above-mentioned conditions is not an exhaustive list and other conditions may exist that would require Company to refuse to grant a license.

4.2 Field/Office Survey

4.2.1 For each Pole and/or Structure upon or within which the Customer requests a new Attachment requiring an electrical connection or the reconfiguration, relocation, Material Change or replacement of an existing Attachment, the Company will determine if a Field/Office Survey is required. The Field/Office Survey shall identify the required work, if any, that is necessary to facilitate the electrical connection and determine whether or not the Pole or Structure is adequate to accommodate the requested Attachment. The Company shall provide the Customer with a Field/Office Survey cost estimate representing all anticipated costs. Company shall perform the Field/Office Survey(s) following receipt of the Customer's written authorization and advance payment of the estimated total cost specified by the Company in accordance with Article 6.0

4.2.2 A Field/Office Survey may not be required if Customer proposes a new, in-kind replacement of an existing Facility having the same physical and operational characteristics and is to be installed in the same location and orientation as the existing Facility.

4.2.3 Company shall specify the space, point, area or location to be utilized by the Customer for an Attachment on a Pole or within a Structure including the point of entry for the circuitry of the Attachment to reach the Connection Point.

4.2.4 A Field/Office Survey will identify existing Facilities within underground Structure(s) which may be required to be removed from within a Structure(s) and relocated external of the Structure(s) as a result of the proposed Attachment.

4.3 Make-Ready

4.3.1 In the event that a Pole or Structure is determined from the Field/Office Survey to be physically inadequate or otherwise requires the reconfiguration of the existing equipment of Electric Distribution System or other attachment facilities, the Company will indicate on the Authorization for Make-Ready Work (APPENDIX II, Form B-2) the cost of the required Make-Ready Work and forward such completed authorization form to the Customer.

4.3.2 The required Make-Ready Work will be scheduled and performed following receipt by Company of the executed Authorization for Make-Ready Work (APPENDIX II, Form B-2) and Customer's advance payment in the estimated amount specified by the Company. Customer shall pay Company for all Make-Ready Work in accordance with Article 6.0. Customer shall also reimburse the owner(s) of other facility attachment(s) upon the Pole or within the Structure for any expense incurred by such owner(s) associated with the transfer or rearrangement of the attachments of such owners in order to accommodate the installation, reconfiguration or removal of the Attachment(s). Upon completion of the Make-Ready Work, Customer shall not be entitled to reimbursement of any amounts paid to Company for Pole and/or Structure replacements, capacity upgrades, or for the reconfiguration or rearrangement of other attachment(s) upon Poles or within Structures by reason of the use by Company or other authorized user(s) of any additional space or structural capacity resulting from such replacement, reconfiguration or rearrangement.

4.3.3 If Company or Joint Owner needs to attach additional facilities or make changes to existing facilities in any Structures within which Customer has Facilities attached, Customer agrees to be responsible to perform and incur all costs to either (i) reconfigure its Attachment(s) in the Structure(s) as determined by the Company, or (ii) transfer its Attachment(s) to a designated Customer structure(s) so that the additional facilities of Company may be attached. When such reconfiguration or transfer is required to facilitate additional attachments of Company, Customer shall assume the expense of such reconfiguration or transfer. This paragraph applies to circumstances under which: (i) an agency of government, whether local, state or federal, requires the removal, relocation, or modification of a Structure affecting Attachment or (ii) a Structure must be repaired or replaced for any reason, including such repair or replacement to accommodate Company's additional attachments.

4.3.4 Company shall use commercially reasonable efforts to perform all Make-Ready Work to accommodate Customer's proposed Attachments as a part of its normal, scheduled workload.

4.3.5 When reconfiguration, transfer or removal of Attachments is required to facilitate attachments of Other Customers or third parties upon Poles or within Structures, Customer shall be responsible for the expenses of such reconfiguration, transfer or removal. Customer has sole responsibility for the recovery of the costs of the reconfiguration, transfer or removal of Attachments from such Other Customer(s) or third party(ies).

4.4 Issuance of License

4.4.1 Company shall authorize the applicable Street and Area Lighting Attachment License(s), attached as APPENDIX II, Form A-1 hereto, simultaneously with the execution of this Agreement for Facilities purchased by Customer from Company.

4.4.2 Prior to the placement, relocation, or Material Change by Customer of any Attachment upon any Pole or within a Structure, Customer shall make application for and have received a license from Company in the form of APPENDIX II, Forms A-1 (Application for Street and Area Lighting Attachment License) and A-2 (Application for Street and Area Lighting Attachment License Detail).

4.4.3 For the Company to provide the Attachment license(s) and to maintain quality assurance of associated billing records, Customer shall issue to Company within fifteen (15) days following the beginning of each calendar year a complete and detailed listing of all Facilities in-service as of December 31st of the preceding calendar year. The minimum detail to be provided shall meet the requirements designated for the Application for Street and Area Lighting Attachment License and Application for Street and Area Lighting Attachment License Detail (as defined in APPENDIX II, Forms A-1, A-2).

4.4.4 The Company may perform random field audits of Facilities for the purpose of quality assurance of the information on the list provided by the Customer. To the extent there are any differences between the Customer's list of Facilities and the Company's list of Attachments which cannot be reconciled to the satisfaction of the Company, such differences shall be resolved through compliance with the terms and conditions of this Agreement, applicable tariffs and/or statutes.

5.0 ATTACHMENT OPERATIONS

5.1 General

5.1.1 Customer shall, at its own expense and in accordance with the terms and conditions set forth in this Agreement, construct and maintain its Attachments upon Poles and/or within Structures safely, in compliance with this Agreement and in a manner that does not (i) interfere with Company's operation of its Electric Distribution System; (ii) conflict with the use of Poles and/or Structures by Company or by any authorized user of Poles and/or Structures; or (iii) electrically interfere with any of the Company's facilities attached thereon or therein.

5.1.2 Unless otherwise stated herein, Customer shall provide specific written authorization for Company to perform construction, maintenance, repairs, reconfiguration, relocation, connection/disconnection or removal of Customer's Attachments upon Poles or within Structures as may appropriately apply in accordance with Articles 3.0, 4.0 and 5.0 of this Agreement.

5.1.3 All Attachment work performed upon Poles or within Structures by the Customer and its contractors or agents shall be performed by a Qualified Electrical Worker.

Customer is required to execute the Acknowledgement For The Use of Qualified Electrical Worker (as set forth in APPENDIX II, Form G) to affirm that any person(s) under contract with and/or the direction of the Customer and performing the installation, maintenance, and/or removal of Attachments upon Poles or within Structures is/are qualified to perform such work in accordance with the requirements of OSHA and Articles 3.0, 4.0, 5.0 and 7.0 of this Agreement and ensuring completion and documentation of any required training, except where such work is performed by Company.

5.1.4 In the event the Customer cannot confirm that its employee, contractor and/or agent performing work on its behalf is a Qualified Electrical Worker in accordance with this Article, the Customer is required to comply with appropriate electrical clearance distances and only perform work on the Attachments in a de-energized condition. If a disconnect device is not installed, the Customer is to schedule a disconnect service request with the Company prior to performing any Attachment work. Following the completion of the work, the Customer is to schedule a connection service request with the Company to re-energize the Attachment.

5.1.5 Customer and its employees, contractors, agents or any persons acting on Customers behalf are prohibited from, have no authority to, and shall not permit, or cause any third party to, access or ingress any of the Company's enclosed or underground primary or secondary Electric Distribution System Structures, including, but not limited to, manholes, handholes, vaults, transformers, and switchgears unless such access or ingress is under the direct supervision of the Company.

5.1.6 The Customer and its employees, contractors, agents or any persons acting on Customers behalf shall comply with all applicable requirements (legal and otherwise) as stated under Article 7.0 when accessing any overhead infrastructure of the Electric Distribution System. If the Customer needs access or ingress to any of the Company's underground or overhead infrastructure of the Electric Distribution System, the Customer shall make advance written request to the Company. The Company shall provide required support, and/or perform the necessary work following its normal work order scheduling protocol, provided, that, the Company determines, in its sole discretion, that such connection/disconnection or other requested work is appropriate under the terms of applicable codes and Agreements. The Customer further agrees to compensate Company for all actual cost and expenses for the work performed by the Company associated with each Attachment consistent with and inclusive of the charges or fees as set forth in this Agreement and/or as defined in the applicable tariffs.

5.1.7 Any materials removed, or caused to be removed, as part of or from within the Structures by Company on behalf of the Customer shall be managed, tested, treated, transported, stored and disposed of by Company in accordance with applicable rules, regulations or statutes at Customer's sole cost and expense.

5.1.8 Customer and its employees, contractors, agents or any persons acting on Customers behalf shall not perform or make any connections (permanent or temporary) to, disconnections from, or in any way handle, tamper or interfere with, or otherwise disrupt, the Electric Distribution System or any other facilities of the Company, in whole or in part, nor shall the Customer permit or cause any third party (including without limitation, Customer's agent or contractor) to do so. The Company shall be the sole party with authority to perform or make any and all (permanent and temporary) connections to or disconnections from the Electric Distribution System or other facilities for the purpose of providing electric service to the Facilities. If and to the extent the Customer has a need for a connection or disconnection associated with the Electric Distribution System or assets, the Customer shall contact the Company by making a connection/disconnection request through normal customer contact channels and Company shall make the necessary connection/disconnection, provided, that the Company determines, in its sole discretion, that such connection is appropriate under the terms of applicable codes, standards, laws, regulations and Company's practices and policies.

5.1.9 All tree trimming necessary to accommodate initial construction, reconstruction, relocation, or Facility Material Change of Customer's proposed Attachments at the time of such installation, provided that the owner(s) of such tree(s) and all other governing authorities grant permission to Customer, shall be performed by qualified contractors approved by Company and Customer, at the sole cost and expense of Customer, but at the direction of Company. All tree trimming made necessary to accommodate prospective maintenance and operation including, but not limited to, the functional performance, lumen output or illumination orientation shall be performed by Customer or Customer's qualified contractor provided appropriate approvals have been granted by the owner(s) of the tree(s) and all other governing authorities. The portion of the tree(s) to be impacted by trimming shall only be within a radial distance of three (3) feet of the luminaire extending below a horizontal plane established from the highest vertical point of the luminaire unless such area is within specified clearance distances of the Electric Distribution System or transmission system as designated by Company and/or other governing authorities.

5.2 Maintenance

5.2.1 Customer shall be responsible for its own underground cable locating and for any participation in the appropriate "call before you dig" association responsible for providing one-call notifications within the Customer's operating service area. This is an independent association which, in compliance with federal, state and local requirements, facilitates the location identification of underground utility infrastructure through a notification/communication process between excavators and underground facility owners. The contact information for a specific geographic area within the United States can be obtained by calling 811 nationally. At the time of this Agreement, Dig Safe System, Inc. is this association.

5.2.2 Customer shall participate, at its sole expense, in any forum, group or organization and utilize any designated common information management system established to facilitate communications, priority, schedule and any other functions necessary to manage, locate or identify the attachment facilities and actions of all customers and other facility owner(s) which are in conjunction with or may have an impact upon an Attachment. This includes, but is not limited to, the coordination of transferring Facilities when Poles have been replaced requiring Company or Joint Owners, Customer, Joint Users and Other Customers to relocate their attachments. At the time of this Agreement, the system in use is National Joint Use Notification System.

5.2.3 Customer may (or may explicitly authorize Company, its employees or third parties acting on Customer's behalf to) access or enter Company's Structures for the purpose of asset verification, inventory, inspection and/or other engineering or asset management functions provided that the Customer provides reasonable advanced notice to the Company to accommodate all aspects of scheduling. A representative of Company shall be present and all parties are to be properly qualified and outfitted for the physical, environmental and electrical conditions to be encountered. Where Customer has been granted access as provided above, the Company may halt Customer's activities if Customer's activities threaten the safety of any person(s), property of third parties or of the Company and/or the integrity or reliability of Electrical Distribution System.

5.3 Removal from Joint-Use Infrastructure

5.3.1 For the Facilities acquired by the Customer [pursuant to/consistent with the requirements described in] R.I.G.L. § 39-30-1, *et seq.* that are an integrated part of the Electric Distribution System ("Coexisting Facilities"), such Facilities shall be physically separated from the Electric Distribution System equipment, except for those attachment applications compliant with established codes, standards, policies and procedures. Coexisting Facilities are currently installed or otherwise coexist, in whole or in part, on or within conduit, ducts, vaults, or other Structures ("Joint-Use Structures"). As such Coexisting Facilities will not be separated from the Joint-Use Structures prior to the closing date of the Agreement of Sale between the parties hereto. Following the closing date, the Coexisting Facilities and/or the Joint-Use Structures may, from time to time, require change or replacement at which time the Customer shall physically separates the Facility(ies) from the Electric Distribution System.

5.3.2 If Company elects, in its sole discretion, to modify/change or replace any Joint-Use Structure, including, without limitation, to upgrade such Joint-Use Structure or associated Company equipment, Company shall provide Customer with written notice of such work and Customer agrees to separate and relocate the Customer's Coexisting Facilities associated with such Joint-Use Structure within six (6) months following the date of the Company's written notice, at Customer's expense and in compliance with all applicable laws, rules, regulations, codes and standards, as if such Coexisting Facilities were new Facilities. The Company's notice shall be provided within a reasonable period of time after commencing such work and provide a brief description of the separation or relocation that will be required with respect to the Coexisting Facilities.

5.3.3 In the course of daily operation or maintenance, should an existing underground Facility require relocation or other Material Change, the Facility is to be relocated outside the Structure and the existing license is to be modified or terminated. The Customer is responsible for the construction of the proposed relocated Facility and the removal of existing Facility outside of the Structure where applicable. For Attachments within Structures or co-existing within a singular common Structure which is also utilized by the Electric Distribution System, the provisions of Articles 3.0, 4.0 and 17.0 shall apply to all work proposed or planned and may be performed by Company at Customer's expense.

5.4 Inspection of Attachments

5.4.1 Company reserves the right, at its sole discretion, to make inspections of any part of Attachments, at any time, without notice to Customer, at Company's own expense.

5.4.2 Company reserves the right, at its sole discretion, to make inspections of any part of Attachments, at Customer's expense, if the inspection performed pursuant to Section 5.4.1 supra reveals any of the following:

(i) No license has been issued by Company for the Attachment pursuant to Article 4.0 *supra*,

(ii) Discrepancy in type, style or size of installed Attachment as compared with Company's records, or

(iii) Any situation creating a safety-related emergency or any condition that prevents safe access to any facilities installed upon Pole(s) and/or within Structures.

5.4.3 Any charge imposed by Company for such inspections shall be in addition to any other sums due and payable by Customer under this Agreement. No act or failure to act by Company with regard to the charge or any unauthorized use by Customer shall be deemed as ratification or the authorization of the unauthorized use. If any license should subsequently be issued, the license shall not operate retroactively nor constitute a waiver by Company of any of its rights or privileges under this Agreement or otherwise.

6.0 <u>FEES, CHARGES AND PAYMENTS</u>

6.1 Customer shall pay to Company the fees and charges in conjunction with each requested Attachment license(s), as calculated in accordance with appropriate federal and/or state rules and regulations, as specified in applicable tariffs, or in accordance with the terms and conditions of APPENDIX I, attached hereto and incorporated herein by reference to Articles 3.0, 4.0, and 5.0 and APPENDIX II, Forms B-1 and B-2.

6.2 Nonpayment by the Customer of any work the Customer authorized and performed by Company for the Customer and the corresponding amount due under this Agreement shall constitute a default of this Agreement, and Company may exercise all of its rights and remedies under this Agreement including, but not limited to, termination under Article 16.0.

6.3 Company may change the amount of fees and charges specified in APPENDIX I, Schedule of Fees and Charges by giving Customer no fewer than sixty (60) days written notice prior to the date the change becomes effective or as otherwise approved and made effective by the PUC. Notwithstanding any other provision of this Agreement, Customer may terminate this Agreement at the end of such sixty (60) day notice period if the change in fees and charges are not acceptable to Customer, provided that Customer gives Company no fewer than thirty (30) days written notice of its election to terminate this Agreement prior to the end of such sixty (60) day period. Upon termination of the Agreement, the Customer shall be responsible for the removal of all Attachments unless otherwise specified in accordance with and to the extent authorized by Article 16.0.

6.4 The Company's performance of the required Field/Office Survey, as authorized by the Customer in compliance with Section 4.2, is contingent on the Customer making advance payment to Company in the amount specified by Company. Such specified amount shall be an estimate sufficient to cover Company's fully loaded costs to perform and complete the required Field/Office Survey. The estimated amount shall include the standard Field/Office Survey charge as found in APPENDIX I, Schedule of Fees and Charges and any other required ancillary service costs incurred in the performance of the Field/Office Survey. The estimated ancillary service costs shall include, but not be limited to, applicable permits, work zone and police detail protection and other safety and environmental functions which shall be required to perform the Field/Office Survey at a specific location. The parties agree that upon completion of the Field/Office Survey by Company, no adjustment of the Field/Office Survey costs paid by Customer shall be made to reflect Company's actual costs to perform the Field/Office Survey, whether or not Company's actual costs are more or less than the estimated costs paid by Customer. The current standard charge assessed to Customer and all Other Customers for the Field/Office Survey can be found in APPENDIX I, Schedule of Fees and Charges and is based on Company's current estimated cost to perform and complete the Field/Office Survey. Company reserves the right to change such standard Field/Office Survey charge assessed to Customer and all Other Customers from time to time and to provide written notice as stated in Section 6.3.

6.5 The Company's performance of the specified Make-Ready Work as authorized by the Customer in compliance with Section 4.3 is contingent upon the Customer making advance payment to Company in the amount specified by Company. Such specified amount shall be an estimate sufficient to cover Company's fully loaded costs to perform and complete the required Make-Ready Work. The parties agree that upon completion of the Make-Ready Work by Company, no adjustment of the Make-Ready Work amount paid by Customer shall be made to reflect Company's actual costs to perform the Make-Ready Work, whether or not Company's actual costs are more or less than the estimated costs paid by Customer.

6.6 The Customer shall pay the Lighting Service Charge for each occurrence per location that the Customer requests the Company perform electrical service related connections/disconnections or other work unrelated to the operation or maintenance of the Electric Distribution System. Should the Customer's requested service result in required work on the Electric Distribution System, the Lighting Service Charge for that occurrence shall be waived. The Lighting Service Charge shall be at the rate as specified in the applicable Tariff as adjusted from time to time and as further referenced in APPENDIX I, Schedule of Fees and Charges.

7.0 LEGAL REQUIREMENTS, REGULATIONS, CODES AND STANDARDS

7.1 The parties hereto, all Attachments (whether existing or new Facilities) and any and all work associated with the Attachments and this Agreement shall comply with all applicable federal, state and local laws, regulations, rules, codes, Company tariffs and Company Requirements, as such may be amended from time to time.

7.2 Attachments shall be located, oriented, operated and maintained in accordance with the applicable requirements and specifications of the most recent editions of the National Electrical Code (NEC), the National Electrical Safety Code (NESC), the rules, regulations and provisions of the OSHA and any governing authority having jurisdiction over the subject matter of this Agreement, as each may be amended from time to time.

7.3 Clearances between communications, Electric Distribution System and street lighting cables shall be compliant with applicable codes, standards and Company Requirements to adequately allow for proper maintenance, repair and reconfiguration of Electric Distribution System, street lighting and communications cables.

7.4 All lighting or illumination sources (i.e. lamps) shall be compliant with the energy consumption schedules and defined hours of operation as set forth in the applicable Company tariffs.

7.5 Subject Section 2.5 herein, Customer shall be responsible for obtaining from the appropriate public and/or private authority any authorizations required to construct, operate and/or maintain its Attachment on the public and private property at the location of Poles and/or

Structures for which Customer has obtained Street and Area Lighting Attachment License(s) under this Agreement before making Attachments on such public and/or private property.

8.0 UNAUTHORIZED ATTACHMENTS

8.1 To the extent authorized by Article 15.0, in the event that any unauthorized Attachments are found attached to Poles or Structures and for which no license exists, Company, without prejudice to its other rights or remedies under this Agreement (including termination) or otherwise, may impose electric delivery service and other charges, pursuant to Article 6.0, and require Customer to submit in writing, within fifteen (15) days after receipt of written notification from Company of the unauthorized Attachment(s), an Application For Street and Area Lighting Attachment License, (Form A-1). The Customer shall notify Company that the unauthorized Attachment has been removed within the fifteen (15) days after receipt of written notification from the Company. Alternatively, Customer may authorize Company to remove the unauthorized Attachment in accordance with Article 15.0. If such application or notification is not received by Company within the specified time period, Company shall remove the unauthorized Attachment(s). The Customer shall be responsible for the cost and expense of removal of the unauthorized Attachment by the Company without any liability incurred by Company to Customer for loss of service provided by Customer or any damage or injury to Customer's unauthorized Attachment(s).

8.2 For the purpose of determining the applicable charges, both parties shall agree that if an unauthorized Attachment is identified within three (3) months following the execution date of this Agreement, the Attachment will be considered to have existed prior to the date of this Agreement, and inadvertently omitted by the parties from the list of Facilities purchased by the Customer. Any unauthorized Attachment that is identified after twelve (12) months following the execution date of this Agreement, shall require its own individual license for which the Customer shall submit an Application For Street and Area Lighting Attachment License. The fees, charges, and interest as specified in Article 6.0, APPENDIX I and APPENDIX II, (Form B-1 and B-2) at the time the unauthorized Attachment is discovered, shall be applicable thereto and due and payable forthwith whether or not Company permits Customer to continue the placement of the Attachment.

8.3 For unauthorized attachments for which the Company is unable to determine ownership following due diligence, the attachment shall be removed by the Company.

9.0 LIABILITY, INDEMNIFICATION AND DISCLAIMER

9.1 Company reserves to itself, its successors and assigns, the right to locate and maintain its Poles and Structures and to operate its facilities in conjunction therewith in such a manner as will best enable Company to fulfill its service obligations and requirements. Company shall not be liable to Customer for any interruption of Customer's service or for interference with the operation of Customer's services arising in any manner out of the use of Poles or Structures, except to the extent caused by Company's negligence or to the extent otherwise required by Company's tariffs.

9.2 Customer shall be liable for any damages it causes to the facilities of Company and of Other Customers attached to Poles and/or Structures, and Customer assumes all responsibility for any and all loss from such damage caused by Customer or any of its agents, contractors, servants or employees. Customer shall make an immediate report to Company and any Joint Owners, Joint Users and/or Other Customers of the occurrence of any such damage and agrees to reimburse the respective parties for all costs incurred by Company, Joint Owners, Joint Users and/or Other Customers in making repairs to their respective facilities.

9.3 Except to the extent caused by the negligence of any of the Company Indemnified Parties, Customer shall, to the full extent allowed by law and to the extent of Customer's insurance coverage (under which Company shall be named an additional insured), and shall cause any party performing work in connection with this Agreement on behalf of Customer to, defend, indemnify and save harmless Company, its affiliates and their respective officers, directors, employees, agents, contractors, representatives, successors (collectively, the "Company Indemnified Parties") and assign, against and from any and all liabilities, claims, suits, fines, penalties, damages, losses, fees (including reasonable attorneys' fees), costs and expenses (including reasonable costs and expenses incurred to enforce this indemnity), (hereinafter "Claims") arising from or in connection with Customer's installation, operation, maintenance, or removal of Facilities and/or Attachments including, but not limited to, those Claims which may be imposed upon, incurred by or asserted against Company, by reason of:

(a) Any work or action done upon the Poles or within Structures licensed hereunder or any part thereof performed by Customer or any of its agents, contractors, servants, or employees;

(b) Any use, occupation, condition, operation of the Poles and/or Structures or any part thereof by Customer or any of its agents, contractors, servants, or employees;

(c) Any act or omission on the part of Customer or any of its agents, contractors, servants, or employees, for which Company may be found liable;

(d) Any accident, injury (including, but not limited to, death) or damage to any person or property occurring upon the Poles and/or within Structures or any part thereof or arising out of any use thereof by Customer or any of its agents, contractors, servants, or employees, except where such work is performed by Company;

(e) Any failure on the part of Customer to perform or comply with any of the covenants, agreements, terms or conditions contained in this Agreement;

(f) Any payments made under any Workers' Compensation Law or under any plan for employee disability and death benefits arising out of any use of the Poles or Structures by Customer or any of its agents, contractors, servants, employees, or;

(g) By the installation, operation, maintenance, presence, use, occupancy or removal of Customer's Attachments by Customer or any of its agents, contractors, servants or employees or by their proximity to the facilities of other parties attached to Poles and/or Structures, including without limitation, taxes, special charges by others, and from and against all claims and demands for infringement of patents with respect to the manufacture, use, and operation of Customer's Attachments in combination with Poles or Structures, or otherwise.

9.4 The Company makes no warranties, representations, guarantees or promises in connection herewith or therewith, whether statutory, oral, written, express, or implied as to the present or future strength, condition, or state of any Poles, Structures, facilities, wires, apparatus, the use of the space upon a Pole or within a Structure or whether it is usable, or otherwise in connection with any Attachment, Facilities or this Agreement. To the extent applicable, the Customer, or its contractors, agents and representatives performing any Attachment work, shall be responsible and liable for observations, assessments and non-destructive testing of the Poles and/or Structures to determine whether the Poles and/or Structures are safe to utilize, support, access or ascend. If the Customer questions the integrity or safety of any Pole and/or Structure or if the Pole or Structure is marked as unsafe, the Customer shall refrain from utilizing, accessing, ascending, or handling the Pole or Structure in any manner whatsoever and shall notify or confirm such condition with Company. Should the Customer, or its contractor, agent or representative decide, in its/his/her sole judgment, to utilize or access a Pole or Structure (including, without limitation, Poles or Structures which are marked unsafe or appear to be unsafe), the Customer, not Company or its affiliates, shall assume all risk of loss, liability and damages (including injury to any person(s) (including death) or property), and the Customer shall indemnify, defend, release and hold harmless Company Indemnified Parties as indicated herein.

9.5 Company, the Company's affiliates, and their respective officers, directors, employees, representatives and contractors shall not be liable to Customer for any indirect, consequential, punitive, incidental, special, or exemplary damages in connection with this Agreement, or the Attachments contemplated herein, including, without limitation, the condition, design, engineering, installation, maintenance, construction, location, operation of, or failure of operation of, the Facilities, under any theory of law that is now or may in the future be in effect, including without limitation: contract, tort, R.I.G.L. § 6-13.1-1 *et seq.*, strict liability or negligence.

9.6 The provisions of this Article 9.0 shall survive the expiration or earlier termination of this Agreement or any license issued under this Agreement.

10.0 INSURANCE

10.1 Except as provided under Section 10.9 herein, Customer shall carry insurance issued by an insurance carrier satisfactory to Company to protect the parties hereto from and against any and all claims, demands, actions, judgments, costs, expenses, and liabilities of every kind and nature which may arise or result, directly or indirectly from or by reason of such loss, injury, or damage as covered in Article 9.0 *supra*.

10.2 Comprehensive or Commercial General Liability Insurance, including Contractual Liability and Product/Completed Operations Liability covering all insurable operations required under the provisions of this Agreement and, where applicable, coverage for damage caused by any explosion or collapse with the following minimum limits of liability:

Bodily Injury Liability	$5,000,000
Property Damage Liability	$5,000,000

If a combined single limit is provided, the limit shall not be less than $5,000,000 per occurrence. Customer's insurance requirements for General Liability or Automobile Liability may be satisfied through any combination of excess liability and/or umbrella. Coverage shall include contractual liability with this Agreement and all associated agreements with respect to the Customer's ownership of the street lights being included. In the event the Customer is a governmental entity and such entity's liability to a third party is limited by law, regulation, code, ordinance, by-laws or statute (collectively the "Law"), this liability insurance shall contain an endorsement that waives such Law for insurance purposes only and strictly prohibits the insurance company from using such Law as a defense in either the adjustment of any claim, or in the defense of any suit directly asserted by an insured entity.

10.3 Workers' Compensation Insurance for statutory obligations imposed by Workers' Compensation or Occupational Disease Laws, including Employer's Liability Insurance with a minimum limit of $500,000. When applicable, coverage shall include The United States Longshoreman's and Harbor Workers' Compensation Act and the Jones Act. Proof of qualification as a self-insurer may be acceptable in lieu of a Workers' Compensation Policy.

10.4 Automobile Liability covering all owned, non-owned and hired vehicles used in connection with the work or services to be performed under this Agreement with minimum limits of:

Bodily Injury & Property Damage
Combined Single Limit - $1,000,000

10.5 The Customer and its insurance carrier(s) shall waive all rights of recovery against the Company and their directors, officers and employees, for any loss or damage covered under those policies referenced in this insurance provision, or for any required coverage that may be self-insured by the Customer**.** To the extent the Customer's insurance carriers will not waive their right of subrogation against the Company, the Customer agrees to indemnify the Company for any subrogation activities pursued against them by the Customer's insurance carriers. However, this waiver shall not extend to the gross negligence or willful misconduct of the Company or their employees, subcontractors or agents.

10.6 All insurance must be effective before Company will authorize Customer to make Attachments to any Pole and/or Structure and shall remain in force until such Attachments have been removed from all such Poles and/or Structures. Customer accepts the obligation to inform Company of changes in insurance or insurance carrier and/or policy on a prospective basis.

10.7 Customer shall submit to Company certificates of insurance including renewal thereof, by each company insuring Customer to the effect that it has insured Customer for all liabilities of Customer covered by this Agreement; and that such certificates will name Company as an additional insured under the General Liability and Automobile Liability policies and that it will not cancel or change any such policy of insurance issued to Customer except after the giving of not less than thirty (30) days' written notice to Company. Customer shall also notify and send copies to Company of any policies maintained under this Article 10.0 written on a "claims-made" basis. The following language shall be used when referencing the additional insured status of Company: National Grid USA, its direct and indirect parents, subsidiaries and affiliates, shall be named as additional insureds.

10.8 Customer shall require all of its contractors to carry insurance which meets the requirements specified under this Article 10.0 of this Agreement, and to name Company as an additional insured.

10.9 Anything in this Article 10.0 to the contrary notwithstanding, the Customer may elect to self-insure provided that the Company consents and Customer provides written notice and evidence of self insurance to the Company.

11.0 AUTHORIZATION NOT EXCLUSIVE

11.1 Nothing herein contained shall be construed as a grant of any exclusive authorization, right or privilege to Customer with respect to attachment rights to the Company's facilities. Company may grant, renew and extend rights and privileges to others that are not parties to this Agreement, whether by contract or otherwise, to attach to or use space upon a Pole or within a Structure subject to this Agreement.

12.0 ASSIGNMENT OF RIGHTS

12.1 Customer shall not assign or transfer this Agreement or any rights or authorization granted hereunder, and this Agreement shall not inure to the benefit of Customer's successors, without the prior written consent of Company.

12.2 In the event such consent or consents are granted by Company, this Agreement shall extend to and bind the successors and assigns of the parties hereto.

12.3 Pole and Structure space licensed to Customer hereunder is for Customer's exclusive use only and is licensed to Customer for the sole purpose of permitting Customer to place or retain existing Attachments. Customer shall not lease, sublicense, share with, convey, or resell to others any such space or rights granted hereunder. Customer shall not allow a third party, including affiliates, to place attachments or any other equipment anywhere on Attachments, upon Poles or within Structures, including, without limitation, the space on Poles or within Structures licensed to Customer for Customer's Attachments, without the prior written consent of Company.

13.0 FAILURE TO ENFORCE

13.1 Failure of either party to enforce or require compliance with any of the terms or conditions of this Agreement or to give notice or declare this Agreement or any authorization granted hereunder terminated shall not constitute a general waiver or relinquishment of any term or condition of this Agreement, but the same shall be and remain at all times in full force and effect.

14.0 TERM OF AGREEMENT

14.1 Unless terminated in accordance with Article 16.0, this Agreement shall remain in effect for a term of five (5) years from the date hereof and shall continue indefinitely thereafter until terminated by either party with at least six (6) months written notice to the other party.

14.2 Termination of this Agreement or any licenses issued hereunder shall not affect Customer's liabilities and obligations incurred hereunder prior to the effective date of such termination, nor Company's and Customer's rights pursuant to the laws, ordinances, regulations, and rulings governing the subject matter of this Agreement, including but not limited to, R.I.G.L. § 39-30-1, *et seq.*

15.0 TERMINATION OF LICENSE

15.1 Any license(s) issued pursuant to this Agreement shall automatically terminate when Customer ceases to have authority pursuant to any laws, ordinances, regulations, and rulings, including but not limited to R.I.G.L. § 39-30-1, *et seq.* to construct, operate, and/or maintain its Attachments on the public or private property at the location of the particular Pole or Structure covered by the license.

15.2 Customer may at any time terminate a license for any Attachment(s) provided written notice of such termination is received by Company no less than fifteen (15) days prior to the proposed removal of the Attachment(s) from the specific Pole(s) or Structure(s) (APPENDIX II, Form D). Following such removal, installation of an Attachment(s) to such Pole(s) or Structure(s) shall not be made again until Customer has first complied with all of the provisions of this Agreement as though no such installation of Attachment(s) to such Pole(s) or Structure(s) had ever been made.

15.3 Company may exercise its Removal Rights requiring Customer to remove its Attachment(s), at Customer's expense, from any of the designated Pole(s) or Structure(s) within fifteen (15) days after termination of the license covering such Attachment(s). If Customer fails to remove its Attachment(s) within such fifteen (15) day period, Company shall have the right to remove such Attachment(s) at Customer's expense.

15.4 Terms and conditions of Articles 5.0 and 17.0 of this Agreement shall govern the removal of Attachments.

16.0 TERMINATION OF AGREEMENT

16.1 If Customer fails to materially comply with any of the terms or conditions of this Agreement or defaults in any of its obligations under this Agreement, or if Facilities or Attachments are maintained or used in violation of any law and Customer shall fail within thirty (30) days after written notice from Company to correct such default or noncompliance, Company may, at its option, either (a) terminate this Agreement and all licenses granted hereunder, or (b) terminate any or all of the licenses covering the Pole(s) or Structure(s) as to which such default or noncompliance shall have occurred.

16.2 If, at any time, an insurance carrier notifies Company that any policy or policies of insurance, acquired pursuant to Article 10.0 *supra*, or any self-insurance is or will be canceled or changed so that the requirements of Article 10.0 will no longer be satisfied, then this Agreement shall terminate automatically unless prior to the effective date of the cancellation or change in the insurance policy(ies), Customer furnishes to Company new certificates of insurance or evidence of self insurance providing insurance coverage in accordance with the provisions of Article 10.0 *supra*.

16.3 In the event of termination of this Agreement, and to the extent Company is exercising Company's Removal Rights, Company may require Customer to remove its Attachments, Customer shall within thirty (30) days of the date of termination of this Agreement submit a plan and schedule to Company pursuant to which Customer (or its agents) will remove Attachments from Poles or Structures within six (6) months from the date of termination, unless otherwise agreed to by both parties or as authorized by Customer, the Company (or its agents) will remove Attachments from Poles or Structures provided, however, that Customer shall be liable for and pay all fees, charges and associated costs due to Company pursuant to the terms of this Agreement until Attachments are removed from Poles or Structures.

17.0 REMOVAL RIGHTS

17.1 The Removal Rights as designated within this article shall apply in all cases where either Customer or Company terminates a License or this Agreement or in the course of normal operation or maintenance of an Attachment upon a Pole or within a Structure and as authorized pursuant to the requirements under Article 7.0, including but not limited to R.I.G.L. § 39-30-1, *e. seq.*

17.2 Company may exercise its Removal Rights and require Customer to remove its Attachment(s), and Customer, at the Customer's sole expense, shall remove or have removed in accordance with this Agreement its Attachment(s) from any Pole(s) and/or Structure(s) within fifteen (15) days of notice. If Customer (or its contractors or agents) fails to remove Attachment(s) from Pole(s) and/or Structure(s) within the applicable time period, Company shall have the right to remove the Attachment(s), at Customer's expense, and without any liability on the part of Company for damage or injury to Attachment(s). If Company exercises its Removal Rights to remove the Attachment(s), Company shall have the option to sell or otherwise dispose of the removed Attachment(s) to cover the expense of the removal. If the sale of the Attachment(s) does not cover the entire expense of the removal, Customer shall be liable for the remaining expense. Customer shall be liable for and pay all fees and charges pursuant to the terms of this Agreement to Company until such Attachment(s) are removed from Pole(s) and/or Structure(s).

17.3 Notwithstanding any other provision of this Agreement, this Agreement is not intended to, and does not by its terms, broaden or expand Company's Removal Rights.

18.0 CHOICE OF LAW

18.1 This Agreement shall be governed by and construed in accordance with the laws of the state of Rhode Island without regard to the conflict of laws principles contained therein.

19.0 SEVERABILITY

19.1 In the event that any provision or part of this Agreement or the application thereof to any party or circumstance is deemed invalid, against public policy, void, or otherwise unenforceable by a court of competent jurisdiction, the remaining provisions or parts hereof shall remain in full force and effect and shall in no way be affected, impaired, or invalidated thereby.

20.0 NOTICES

20.1 All written notices required under this Agreement shall be given by posting the same via first class mail as follows:

(a) **To Customer:** All correspondence related to Customer's street and area lighting including but not limited to; this Agreement, Application for Street and Area Lighting Attachment License(s), Authorization for Field/Office Survey, Authorization for Make-Ready Work, and Notification of Discontinuance of Street or Area Lighting Attachment to Customer's office at:

______________________________ (Customer Contact Name)
______________________________ (Title of Customer Contact)
______________________________ (Customer Department Name)
Customer Name
Street Address
City/Town, RI Zip Code

(b) **To Company:** Application for Street and Area Lighting Attachment License, Authorization for Field/Office Survey Work, Authorization for Make-Ready Work, and Notification of Discontinuance of Street or Area Lighting Attachment, and a copy of all certificates of Insurance to Company's district office at:

The Narragansett Electric Company d/b/a National Grid
Attention: Manager, Community & Customer Management
280 Melrose Street
Providence, RI 02907

All original certificates of Insurance to:

National Grid USA Service Company, Inc.
Attn: Risk Management, B-3
300 Erie Boulevard West
Syracuse, NY 13202

A copy of all applications, notices, authorizations and certificates to:

The Narragansett Electric Company d/b/a/ National Grid
Attention: Outdoor Lighting and Attachments
40 Sylvan Road
Waltham, MA 02451-1120

(c) Each party has the right to add, modify, change or remove contact information as presented herein provided such corrections are communicated in writing to the other party and made part of this Agreement.

21.0 <u>ENTIRE AGREEMENT</u>

21.1 The parties have freely entered into this Agreement and agree to each of its terms without reservation. Paragraph headings are for the convenience of the parties only and are not to be construed as binding under this Agreement. This Agreement constitutes the entire Agreement between Company and Customer, and all previous representations either oral or written, (insofar as Customer is concerned except as to liabilities accrued, if any) are hereby annulled and superseded.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement in duplicate on the day and year first above written.

The Narragansett Electric Company d/b/a National Grid

By: ______________________________

Name: Christopher Kelly

Title: Senior Vice President, Electric Process and Engineering

Customer Name

By: ______________________________

Name: ______________________________

Title: ______________________________

APPENDIX I

SCHEDULE OF FEES AND CHARGES
FOR CUSTOMER-OWNED STREET AND AREA LIGHTING ATTACHMENTS

(A) Attachment

To the extent that the PUC may, in the future, allow Company to charge fees for the use of its Poles and Structures by Customer's Attachments, Customer agrees to pay such fees.

(B) Field/Office Survey

Whenever a Field/Office Survey is required under this Agreement, Customer shall pay Company for the expense thereof. The current standard charge assessed to Customer and all Other Customers for the Field/Office Survey is $130.00 per Attachment and is based on Company's current estimated cost to perform and complete the Field/Office Survey. Specific to each occurrence, any actions required by the Company to remedy a Pole or Structure ingress or egress condition in compliance with applicable laws, regulations, codes and company policies and procedures is considered to be in addition to the Field/Office Survey function. The Customer shall be responsible for the associated costs which will be predefined as an estimate in addition to the aforementioned fee.

(C) Make-Ready Work

Whenever Make-Ready Work is required under this Agreement, Customer shall pay Company for the expense thereof. Make-Ready Work may include, but is not limited to, the modification or replacement of the Pole upon and/or Structure within which Customer's Attachments will be placed to safely accommodate Customer's Attachments, and such other changes in the existing facilities upon and/or within such Pole and/or Structure as accommodating Customer's Attachments may require. Make-Ready Work expenses charged by Company may also include the following:

(1) The net loss to Company on the replaced Pole and/or Structure based on its reproduction cost less depreciation, plus cost of removal;

(2) Transferring Company's Attachments from the old Pole and/or Structure to the new Pole and/or Structure; and

(3) Any other rearrangements and changes necessary by reason of Customer's proposed or existing Attachments.

(D) Other Charges and Fees

Customer shall be subject to and responsible for all other charges and fees under the applicable tariff.

(E) Payment Date

Failure to pay all authorized fees and charges within 30 days after presentment of the bill therefore or on the specified payment date or as otherwise provided in the applicable tariff, whichever is later, shall constitute a default of this Agreement with respect to the Facilities in question.

For bills rendered by Company, the following shall be applicable:

> "Interest shall accrue and be payable to Company at the rate set by the Commissioner of Internal Revenue pursuant to Internal Revenue Code, Section 6621; Treasury Regulations Section 301.6621-1, from and after the payment date of any payment required by this Agreement. The payment of any interest shall not cure or excuse any default by Customer under this Agreement."

APPENDIX II

ADMINISTRATIVE FORMS AND NOTICES

INDEX OF ADMINISTRATIVE FORMS

Agreement Number: XXXX **Form A-1**
Application Number: ___________ (to be provided by Company)

NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID

APPLICATION FOR STREET AND AREA LIGHTING ATTACHMENT LICENSE

Date of Application: ___________

Customer Name: ___________________________

In accordance with the terms and conditions of the Agreement for Customer-Owned Street and Area Lighting Attachments between Customer and Company, dated ____________, application is hereby made for license(s) to make _____ (quantity) Attachments to Joint-Owned or Sole-Owned Poles or Underground Structures as indicated on the attached Form A-2.

By (Print Name) _____________________________________

Signature ____

Title ____

Telephone No. ___________________ Email ______________________________

STREET AND AREA LIGHTING ATTACHMENT LICENSE

Street and Area Lighting Attachment License(s) is hereby granted to make the Attachment(s) described in this application, identified as License No(s).:_______________ as Attachments to Structures as indicated on the attached Form A-2.

Date License Granted _______________

The Narragansett Electric Company d/b/a National Grid

By (Print Name)_______________________________________

Signature____

Title____

Telephone No. ___________________ Email _____________________________

NOTES:
1. Applications shall be submitted to Company.
2. Applications to be numbered in ascending order.
3. Company will process in order applications are received.

Agreement Number XXXX **Form A-2**
Application Number ___________ (to be provided by Company)

NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID

APPLICATION FOR
STREET AND AREA LIGHTING ATTACHMENT LICENSE DETAIL

Date of Application: ___________ Customer Name: ___________________________

Jurisdiction where Street and Area Lighting Attachment is to be made:
____
(Note: One Attachment request per Form A-2. Additional locations should be submitted on separate Form A-2.)

Attachment Electrical Feed Type: Overhead ___ Underground ___

Location Reference Information:
Street Name ____
Pole Number ___________ Pole Suffix ________
If underground fed, location of connection point: ___________________________________

Attachment Description:
Fixture Source Type: __________________ (Light Emitting Diode, High Pressure Sodium, etc.)

Nominal Wattage: _______
(Total System Wattage inclusive of the entire HID luminaire or LED device, ballast/driver, control device, color temperature and environment adjustment factor. Include manufacturer's specification and/or catalog sheet.)

Billing Information:
Bill to existing unmetered S-05 Bill Account? If yes, enter account #: _________ - __________
If no, a new account will be created by the Company.

Operating Schedule per Company's S-05 Tariff:
Dusk-to-Dawn ____ Continuous Operation ____
Part-Night ____ Dimming ____

Is this replacing an existing Customer-owned street or area light?:Yes ____ No ____

Note: A field survey may be required and if so, the Customer will be charged the Field/Office Survey Charge.

____ (Yes/No) CUSTOMER HEREBY REQUESTS COMPANY TO PROVIDE AN ITEMIZED ESTIMATE OF MAKE READY WORK REQUIRED AND ASSOCIATED CHARGES (APPENDIX II FORM C).

By (Print Name)____

Signature____

Title____

Telephone No.______________________ Email ____________________________

Agreement Number XXXX
Application Number __________

Form B-1

NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID

ESTIMATE FOR FIELD/OFFICE SURVEY

Customer Name: ____________________________

In accordance with the Agreement for Customer-Owned Street and Area Lighting Attachments, dated __________, the following is a summary of the charges which will apply to complete a field survey covering Application Number ____________.

	Unit Quantity		Rate / Unit		Total
Field/Office Survey	_________	x	$__________	=	$ _______________
Ancillary Services	_________	x	$__________	=	$ _______________
Administrative Compensation			__________ %	=	$ _______________
			TOTAL		$ _______________

If you wish us to complete the required field survey, please sign this copy below and return with an advance payment in the amount of $ _______________.

Date _______________

The Narragansett Electric Company d/b/a National Grid

By (Print Name)____

Signature____

Title____

Telephone No.______________________ Email __________________________

AUTHORIZATION FOR FIELD SURVEY

The required field survey covering Application Number ___________ is authorized and the costs therefore will be paid to Company in accordance with Appendix I to Agreement for Customer-Owned Street and Area Lighting Attachments.

Date _______________

By (Print Name)____

Signature____

Title____

Telephone No.______________________ Email ___________________________

Agreement Number: XXXX
Application Number ___________

Form B-2

NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID

MAKE-READY WORK ESTIMATE

Customer Name: ____________________________

Field survey work associated with your Application for Street and Area Lighting Attachment License Number ___________ dated __________, for Attachment to Joint-Owned or Sole-Owned Poles or Underground Structures has been completed. The following is a summary of the charges which will apply to complete the required Make-Ready Work to support the Customer-requested Attachment(s).

TOTAL MAKE-READY CHARGES $ _______________

Attached as requested, is an itemized description (Form C) of required Make-Ready Work. A cost estimate of associated Make-Ready Work is also attached. If you wish us to complete the required Make-Ready Work, please sign the authorization below and return with an advance payment in the amount of $_______________.

Date ____________________

The Narragansett Electric Company d/b/a National Grid

By (Print Name)____

Signature____

Title____

Telephone No.______________________ Email ___________________________

AUTHORIZATION FOR MAKE-READY WORK

The Make-Ready Work associated with Application for Street and Area Lighting Attachment License Number ___________ is authorized and the costs therefore will be paid to Company in accordance with Appendix I to Agreement for Customer-Owned Street and Area Lighting Attachments.

Date ____________________

By (Print Name)____

Signature____

Title____

Telephone No.______________________ Email __________________________

Agreement Number XXXX
Application Number ___________

Form C

NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID

<u>ITEMIZED MAKE-READY WORK</u>

Sheet ___ of ____	Customer:
Prepared By:	Jurisdiction:
Date Prepared:	

LOCATION REFERENCE INFORMATION		MAKE-READY WORK REQUIREMENTS	
Pole or Structure Reference No.	Location No. (Street)	Qty.	Description of Work

Agreement Number: XXXX **Form D**

NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID

NOTIFICATION OF DISCONTINUANCE OF STREET OR AREA LIGHTING ATTACHMENT

Customer Name: ___________________________

Street Address____

City, State, Zip Code____

In accordance with the terms and conditions of the Agreement for Customer-Owned Street and Area Lighting Attachments dated __________, notice is hereby given that specific Attachment to Joint-Owned or Sole-Owned Pole or Underground Structure, as listed below, covered by permit number ____________ was removed on _______________________.

Attachment License No.	Location Reference Street Address	Pole or Structure Reference No.	Attachment Description	Removal Date

Total quantity of Attachments upon Poles and/or within Structures to be discontinued is _______________.

Date ____________________

By (Print Name)____

Signature____

Title__________________________ Email _____________________

ACKNOWLEDGMENT OF DISCONTINUANCE OF STREET AND AREA LIGHTING ATTACHMENT

Use of Joint-Owned or Sole-Owned Pole or Underground Structure has been discontinued as above.

Date ____________________

The Narragansett Electric Company d/b/a National Grid

By (Print Name)____

Signature____

Title__________________________ Email _____________________

Form E

IDENTIFICATION OF OWNERSHIP LABELS

(A) GENERAL

This Appendix describes identification labels to be installed and maintained by Customer on its luminaires, cables and other apparatus to allow Company to readily identify the owner of such luminaires, cables and apparatus.

(B) DESCRIPTION OF IDENTIFICATION LABELS

STREET LIGHT PROPERTY OWNED AND OPERATED BY ***CUSTOMER'S NAME***

FIGURE 1: Ownership Identification Label

The label shall be in a form mutually agreed upon by the Parties. Customer shall be responsible for maintaining the legibility of ownership identification labels at all times.

The Ownership Identification Label shall be placed on Customer's facilities including, but not limited to, luminaires, cables, Guy Strands, terminals, terminal closures, and cabinets. The Identification Label shall read as follows: "STREET LIGHT PROPERTY OWNED AND OPERATED BY" and clearly display Customer's name. Customer's name may be printed on the label using indelible ink.

(C) PROCUREMENT OF LABELS

It shall be the responsibility of Customer to obtain, place, and maintain Ownership Identification labels.

(D) INSTALLATION OF OWNERSHIP IDENTIFICATION LABELS

When required by Section 3.3, Ownership Identification Labels shall be installed at the following locations:

(1) AERIAL APPLICATIONS

(a) On each luminaire, on the bottom of the luminaire so that it is visible from the ground.

(b) On cables at each pole on the bottom of the cable so that it is visible from the ground.

(c) On cable risers at each pole, on the riser conduit approximately 6' above

IDENTIFICATION LABELS – Continued

ground.

(d) At anchor and guy locations.

(e) Between the device used to secure the strand (i.e., strand vise, guy grips or clamps) and the eye of the rod, or

(f) If a guy shield is in place, at the top of the guy shield on the strand.

(g) At terminal or Connection Point locations, at the neck of the terminal.

(h) At cabinets, on the front of the cabinet.

(2) UNDERGROUND APPLICATIONS

(a) On cables at each manhole or handhole, on the top of the cable so that it is visible from outside the manhole or handhole.

(b) At terminal or Connection Point locations.

(c) Within cabinets or other equipment where appropriate.

LIGHTING SOURCE IDENTIFICATION LABELS

The Customer is required to provide and affix to each luminaire a clear, legible and comprehensive lighting source identification label consistent with ANSI-NEMA Standards for Roadway and Area Lighting Equipment – Luminaire Field Identification, (ANSI/NEMA C136.15, latest revision) or other industry standard compliant with the specific lamp or lighting source, as applicable.

Form G

ACKNOWLEDGEMENT FOR THE USE OF QUALIFIED ELECTRICAL WORKERS

The Customer Name hereby acknowledges and agrees to the following:

1. The Narragansett Electric Company, d/b/a National Grid (hereinafter "National Grid") expects the use of electrically-qualified personnel as required by OSHA in 29 CFR 1910.269 for all work associated with the AGREEMENT FOR CUSTOMER-OWNED STREET AND AREA LIGHTING ATTACHMENTS BETWEEN THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID and CITY/TOWN OF CUSTOMER NAME DATED MONTH __, YEAR (hereinafter "CUSTOMER NAME AGREEMENT").

2. The Customer Name hereby agrees that any work being done pursuant to CUSTOMER NAME AGREEMENT will be done by qualified electrical workers as defined by OSHA in 29 CFR 1910.269 and in accordance with all relevant laws, regulations, codes, and industry standards.

3. The Customer Name understands and agrees that any injuries to persons or property arising out of or related to this work, including without limitation as a result of a failure to comply with this ACKNOWLEDGMENT, will be the sole responsibility of the Customer Name pursuant to ARTICLE 9.0 of CUSTOMER NAME AGREEMENT, except to the extent attributable to the negligence or willful misconduct of National Grid.

CUSTOMER NAME

BY: ____
NAME: ______________________
TITLE: ______________________
DATE: ___/___/2017

PUC 3-41

Request:

How is Narragansett Electric proposing to collect its annual contact voltage expense?

Response:

Narragansett Electric is proposing to collect its annual contact voltage expense as a component of the Inspection & Maintenance costs included in the electric Infrastructure, Safety, and Reliability (ISR) O&M Factors. Therefore, seven months (September through March) of actual contact voltage costs would be included in the proposed revenue requirement submitted in the Company's Fiscal Year 2019 electric ISR reconciliation filing. The test-year level of contact voltage expense ($221,720) has been removed from the cost of service for Narragansett Electric in the Company's filing in this docket through a normalizing adjustment made to Other Operation & Maintenance expense.

Prepared by or under the supervision of: Melissa A. Little

PUC 3-42

Request:

How many mobile home parks are customers of National Grid in Rhode Island?

a. Of these mobile home parks, how many are master metered?

b. If they are master metered, how what is the rate class under which they are billed?

c. Can individual residents of the mobile home parks qualify for the income eligible rates and programs offered by National Grid?

Response:

The Company is not able to quantify how many of its customers are mobile home parks.

a. Since the Company cannot identify customers that are mobile home parks, it does not know how many are master metered.

b. If a mobile home park were master metered, the account would be set up under one of the Company's general service rates, depending on the usage of the mobile home park as measured by the master meter.

c. If individual residents of a mobile home park are individually metered and qualify to receive retail delivery service on the Residential Low Income Rate A-60 (Rate A-60) pursuant to the availability provision of the Rate A-60 tariff, then an individually-metered residential customer is eligible to receive retail delivery service on Rate A-60 and will be transferred to Rate A-60 upon the Company's receipt of the appropriate documentation of their qualification for the rate.

PUC 3-43

Request:

Please outline your procedures and policies for collection of unpaid utility bills for each rate class, for protected and non-protected residential customers, for the months during the winter moratorium and the non-moratorium period.

Response:

Residential Rate Classes: Non-Protected

Non-Moratorium

Three business days following the issuance of the Disconnect Notice, the accounts enter the three-day Residential Disconnect Notice Call File. Seven business days after the conclusion of that Call File, the accounts become eligible for service termination. Low income customers are not protected during cut season.

Winter Moratorium

Three business days following the issuance of the Disconnect Notice, the accounts enter the three-day Residential Disconnect Notice Call File. Seven business days after the conclusion of that Call File, the accounts become eligible for the affidavit process, where the Company attempts to notify the customer in person before terminating service:

Field Collectors attempt a "business hours" visit and, if no contact is made on that visit, an "after hours" or Saturday visit is required.

- If contact with anyone at the premises is made (it does not have to be the account holder), the customer is notified that service could be terminated in 48 hours. The contact is noted on the Affidavit Form, which is notarized and sent to the Division of Public Utilities and Carriers (the Division).
- If no contact is made on both the "business hours" and "after hours" visits, the outcome is noted on the Affidavit Form, which is notarized and sent to the Division.
- In both instances, the account is eligible to be cut in 48 hours, if the Company does not hear anything to the contrary from the Division.

Customers with no collection handling protections are still protected during the period of the winter moratorium. This period is defined as November 1 through April 15. If a customer has heat-related service, in order for the Company to disconnect service, the minimum arrears must exceed $500. If the customer has non-heat service, the minimum arrears must exceed $200. It is assumed that electricity is required to run heating systems.

Residential Rate Classes: Protected

Non-Moratorium

Customers identified as elderly, handicapped, infant hardship, financial hardship, or low income are issued Protection Termination Notices and Affidavits as provided in the Public Utilities Commission's Rules and Regulations Governing the Termination of Residential Electric, Gas and Water Utility Service (the Termination Rules). Customers identified with a serious illness are not issued field Protection Termination Notices and Affidavits at this time because of the temporary stay related to *Laura Bennett, et al. v. Sidney McCleary, in his official capacity as the Administrator of the State of Rhode Island Division of Public Utilities and Carriers, et al.*, pending in Rhode Island Superior Court, Providence County (C.A. No. PC-15-4214) (the Bennett case).

Elderly and handicapped accounts progress through the following steps:

1. Pre-Petition Letter;
2. Field Protection Termination Notice and Affidavit (10 Days Post Pre-Petition Letter);
3. Petition to Terminate;
4. Receive approval from the Division;
5. Wait 10 Days for elderly/20 Days for handicapped prior to termination; and
6. Terminate services for non-payment.

Winter Moratorium

Customers identified as elderly, handicapped, infant hardship, financial hardship, or low income are issued Protection Termination Notices and Affidavits as provided in the Termination Rules. Customers identified with a serious illness are not issued field Protection Termination Notices and Affidavits at this time because of the temporary stay related to the Bennett case.

Elderly and handicapped accounts progress through the following steps:

1. Pre-Petition Letter;
2. Field Protection Termination Notice and Affidavit (10 Days Post Pre-Petition Letter);
3. Petition to terminate;
4. Receive approval from the Division; and
5. Wait until winter moratorium has ended before moving forward.

Prepared by or under the supervision of: Jody Allison

Non-Residential Rate Classes (non-protected only)

Winter Moratorium and Non-Moratorium

Accounts with overdue balances greater than $50 enter collections. Eligibility for service termination for all non-residential accounts occurs 11 business days following the Disconnect Notice, with the exception of Government and Summary Bill accounts.

Prepared by or under the supervision of: Jody Allison

PUC 3-44

Request:

Please explain the difference between accounts that are classified as uncollectible and those that are classified as having arrearages.

Response:

Any customer account that has an unpaid balance is an account in arrears. Arrears are classified as uncollectible when they are written off in the Company's Customer Service System. This occurs 90 days after an account is finaled.

Prepared by or under the supervision of: Jody Allison

PUC 3-45

Request:

What is an inactive account? At what point does it become inactive?

Response:

National Grid does not use the term "inactive" to describe an account status. National Grid uses the following terms to describe an account's status: "active", "pending active", "pending transfer", "void", "final", "written off", and "escheat". For purposes of responding to this data request, the Company interprets the term "inactive" to means "final". An account enters the final status seven days after it is closed involuntarily for non-payment, or whenever the customer voluntarily closes it. A customer may request voluntary termination of an account with arrears. An account that is finaled voluntarily will always have at least the final bill outstanding when the account is closed. If the account is finaled for 90 days (with arrears), the account status will then change to written off.

Prepared by or under the supervision of: Jody Allison

PUC 3-46

Request:

At what point does an account become uncollectible?

Response:

Please see the Company's response to PUC 3-44.

Prepared by or under the supervision of: Jody Allison

PUC 3-47

Request:

Does an inactive account differ from an uncollectible account?

Response:

The Company does not use the term "inactive" to describe an account status. The Company interprets the question to refer to accounts that the Company describes as "final". An account enters the final status seven days after it is closed involuntarily, or whenever the customer voluntarily closes it. An account becomes uncollectible when the arrears are written off in the customer service system 90 days after being finaled.

Prepared by or under the supervision of: Jody Allison

PUC 3-48

Request:

When is an account written off? Is the process or effect different from classifying an account as inactive?

Response:

The term "written off" is understood by the Company to be identical to "uncollectible". The term "inactive" is understood by the Company to mean "final". Please refer to the Company's response to PUC 3-47 for an explanation of the difference between the terms "final" and "written off/uncollectible".

Prepared by or under the supervision of: Jody Allison

PUC 3-49

Request:

What happens to an account where the customer leaves a balance and then returns months or years later? How is it classified?

Response:

Residential: As part of the Company's account initiation process, customers are required to address any past due balances before they can obtain new active service.

When a customer requests new service or a move, the Company'representative reviews all current and previous accounts for the customer, using the Company's Customer Service System (CSS) to determine whether the customer has any outstanding debt to the Company.

Multiple accounts belonging to a single customer are reconciled with a common customer number. National Grid utilizes Experian's ConnectCheck program to assign a unique identifier (a Personal Identification Number, or PIN) to each National Grid customer with an uncollectible bill. When processing a new service or move request for a customer, Company representatives submit the customer's identification information to Experian. Experian uses that information to retrieve the customer's PIN, perform a search of its database, and notify the Company's representative of any uncollectible bills belonging to the customer. This is an automated process. If the customer has outstanding debt to the Company within the last ten years, before the customer can obtain new active service, the customer is required to pay the balance in full or enter into a payment agreement with the Company to repay the prior balance(s).

If the debt has been sent to a collection agency, it is recalled from the agency and the customer must enter into a payment agreement with the Company to repay the unpaid balance.
The payment agreement offer is mailed, faxed, or emailed to the customer. Once it has been signed and returned to the Company's back office along with any required down payment, back office staff will transfer the debt from the uncollectible account to the new account and establish the payment agreement on the new account.

The Company places a hold on the new service order until the Company receives the required payment from the customer. Once the Company confirms receipt of the required payment from the customer, the Company removes the hold on the new service order and the outstanding balances on any final or written-off accounts connected to the customer are automatically transferred to the customer's newly-activated account.

Prepared by or under the supervision of: Jody Allison

Non-residential: Past-due balances may be transferred in the event that a customer with multiple accounts has an account disconnected (per request or for non-payment) with a remaining balance. Past due balances may also be transferred if an outstanding balance remains on a final or a written-off account.

When a customer requests new service or a move, the representative reviews all current and previous accounts for the customer using CSS to determine whether the customer has any outstanding debt owed to the Company. In the same manner described above for residential accounts, multiple accounts belonging to a single customer are reconciled with a common customer number.

If the new account is in the same legal name as the closed account and the tax ID numbers and business papers are the same, the outstanding balance can be transferred to the new account. However, CSS does not automatically transfer the outstanding balance to the active account. If the debt has been sent to a collection agency, it is recalled from the agency and then applied to the new account.

If the customer inquires about entering into a payment agreement with the Company to repay the transferred balance, the Company will consider offering a payment arrangement if it is reasonable and prudent to do so. In those instances, the Company would consider the size of the transferred unpaid balance, the customer's financial condition, and any special situations that impact the customer's ability to pay.

Prepared by or under the supervision of: Jody Allison

PUC 3-50

Request:

Does National Grid use a collection agency? If so, please explain how that process works. How is the collection agency compensated?

Response:

Yes, the Company uses collection agencies. When an account is finaled with a balance, the following day the account is uploaded into Experian's Tallyman middleware platform. Tallyman manages the referral of accounts to collection agencies.

On, or slightly after, calendar day 90 of this process, any uncollected debt will be written off for both residential and non-residential accounts.

Good-paying customers will see a final bill message on their last bill and receive subsequent final bill notices. If they have not resolved the balance within 60 calendar days, the account is referred to a primary agency.

Poor-paying customers will see a final bill message on their last bill. If they have not resolved the balance within 31 calendar days, the account is referred to a primary agency.

Primary collection agencies (also referred to as the first tier agency) usually have 120 calendar days to collect the outstanding balance. If the balance is not collected in full by the primary agency, the account is recalled for 10 calendar days, and then referred to a secondary agency.

The **Secondary** agency (the second tier agency) has eight months to collect the outstanding balance. If the balance is not collected in full by the secondary agency, the account is recalled for 10 calendar days and then referred to a tertiary agency.

The **Tertiary** agency (the third tier agency) has one year to collect the outstanding balance. After a year assigned to a tertiary agency, the account enters an agency's "Trigger" Program.

Under the **Trigger** Program (also referred to as the fourth tier agency), the agency contracts with a credit reporting agency that will trigger a notice if any positive credit action occurs on the customer's credit report. The collection agency will receive updated contact information after the trigger occurs. The account will remain in the Trigger Program until the end of the statute of limitations, which can last up to 10 years.

Prepared by or under the supervision of: Jody Allison

Collections agencies are compensated on a commission basis. The Company's customer service system allows for net back. An example of net back is, if the agency receives 20 percent commission when collecting $100.00, the agency sends the Company $80.00 on its weekly transmission and the account is credited for $100.00.

Prepared by or under the supervision of: Jody Allison

PUC 3-51

Request:

When does National Grid transfer accounts to a collection agency?

Response:

Please refer to the Company's response to PUC 3-50.

Prepared by or under the supervision of: Jody Allison

PUC 3-52

Request:

Are active customers' arrearages and collections handled internally or by an external third party? Please explain.

Response:

The arrears of active customers are handled internally. Agencies are not used for active customers, but representatives are contracted to perform outbound calling campaigns.

Prepared by or under the supervision of: Jody Allison

PUC 3-53

Request:

During the last three years, what was the annual expense of using a third-party collection agency?

Response:

Please refer to the table below for collection agency commission costs for the last three full calendar years.

Commission Fees Incurred for Collection Agencies			
	2014	**2015**	**2016**
Calendar Year Total	**$989,428.76**	**$1,030,447.97**	**$987,840.68**

Prepared by or under the supervision of: Jody Allison