PBR for the Electric "Utility of the Future"

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Pacific Economics Group Research, LLC

Introduction

The electric utility industry is in a period of rapid change

Traditional cost of service regulation ("COSR") has difficulty accomodating these changes.

Performance based regulation ("PBR") and other forms of incentive regulation ("IR") have been touted by many as needed reforms

This presentation considers the potential role of IR in regulating the "utility of the future"

Plan of Presentations

- The Winds of Change
- Introduction to Incentive Regulation
- Award/Penalty Mechanisms
- Revenue Decoupling
- Multiyear Rate Plans
- Conclusions

Introduction to Incentive Regulation

Traditional Cost of Service Regulation ("COSR")

Base rates adjusted only in general rate cases

- Earnings linked to plant ownership
- Revenue requirement must be allocated between services to set rates

High volumetric charges recover many "fixed" costs

- Earnings sensitive to difference between volume and capacity growth (average use)
- Volume growth exceeding capacity growth produces "gravy" that helps finance cost growth

Winds of Change

The US electric power industry is experiencing sweeping change today

Mounting environmental concerns have triggered policy changes

- Renewable portfolio standards
- New emissions restrictions
- Expanded DSM programs
- Subsidies for electric vehicles

Gas-fired generation is low cost choice

Solar & gas fired distributed generation ("DG") increasingly cost competitive

Most utilities acquire solar surpluses via net metering

Winds of Change (cont'd)

Sluggish economic growth; states compete for manufacturing jobs

Aging plant jeopardizes reliability, increases O&M expenses

Rapid change in metering & distribution (aka "smart grid") technologies

- TOU pricing more feasible
- Makes value added services possible
- May ultimately lower cost of reliability attainment

Some customers want cleaner, more reliable power

Impact of Change

Utilities need fewer generating plant additions

Additions that are made are smaller

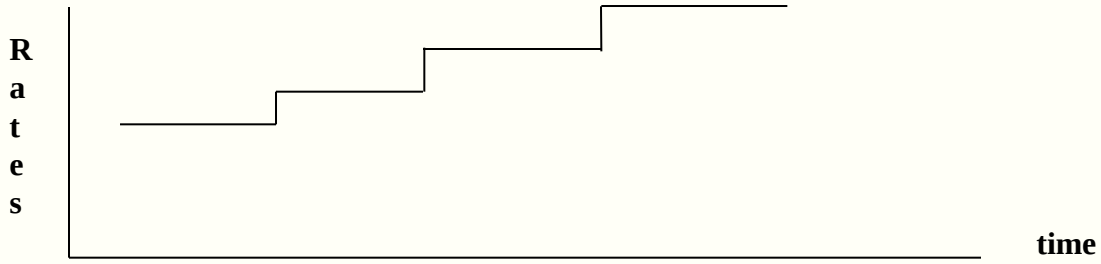
No “gravy” from brisk volume growth

Smart grid investments have less % impact on vertically integrated electric utility (“VIEU”) cost

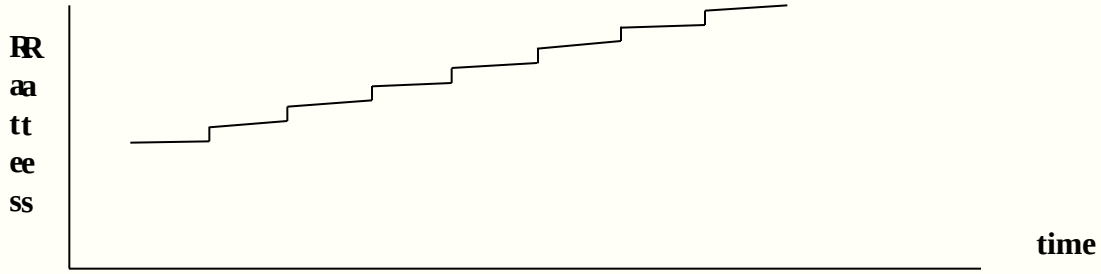
>>> VIEUs need smaller, more frequent rate increases

Typical Rate Escalation Patterns: VIEUs

Traditional



Contemporary



Impact of Change (cont'd)

Utilities face increased competition, should mind cost & quality

Utilities need more operating flexibility

- More cost causative (e.g. TOU) tariffs
- Special tariffs for price sensitive large load customers
- Optional rates and services

  (e.g. Premium quality, clean energy, smart grid–facilitated services, DG?)
- Solar purchase tariffs that vary by location, time of day

Problems With Traditional Regulation

Utilities profit by building plant & boosting system use

>>> Disincentive to aggressively promote DSM and DG

Smart grid, DG increase rate case complexity

Marketing flexibility discouraged

- Limited rate and service offerings
- Rate designs inflexible, send wrong price signals
- DG can lead to cross-subsidies, uneconomic bypass

Problems With Traditional Regulation (cont'd)

Frequent rate cases are problematic

Weaker cost containment & marketing incentives

High regulatory cost discourages other worthwhile activities

- Generic proceedings
- Utility planning proceedings

Marketing flexibility restricted

- Concerns about cost allocations & cross subsidies
- Higher regulatory cost

But utilities more incented to make investments, promote DSM & DG

Alternative Regulation

Alternative regulation ("Altreg") encompasses diverse alternatives to COSR

Targeted Remedies (aka "Single Issue Ratemaking")

- Cost Trackers
- Revenue Decoupling
- Award/Penalty Mechanisms ("APMs")

Comprehensive Remedies

- Multiyear Rate Plans ("MRPs")
- Formula Rate Plans

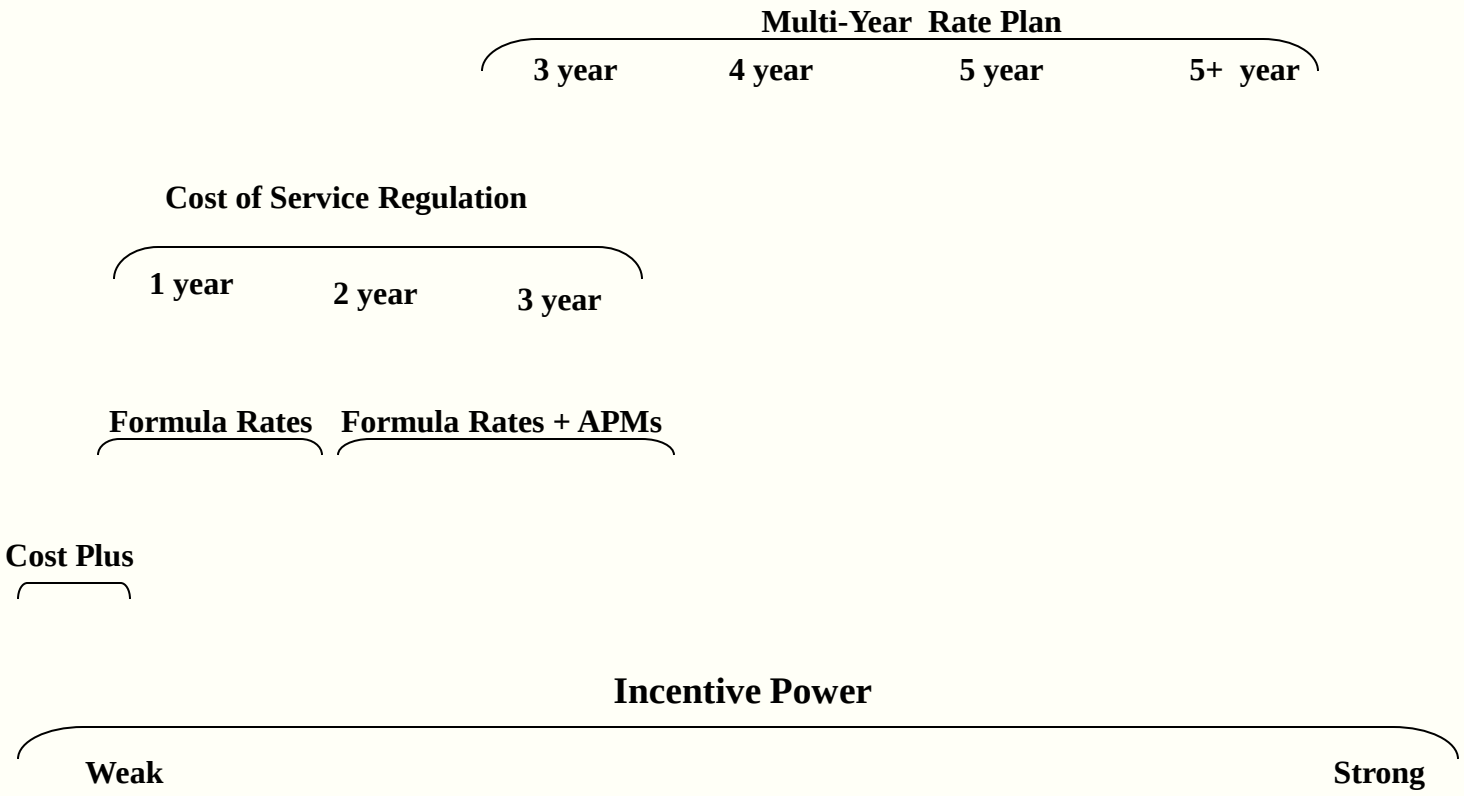
Incentive Regulation

"Incentive power" of regulatory options varies

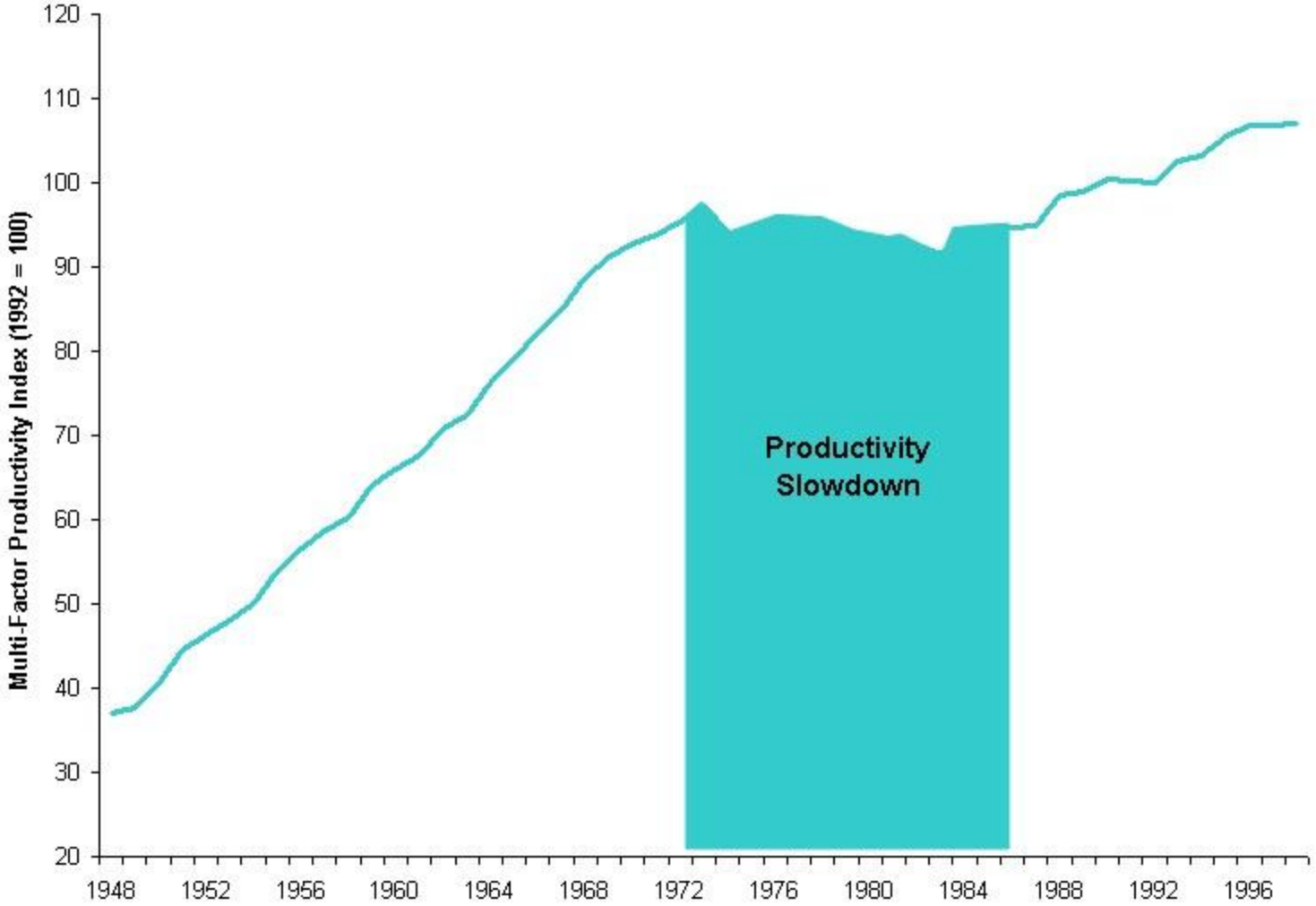
Incentives under COSR vary with business conditions

Conditions	Rate Cases	Cost Control Incentives
favorable	infrequent	stronger
unfavorable	frequent	weaker

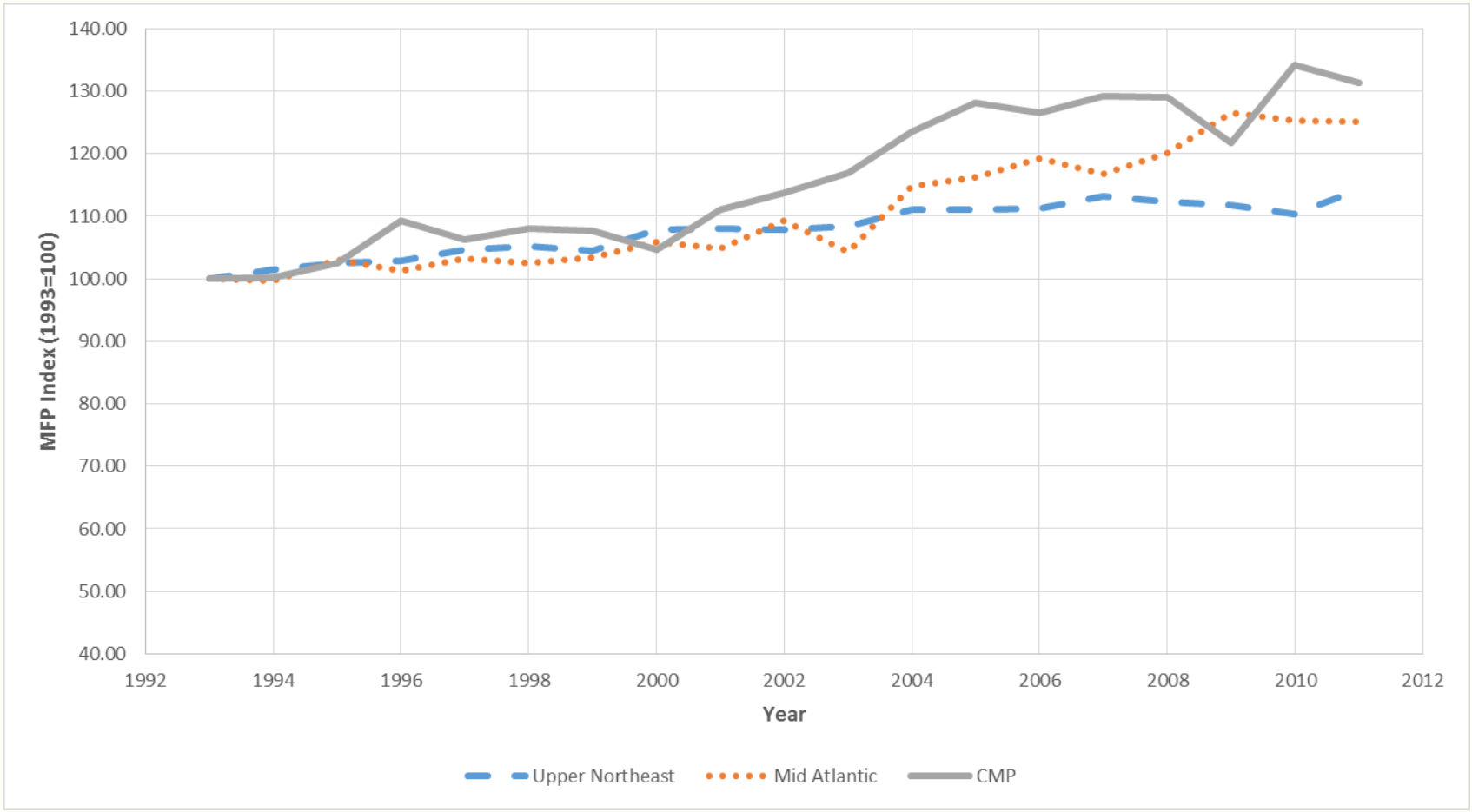
Cost Containment Incentive Spectrum



Productivity Trend of Electric, Gas, and Sanitary Utilities



Distribution Productivity Trends of Central Maine Power and Two Northeast Regions



Incentive Regulation (cont'd)

Incentive Regulation

An approach to regulation that bolsters utility performance incentives by linking financial returns to performance

- Award/Penalty Mechanisms
- MRPs
- Revenue Decoupling (?)

Typically also involves lower regulatory cost & greater operating flexibility

>>> Advance in regulatory "technology"

Incentive Regulation (cont'd)

Performance Based Regulation (PBR)

An approach to incentive regulation calibrated to yield superior returns for superior performance

Typically involves statistically-based benchmarks

"Results-Based" Regulation

A British-style MRP in which APMs figure prominently (?)

Formula Rates

Revenue requirement adjusted annually to reflect pro forma cost of service --- "cost of service formula"

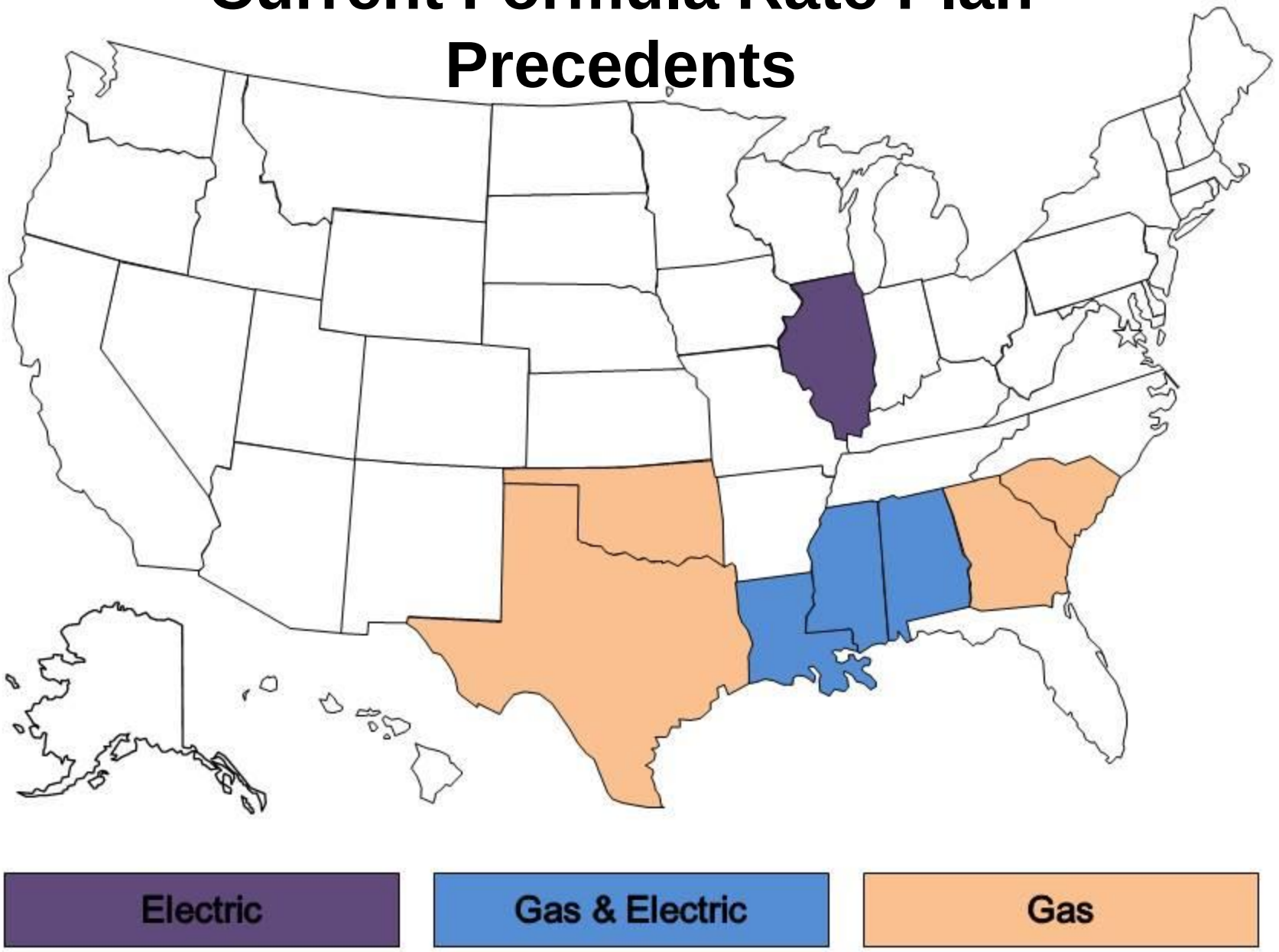
Southeast variant: reset rates automatically to achieve target ROE when actual (or forecasted) ROE differs materially

Expedited prudence reviews

"Bells & whistles" may strengthen incentives

- Historical review window
- ROE deadband
- *growth Revenue$^{O\&M}$ < Growth CPI+ 0.5%*

Current Formula Rate Plan Precedents



Award/Penalty Mechanisms

Basic Idea

Strengthen incentives in targeted areas by linking revenue to performance appraisal

APM Award/Penalty = $ x (SAIDI - SAIDI bench)

Key Performance Indicator ("output") quantifies behavior e.g. SAIDI

Performance Benchmark e.g. SAIDI bench

Performance Appraisal e.g. SAIDI - SAIDI bench

Award/Penalty Rate e.g. "$"

Performance sometimes summarized in "scorecard"

Key Design Issues

APM vs Monitoring

Symmetry

Award/penalty rates

Basis for benchmark (company history or industry norms)

Choice of outputs

- Relevant
- Quantifiable
- Verifiable
- Controllable

Outputs

Reliability
- SAIDI
- SAIFI
- CAIDI

Cost
- Generation Capacity Factor
- Line losses
- Consumption on inactive meters
- Uncollectible bill expense
- Retail Revenue/kWh

Safety

OSHA reportable rate (ratio of OSHA-reportable lost time injuries & illnesses to total hours worked by employees)

Outputs (*cont'd*)

Customer Service

- Customer complaints
- Telephone response time
- Invoice accuracy
- Number of estimated bills
- Customer satisfaction

AMI

- Customer participation in dynamic pricing pilots
- Reduction of peak load amongst customers participating in dynamic pricing pilots

Outputs (*cont'd*)

DSM

- % of retail sales avoided
- % of net benefits

Renewables

- % of consumption from all renewables
  solar DG
- % of net benefits from all renewables
  solar DG
- Average days to process DG connection requests

Revenue Decoupling

Revenue Decoupling

Revenue decoupling mechanism ("RDM") ensures revenue requirement recovery using balancing accounts, true ups

Pros & cons

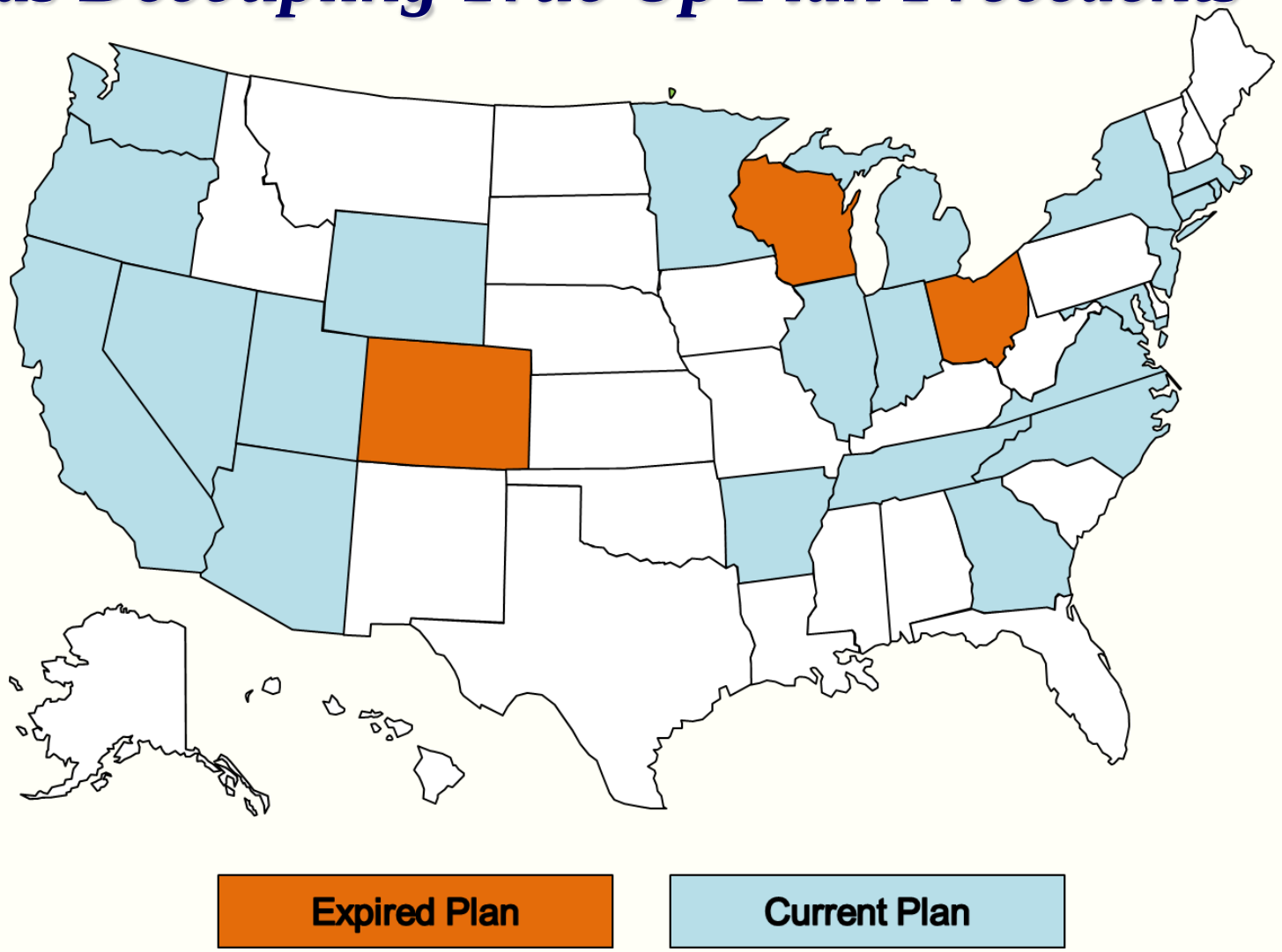
- Removes utility disincentive to promote DSM and DG without restrictive rate designs
- Cost causative rates are cost management tool
- Also removes incentive for *desirable* marketing

Design Issues

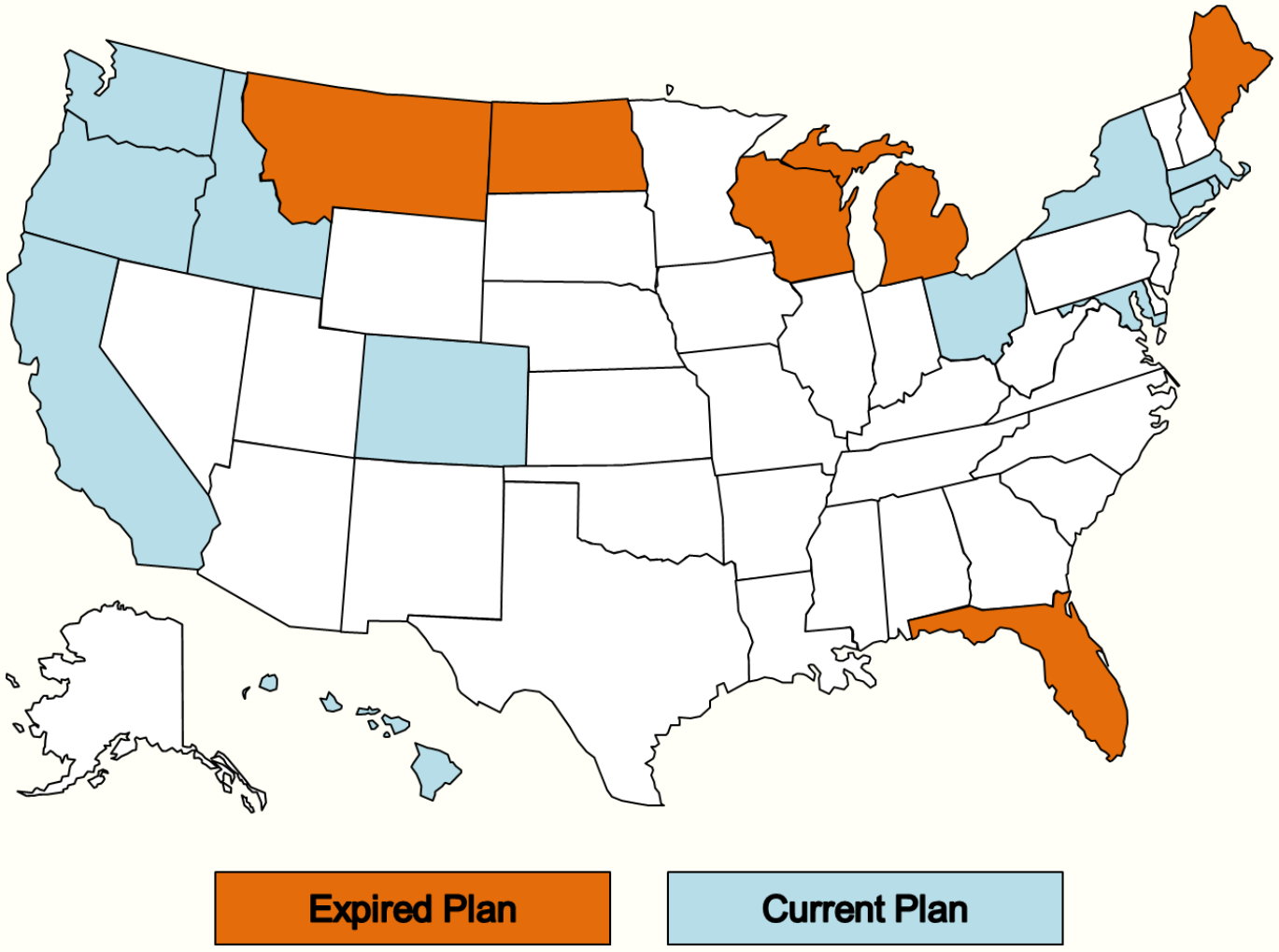
- Application to electric vehicles, price sensitive large load customers, optional rates and services

Revenue Adjustment Mechanism ("RAM") adjusts revenue requirement automatically between rate cases

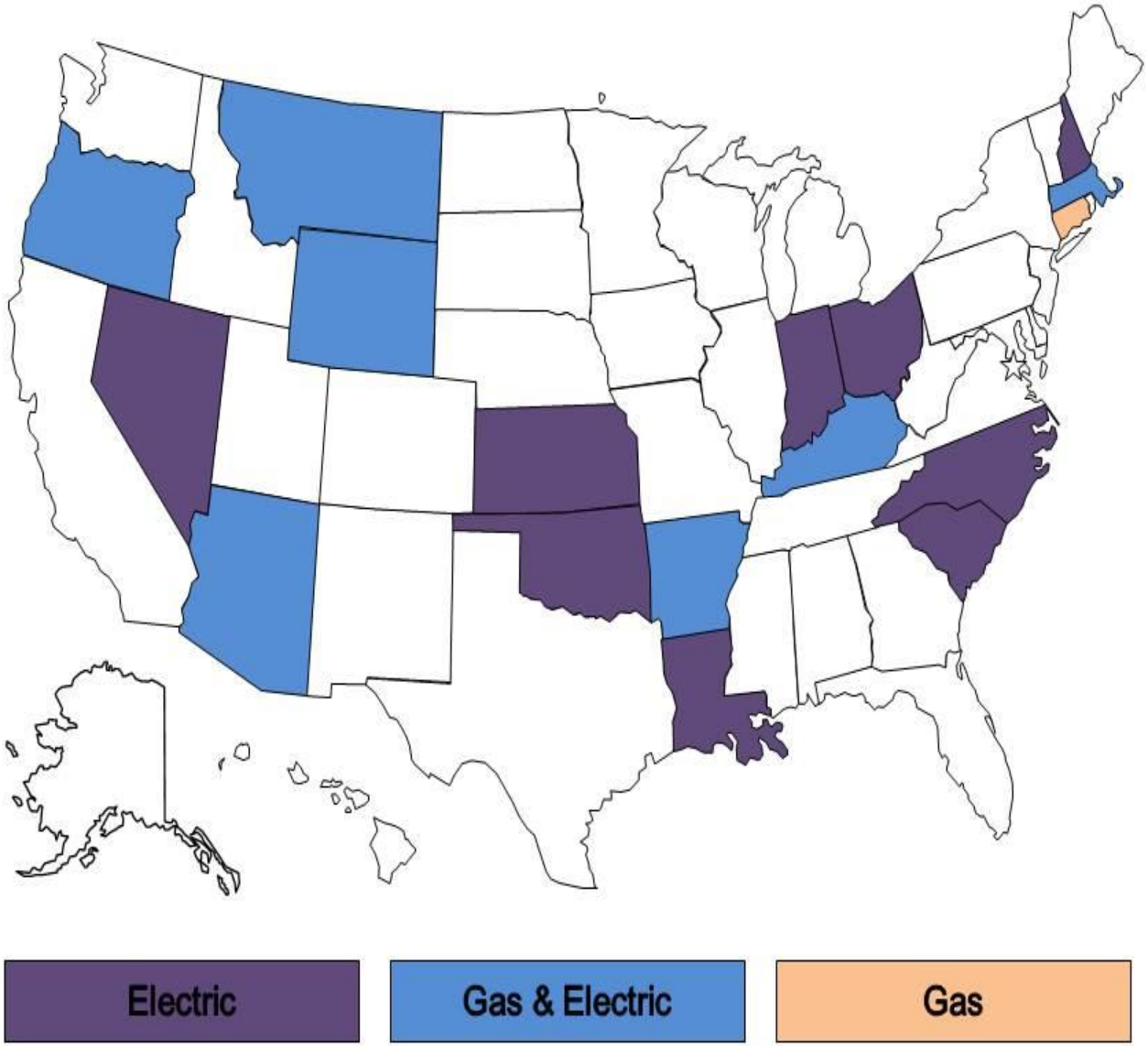
Gas Decoupling True Up Plan Precedents



Electric Decoupling True Up Plan Precedents



Recent LRAM Precedents



Revenue Adjustment Mechanisms

Under decoupling,

growth Rates = growth Revenue Requirement
– growth Billing Determinants

>>> If billing determinants rise, rates would *decline* if revenue requirement fixed

Revenue requirement should, in any event, grow with cost

Solutions: Frequent rate cases
RAM

>>> Vast majority of decoupling plans have RAMs

"Broad based" RAMs make MRPs possible

Multiyear Rate Plans

MRPs (aka "price controls") are world's most common form of Altreg

MRP Basics

Rate case moratorium (4-5 year rate case cycle typical)

Attrition relief mechanism ("ARM") provides automatic relief for changing business conditions

- Rate caps
- Revenue caps (often combined with RDM)

Some costs addressed separately via trackers

APMs incentivize behavior in other areas (e.g. reliability)

MRP Basics (cont'd)

Marketing Flexibility

MRPs (especially *price* caps) can afford utilities more flexibility

Gradual redesign of tariffs (cost causative rates help lower cost)
Light-handed regulation of special contracts
optional tariffs and services
special service bundles

Many plans feature earnings sharing mechanisms ("ESMs")
off ramps

Efficiency Carryover Mechanism ("ECM")

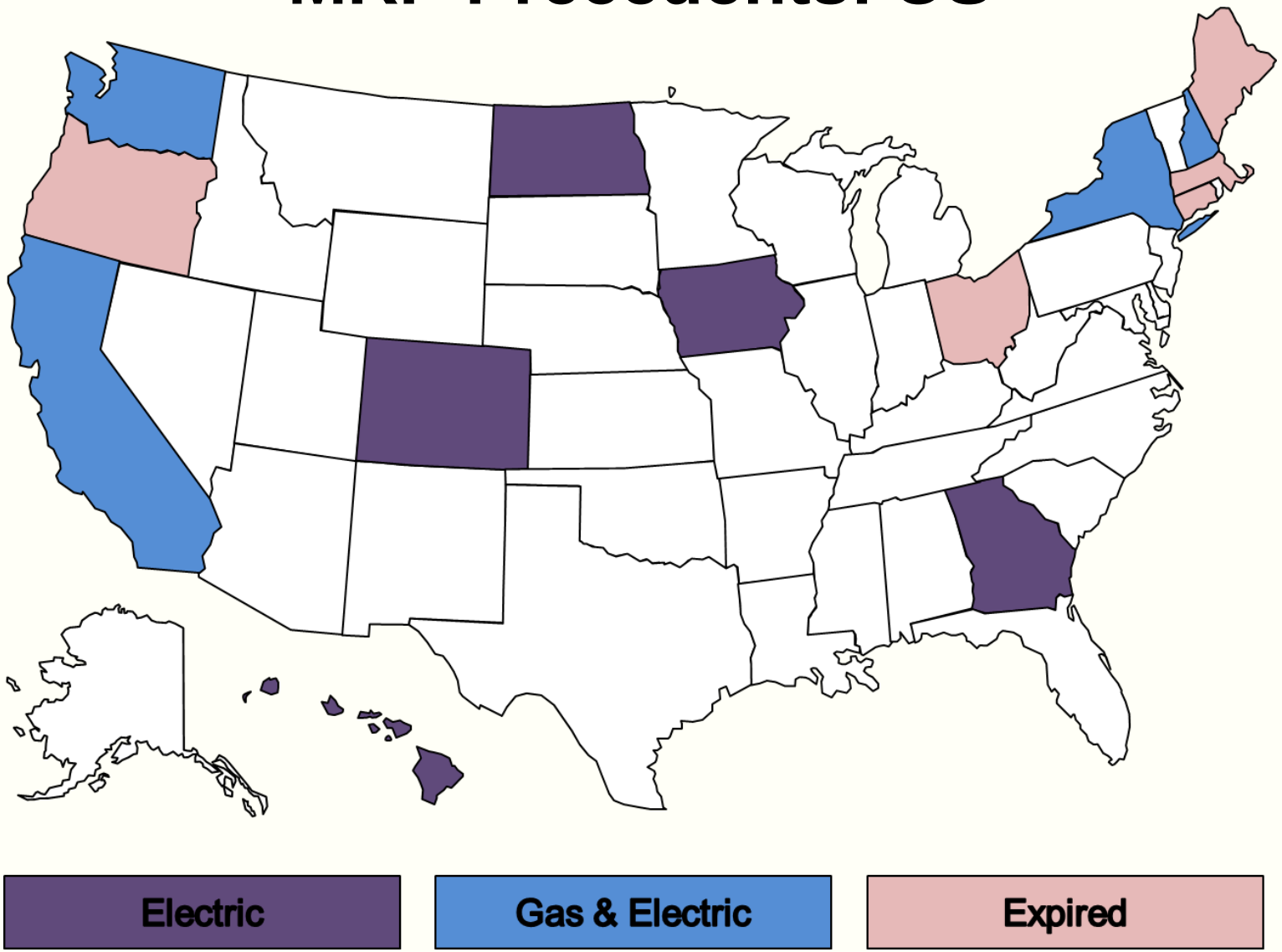
Basic Idea Revenue requirement not 100% trued up to cost in next rate case

>>> Keep some benefits of superior performance

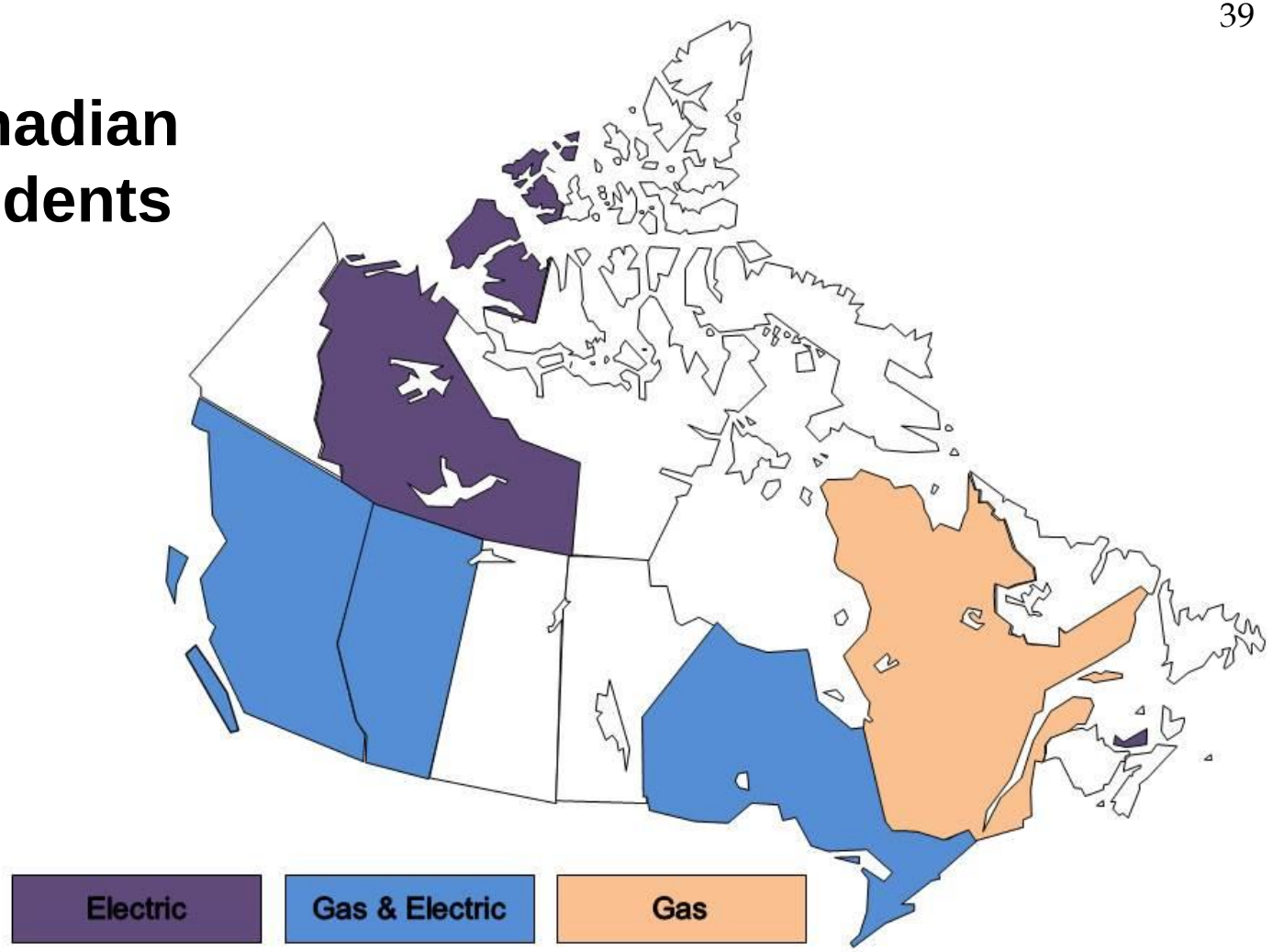
Absorb some costs of inferior performance

Discourage opportunistic timing of expenses

MRP Precedents: US



Recent Canadian MRP Precedents



MRPs ubiquitous overseas (*e.g.* Australia, Britain, Germany, NZ)

ARM Design

Biggest issue in an MRP proceeding

3 well-established approaches to ARM design

- Indexing
- Stairstep
- Hybrid

Regulatory cost of implementation varies

All may coexist with cost trackers

We discuss here the design of *revenue* cap escalators (RAMs)

Indexed ARMs

Basic Idea Indexing formula based on industry cost research

growth Revenue = Inflation - X + growth Scale + Y + Z

X = "X-factor" (aka "productivity offset")
Y = "Y factor" recovers costs that are hard to index (*e.g.* energy, major plant additions)
Z = "Z-factor" adjusts rates for miscellaneous events (*e.g.* severe storms)

Current Precedents: CalPECO, ALTA, BC, ON & NZ distributors
US oil pipelines

Indexed ARMs (cont'd)

Cost theory provides rationale for formula

trend Cost = trend Input Prices – trend Productivity + trend Scale

X factors commonly based on index research

e.g. Input price & productivity trends of utility peer group

0.47% recent productivity trend of VIEUs much slower than 3% input price inflation

"Stretch factor" (typically 0.2-0.5%) often added to X to share benefits of faster productivity growth

Indexed ARMs (cont'd)

If inflation = productivity growth,

$$growth\ Revenue = growth\ Customers + Y + Z$$

>>> Revenue per customer "freeze"

Precedents: Common approach to regulating US gas distributors

Rarely provides basis for MRP

Stairstep ARMs

Predetermined fixed increases in allowed revenue gives them "stairstep" trajectories

e.g. 3% in 2015, 2.5% in 2016 etc.

Various methods used to establish "risers"

Terms often negotiated

Precedents: NSP (ND), PS Colorado, Puget Sound, Georgia Power, SDGE, PG&E & New York distcos

Hybrid ARMs

Hybrid approaches combine elements of indexing & forecasts

North American Approach

Different RAM design approaches to address different costs

O&M expenses	Indexing
Capital	Stairsteps

Precedents: "Old School" California approach
Southern California Edison
Hawaiian Electric

Hybrid ARMs (cont'd)

British/Australian (aka "Building block" or "RPI-X") Variant

Given forecasts of growth in

- Cost
- Macroeconomic price index ("RPI")
- Billing determinants

choose RPI – X formula which has equivalent NPV

Benchmarking, index-based escalators increasingly used for O&M budget (*e.g.* Australia)

Marketing Flexibility

MRPs with index-based *price* caps developed in 1980s to regulate utilities facing competition (*e.g.* Railroads, Telecom, Oil Pipelines)

- Price caps most restrictive for core (*e.g.* residential) services
- Greater flexibility for new services, more competitive markets

Central Maine Power enjoyed extensive marketing flexibility in 1990s under index-based price caps

- Discounts
- Special Contracts
- New services

RIIO

Britain has regulated utilities using MRPs since 1980s

RIIO (**R**evenue set to deliver strong **i**ncentives, **i**nnovation, & **o**utputs) is latest iteration

Evolution, not revolution

Already implemented for power transmission, gas. Begins 2015 for 14 power distributors

Similar regulation in Australia

RIIO Basics

MRPs with *8 year* terms (2015-2023)

Revenue cap with "building block" design

- Ofgem must consider complicated multiyear business plans
- Extensive use of benchmarking to determine revenue requirement
- "Information Quality Incentive" discourages utility forecast games

Up to 30 months to process filings

"Proportionate treatment" policy rewards good proposals

ESM sharing rate (aka "efficiency incentive rate") depends on efficiency

RIIO Basics (cont'd)

Innovative use of cost trackers

- AMI
- Improve performance to worst-served customers
- Annual Network Innovation Competition for clean energy projects
- Network Innovation Allowance in each company's budget
- Innovation Rollout Mechanisms provide supplemental funds for rolling out innovations

RIIO Basics (cont'd)

Extensive array of APMs include innovative outputs

- DG connection time
- Business carbon footprint
- Social obligations to vulnerable consumers

Reliability penalties include direct payments to customers

Some APMs are award only

APMs supplemented by monitoring of "secondary" outputs

Conclusions

Reforms will needed to regulate "utility of the future"
This reform package seems indicated For the foreseeable future

Incremental Reforms

Extend formal planning process to incorporate DG and distribution (and transmission?)

Redesign rates for utility services and DG purchases

- More cost causative
- Time (and possibly location) varying

Revise/expand APMs for DG

Further encouragement for EVs

Encourage innovative smart grid and DG pilots

More Sweeping Reforms

Revenue decoupling (or LRAMs)

<u>Multiyear Rate Plans</u>

Longer plan terms

Some kind of ARM (could be separate ARMs for G&D)

Judicious use of cost trackers

- Major plant additions
- Costs of DSM and DG
- Innovative "pilot" projects

Greater utility marketing flexibility

- Gradual redesign of tariffed rates
- Light-handed regulation of optional rates and services

Appendix

PEG Research

Pacific Economics Group Research, LLC

Pacific Economics Group

Consortium of economic consulting firms with common heritage

- Pacific Economics Group LLC (Pasadena, CA)
- Pacific Economics Group Research LLC (Madison, WI)

Principals include five respected PhD economists

- Charlie Cicchetti, University of Southern California
- Jeffrey Dubin, UCLA
- Mark Newton Lowry
- Larry Kaufmann
- Blaine Gilles

PEG Research LLC

Leading North American Altreg consultancy

60+ person years of Altreg experience

Benchmarking, marketing flexibility are other specialties

Multinational practice, many Canadian & ANZ projects

Diverse client base	Utilities
	Trade Associations
	Regulators
Altreg Services	Plan design
	Empirical (*e.g.* productivity) research
	Expert witness testimony

Altreg Clients: Electric

Alberta Power
Atlantic City Electric*
Arizona Public Service
Baltimore Gas & Electric
Bangor Hydro Electric*
BC Transmission
Energy Efficiency Resource Management Council
Entergy
Bundesnetzagentur (Ger)
Vectren
Canadian Electricity Association
Central Maine Power*
Central Vermont Public Service*
Commercial Energy Consumers of BC*
Commonwealth Edison*
Commonwealth Electric
Consumers' Coalition of Alberta*
EPCOR
Delmarva Power & Light
Detroit Edison
Georgia Power*
Hydro One Networks *
Kentucky Utilities*
Edison Electric Institute
Electricity Association of New South Wales
Energy Safe Victoria
Essential Services Commission* (Aus)
Electric. Assn. New South Wales (Aus)
Electricity Networks Association (NZ)
Electric Power Research Institute
Electric. Supply Ass. Australia (Aus)
Hawaiian Electric*
Hawaiian Electric Light*
Maui Electric*
Hydro Quebec*
TXU Electric*
TXU Australia* (Aus)
Louisville Gas & Electric*
Newfoundland Dept. of Natural Resources
National Electricity Distributors Forum (Aus)
Pacific Gas & Electric
Portland General Electric
Potomac Electric Power*
Puget Sound Energy
Northern Electricity Distribution (UK)
Niagara Mohawk Power*
SPI Net (Aus)
Yorkshire Electricity Distribution
Tokyo Electric Power
National Grid
Public Service of Colorado*
NSTAR Electric & Gas*
Oklahoma Gas & Electric*
United Energy
United Networks
Ontario Energy Board*
Pacific Gas & Electric*
Public Service Electric & Gas
Southern California Edison
Public Service of New Mexico
SPAusNet (Aus)
SPI Networks (Aus)
Queensland Competition Authority (Aus)
San Diego Gas & Electric*
TXU
United Utilities
Unitil
Yorkshire Electricity Distribution (UK)*

***Testimony**

Altreg Clients: Gas

Atlanta Gas Light*
BC Gas*
Baltimore Gas & Electric
Bay State Gas*
Boston Gas*
Canadian Gas Association
Commercial Energy Consumers of BC*
Comision Reguladora de Energia (Mex)
Consumers' Coalition of Alberta*
Gaz Metro*
Enargas (Arg)
Enbridge Gas Distribution
Essential Services Commission (Aus)
Illinois Power
Interstate Natural Gas Association of America
Minnegasco
New England Gas*
Nicor Gas
NSTAR Electric & Gas*
Pacific Gas & Electric
Public Service of Colorado*
Public Service Electric & Gas
Puget Sound Energy
Questar Gas
NMGas*
San Diego Gas & Electric*
Southern California Gas*
Ontario Energy Board*
Union Gas

*** Testimony**

Mark Newton Lowry

President, PEG Research

Regulatory economist 28 years

Testified 30+ times on Altreg issues

PhD Applied Economics, University of Wisconsin

Previously Assistant Professor, Pennsylvania State University
Vice President, Christensen Associates

Case Studies

MRP Case Study: Central Maine Power

Attrition Relief Mechanism:

growth Rates = growth GDPPI – X + Y + Z (X=1%)

Capital Cost Tracker: AMI

Earning Sharing: Asymmetric, sharing of surplus earnings only

Plan term: 5 years (2009-2013)

Service Quality: Multi-indicator penalty mechanism

Reference: Maine Public Utilities Commission, "ARP 2008 Settlement", June 2008

MRP Case Study: California Pacific Electric

RDM

Attrition Relief Mechanism:

- growth Revenue = growth Inflation-X+Y
- Inflation: Global Insight forecast of CPI^{US}
- X = 0.5%

Capital Cost Tracker for major plant additions

Plan term: 3 years (2013-2015)

Reference: California Public Utilities Commission Decision 12-11-030, Issued December 10, 2012

Case Study: Georgia Power

Attrition Relief Mechanism

- Stairstep Revenue Cap
  - 4/1/2012 Revenue requirements for Plant McDonough Units 4 & 5, DSM expenses, & franchise fees
  - 1/1/2013 Revenue requirements for Plant McDonough Unit 6, DSM expenses, & franchise fees

Cost Trackers

- Environmental compliance
- Nuclear construction
- DSM expenses
- Franchise fees

Plan term 3 years (2011-2013)

ESM Company retains 1/3 of overearnings beyond an ROE of 12.25%

Off-ramps Company may request formula rates or file a rate case if underearning beyond an ROE of 10.25%

Reference: Docket 31958

Case Study: Pacific Gas & Electric

Application Base revenue for generation and energy distribution

Attrition Relief Mechanism

- Stairstep RAM

	2012	2013
Generation:	1.3%	1.6%
Distribution:	3.9%	3.7%

Capital Cost Trackers

- AMI
- Power distribution reliability

Plan term 3 years (2011-2013)

Reference: Decision 11-05-018, Application 09-12-020, May 2011

MRP Case Study: Southern California Edison

RDM

Hybrid RAM

Revenue for three kinds of O&M expenses escalated for inflation

- Non-union labor & non-labor O&M: Global Insight forecasts
- Medical programs, including Post-Retirement Benefits other than pensions: inflated 7.5% annually
- Unionized labor: escalated at rates agreed to in contracts

Capital based on forecast

- 2012 capital additions escalated by 3.05% for 2013 and 2.93% for 2014

Capital Trackers for AMI/Smart Grid, Solar PV projects, nuclear generation

Plan term: 3 years (2012-2014)

Reference: California Public Utilities Commission Decision 12-11-051, Issued December 10, 2012, pp. 599-609, 876.

Miscellaneous Topics

Average Annual Electricity Use per Residential & Commercial Customer 1926-2011

Year	Residential		Commercial	
	Level	Growth Rate	Level	Growth Rate
1927-1930	478	7.1%	3,659	6.7%
1931-1940	723	5.4%	4,048	2.0%
1941-1950	1,304	6.5%	6,485	5.1%
1951-1960	2,836	7.5%	12,062	6.3%
1961-1970	5,235	6.1%	28,893	9.5%
1971-1980	8,205	2.5%	49,045	3.1%
1981-1990	9,062	0.6%	56,571	1.4%
1991-2000	10,061	1.1%	67,006	1.7%
2001-2007	10,941	0.7%	74,224	0.6%
2008-2011	11,181	0.1%	75,265	-0.5%

Sources: U.S. Department of Energy, Energy Information Administration, Form EIA-861, "Annual Electric Utility Report," and Form EIA-826, "Monthly Electric Utility Sales and Revenues Report with State Distributions," and EIA-0035, "Monthly Energy Review."

>>> Volume growth "gravy" available to finance cost growth is disappearing

Digression on Productivity

growth Productivity = growth Scale – growth Inputs

Productivity growth has diverse drivers that include change in

- Technology
- Other business conditions
  (*e.g.* undergrounding requirements, reliability & safety standards, emissions policies, system age)
- "X-inefficiency"

Productivity is volatile but trends upward

A Digression on Productivity (cont'd)

Productivity growth of energy distributors generally slow, predictable

- Rate base grows gradually as system expands
- But rate base growth stimulated by accelerated modernization

Vertically integrated electric utilities ("VIEUs") traditionally experienced capex surges (and productivity plunges) during major generation plant additions

Productivity growth traditionally much more rapid *between* major additions as depreciation slows rate base growth

A Digression on Productivity (cont'd)

VIEU productivity (and hence cost) growth more gradual today

Slowing volume growth slows need for G&T construction

Plant additions less "lumpy"

- Gas-fired generation
- Renewable generation
- Emissions controls

Trends in the Base-Rate Cost per Customer of Northeast Power Distributors

Year	Growth Rate
2004	-3.67%
2005	1.86%
2006	3.73%
2007	2.00%
2008	1.91%
2009	4.00%
2010	5.30%
Average Annual Growth Rate 2004-2010	**2.16%**

Data Sources: FERC Form 1 (power distributor cost and bond yield), Form EIA-861 (customers), and Regulatory Research Associates (electric utility allowed ROE)

Northeast Sample: Baltimore Gas & Electric, Central Maine Power, Connecticut Light & Power, Consolidated Edison, Jersey Central Power, Maine Public Service, Metropolitan Edison, PECO Energy, Potomac Electric Power, Public Service Electric & Gas, United Illuminating, West Penn Power, and Western Massachusetts Electric
Northeast Urban Sample: Baltimore Gas & Electric, Consolidated Edison, PECO Energy, Potomac Electric Power, Public Service Electric & Gas

>>> RPC freeze uncompensatory for typical power distributors

LRAMs

Basic Idea

Compensate utilities for margins lost due to *their* DSM and DG

Requires estimates of load losses [which may also be used in incentive mechanisms]

Utilities

- assume risk of conventional demand fluctuations
- retain rate design freedom
- can benefit from externally-driven growth in average use

LRAMs (cont'd)

Pro

Removes disincentives for DG & conventional DSM

Utility still incented to develop market-responsive rates & services

- Large load, price sensitive customers
- EVs
- Value-added services

Con

Doesn't remove disincentives for all utility actions

DSM savings estimates complex, controversial

High administrative cost discourages application to all DSM & DG

Stairstep ARMs (cont'd)

Capital cost computed by traditional means

Rate of return may be subject to index-based adjustments

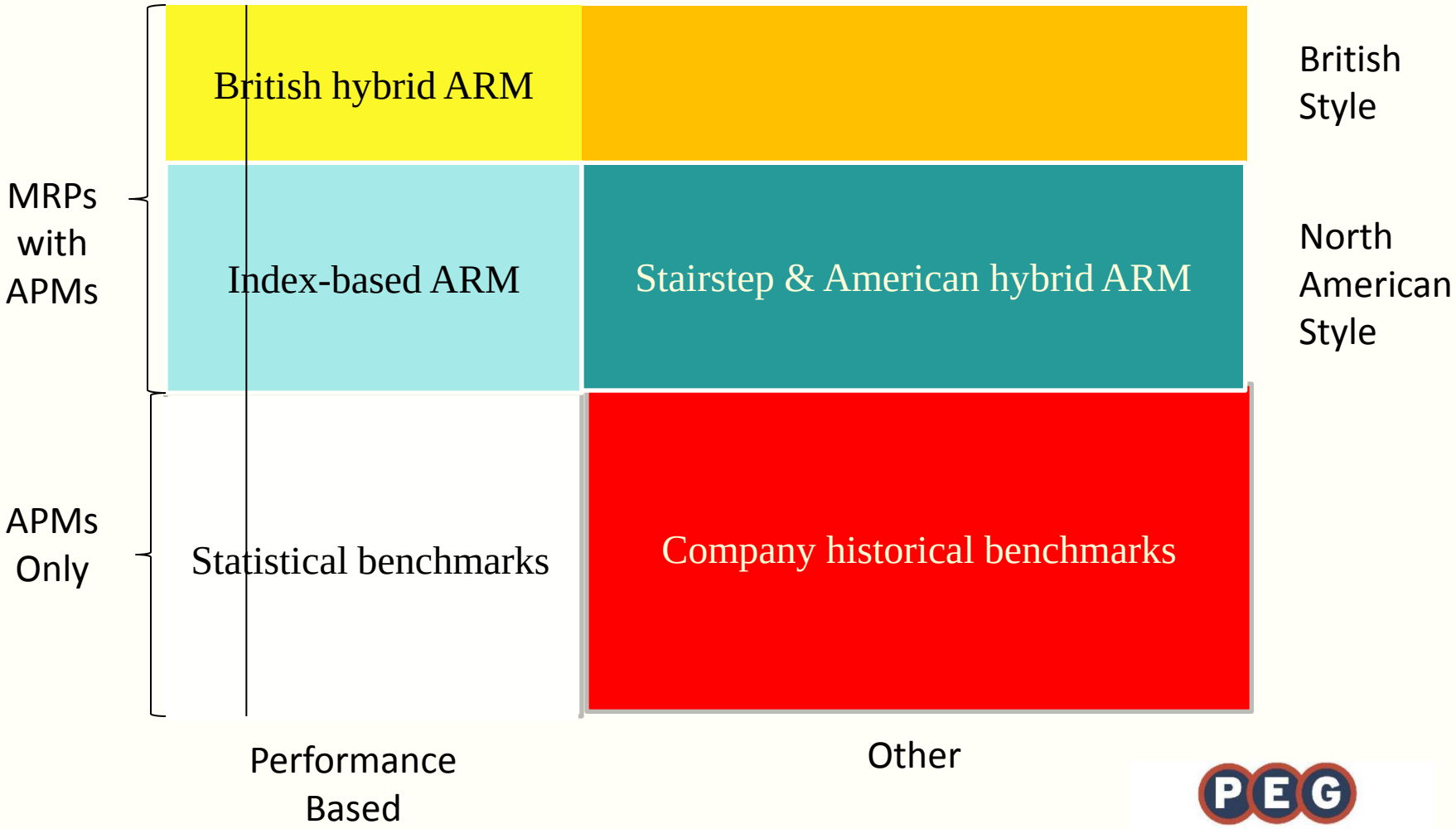
Several methods used to set budgets

- Multiyear forecast
- Average of recent historical values
- Test year

Budgets may be adjusted for construction cost inflation

Steps for VIEUs may reflect only generation plant additions

Incentive Regulation Taxonomy



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Suggestions for Further Reading

Jim Lazar, Frederick Weston, and Wayne Shirley (2011), *Revenue Regulation and Decoupling: A Guide to Theory and Application*
http://www.raponline.org/document/download/id/902

Steven Nadel and Garret Herndon, *The Future of the Utility Industry and the Role of Energy Efficiency*. ACEE Report Number U1404, July 2014

Larry Kaufmann, John Rich, Lullit Getachew, and Matt Makos (2010), *System Reliability Regulation: A Jurisdictional Survey*, Report prepared for the Ontario Energy Board
http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0249/PEG_OEB_Service_Quality_Report.pdf

Suggestions for Further Reading (cont'd)

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OFGEM, *Strategy Decision for the RIIO-ED1 Electricity Distribution Price Control – Overview* OGEM 26-13 (March 2013)

California Public Utilities Commission Decision 12-11-051 on Southern California Edison 2012 GRC

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Georgia Public Service Commission Decision Resolving Georgia Power's 2010 Rate Case

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