MASSACHUSETTS
DEPARTMENT OF ENERGY RESOURCES

Cost of Service Regulation

Expert Presentation Series | September 8, 2025

This expert level presentation series session will provide the Massachusetts Electric Rate Task Force an opportunity to learn from experts and/or other jurisdictions on the above topic.

Note: The contents of this presentation do not necessarily reflect the views or positions of the Massachusetts Department of Energy Resources.

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Massachusetts Electric Rate Task Force Goals

The Rate Task Force brings together diverse stakeholders to reimagine how electric rates and the regulatory framework can drive an affordable, equitable, and decarbonized energy future.

Through targeted conversations, expert presentations, and thoughtful exploration of complex issues, the Task Force aims to deepen understanding, surface critical questions, clarify challenges, and build the foundation for durable regulatory reform and action.

The Rate Task Force will use the Massachusetts Interagency Rates Working Group's Long-Term Ratemaking Study and Recommendations as a starting point for discussion and knowledge building on rate designs, ratemaking, and regulatory mechanisms.

Build technical knowledge

Provide an opportunity for **knowledge-building** by and amongst stakeholders, including those who have not traditionally been involved

Develop shared understanding

Converge towards **shared understandings** of the challenges and priorities

Today's Focus

Facilitate open, inclusive dialogue

Engage in **open, inclusive dialogue** about complex ratemaking and regulatory issues outside of a regulatory proceeding

Frame critical questions and opportunities

Empower stakeholders to identify **critical questions and opportunities** for the advancement of rate design and ratemaking reform

Ground Rules & Engagement

This work is complex – and your insight matters; let's focus on learning, listening, and shaping together!

Participation, Engagement, & Respect
- Everyone's perspective is valuable – this space works best when all voices are heard
- Respect differences in background, experience, and priorities
- Bring curiosity – ask questions and offer potential answers
- Focus on understanding others' goals and values, not just their positions
- It's okay not to have a solution – help us shape the right questions

Collaboration, Not Consensus
- This body is deliberative, it is not a decision-making space
- We don't need to agree on everything, but we should work toward shared understanding
- Where we disagree, help clarify what the tension is and why it matters

Transparency & Trust
- We'll be clear about how input is used
- Share what you can; identify when you're speaking on behalf of your organization or personally
- Materials, summaries, and key findings will be shared openly to support accountability

Focus & Productivity
- Stay on topic and honor the scope of the Task Force
- Raise related concerns, but help us stay anchored in the rate design and regulatory issues at hand
- Use the structures provided (i.e., expert sessions, targeted conversations, office hours) to deepen discussion
- Avoid discussion about open and ongoing proceedings at the DPU

Expert Presentations

I. Reconciling Mechanisms, Riders, and Trackers in Massachusetts

Massachusetts Department of Energy Resources, Austin Dawson

Present on the current approaches and utilization of reconciling mechanisms, commonly referred to as riders and trackers, in Massachusetts

II. Allocated Cost Studies & Historical Test Years in Massachusetts

Massachusetts Electric Distribution Companies

Present on the current approach to allocated cost of service studies (ACOSS) and the development and application of historical test years in Massachusetts

III. Future and Multi-Year Test Years

Wisconsin Public Service Commission, Commissioner Kristy Nieto

Present the applications and use of future and multi-year test years in Wisconsin regulatory environment to support oversight over expanding levels of investment to support load growth

IV. CapEx/OpEx Equalization

RMI, Gennelle Wilson & Current Energy Group, Dan Cross-Call

Present on capex-opex equalization mechanisms, with examples including totex ratemaking as employed in Great Britain's Revenues = Incentives + Innovation +Outputs (RIIO) framework

Reminder

Expert presentation sessions are not for substantive deliberation amongst participants. Questions for each speaker will be taken as time allows.

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Reconciling Mechanisms

Massachusetts Electric Rate Task Force

September 8, 2025

This presentation explores the current approaches and utilization of reconciling mechanisms, commonly referred to as riders and trackers, in Massachusetts

Note: The contents of this presentation do not necessarily reflect the views or positions of the Massachusetts Department of Energy Resources.

Presented by

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Delivery rates include various charges besides base distribution

Charges support recovery of costs associated with providing service, in addition to specific investments, programs, policies, and legislative directives

- All three electric distribution companies (EDCs) have various charges outside of base distribution rates, each governed by a tariff reviewed and approved by the DPU
- All charges summarized in later slides, but include base distribution, transmission, revenue decoupling, distributed solar, energy efficiency, renewable energy, pension adjustment, residential assistance, attorney general consulting expense, vegetation management, storm recovery costs, etc.

Electric Tariffs and Rules

- Eversource
- National Grid
- Unitil

cents/kWh	Eversource	National Grid	Unitil
Base Distribution	6.264	6.546	10.176
Other Charges *(# of charges)*	12.603 (*26*)	13.711 (*28*)	15.992 (*21*)
Total Delivery Rate	18.867	20.257	26.168

- Reconciling mechanism is a type of charge that adjusts periodically to collect over- or under-recovery from a prior period based on (1) actual costs, (2) collected revenues, and (3) carrying costs, if applicable
- Most charges are reconciling mechanisms except for the base distribution charge, in addition to energy efficiency system benefits charge (0.250 cents/kWh) and renewable energy charge (0.050 cents/kWh) established in statute (G.L. c. 25 c. 25, §§ 19-20)

Supporting service, investments, programs, and policies

Reconciling mechanisms support capital investments and non-capital spending (i.e., O&M expenses)

- Reconciling mechanisms that provide utilities with accelerated cost recovery for utility-owned capital investments are often referred to as capital cost recovery mechanisms
- Several reconciling mechanisms provide cost recovery for incentives that promote third-party capital investments, while other reconciling mechanisms support operational and maintenance expenses traditionally or historically in base distribution rates

cents/kWh	Eversource	National Grid	Unitil
Transmission (incl. base, adjustments, internal, and external)	4.545	5.798	4.076
Transition (incl. base and adjustments)	(0.095)	(0.036)	-
Grid Modernization (incl. grid modernization, advanced metering, and electric vehicle, and electric sector modernization plans)	1.003	0.609	1.094
Distributed Generation (incl. SMART, net metering, provisional system plan factor, solar program cost, solar expansion)	2.039	2.464	3.830
Energy Efficiency (incl. energy efficiency reconciliation factors)	2.256	2.629	2.424
Ratepayer Assistance (incl. residential discount and net debt management costs)	1.047	1.149	2.527
Renewable and Carbon-Free Electricity (incl. long-term renewable contract)	0.052	0.067	(0.030)
Other Distribution (incl. pension, AG expenses, vegetation management, storm costs, basic service, etc.)	1.456	0.731	1.771

Reconciling mechanisms provide cost recovery from customers

Ratemaking tool for recovery of costs outside of base distribution rates

DPU reviews and approves reconciling mechanisms

- DPU considers the following factors regarding the costs to be recovered in evaluating new and existing reconciling mechanisms:
  1. Volatile and large in magnitude
  2. Neutral to fluctuations in sales volumes
  3. Beyond company control
- DPU decides between reconciling mechanisms or base distribution rates as optimal cost recovery method on a case-by-case basis in rate cases
- Costs submitted for recovery must be incremental to, and not duplicative of, cost recovered through base distribution rates or other mechanisms

Use of reconciling mechanisms changes over time

- Between 2013 and 2025, the number of reconciling mechanisms in effect for each EDC have approximately doubled
  - In 2013, Unitil (10), National Grid (13), Eversource (NSTAR: 11; WMECo: 12)
  - In 2025, Eversource (24), National Grid (26), Unitil (21)
- The DPU has recently approved new reconciling mechanisms (e.g., Electronic Sector Modernization Plan, Provisional System Plan Factor, Electronic Payment Recovery); however, the DPU has also recently directed the phase-out of existing reconciling mechanisms (e.g., Pension Adjustment Factor, Vegetation Management, etc.)

Allocation of costs to customer classes and carrying costs

Reconciling mechanisms recovery costs from customers

- **Allocation of costs to customer classes**
  - In 2013, DPU reviewed and updated reconciling mechanisms under cost-based criteria, if possible; otherwise, the DPU permits setting the charges in direct proportion to the contribution of distribution revenues from each customer class (DPU 12-126)
  - Most reconciling mechanisms employ the base distribution revenue allocators which are established in each company's rate cases through their allocated cost of service studies (ACOSS), although reconciling mechanisms also use coincident peak demand allocators, labor allocators, capital cost adjustment allocators, and overhead line allocator
  - Some reconciling mechanisms apply uniform across all customers classes (e.g., long-term renewable contract adjustment), apply only to a single customer class (e.g., electronic payment recovery), or apply uniform by sector with adjustments (e.g., energy efficiency reconciliation factor)

Base Distribution Revenue Allocators, eff. 2025

	Eversource	National Grid	Unitil
Residential	50.795%	60.6%	61.18%
Small C&I	21.268%	12.0%	19.97%
Medium C&I	17.654%	10.7%	-
Large C&I	10.283%	16.3%	18.30%
Streetlights	(incl. in Sm. C&I)	0.4%	0.55%

- **Carrying costs**
  - EDCs are typically, but not always, permitted carrying costs for any under- and over-recovery, generally set at the prime rate (i.e., few percentage points higher than federal fund rate) or customer deposit rate (i.e., rate paid on two-year, U.S. Treasury notes)

Minimizing deferred costs while protecting against volatility

Provides more contemporaneous cost recovery

- Each companies' stay-out provision (i.e., agreement not to file a rate case for a period of 5-years in the case of the EDCs) limits the discretion they would otherwise have to file a rate case if costs rose significantly or unexpectedly
- Reconciling mechanisms can protect against these contingencies, smooth costs for customers, and provide more current recovery of costs incurred
    - Base distribution rates may account for an allowance towards storm cost recovery, represented by a storm fund, while reconciling mechanisms can recover extraordinary storm costs or to replenish storm fund deficiency balance, thereby reducing carrying costs

Most reconciling mechanisms use forecasted sales

- In prospectively establishing the charge for reconciling mechanisms, the DPU has permitted utilities to use forecasted sales
    - Forecasted sales, as compared to test year sales, is more likely to minimize reconciliation amount and therefore carrying costs
    - DPU has treated the use of forecasted sales only for the purpose of recovery and reconciliation of reconciling mechanisms and has concluded that doing so does not constitute the use of a forecasted, or future test year in the context of a general rate case
- Forecasted sales may be more difficult during periods of load growth and increased weather-dependent electricity use

Reducing cost control incentives and increasing administration burden

Reconciling mechanisms can reduce cost control incentive and shift risk to ratepayers

- Reconciling mechanism can reduce incentive for company to control costs for O&M expenses (see e.g., DPU's recent rejection of Unitil's proposed reconciling mechanism for its Storm Resilience Program)
- Reconciling mechanisms erode regulatory lag (i.e., gap between incurred cost and recovery of cost), which otherwise provides incentive for cost control and wise capital investment
- Reconciling mechanisms act to reduce variability of a company's revenues and shifts risk onto ratepayers
- Pilot programs play an important role in developing innovative and cost-effective programs to help better service customers; though ratepayers bear the risk of pilot programs supported by reconciling mechanisms

Reconciling mechanisms increase rate complexity and administrative burden

- In the past 12 months, the EDCs had **at least 44 docketed proceedings** solely for the review and approval of reconciling mechanisms**,** each of which is generally annual (Unitil: 13; National Grid: 16; Eversource: 15)
- Administration burden on EDCs from administration of tariffs and filings with DPU, on DPU for review of filings, and on other stakeholders involved in proceedings
- Concern over the risk of double-recovery requires additional scrutiny, a concern that led the DPU recently to direct all meter-related costs from base distribution rates into existing reconciling mechanisms

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Thank You!

Summary of Electric Charges

Distribution and transmission system charges

Charge	Category	Definition
Customer Charge	Distribution System	Covers a portion of fixed costs to provide electricity, including meters, billing, and customer service
Base Distribution	Distribution System	Covers cost of wires, poles, and other distribution system infrastructure, including the operation and maintenance necessary to support the operation of the distribution utility's system
Capital Cost Adjustment	Distribution System	Cost recovery mechanism for expenses associated with utility plant additions since specified date *[Unitil only]*
Infrastructure, Safety, Reliability, and Electrification Factor	Distribution System	Cost recovery mechanism for incremental costs associated with core capital investments *[National Grid only]*
Transmission Charges	Transmission System	Covers costs of transmission service (i.e., delivering electricity across transmission lines from generators to distribution system), includes Base Transmission, Internal Transmission, Transmission Service Cost Adjustment, External Transmission *[utility specific]*

Grid modernization and associated program charges

Charge	Definition
Grid Modernization Factor	Covers the costs associated with the companies' Grid Modernization Plans
Advanced Metering Infrastructure Factor	Covers the costs of legacy meter and enterprise IT and costs associated with the implementation and deployment of AMI approved by the DPU *[National Grid and Eversource only, Unitil's AMI expenses recovered in company's Grid Modernization Factor]*
Provisional System Plan Factor	Covers costs associated with the Capital Investment Projects (CIPs) to enable interconnection of distributed facilities *[National Grid and Eversource only]*
Electric Vehicle Program Factor	Covers costs associated with the companies' Electric Vehicle (EVs) Plans *[National Grid and Eversource only, Unitil's AMI expenses recovered in company's Grid Modernization Factor]*
Electric Sector Modernization Plan Factor	Covers the costs associated with investments identified in the companies' Electric Sector Modernization Plans

Other distribution charges

Charge	Definition
Exogenous Cost Adjustment	Covers costs beyond the Company's control due to a change in accounting requirements, policy, or other exogenous events
Pension Adjustment Factor	Covers the costs of pension and post-retirement benefits other than pensions (PBOP) not included in distribution rates
Attorney General Consulting Expense	Covers the costs incurred by the Attorney General of Massachusetts, the statutorily designated ratepayer advocate, for experts and consultant services in DPU proceedings
Basic Service Adjustment Factor	Covers the cost difference between the costs of Basic Service supply and the collected revenues from Basic Service (i.e., power supply reconciliation) and the administrative costs of providing Basic Service to customers
Vegetation Management Factor	Covers the costs associated with vegetation management [*Eversource's Resiliency Tree Work program; National Grid's Vegetation Management Pilot]*
Vegetation Management Reconciliation Factor	Covers the cost difference between allowed vegetation management expenses and the collected revenues from the Vegetation Management Factor [*National Grid only]*
Storm Reserve/Fund Adjustment Factor	Covers the costs to maintain a storm reserve fund, impacted by storm costs in excess of reserve funding
Storm Cost Recovery Adjustment Factor	Covers the costs of exogenous storm events above a certain threshold *[Eversource and National Grid only; Unitil's exogenous storm costs recovered in company's Storm Reserve Adjustment Factor]*

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Other distribution charges

Charge	Definition
Tax Act Credit Factor	Returns an amount of collected in association with the Tax Cuts and Job Acts of 2017 *[Eversource and National Grid only]*
Electronic Payment Recovery	Covers the cost of implementation and administration of Fee Free Credit and Debit Card Payment Option *[Eversource and National Grid only]*
Revenue Decoupling Adjustment Factor	Covers the cost difference between the companies' revenue target and the collected revenues from customer charges and base distribution charges
Solar Cost Adjustment Factor	Covers the investment and ongoing maintenance costs of solar generation projects constructed, owned, and operated by the companies *[Eversource also charges a Solar Expansion Cost Recovery Factor]*
Transition Charges	Covers stranded or transition costs associated with utilities divesting from generation *[Eversource and National Grid only; National Grid delineates between Base Transition Charge and Transition Charge Adjustment Factor]*
Service Quality Penalty	Refund to customers for service quality penalties imposed on utility, as applicable

Climate and affordability program charges

Charge	Definition
Energy Efficiency System Benefits Charge	Contributes to the costs of energy efficiency, established at $0.00250/kWh pursuant to G.L. c. 25, § 19(a)
Energy Efficiency Reconciliation Factor	Covers the incremental, or net, costs of energy efficiency included in the companies' Three-Year Energy Efficiency Plans
Net Metering Recovery Surcharge	Covers the cost of net metering credits applied to customers, lost revenue from customers who have installed on-site generation facilities, and other associated costs
Distributed Solar (SMART)	Covers the cost of DOER's Solar Massachusetts Renewable Target (SMART) program to incentive the development of solar in Massachusetts
Long-Term Renewable Contract Adjustment	Covers the costs and contract remuneration for long-term renewable energy contracts (e.g., large-scale renewable generation, offshore wind procurements) and transmission service agreements
Renewable Energy	Provides funding to the Massachusetts Renewable Energy Trust Fund, administered by the Massachusetts Clean Energy Center, a quasi-public research and development agency, established at $0.00050/kWh pursuant to G.L. c. 25, § 20(a)
Residential Assistance Adjustment Factor	Covers the cost of the low-income discount rate and incremental expenses of the Residential Arrearage Management Program (i.e., debt management)

Allocated Cost Studies
And
Historical Test Years in Massachusetts

Presented to the Massachusetts Electric Rate Task Force on behalf of Eversource Energy, National Grid and Unitil

September 8, 2025

Agenda

- Overview
- Allocated Cost of Service Studies
- Current Allocated Cost Studies for Distribution Service in Massachusetts
- Applications/Use of of Allocated Distribution Cost Studies in Rate Making

Overview

Cost-of-service studies are often considered as a reference or guide in the ratemaking process. The type of study and methods employed when conducting a study depend in large part on the type and nature of costs involved, service provided and customer utilization characteristics. Allocated cost studies serve to distribute the total cost of service or revenue requirements among rate classes, while marginal cost studies are concerned with the incremental or marginal cost of providing service. The scope of costs and methods applied in conducting of a given study depend on the type of cost and their function in the service provided. Our focus today is on the allocation of costs associated with providing Distribution service to various retail rate customers.

The Allocated Distribution Cost of Service Study

An allocated cost-of-service study is intended to identify the relative responsibility of each rate classification for the recovery of the overall costs of distribution service in a particular test year. In a Distribution rate case, an allocated cost-of-service study is conducted to determine the rate of return, overall and by rate class, and the degree of over/under recovery of allocated costs under existing tariffs. This result informs the revenue requirement and changes from current rates necessary to achieve a designated rate of return on rate base for each class. A study based on a historic test year is utilized to design of rates that will apply to service provided in a future period.

Class Cost of Service, Revenue Requirements and Rate Design

A rate class contributing less than the average rate or return on rate base is shown from the perspective of the cost study to be cross-subsidized by other classes. When relying on the allocated cost of service study to develop proposed allocations in a rate case, a balance is sought between the extent to which changes to revenue requirements allocation would be made and customer impacts at a class level and among customers within a class.

Iterative analysis is performed to evaluate changes to revenue allocations at a total class level and for the various types of charges with a class (customer, volumetric, demand), and to customer bill impacts. These and other rate principles and considerations are also given in determining rates for each class, and ultimately the allocation of the cost of providing service to each rate class.

Role of an Allocated Cost of Service Study in the Rate Making Process

Determine Revenue Requirement/ Overall Cost of Service

Evaluate and Categorize Components of the Cost Study (Functionalize and Classify Costs)

Assign and Allocate Costs to Customer/Rate Classes (e.g., residential; small, medium and large general service; lighting)

Design Cost-Based Rate Elements for each Customer Class (depending on structure: customer, demand, volumetric based)

Current MA Allocated Cost of Service Study Applications

- Allocated Cost Studies
  - Scope: Total company cost of service (i.e., revenue requirements) for retail Distribution service using historic test year
  - All elements of the total cost of service are evaluated for allocation among rate classes
  - Established methods for classification and allocation of costs among rate classes
    - Costs typically classified as either customer or demand
      - Further differentiation if relevant (e.g., primary vs. secondary service)
    - Allocations
      - Allocation method and factors depend upon the type of cost and cost causation
        - Some costs will be directly allocated

          Ex. O/H line plant costs allocated using class NCP demand
        - Other cost allocations indirect

          Ex. O/H line O&M expenses follow the plant allocation
        - Allocators may be directly measured (#customers, demand), weighted or determined by special study (e.g., weighted cost of meters for each class; direct vs. shared costs of service transformers)
    - (see additional illustrations)
  - Class revenue requirements determined in accordance with designated ROR (e.g., equalized ROR)

Allocated Cost of Service Study – Detailed Allocations

Illustration -Each element of total company cost of service allocated to rate classes

		Class Allocations Rate Class					
	Total Company	Resid.	Small Gen. Svc	Med. Gen. Svc	Lg. Gen. Svc	...	Street Ltg.
Total Rate Base (net plant, adjustments)	x						
Operating Revenue	x						
O&M Expense							
Distribution O&M	x						
Customer	x						
A&G	x						
Depreciation	x						
Amortization	x						
Property Tax	x						
Payroll/Other Taxes	x						
Federal/State Income Tax	x						
DIT/ITC	x						
Total Operating Expenses (Inc. IT)	x						
Operating Income	x						
Required Operating Income	x						
Distribution Revenue Requirement	**x**	**x**	**x**	**x**	**x**	**x**	**x**
Current Distribution Revenue	x						
Required Change in Rates	x						

MA Allocated Cost of Service Study Applications (cont.)

- Use and application of COS results
  - Rate making principles applied to balance cost causation and cost of service with bill impacts and other considerations – DPU rate making principles and standards
    - Schedule 10
  - Base Distribution Rates - Resulting class allocations provide total class revenue targets
    - Revenue associated with customer vs. demand related costs, unit costs from allocated cost study applied in designing customer, demand and volumetric rates by class
  - Other Rate Mechanisms
    - Class rate design revenue targets applied in other rate mechanisms
      - Ex. As allocation factors for tracking/reconciling mechanism
      - Ex. Labor allocator from allocated study applied in pension tracker

Revenue Allocations Subject to Established Controls and Constraints – Schedule 10

SCHEDULE 10 - Illustrated Allocated Cost of Service vs. Final Proposed Revenue Allocation

RATE GROUP	BASE DISTRIBUTION REVENUE @ CURRENT RATES	BASE DISTRIBUTION REVENUE @ EROR (1)	ITERATION 1: BASE DISTRIBUTION REVENUE INCREASE IN EXCESS OF 10% CAP	ITERATION 1: ALLOCATION OF BASE DISTRIBUTION INCREASE IN EXCESS OF 10% CAP	BASE DISTRIBUTION REVENUE INCREASE IN EXCESS OF 200% CAP	ALLOCATION OF BASE DISTRIBUTION REVENUE INCREASE PER 200% CAP	REVENUE FLOOR ADJUSTMENT	ALLOCATION OF REVENUE FLOOR ADJUSTMENT	PROPOSED ALLOCATION OF BASE DISTRIBUTION REVENUE INCREASE	PROPOSED BASE DISTRIBUTION REVENUE TARGET	Prop. vs. ACOS	Distribu-tion Increase
	(b)	(f)	(j)	(l)	(r)	(t)	(v)	(x)	(y)	(z)		(aa)
Residential	$ 519,018,176	$ 573,269,638	$ -	$ 643,714	$ -	$ 8,162,044	$ -	$ (10,418,946)	$ 52,638,274	$ 571,656,450	99.7%	7.9%
Small General Service	$ 223,538,825	$ 215,739,998	$ -	$ 242,251	$ -	$ 3,071,642	$ 9,090,387	$ -	$ 4,605,453	$ 228,144,278	105.7%	0.0%
Medium General Service	$ 194,675,611	$ 191,783,250	$ -	$ 215,350	$ -	$ 2,730,553	$ 3,957,257	$ -	$ 4,010,799	$ 198,686,411	103.6%	0.0%
Large General Service	$ 105,805,745	$ 131,187,753	$ -	$ 147,308	$ 13,217,754	$ -	$ -	$ (2,384,285)	$ 9,927,278	$ 115,733,023	88.2%	7.2%
Lighting - Company	$ 8,115,357	$ 10,767,308	$ 1,251,633	$ -	$ 456,015	$ -	$ -	$ (195,692)	$ 748,612	$ 8,863,969	82.3%	7.0%
Lighting - Customer	$ 2,143,829	$ 2,680,745	$ -	$ 3,010	$ 290,471	$ -	$ -	$ (48,721)	$ 200,735	$ 2,344,563	87.5%	7.2%
Total Company	$ 1,053,297,543	$ 1,125,428,693	$ 1,251,633	$ 1,251,633	$ 13,964,239	$ 13,964,239	$ 13,047,644	$ (13,047,644)	$ 72,131,150	$ 1,125,428,693	100.0%	4.7%

Additional Considerations

- Classification and development of corresponding allocators provide important insights into the characteristics of customers in each class and facilities utilized to provide service

- Care is needed to ensure allocators represent cost causation and appropriate demand and customer/demand weighting factors for a given period

- DPU method of cost allocation addresses equalized ROR's and intra class subsidies

- Appropriate cost classification supports alignment of customer and demand revenue requirements and corresponding rate design (depending on structure of rate class)

- Marginal customer, demand or volumetric costing informs efficient pricing by function and class; requires reconciliation with class revenue requirements – form of marginal cost study matters (i.e., engineering study with forward look vs. statistical with historic and trending perspective)

- Historic vs. forward-looking test year – not a new concept; worth exploring depending on overall rate plan for Distribution rates; may not eliminate or replace other mechanisms

Appendix – Additional Illustration of Classification and Allocations Applied when Conducting Allocated Cost of Service Study Analysis

Illustrated Classification of Costs for Direct Allocation

	Customer	Demand	Direct Assigned
Rate Base (plant)			
Substations		x	
Poles	x	x	
Overhead Lines	x	x	
Conduit	x	x	
Underground Lines	x	x	
Transformers	x	x	
Meters	x		
Services	x		
Street Lights			x
O&M Expense follows plant			
Customer Expense			
Meter Reading	x		
Records	x		
Customer Service	x		
etc.			

Plant and Expense Items may be classified as customer and/or demand related, or direct assigned
- cost causation
- can vary by regulatory policy, practice, precedent

Special studies may be required to determine more detailed cost characteristics
- primary vs. secondary
- weighting studies
- discrete customer, class or equipment (e.g., st. lights; rental equip)

Allocators are developed in accordance wtih the cost classification and other charactertics.

Examples:

- Customer counts
- Weighted customer related allocators
  - meters, services
  - transformers
  - customer service expense

Illustrated Service Class Differentiation

		Class Allocations Rate Class					
	Total Company	Resid.	Small Gen. Svc	Med. Gen. Svc	Lg. Gen. Svc	…	Street Ltg.
Overhead Lines							
Primary	x	x	x	x	x		x
Secondary	x	x	x				x
Overhead Lines							
Primary							
Customer	x	x	x	x	x		x
Demand	x	x	x	x	x		x
Secondary							
Customer	x	x	x				x
Demand	x	x	x				x

Break: 5-10 minutes
(if time allows)

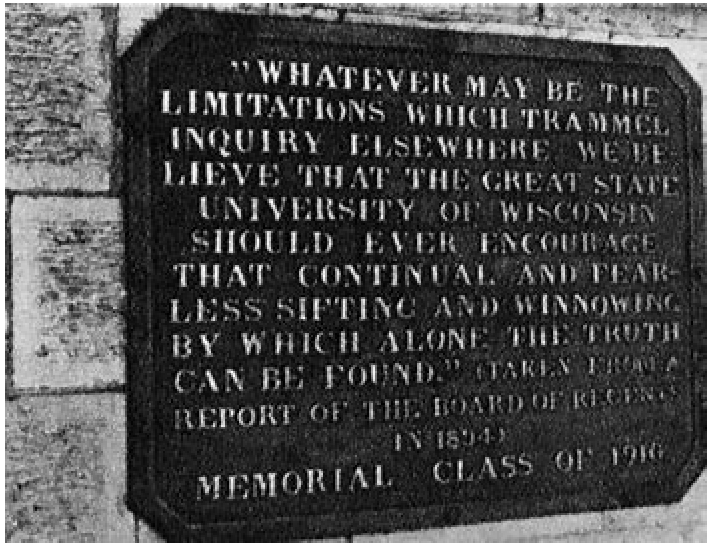
Future and Multi-Year Test Years

Kristy Nieto, Commissioner

Public Service Commission of Wisconsin

September 8, 2025

Proud History



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Future Test Years: Evidence from State Utility Commissions

Ken Costello, Principal Researcher

National Regulatory Research Institute

Report No. 13–10

October 2013

A recent study noted that:

> Forward test years were adopted in many jurisdictions during the 1970s and 1980s when rapid price inflation and major plant additions coincided with slowing growth in average use…Several additional states have recently moved in the direction of FTYs. Many of these states are in the West, where comparatively rapid economic growth has required more rapid build out of utility infrastructure.[15]

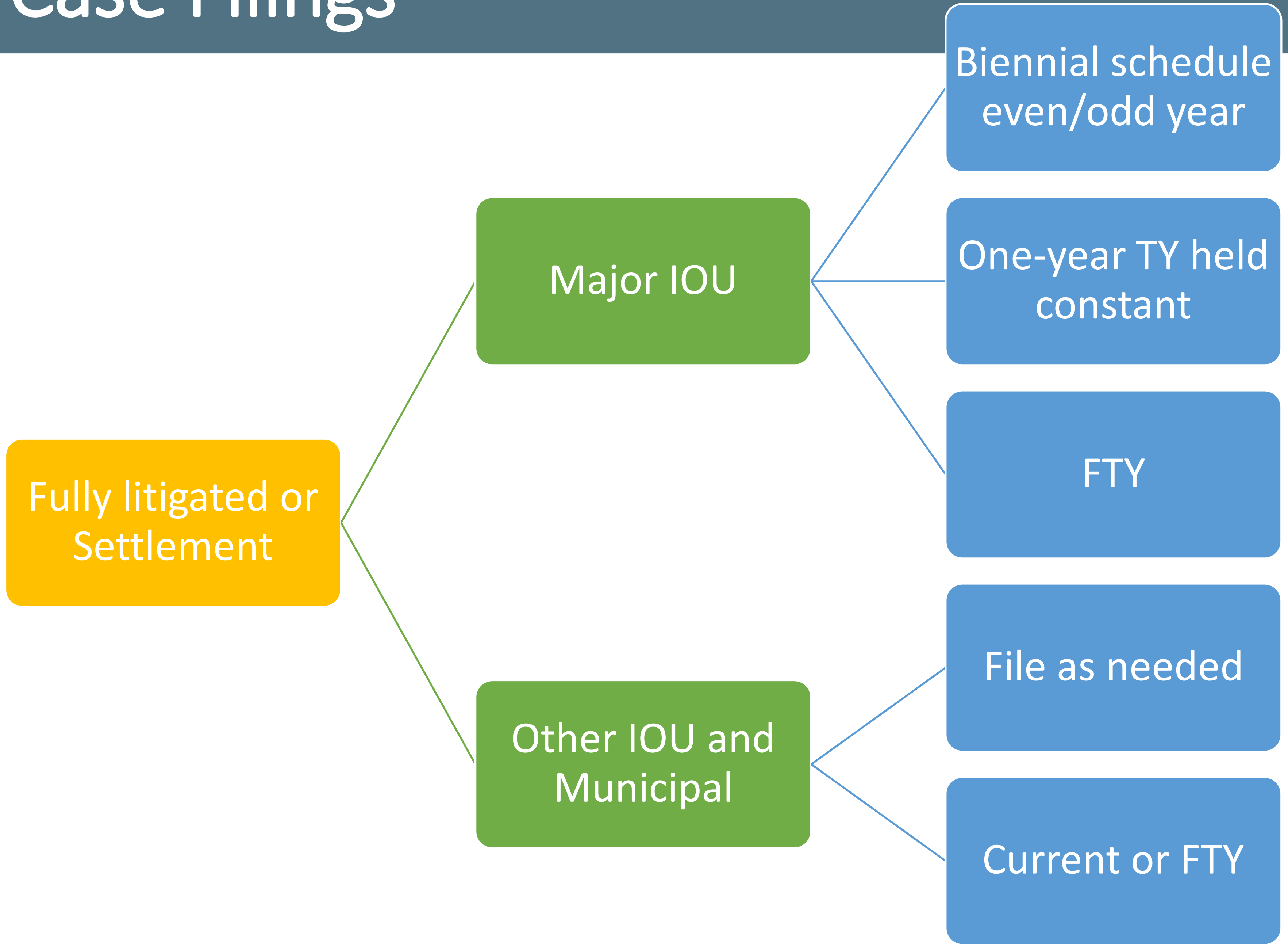
A 2012 survey reported that 23 states allow or require commissions to use an FTY for ratemaking, at least for electric utilities.[16] In addition to Indiana, which the survey did not include, the other most recent states passing legislation that allow an FTY are Pennsylvania and New Mexico.[17] Over half of the states now allow the use of a test year other than historical, and this number has grown over time.[18]

Wisconsin	The Commission has used a future test year approach for at least 35 years and there is no knowledge available regarding the transition to a future test year.

WI Rate Regulated Utilities

- 16 IOU (5 Major IOU)
- 81 Electric Municipal
- 1 Natural Gas Municipal
- 575 Water Utilities

Rate Case Filings



Focus Area

Revenue Requirement

- The amount of revenue necessary to recover the utility's costs and provide and opportunity to earn a reasonable return on investment
- Revenue Requirement is determined by a representative test year
- Wisconsin uses a future or forward-looking test-year for major IOUs

Revenue Requirement Components

$$RR = OR - O + T + D + r(RB)$$

Revenue Requirement Components

O&M

- Above the Line = Recoverable

  All costs prudently incurred and necessary for the provision of safe and reliable service are recoverable from ratepayers

- Below the Line = Not Recoverable

  Costs that are deemed imprudent or not necessary for provision of service are not recoverable from ratepayers

Taxes

Taxes are a recoverable expense that must be estimated for the test year

Depreciation

Depreciation, as an expense, is an accounting mechanism to recognize plant placed into service has a useful life

Revenue Requirement Components

Rate Base

- Net value of a utility's *used and useful* property for which they are allowed to earn a specified rate of return.

Plant in Service	Accumulated Depreciation
Materials and Supplies	Fuel/Gas in Storage
Customer Advances	Accumulated Deferred Income Tax

- The authorized rate of return on rate base is derived from the weighted average cost of capital (includes both debt and equity).

CWIP and AFUDC

- Construction Work in Progress (CWIP) – amount on utility balance sheet for construction of new facilities that are not yet placed into service (not used and useful)

- Allowance for Funds Used During Construction (AFUDC) – accounting treatment that allows for capitalization of carrying costs associated with CWIP when the project goes into service

DM Example

FINAL Decision Matrix
Wisconsin Electric Power Company and Wisconsin Gas LLC
Docket 5-UR-111
October 29, 2024

Issue 26a: What is a reasonable amortization period for the regulatory liability balance associated with the Paris Solar and BESS deferral due to the change to the in-service date?

Issue Scope: In the Commission's Final Decision in docket 5-UR-110 (PSC REF#: 487244) it ordered WEPCO to defer the incremental revenue requirement impact of the change to the in-service date for the Paris Solar and BESS projects, with carrying costs at the short-term debt rate, to a future rate proceeding.

In direct testimony of the applicants' witness Joseph Zgonc, WEPCO identified that the forecasted regulatory liability associated with the deferral at the end of 2024 will be $35.8 million and WEPCO is amortizing that liability over one year (2025) and is requesting a true up in its next rate proceeding for any difference. (Direct-WEPCO WG-Zgonc-cr2-22.)

PARTY POSITIONS	AMOUNT*	TRANSCRIPT REFERENCES
Applicants: Alternative One. WEPCO has deferred the difference between the forecast and actual revenue requirement for Paris, as ordered. WEPCO's proposal to amortize the resulting regulatory liability over one year is reasonable, and uncontested (in fact, this issue should be treated as uncontested).		Direct-WEPCO WG-Zgonc-r2-22; Ex-WEPCO WG-Zgonc-1
CUB: Takes no position.		
Walmart: Takes no position.		
Commission Staff: The Commission could find the applicants' proposal to be reasonable as the project is not yet in service and the actual incremental revenue requirement impact of the change to the in-service date could still change.		Direct-PSC-Maly-r-33

COMMISSION ALTERNATIVES

Alternative One: Accept WEPCO's proposal to amortize the regulatory liability over one year (2025) and require a true-up in the applicant's next rate proceeding.

Alternative Two: Require WEPCO to amortize the regulatory liability over a period to be determined by the Commission and require a true-up in the applicant's next rate proceeding.

Commissioner Notes:

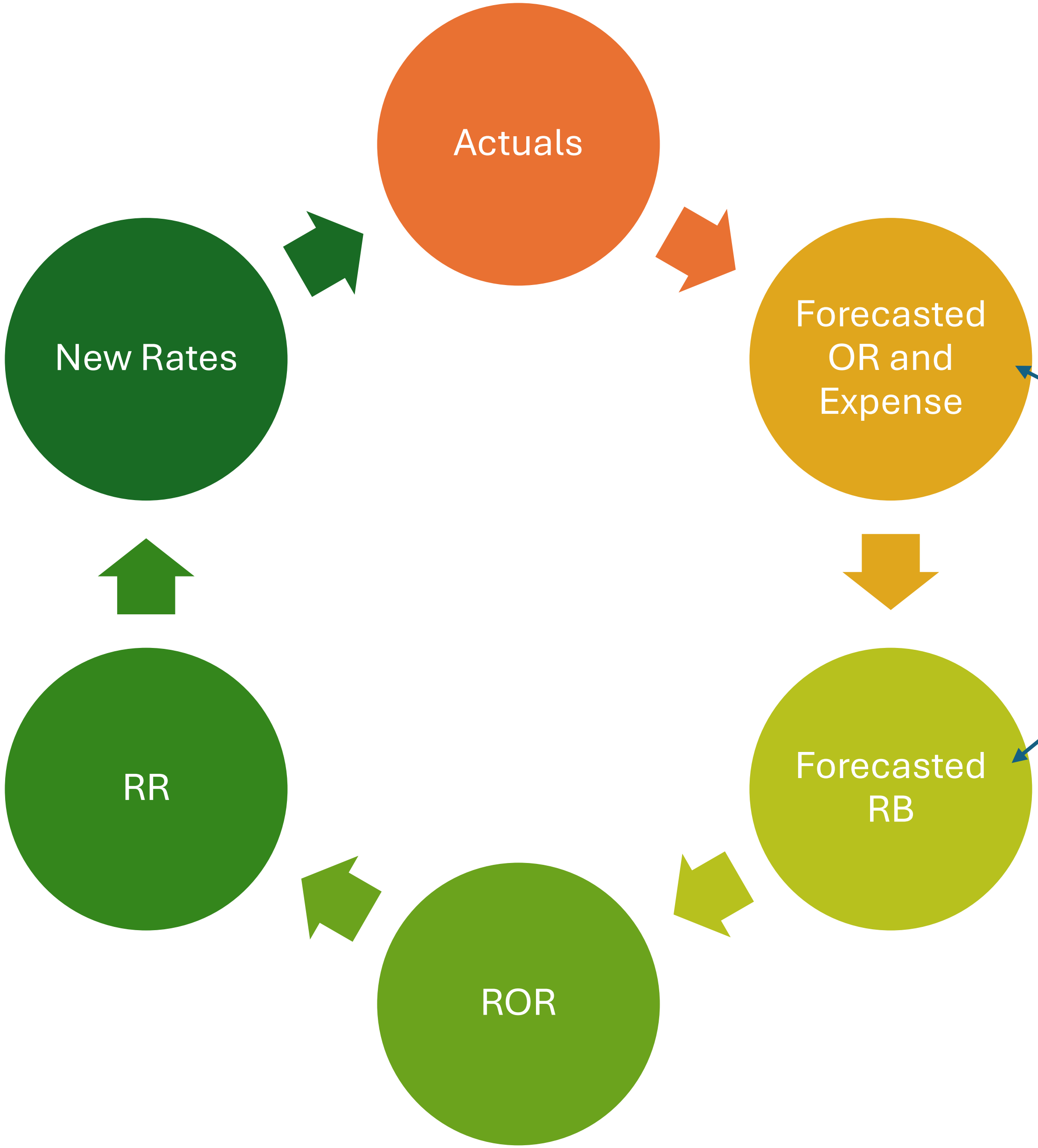
Capital Structure

PSC of WISCONSIN

2026 Weighted Average Cost of Capital (WACC) Calculation
9.50 | 9.65 | 9.80 | Percent Return on Common Equity

	Regulatory Capital Structure Component	Amount (000's)	Percentage of Capital Structure	Annual Cost Rate with 9.50% Return on Common	Weighted Cost	Annual Cost Rate with 9.65% Return on Common	Weighted Cost	Annual Cost Rate with 9.80% Return on Common	Weighted Cost
(A)	Common Stockholders' Equity	$6,875,251							
	Less: Nonutility Property	(10,837)							
	Adjusted Common Stockholders' Equity	$6,864,413	56.58%	9.50%	5.38%	9.65%	5.46%	9.80%	5.54%
(B)	Preferred Stock Equity	30,450	0.25%	3.95%	0.01%	3.95%	0.01%	3.95%	0.01%
(C)	Long Term Debt	$5,023,462	41.41%	5.19%	2.15%	5.19%	2.15%	5.19%	2.15%
(D)	Short-Term Debt	213,918	1.76%	4.44%	0.08%	4.44%	0.08%	4.44%	0.08%
(E)	Total Capital | Weighted Average Cost of Capital	$12,132,243	100.00%		**7.62%**		**7.70%**		**7.78%**
(F)	Income Taxes on Equity Capital				2.01%		2.04%		2.07%
(G)	Ratepayer | Economic Cost of Capital				**9.63%**		**9.74%**		**9.85%**
	Interest Coverage								
	Before Tax Coverage								
(H)	Line (G) / Lines (C) + (D) + (E)				4.32x		4.37x		4.42x
	After Tax Coverage								
(I)	Line (E) / Lines (C) + (D)				3.42x		3.45x		3.49x

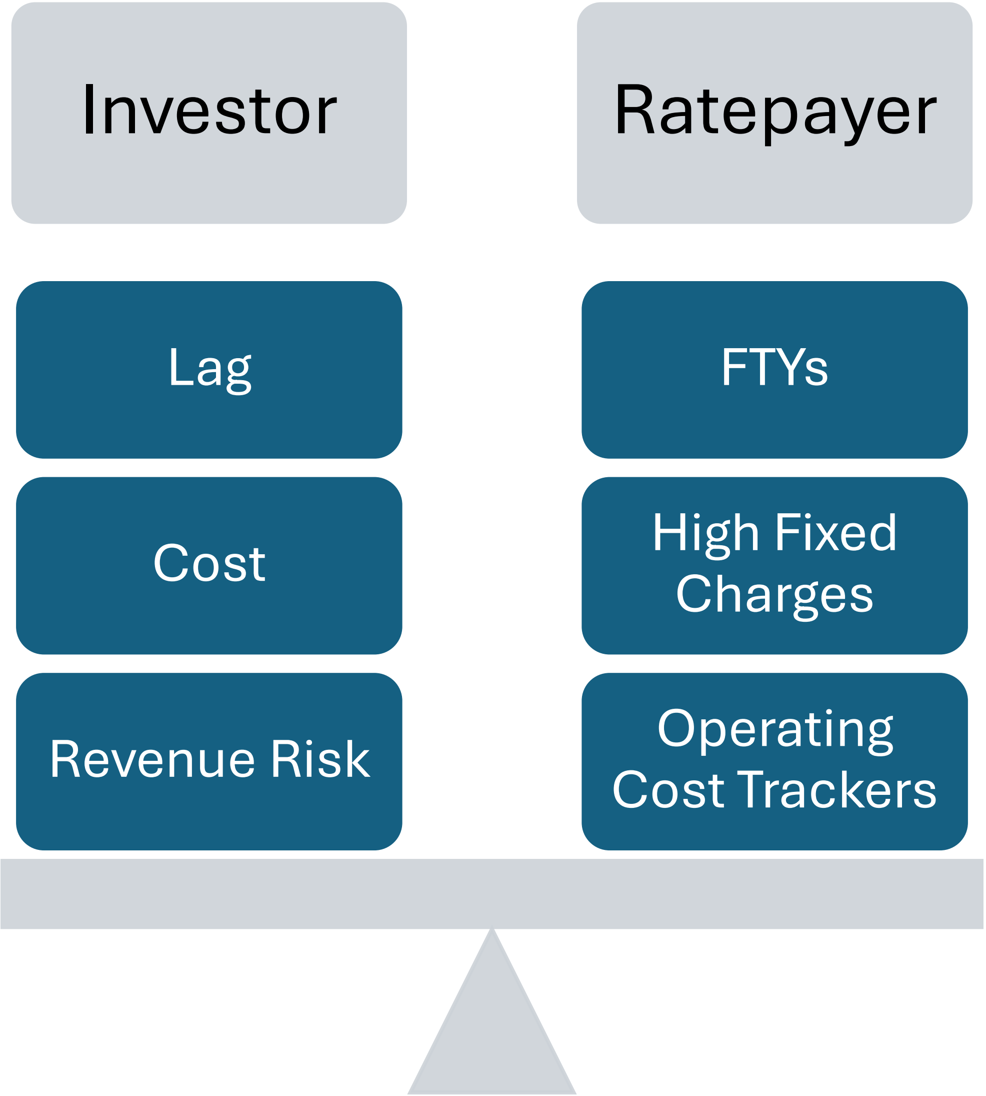
FTY Cycle



- 3-year inflated averages
- Linear trends
- CAGR
- Budget-to-actual reviews
- Payroll: inflation, union contract, vacancy rates and historic trends

Ratemaking Modifications and Risk Allocation

For example:



Common Contested Issues

- Sales Forecasts (determine revenue deficiency/sufficiency at current rates)
- Budget-to-Actual (historical) expenditures
- Fuel Costs (notoriously difficult to predict)
- Payroll/Incentive Compensation
- Rate of Return – particularly, return on equity
- Capital Structure – How much debt/equity is imputed
- Rate Base – What gets capitalized, depreciated in rate base
- COSS / Revenue Allocation / Rate Design
- Tariff Modifications

Other Issues

Affordability

Construction Cost Overruns

Data Center Tariffs

Net Metering

Demand Response Tariffs

Low-Income Programs

FTY Pros

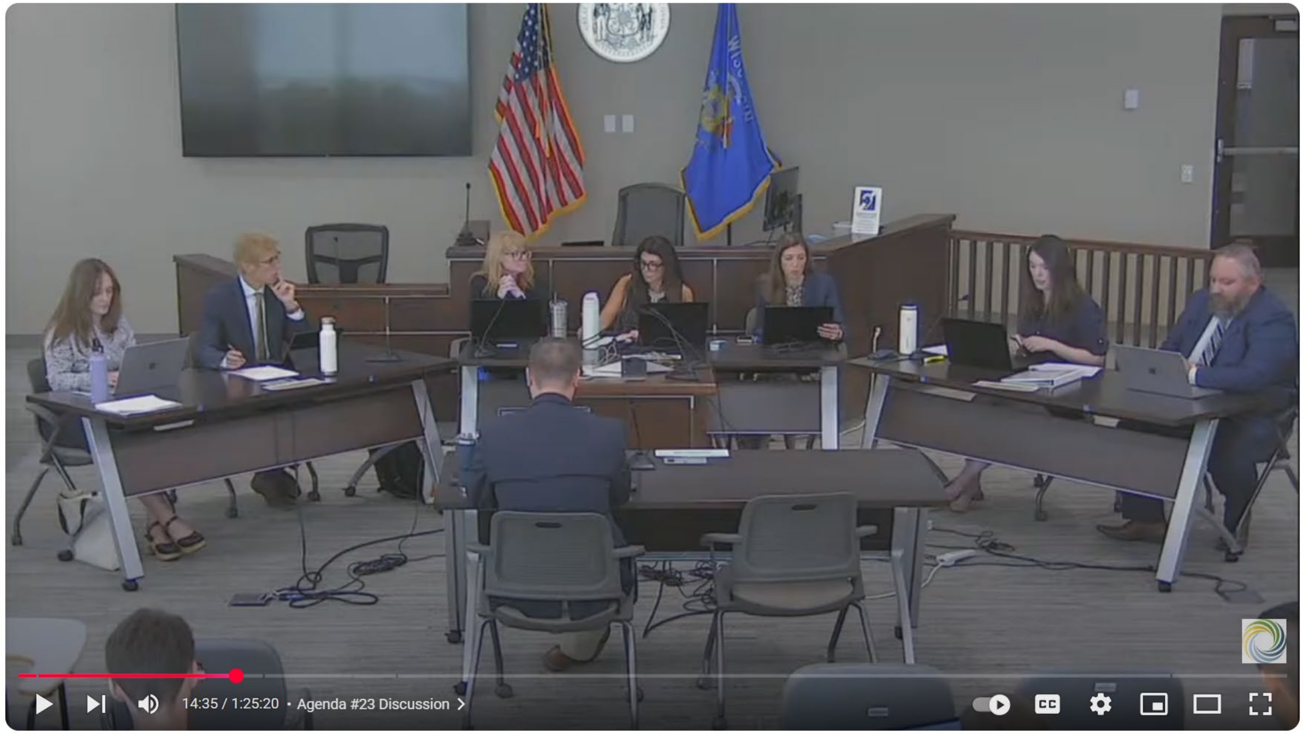
- Clear, tested framework
- Parties know what to expect
- Elegant process for baking past budget variances into new rates
- For investors, reduces risk and improves earnings

FTY Cons

- Risk shifting / risk allocation
- Requests to increase budget lines beyond historical trends
- May reduce some incentive to seek out operational savings or efficiencies, *but*
  - Traditional rate of return regulation *in general* – potential for misaligned incentives and the Averch-Johnson Effect

PBR


WisconsinGov
Public Service Commission
of WISCONSIN
E-Services Portal
Case Management System(CMS) :: Docket Information
5-EI-158 (Active)
Roadmap to Zero Carbon Investigation
Docket Summary
Documents
Events
Related Dockets
Staff Involved
Ex Parte
Hearing Reports
All documents
Minutes
ALJ Order
Motion
Brief
Notice
Comments
Order
Correspondence
Report
Data Request / Response
Request for Intervention / Notice of Appearance
Mailing / Service List
Unacceptable Filing
Memorandum



PSC Commission Meeting 8/28/2025

CURRENT
ENERGY GROUP

RMI

Capex-Opex Equalization

Massachusetts Electric Rate Task Force

September 8, 2025

Massachusetts seeks reforms to remake the electricity delivery model

Near- and Long-Term Rate Design and Ratemaking Priorities:

Promote electrification by removing operating barriers inherent in electric rates

Increase adoption of cost-effective distributed energy resources (DER) to advance decarbonization and electrification

Integrate distribution system planning into the utility's business-as-usual operations and investments

Promote operational efficiency to facilitate the transition of the distribution grid

MA Interagency Rates Working Group, Near-Term Rate Strategy Recommendations report (Dec 2024)

Long-Term Ratemaking Recommendations:

"The development of a regulatory framework that advances a clean, equitable, electrified, and decarbonized energy future"

Including:

- Default seasonal TOU rates for residential customers
- Additional advanced rate designs (e.g., opt-in CPP)
- Effective marketing, education, and outreach of TVR options
- Complementary policies and programs

Adapted from Long-Term Rate Ratemaking Recommendations report (Mar 2025)

But outdated practices and structures persist

20th Century

- System objectives for
  - Universal service (system build out)
  - Reliability
  - Affordability
- Large, centralized generation with very high capital expense
  - Coal
  - Nuclear
  - Gas and Oil
- Limited communication and metering capabilities
- Natural monopoly and economies of scale

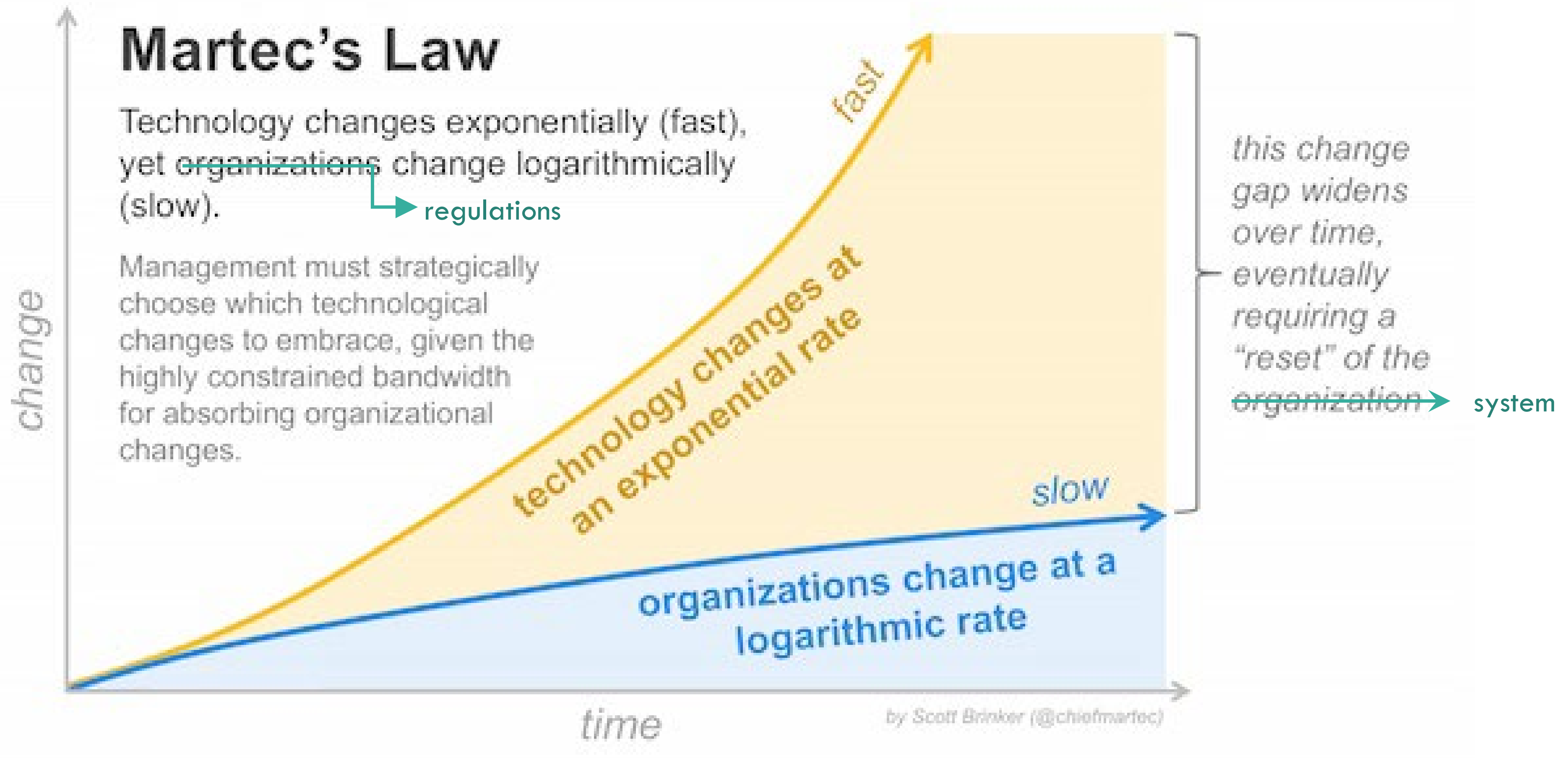
21st Century

- Expanded (added) objectives including
  - Clean
  - Resilient
  - Customer engagement (e.g., digital tools)
- New and expanded technology capabilities with dispersed investment paradigm
  - Distributed generation
  - Demand-side management (EE, DR)
  - Electrification (transport, buildings)
- Robust telecommunication and data capabilities (AMI, DERMs, etc.)
- Greater opportunities for competition and “Utility as a Platform” business model

  >> Integrator; no longer exclusive provider

Industry structure that rationalized an emphasis on earnings for capital expenditure is no longer the defining paradigm of the utility system …*or should not be*.

The Times are A'Changin'. Can regulation keep up?



Source: https://chiefmartec.com/2016/11/martecs-law-great-management-challenge-21st-century/

Traditional cost-of-service regulation supported the goal of "build big, build more"

Revenue Requirement	=	Rate Base	x	Rate of Return (ROR)	+	Operating Expenses, Depreciation, and Taxes

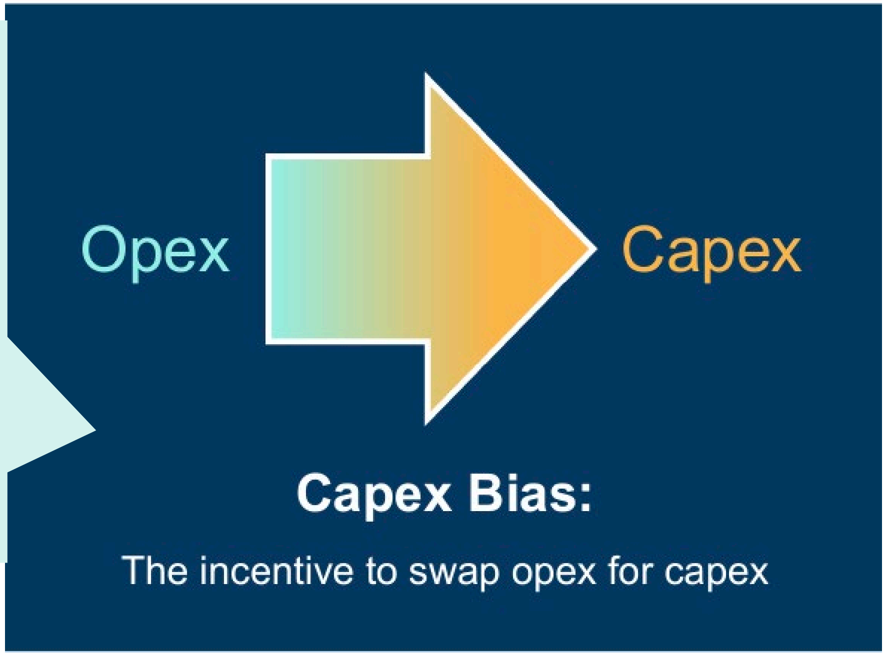
Capital expenditures (capex) becomes part of the utility's rate base (by which the ROR is multiplied) and depreciated over time.

Operating expenses (opex) are simply passed through to customers.

Under cost-of-service regulation, capex presents an earnings opportunity for shareholders but opex does not.

Capex bias and gold plating incentives motivate utilities to overinvest in costly, capital solutions

Example:
A utility may opt for replacing a substation rather than a portfolio of distributed energy resources (e.g., a virtual power plant)



Example:
A utility may overspend on traditional transmission wires rather than enhancing existing grid capacity through reconductoring or grid-enhancing technologies

Additionally, traditional utility regulation typically does not support innovation

There is no upside incentive for innovation

- Under the traditional utility business model, a utility cannot earn more by improving product quality

It tends to be backwards, not forward looking

- For example, reliance on historical test years in some states

There is no clear role for third parties

- Despite the fact that third parties may be more innovative and motivated to find novel solutions than regulated utilities (and that those solutions may be more cost effective)

Change happens slowly

- For example, the focus on detailed documentation and the quasi-judicial nature of the process means that changing a regulation can take years

The results are predictable

1. Utilities do not innovate fast enough to address current needs
2. The regulations that govern utilities do not adapt quickly enough

Capex-opex equalization strategies can level the playing field between capex and opex

What is It?

Capex bias leads utilities to prefer investing in capital over opex-based alternatives, even when they cost less or provide more benefits to customers.

Capex-opex equalization refers to a set of strategies that intend to create an incentive for all or certain categories of opex that is equivalent to the utility's incentive to pursue capex.

Key Benefits & Drawbacks

- Reduces capex bias
- Narrow approaches are likely to be easier to implement and the consequences of getting them "wrong" more limited
- However, more comprehensive approaches can more thoroughly address capex bias, though they tend to be more complex and take longer to implement
- Although capex bias can be reduced, harder to remove *expenditure bias* (i.e., gold plating)

For more information on totex ratemaking, see: *Making the Clean Energy Transition Affordable: How Totex Ratemaking Could Address Utility Capex Bias in the United States*, RMI, 2022.

Capex-opex mechanisms come in different forms, with varying scopes

- All these mechanisms except calibrated ECM and totex ratemaking have been adopted in the US
- Totex ratemaking levels the playing field between capex and opex more comprehensively than the other mechanisms

**The "broad" mechanisms can be implemented in a narrow fashion if desired – for example, to pilot their application.*

For more information on totex ratemaking, see: *Making the Clean Energy Transition Affordable: How Totex Ratemaking Could Address Utility Capex Bias in the United States*, RMI, 2022.

Earn on that Opex. Or better, equalize.

Narrow

Broad

Targeted PIMs	Allow earning if prescribed targets are met on programs that are otherwise paid from opex (and which can/should offset capex).
Opex Capitalization	Allow rate basing for inclusion in allowed earnings of select areas of operating expense, such as software or DER program management.
Modified Clawback Mechanisms	Permit the utility to retain a share of the cost savings that would otherwise be "clawed back" (hence the modification) in cases in which operating expense is substituted for capital expense.
Calibrated ECM	Equalize the cost-containment incentive for both capex and opex within an efficiency carryover mechanism (ECM). Calibrated ECM is a variation on an ECM, which allows the utility to retain a portion of cost savings achieved during an MRP.
Totex Accounting	Replace standard capex and opex accounting categories with a single "total expenditures" (totex) account. Divide this into "fast money" and "slow money", the latter of which earns a return similar to rate-based capex.

Totex ratemaking treats capex and opex equivalently for ratemaking purposes

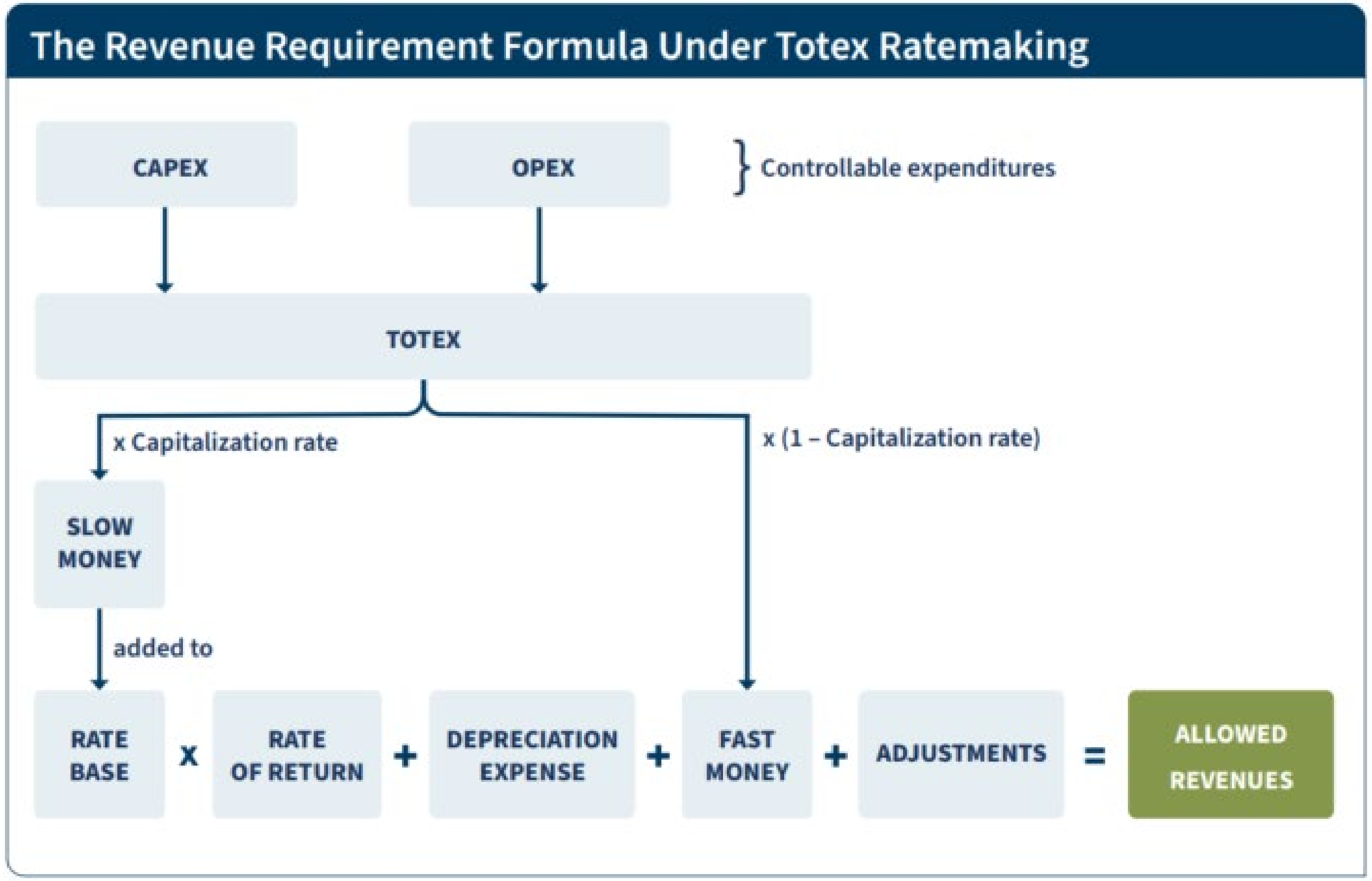


Diagram: RMI (2024)

- **Implemented in UK (RIIO framework) & Italy.**
- **Benefits**
  - Can help keep rates affordable by addressing capex bias
  - Broadly applicable to all utility expenditures
- **Limitations**
  - Alone, does not address gold plating - should be paired with other reforms that motivate cost-efficiency.
  - Time consuming to adopt.

Case study: In UK, totex is implemented alongside strategies to encourage cost control

The UK RIIO framework includes the following design features:

- An <u>MRP with a revenue cap</u> which sets the totex allowance in advance, and indexes it to external cost drivers rather than the utility's own spending decisions.
- <u>Capitalization rates</u> generally around 70-80% slow money
- <u>Totex incentive mechanism (TIM)</u> to let utility retain savings below the revenue cap (and bear cost for overspend), which mitigates gold plating and encourages cost containment.
  - Totex incentive rate is set ex ante to dictate what portion will be retained (or borne) by utility. Symmetric design.
- <u>Depreciation rates</u> set for assumed average asset lifetimes (but different between system levels – i.e., trans vs. dist, etc)
- Separate treatment for <u>uncontrollable costs</u> (taxes, pension expense, etc.)

OXERA, Dec 2021

Alone, totex does not encourage cost control.

In the RIIO framework, the **<u>MRP with a revenue cap</u>** and the **<u>TIM</u>** incentivize cost containment by addressing the gold plating incentive.

Totex ratemaking encourages utility pursuit of lower cost, high-value opportunities

Enterprise-wide reorientation away from "capital first" planning can permit new and innovative solution development

UK RIIO stakeholders have identified totex ratemaking as one of primary enablers for other reforms to move forward, including for flexibility services and creation of DSO market structure.

The **totex incentive mechanisms (TIM)** motivates pursuit of alternative solutions to achieve cost savings

Commensurate opportunities for utility innovation in broad-based, and interconnected, solutions.

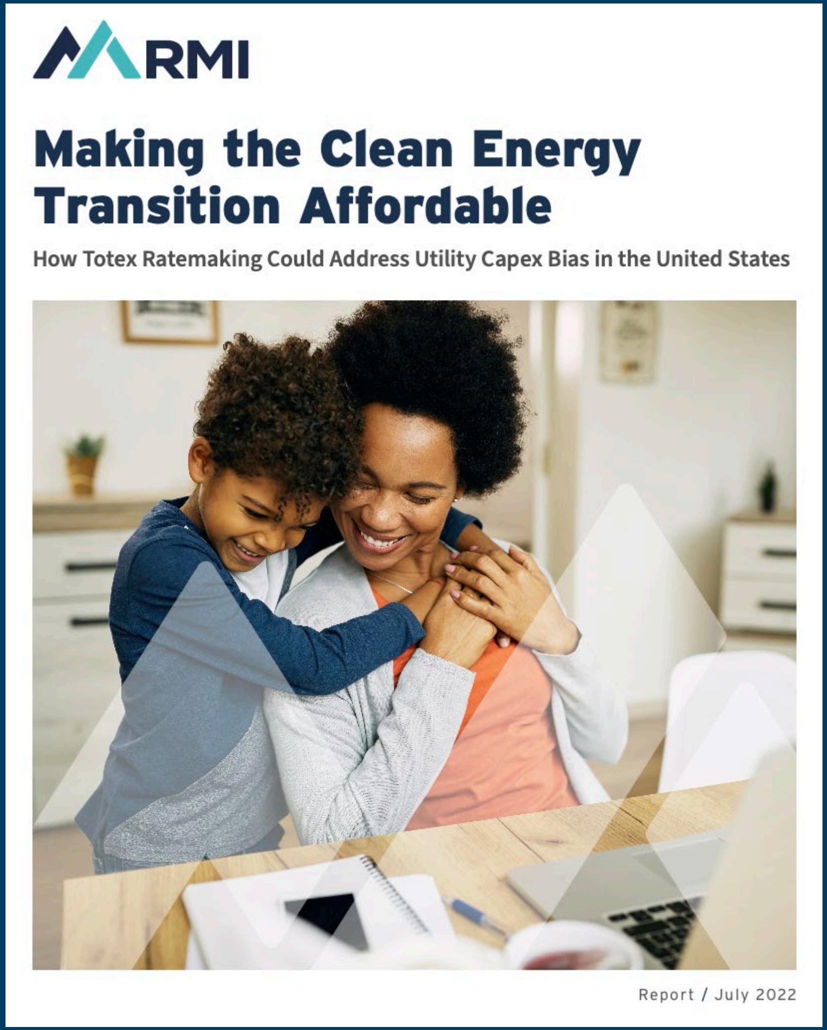
- DER integration
- Non-wires and non-pipeline alternatives
- Uptake of alternative rate designs (e.g., customer-oriented design; marketing and outreach strategies)
- Partnerships with third-party solution providers

Totex has "facilitated **greater openness towards collaboration and partnership-oriented ways of funding and operating** because contract payments would be treated equally with in-house capital expenditure from a regulatory perspective."

UK water utility regulation; Ofwat, 2021; 'PR14 review: discussion paper on findings'

Totex ratemaking is feasible in the U.S.

- Key finding: the conflict with US accounting standards is a perceived one, and Totex would be feasible to use in the US.
- Other questions explored in the report:
  - Would adopting Totex ratemaking affect the utility's financial health?
  - Would adopting Totex ratemaking alter the pace of decarbonization?
  - Would adopting Totex ratemaking make utility accounting more complex?
  - And several design questions (e.g, What share of the utility's total costs should be included in totex, should regulatory assets and liabilities be included in totex, setting the totex allowance amount, totex incentive, and capitalization rate, etc.)



Report link: https://rmi.org/insight/making-the-clean-energy-transition-affordable/

Calibrated Earnings Carryover Mechanism (ECM) creates an incentive to spend less capex and opex.

- Under an MRP, an ECM preserves the cost-containment incentive by allowing the utility to retain a portion of cost savings for a prolonged period (past the end of an MRP).
- If an ECM is applied to *both* capex and opex, and is calibrated to equalize incentives, it can also address capex bias.

- **Benefits**
  - Ensures the cost-efficiency incentive does not diminish in later years of the MRP
  - Strong cost-efficiency incentive applicable to both capex and opex
- **Limitations**
  - Data collection and accounting requirements to calculate appropriate adjustments can be complex
  - Process to determine adjustments can be administratively onerous
  - Potential for some bias or information asymmetries to persist

Case study: Calibrated ECM in Australia

- 5-year MRP; ex *ante* (forecasted) determination of expenditure allowances
- Opex: Efficiency Benefit Sharing Scheme (EBSS) adopted 2007
  - Rolling incentive with symmetric rewards/penalties for over and under performance
  - Savings (or overspend) is placed in carryover account then distributed (collected) over next five years to company
- Capex: Capital Expenditure Sharing Scheme (CESS) adopted 2013
  - Adjustment at end of MRP period
  - 30% sharing rate (Customers receive 70% of savings, or costs of overspend)
- These tools have generated majority of approx. AU$1400/year per customer benefits

HoustonKemp, 2022

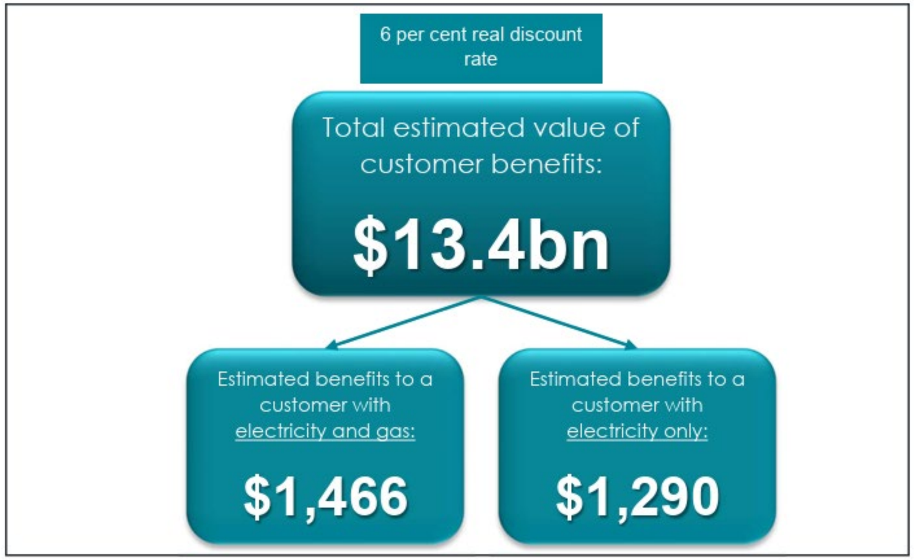
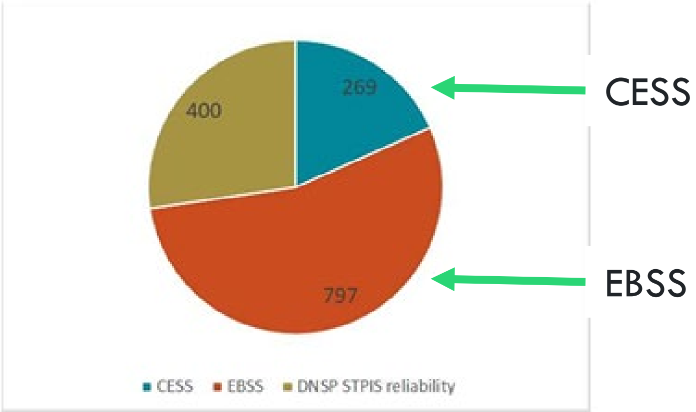


Figure 3: Electricity and gas consumer benefits per consumer by incentive scheme ($, PV'2020)



Modified clawbacks can incentivize a utility to seek cheaper, short-term opex alternatives

- **A *modified* clawback allows the utility to retain the difference between approved capex budget and actual opex until rates are reset.**
- **Benefits:**
  - Allows the utility to maintain its earnings as if it had invested the budgeted capital
  - Customers benefit from the savings in next rate case since the capital budget has been reduced.
- **Drawbacks:**
  - Mechanism benefits are shortlived for the utility – unless the avoided capital investment is deferred.
  - Challenging to ensure capex budget is not inflated to maximize savings.

Case Study: **New York Modified Clawback**

- If a portion of capital budget was avoided by a service expense for DER, the clawback mechanism would not be applicable to that portion of the budget.
- The utility could retain
  - avoided portion of the capital budget & associated earnings
  - service expense without additional rate recovery.
- In next rate case, the elements of the revenue requirement associated with the avoided capital were removed and the DER service expenses were added to O&M budget.
- Mechanism replaced in 2017 by NWA SSM.

Advanced Energy United, *Utility Earnings In A Service-oriented World*, 2018

PIMs & SSMs can equalize capex-opex incentives for particular spending categories

- PIMs attach a financial reward or penalty to a utility's performance in a specific opex-dependent domain (e.g., energy efficiency).
- SSMs allow the utility to retain a share of the cost savings (or net benefits) when it implements a cheaper (or more beneficial) alternative – which can be opex.
- Benefits
  - Can reduce information asymmetry.
  - Can be designed flexibly to be broad or narrow, but tend to be narrower.
- Drawbacks
  - In the case of PIMs, can be challenging to determine metric, target, and incentive to ensure incentive is requisite with performance and value to customers.
  - In the case of SSMs, can be challenging to determine appropriate baseline (i.e., counterfactual) for estimating the savings.

Case Studies:

- Three-year EE plan performance incentives (MA) provide program administrator with incentives to maximize total and net benefits by pursuing all cost-effective EE.
- Collective SSM (HI) provides an incentive to contain costs not subject to the cost containment incentive of the MRP (i.e., fuel costs, purchased power costs, and tracked capital costs).
- Non-wires and non-pipes alternatives PIMs (NY, CT)
- Demand-side management shared savings incentive mechanisms (MN)

More examples in RMI PIMs Database

Opex capitalization provides a long-term incentive to invest in certain opex categories

- Amortizes a category of opex and lets the utility earn a return on it over time.
- Frequently applied toward energy efficiency, but could also be used for:
  - IT and software investments
  - Efficiency and DER programs
- Can be helpful to make capitalization contingent upon meeting a minimum threshold or delivering a quantifiable level of benefit.
- Benefits
  - Enables efficient substitution of less-costly opex alternatives
  - Can support an NWA or NPA planning process
- Drawbacks
  - Does not address gold plating for the opex solution

Examples:

- MD formerly allowed utilities to rate base and amortize EE for a five-year period; investment was capitalized using weighted average cost of capital.
- Similar approaches used in Utah, New Jersey, and Illinois.

ACEEE, 2018

Solutions range from "ready now" to "roll up your sleeves"

Narrow

Mechanism	Opportunity	Limitations
Targeted PIMs	PIMs are a well established and accepted regulatory mechanism, which can be targeted to new (emergent) outcomes and needs. Ties reward to performance (and to value created)	Narrowly applied to one or a limited number of identified objectives. Restricts utility's strategic decision-making by pre-determining "winners". Maintains same capitalization and earnings on traditional investments (i.e. underlying capex bias likely to persist).
Opex capitalization	"Easy" implementation to allow earnings on known needs and opportunities for modern expenditures (e.g., software as a service).	
Modified clawback mechanism	Aligns with wide interests in non-wire solutions and identified needs for *shared savings* to allow utility and ratepayers to mutually benefit.	Requires that a pre-determined capital budget is established, to which the alternative can be compared. Can create a perverse incentive to not meaningfully consider opex alternatives until after IRP and rate cases are complete.
Calibrated ECM	Incorporate with MRP to encourage utility motivations for pursuit of cost efficiency, while looking beyond capex-only savings opportunity.	Complex data collection and accounting requirements needed to calculate appropriate adjustments. Administratively burdensome with potential for some bias or information asymmetries to persist.
Totex accounting	Full break from capex-based ratemaking and earnings opportunity. More reflective of competitive market outcomes in which a business earns based on decision-making across entire business.	Need to overcome or modify foundational rate base construction (i.e., status quo bias). Perceived* incompatibility with US accounting standards. Capex bias shifts to *expenditure bias.*

Broad

Where to begin?

Evaluate efficacy of existing approaches

Massachusetts EE PIMs offer earnings as percentage of EE budget.

Evaluate whether these mechanisms are effective and if so, consider ways to strengthen them.

Refine complementary mechanisms

Capex-opex equalization works in concert with other regulatory structures, including revenue cap MRPs.

Evaluate whether MRP is designed effectively to limit capex bias and gold plating.

Learn by doing

"Pilots" can allow testing of new structures for targeted categories of expense (e.g., smart meter rollout)

Pilots are not just for technical solutions; opportunity to test ratemaking and revenue structures.

Mind the ROE

Benefits of most or all incentive improvements are diminished as long as expenditure bias (gold plating incentive) persists.

Investigate applicability of totex reform

Explore whether totex ratemaking could work in Massachusetts.

Thank you.

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Gennelle Wilson

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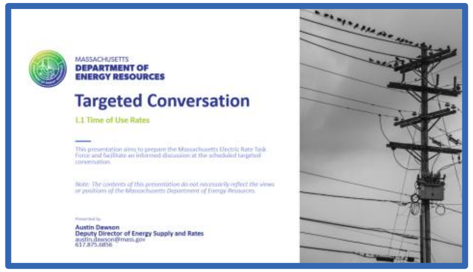
Next Steps

Targeted Conversation

September 17, 2025, 2-4pm

- Will serve as a deliberative space following related expert presentations to prompt informed discussion on policy questions and priorities

Illustrative Presentation



Optional Office Hours

September 24, 2025, 2-4pm

- Optional office hours for further conversation, serving as a structured opportunity to work towards common understandings and positions. We also encourage participants to have discussions amongst each other beside formal Task Force sessions
- Please reach out to chris.connolly2@mass.gov to request an invitation.