Christensen ASSOCIATES

Jurisdictional Review of Utility Remuneration Models

for
The Ontario Energy Board

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Table of Contents

EXECUTIVE SUMMARY

E. 1 Purpose of the Report

This report contains analysis to assist the OEB with efforts to address the evolving electric industry landscape using regulatory innovation. The report summarizes the current electric distribution utility remuneration ("UR") model in effect in Ontario and reviews five different jurisdictions for purposes of comparison and perspective.[1]

Through this jurisdictional scan, we discuss each jurisdiction's similarities and differences to Ontario, the key issues and policy goals identified, and the evolution of the rate-regulation framework, including the development of performance incentives that make some portion of utilities' total remuneration contingent on the achievement of certain performance goals. This review aims to inform the OEB's ongoing efforts to advance Ontario's performance-based approach to rate-regulation and ensure clean, reliable and affordable energy against the backdrop of the energy transition.

The jurisdictions covered in this report include Australia, California, Hawaii, New York, and Great Britain. The industry organization and regulatory constructs of the five selected jurisdictions do not perfectly match industry conditions in Ontario and they each employ different forms of incentive regulation. However, the varying utility remuneration models and alternative rate-regulation tools in place in these jurisdictions may be informative to the OEB.

E.2 Key Findings from Jurisdictional Scan

Each of the five jurisdictions share two key attributes that pertain to the OEB's UR investigation. First, in formulating their regulatory framework, regulatory authorities in each jurisdiction cited the energy transition as a key consideration. Second, all jurisdictions adhere to some form of multi-year rate plan, capping prices or revenues over a set period of time.

E.2.1 New York

Under the most recent UR framework known as Renewing the Energy Vision ("REV"), electricity distribution utilities in New York typically operate under a three-year rate plan with performance incentives. The New York Public Service Commission has stated that distribution utilities may eventually serve as generic distribution service providers or what are referred to in Ontario as Distribution System Operators. This means that the utilities would earn revenue from the operation and facilitation of a distribution-level market. Though this vision has not been fully realized, the ideas behind this reform may be helpful for Ontario in its consideration of next generation UR models and research into Distribution System Operator models. In addition, New York has put in place mechanisms that encourage utilities to adopt non-wires solutions (i.e., alternative strategies that utilities can employ to address energy needs without investing in traditional infrastructure) to provide earning opportunities for the utilities and generate savings for customers.

[1] The jurisdictional review section of the report specifically focuses on utility remuneration in the electric industry in each jurisdiction.

The regulator in New York has established categories in which the state's utilities can propose performance incentives associated with the energy transition. Some of the proposed or existing Performance Incentive Mechanisms ("PIMs")—called "earnings adjustment mechanisms" in New York—may provide ideas about what categories of performance are important and how PIMs can be structured.

The New York experience also illustrates a more comprehensive reform like REV takes a long time to develop and implement. The REV proceeding was initiated in 2014. After a decade, the visions set out in the proceeding are still not fully realized.

E.2.2 California

California's fully integrated utilities operate under four-year rate plans based on forecasted revenue requirements.

A key aspect of California's regulatory framework is its focus on mandate-based mechanisms to achieve energy transition goals. The California Public Utility Commission mandates that utilities maintain robust energy efficiency portfolios, manage demand response programs, and actively seek opportunities to defer capital investments. This approach differs from the model in other jurisdictions in this review, which rely more heavily on financial incentives to drive similar outcomes. California's strategy places a greater emphasis on regulatory requirements and utility obligations to achieve energy transition objectives.

E.2.3 Great Britain

Great Britain's "Revenue using Incentives to deliver Innovation and Outputs" ("RIIO") framework regulates distribution utilities and consists of a five-year rate plan based on a complex mix of revenue targets and performance incentives. Some of the components of RIIO include targeted performance incentives and revenue decoupling, which are comparatively discrete tools that can be incorporated into other rate-regulation frameworks. Other features of the RIIO model, like the "totex" method of earning a rate of return on a combination of capital and operational expenditures (as opposed to the more common, traditional approach of earning a return only on capital), may, in theory, be possible to implement in Ontario, but would require careful consideration in the context of both the goals of the regulatory construct and the means of calculating allowed revenue.

RIIO's complexity sets it apart from other jurisdictions in this review. More complex UR models have the potential to be contentious and possibly lead to prolonged, resource-intensive rate-proceedings to determine the application of each component in each utility's specific circumstances.

E.2.4 Hawaii

The Hawaiian Electric Companies are integrated utilities currently operating under a five-year revenue cap plan with a capital supplement somewhat similar to Ontario's incremental capital module. This jurisdiction has also adopted performance incentives aimed at addressing issues related to the energy transition.

Hawaii's process for designing performance metrics may be informative for Ontario. The Hawaii PUC began with a set of specific goals at the outset of its performance-based regulation design process, and then crafted the utility remuneration framework around those goals. The state utility commission conducted a thorough stakeholder engagement process with a working group, and subsequently allowed comments on proposed performance incentive designs through an open docket. This methodology for designing the PIMs allowed for input from diverse perspectives about what different groups deemed important and feasible, as well as the value of achievement in different performance categories.

E.2.5 Australia

As in Ontario, electricity distributors in Australia operate under a five-year rate plan.

Australia's incentive schemes show how performance incentives can be designed to work in conjunction with one another to balance cost efficiency and service quality such that efforts to reduce operational and capital expenditures don't compromise reliability. Similar to Ontario's "Custom IR" option, Australia's rate-regulation framework demonstrates flexibility by allowing utilities to propose tailored incentive schemes within a structured framework.

Building on this foundation, the Australian regulator has implemented additional initiatives to encourage utilities to pursue innovative means of meeting consumer demand while minimizing environmental impact. These mechanisms offer non-wires solutions incentives that may ultimately reduce utility investments in physical plant.

E.3 Conclusions

Like Ontario, all five jurisdictions reviewed in this report employed some form of multi-year rate plan ranging from three to five years in length. No two rate plans were exactly alike.

Four of the jurisdictions (all but California) have implemented targeted performance incentives. In some cases, these incentives are penalty-only. Others may be symmetrical or reward-only. In the four jurisdictions where performance incentives were employed, the incentives were put in place to align the utility's incentives with policy goals without mandating action. However, in some jurisdictions, as in California and in some instances Great Britain, mandates were used instead of financial incentives, requiring certain actions while providing revenue recovery as in a traditional regulatory framework.

Although some jurisdictions (e.g., New York and Hawaii) considered adopting a UR model that would provide a rate of return to operating expenses, only one jurisdiction (Great Britain) has adopted a form of totex cost recovery. Under the totex approach, a subset of operating expenditures is grouped together with capital, earning an annual rate of return in an effort to balance a perceived capital spending bias. In both New York and Hawaii, regulators cited accounting issues with transitioning to totex. Some investigation is required to determine whether the same accounting obstacles would exist for adopting a totex approach in Ontario.

Across each jurisdiction, we found that changes to rate regulation often occur over lengthy time horizons. Formulation of new elements to the regulatory model, followed by stakeholder engagement, generally constitute the first stage in a multi-year process that concludes with regulatory or legislative changes to utility remuneration. This is important context when considering possible updates to a utility remuneration model.

The diverse approaches used in other jurisdictions to achieve a similar set of policy goals indicate that there are many tools available to the OEB in the regulation of utilities. The regulatory concepts and mechanisms contained in this report can be informative as the OEB seeks to evolve its current approach to ensure clean, reliable and affordable energy and meet the demands of the energy transition. Each jurisdiction practices some form of regulation that could be added incrementally to the province's current incentive regulation model. For example, targeted performance incentives could be designed to address specific goals. In other cases, specific policy-oriented programs with funding may be better suited. To the extent that Ontario ultimately seeks a more comprehensive change to the status quo, each of these five jurisdictions may offer lessons about balancing incentives, oversight, and regulatory complexity.

1. INTRODUCTION

1.1 Background and Scope of Work

In its 2023 Letter of Direction, the Minister of Energy directed the OEB to conduct a review of utility remuneration ("UR") models in other jurisdictions as part of the effort to consider potential changes to the province's current UR model to "ensure timely investments to support outcomes that benefit Ontario ratepayers." In addition, the Minister endorsed the OEB's proposal for considering improvements to cost-efficient service through the inclusion of performance incentives in its rate-setting framework.

To address the Minister's Letter of Direction, the OEB has engaged Christensen Associates Energy Consulting ("CA Energy Consulting") to review the evolution of utility remuneration models in both Ontario and other jurisdictions. This report contains a review of five jurisdictions, each with different forms of incentive regulation. Through this scan, we discuss each jurisdiction's similarities and differences to Ontario, the key issues and policy goals identified, and the evolution of the rate-regulation framework including the development of Performance Incentive Mechanisms ("PIMs") that make some portion of utilities' total remuneration contingent on the achievement of certain performance goals. This review aims to inform potential changes to Ontario's UR model as part of ongoing efforts to advance the OEB's performance-based approach to rate-regulation and ensure the rate-setting framework will continue to drive cost effectiveness and strong utility performance against the backdrop of the energy transition.

1.2 Rate Regulation and Incentives

Electric utilities traditionally operate under some form of rate regulation, in which firms submit an accounting of annual costs (i.e., a revenue requirement) in periodic rate filings before their regulatory authority. Rates are then set to recover approved costs. An alternative approach, which is used in Ontario and commonly called either incentive regulation or performance-based regulation ("PBR"), aims to mitigate the shortcomings of traditional cost-of-service regulation by providing superior economic efficiency incentives and administrative savings. This alternative form of rate regulation has a decades-long history across multiple industries, including telecommunications, railroads, postal services, and oil transmission pipelines, as well as gas and electric distribution utilities.

The OEB's approach to incentive regulation, which uses price caps (and in some cases revenue caps), limits the growth of utility customer prices to an annual inflation rate that is adjusted by a measure of industry productivity growth. This mechanism introduces competitive market pressures into the electricity distribution utility market, a market that is largely considered to be dominated by non-competitive firms. At the same time, the cap provides relief to the utility from revenue attrition over time by allowing rates to increase by a simple formula based on inflation and productivity.

Recently, an additional form of incentive regulation—PIMs—has also gained interest among utilities and regulators. Whereas price caps focus on providing incentives for the utility to optimize the cost efficiency of its *inputs*, PIMs provide incentives for the utility to produce certain *outputs*. As the current energy transition unfolds, PIMs may serve as a tool to adjust utility remuneration so that the utility's outputs align with the needs of the changing industry.

1.3 Structure of the Report

This report is organized as follows: Section 2 of the report covers a brief history of Ontario's UR model for electricity, an overview of the current UR approach, and ongoing OEB initiatives relating to UR. Section 3 presents the review of UR models in the five selected jurisdictions. Section 4 concludes the report by summarizing the lessons from other jurisdictions and how it may be relevant for Ontario.

Terminology for similar UR concepts often varies across jurisdictions. To ensure clarity and consistency throughout this report, Table 1.1 provides brief descriptions of commonly applied UR elements.

Table 1.1 Description of Commonly Applied UR Elements

UR Element	Brief Description
Multi-year Rate Plans	Rate-regulation frameworks that set rates or revenues for utilities over multiple years, typically 3-5 years, to provide predictability and incentivize cost efficiency.
Revenue Decoupling	A mechanism that separates a utility's revenues from its energy sales volume, reducing the incentive to increase energy sales and supporting energy efficiency initiatives.
Revenue Cap[2]	A regulatory approach that sets a maximum allowed revenue for a utility, regardless of sales volume, adjusted for external factors such as inflation and efficiency factors.
Price Cap	A method of rate-regulation that places a limit on the prices a utility can charge, typically adjusted annually for inflation and expected efficiency improvements.
Performance Incentive Mechanisms	Regulatory tools that link utility revenues or returns to achievement of specific performance targets, such as reliability, customer service, or environmental goals.
Earnings Sharing Mechanisms	Arrangements that divide a utility's earnings above (or below) a predetermined threshold between the utility and its customers, balancing utility profitability with consumer protection.

[2] 'Revenue cap' definitions vary across jurisdictions. In this report, it refers to an indexed approach where a utility's allowed revenue is adjusted based on predefined external factors, such as inflation and productivity.

2. ASSESSMENT OF OEB UTILITY REMUNERATION MODEL

The jurisdictional scan in this report reviews utility remuneration models through the lens of what may be applicable or useful in regulating electricity distributors in Ontario. To better contextualize the research presented in subsequent sections, we first provide an overview of Ontario's current regulatory paradigm. In this section, we offer a brief history of the evolution of incentive regulation in Ontario, a description of the current state of distribution utility remuneration in the province, and some perspective on developments in the electricity sector that may affect distributors. Table 2.1 presents an overview of Ontario's electricity sector.[3]

Table 2.1 Profile of Ontario's Electric Utility Sector

Distribution Regulation	
Regulated Distribution Utilities	56[5]
Ratemaking regulator	Ontario Energy Board
Market Operator and Resource Planner	Independent Electricity System Operator

UR Elements	
Multi-Year Rate Plans	✓
Revenue Decoupling	(Limited)[7]
Revenue Cap	✓[8]
Price Cap	✓
PIMs	-
Earnings Sharing Mechanisms	In some cases.[11]

Fuel Mix[4]			
Nuclear Energy	50.8%	Solar	2.3%
Hydro	24.5%	Bioenergy	0.4%
Natural Gas	12.5%	Other Renewable	0.8%
Wind	8.7%		

Energy Industry Facts	
Total Installed Capacity	38,264 MW[6]
Total Generation	156.04 TWh[9]
Electric Vehicles	171,409[10]

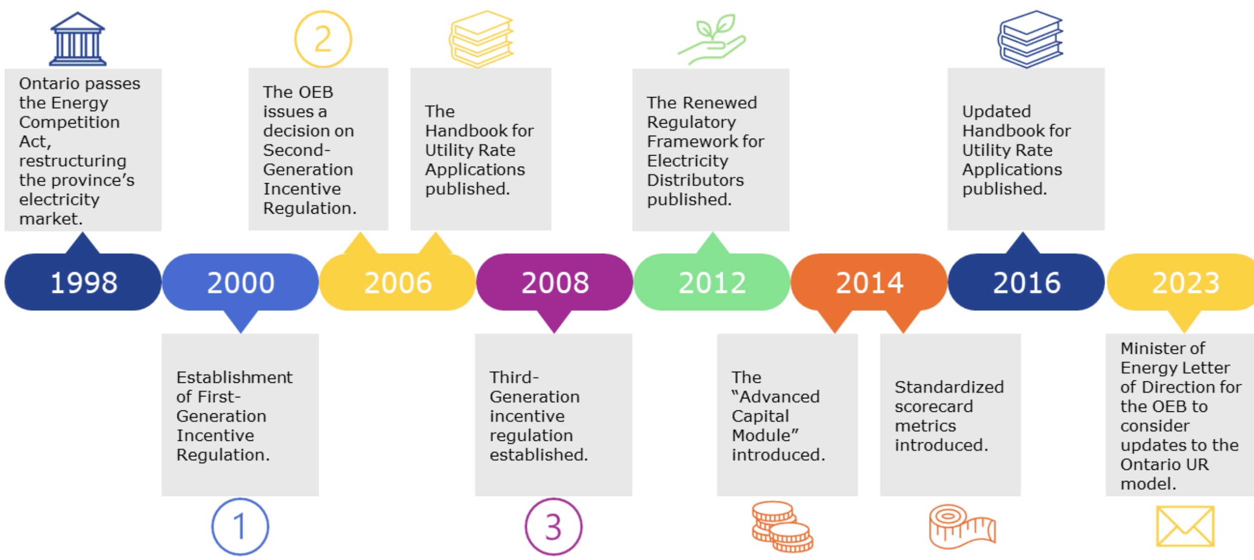
[3] The information in the table pertains solely to the electric utility industry and excludes data on gas utility regulation.
[4] Ontario Energy Board. *Ontario's System-Wide Electricity Supply Mix: 2023 Data.* May 22, 2024.
[5] Ontario Energy Board. *List of licensed companies.*
[6] Independent Electricity System Operator. *Reliability Outlook. An adequacy assessment of Ontario's electricity system.* July 2024 to December 2025.
[7] Although Ontario does not operate with full revenue decoupling, utilities in the province have the option of applying for a Lost Revenue Adjustment Mechanism ("LRAM"). In addition, for residential customers, distribution charges are recovered through fixed, monthly customer charges, effectively decoupling a portion of distributor revenues from sales volumes.
[8] Under the Custom IR rate setting option, utilities are able to customize the rate setting mechanism and choose a revenue cap approach for determining the revenue requirement and setting rates.
[9] Ontario Energy Board. *Ontario's System-Wide Electricity Supply Mix: 2023 Data.* May 22, 2024.
[10] Government of Ontario. *Electric Vehicles in Ontario – By Forward Sortation Area*. June 30, 2024
[11] Earnings sharing mechanisms do not exist for all LDCs, but they do apply to Hydro Ottawa, Hydro One, Elexicon, Alectra, and Toronto Hydro.

2.1 Brief history of Ontario's utility remuneration model since 2000

Prior to restructuring, Ontario's primary vertically integrated electric utility, Ontario Hydro, operated under a cost-of-service regulation model, where rates were set based on the utility's costs plus an allowed return on investment.[12] In the late 1990s, the government of Ontario passed the Energy Competition Act, which led to the restructuring of the province's electricity market,[13] unbundling the generation, transmission, and distribution functions of the electric utility business. In the wake of this restructuring, the Ontario Energy Board ("OEB") reorganized the utility regulation model of the province, shifting the sector from traditional cost of service regulation to PBR. In the development of each generation of incentive regulation, the OEB attempted to build incrementally on the prior generation to incorporate additional performance incentives for utilities.[14]

In this section, we provide a summary of the evolution of Ontario's electric distribution utility remuneration since the unbundling of Ontario Hydro. Figure 2.1 below presents a timeline of these key events.

Figure 2.1 Ontario Regulation Development Timeline



First Generation Incentive Regulation

In early 2000, the OEB issued a decision to transition away from traditional cost-of-service regulation to the province's first PBR regime.[15] The decision stipulated a three-year price cap mechanism, stating that this approach would provide incentive for efficiency improvements and will at the same time provide utilities with the ability to maintain service quality. The OEB acknowledged that a three-year PBR term was relatively short but concluded that this shorter time period would serve as transition term into future generations of PBR. The first-generation price cap model was defined generally by the formula, below:[16]

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[12] Ontario Energy Board. *Decision RP-1999-0034*. January 18, 2000.

[13] Legislative Assembly of Ontario. *Energy Competition Act.* 1998.

[14] See, for example, Ontario Energy Board. *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors.* July 14, 2008, p. 5.

[15] Ontario Energy Board. *Decision RP1999-0034*. January 18, 2000.

[16] Ontario Energy Board. *Chapter 2: Overview of the Electric Distribution Rate Regulation Framework*. p. 2.

$$\%\Delta P_t = \%\Delta IPI_t - X + \%\Delta Z_t$$

Where:

$\%\Delta P_t$ = *percentage change in distributor's price ceiling in year t*

$\%\Delta IPI_t$ = *percentage change in Ontario electric utility input prices from t-1 to t*

X = *the productivity factor*

$\%\Delta Z_t$ = *adjustment for extraordinary events*

This formula reflects the standard approach to price cap regulation. A similar framework had been used throughout the 1990s in capping utility prices in Great Britain, as well as telecommunication and oil pipeline companies in the United States. Since that time, regulators have applied this approach to electricity distributors in Alberta and borrowed the "I-X" formula for revenue caps across numerous states in the United States.

Under a price cap, initial rates are set based on a test year revenue requirement for each utility and subsequently updated each year using the formula. Generally, the inflation factor draws from a government inflation report, such as the Consumer Price Index, while the X factor is set using a calculation of industry productivity. In the OEB's first generation PBR model, the OEB decided to use an sector-specific input price index ("IPI"), which aligned with the goal of using the most accurate input price inflation measure for the cost experience of the utilities. Although this approach provided more accurate inflation data, a drawback of the IPI choice was that it required the OEB to collect cost information and publish an annual inflation factor rather than relying on government data published by, for example, Statistics Canada.

Economic literature generally agrees that price cap regulation provides enhanced incentives for firms to seek cost efficiencies over time.[17] Thus, by adopting price cap regulation, the OEB imposed a UR model with inherent input incentives on Ontario's distributors. However, the OEB also considered incentives for output efficiency in the form of improved service quality. In its first-generation incentive regulation decision, the OEB recognized its responsibility to oversee service quality through a set of metrics for annual publication by each utility in the province. Citing a diversity in the size, circumstances, and service standards of distribution utilities, the OEB initially limited the number of service quality indicators to six:

- Time to connect new services;
- Time to locate underground cables;
- Appointments;
- System average interruption duration index ("SAIDI");
- System average interruption frequency index ("SAIFI");
- Customer average interruption duration index ("CAIDI").

These metrics did not have any associated financial incentives. Three additional indicators were adopted that did not require reporting.[18] The OEB limited the number of service quality metrics,

[17] See, for example: "Incentives for Cost Reduction Under Price Cap Regulation," Cabral, Luis, and Michael Riordan. *Price Caps and Incentive Regulation in Telecommunications.* 1991.

[18] These three indicators were: (1) telephone accessibility; (2) written response to inquiries; (3) emergency response.

in part, because concurrent industry restructuring introduced unknown factors and, at least initially, sought to focus on data collection, reporting, and monitoring of service quality.[19]

Second Generation Incentive Regulation

In December 2006, the OEB issued a policy with updates to Ontario's incentive regulation framework. The decision maintained the same general price cap structure, such that distributors would continue to face a cap on annual rate adjustments according to inflation, industry productivity, and an allowance for extraordinary events. The OEB made marginal changes relative to the first-generation framework, including an update to the X factor value and a more restrictive criteria for the use of Z-factors.[20] The OEB also changed the inflation factor from an sector specific input price measure of inflation to an economy-wide measure using government data, GDP-IPI, citing that the updated approach would be less controversial and easier to implement.[21]

No changes were made to the distributors required service quality indicators.

Third Generation Incentive Regulation

Further updates were made to Ontario's PBR framework following the OEB's third generation incentive regulation ("3GIRM") policy in 2008.[22] Once again, the OEB maintained the existing structural form of utility remuneration for distributors—price caps calibrated with inflation and productivity factors—but made incremental updates in response to feedback from stakeholders. Most substantively, participants in the 3GIRM consultation period voiced a need for capital funding support beyond the price cap mechanism.

In response to concerns about capital funding, the OEB introduced a capital supplement known as the "Incremental Capital Module" ("ICM"). The mechanism allowed electric utilities to collect revenues for extraordinary and unanticipated capital spending requirements other than the normal course of business during the PBR term. In other words, capital funding under the ICM can be requested between rebasing periods, such that the utility is not required to wait until the end of the price cap period. However, the utility must file a specific application for incremental capital expenditures to be considered for recovery prior to rebasing, and the related spending must satisfy the eligibility criteria set out in Table 2.2.

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[19] Ontario Energy Board. *Decision RP1999-0034*. January 18, 2000. p. 50.

[20] Z-factors in the second generation IR framework were limited to changes in tax rules and natural disasters, based on causation, materiality, and prudence criteria.

[21] Ontario Energy Board. *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*. December 20, 2006.

[22] Ontario Energy Board. *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors.* July 14, 2008.

Table 2.2 Rebasing Eligibility Criteria

Criteria	Description
Materiality	The amounts must exceed the Board-defined materiality threshold and clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing.
Need	Amounts should be directly related to the claimed driver, which must be clearly non-discretionary. The amounts must be clearly outside of the base upon which rates were derived.
Prudence	The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

2.2 Current state of electricity distribution utility remuneration.

Ontario's current UR model is set out in the OEB's Renewed Regulatory Framework for Electricity ("RRFE"), which was set forth in 2012. With the release of OEB's Handbook for Utility Rate Applications in 2016, which extended the principles and approaches of the RRFE to electricity transmitters, natural gas utilities, and Ontario Power Generation, the RRFE was renamed the Renewed Regulatory Framework ("RRF"). The RRF requires that utilities submit, as part of the periodic rate application process, a Distribution System Plan that provides information related to a distributor's approach to evaluating its performance, management of its assets, and capital investment plans. In addition, the OEB's Handbook for Utility Rate Applications states that rate applications are expected to provide an overview of customer needs, obtained through customer engagement, along with a description of how those needs are met through the proposed business plan.[23]

The RRF introduced a new comprehensive framework for utility rate-regulation that allowed distributors more flexibility in their regulatory framework. In particular, the RRF allows each distributor to select from a menu of three optional approaches to incentive regulation:

1. *Price Cap IR* - Rates are set on a single forward test-year cost of service basis and subsequently indexed by the 4th generation price cap index formula over a five-year period. A regulatory review may be initiated if the distributor performs outside of the ±300 basis points earnings dead band or if its performance erodes to unacceptable levels.
    - Under Price Cap IR, the OEB made refinements to the inflation factor, relying on an sector-specific inflation measure for non-labor costs and a general measure of labor costs for the labor price component. The X factor for all utilities is set to be the same value under Price Cap IR, equal to an empirical measure of Ontario sector total factor productivity growth. However, company-specific stretch factors adjust this value based on utility performance in cost benchmarking analysis. For this option, the ICM was maintained with minor updates relative to the 3GIRM.
    - The OEB viewed the Price Cap IR approach as appropriate for distributors that anticipate that some incremental investment needs may arise during the term of the rate method.

2. *Custom Incentive Regulation* - In the Custom IR method, rates are set based on a five-year forecast of a distributor's revenue requirement and sales volumes. As the "custom" option, each utility that selects this option files an individually tailored proposal.

[23] Ontario Energy Board. *Handbook for Utility Rate Applications.* October 13, 2016.

- The ICM is not available to distributors that select this option, as allowed revenues are based on a multi-year rate plan set using company forecasts. Once rates have been approved, the OEB monitors capital spending against the approved plan, requiring distributors to report annually on actual amounts spent. If actual spending is significantly different from the level reflected in a distributor's plan, the OEB will investigate the matter and could, if necessary, terminate the distributor's rate-setting method.
- The Custom IR method is most appropriate for distributors with significantly large multi-year or highly variable investment commitments that exceed historical levels.

3. *Annual Incentive Regulation* – This option allows utilities to adjust rates according to the price cap parameters set out in the Price Cap IR option but does not require a forecast test-year cost of service filing. Instead, rates are adjusted annually, and indefinitely, based on existing rates. In this sense, the Annual IR approach is administratively simpler.
    - The OEB stated that the Annual IR approach is appropriate for distributors with primarily sustainment investment needs, and thus, the ICM is not available for firms who select this option.

Table 2.3 provides a summary of the defining features of each regulatory option provided in the RRF. One element not included in this table, which is present in the Ontario UR model, is a "Z-factor," which allows distributors to recover costs beyond the control of the company during the PBR term. This provides a guardrail to the utilities if major, costly, exogenous events occur. The utilities also carry specific costs in deferral and variance accounts between rate applications to provide targeted revenue recovery of these expenses.

Table 2.3: Rate-Setting Overview

		4th Generation IR	Customer IR	Annual IR Index
Setting of Rates				
"Going in" Rates		Determined in single forward test-year cost of service review	Determined in multiyear application review	No cost of service review, existing rates adjusted by the Annual Adjustment Mechanism
Form		Price Cap Index	Custom Index	Price Cap Index
Coverage		Comprehensive (i.e., Capital and OM&A)		
Annual Adjustment Mechanism	**Inflation**	Composite Index	Distributor-specific rate trend for the plan term to be determined by the Board, informed by: (1) the distributor's forecasts (revenue and costs, inflation, productivity); (2) the Board's inflation and productivity analyses; and (3) benchmarking to assess the reasonableness of the distributor's forecasts	Composite Index
	Productivity	Peer Group X-factors comprised of: (1) Industry TFP growth potential; and (2) a stretch factor		Based on 4th Generation IR X-factors
Role of Benchmarking		To assess reasonableness of distributor cost forecasts and to assign stretch factor		n/a
Sharing of Benefits		Productivity factor		
		Stretch factor	Case-by-case	Highest 4th Generation IR stretch factor
Term		5 years (rebasing plus 4 years).	Minimum term of 5 years.	No fixed term.
Incremental Capital Module		On application	N/A	N/A
Treatment of Unforeseen Events		The Board's policies in relation to the treatment of unforeseen events, as set out in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, will continue under all three menu options.		
Deferral and Variance		Status quo	Status quo, plus as needed to track capital spending against plan	Disposition limited to Group 1 Separate application for Group 2
Performance Reporting and Monitoring		A regulatory review may be initiated if a distributor's annual reports show performance outside of the ±300 basis points earnings dead band or if performance erodes to unacceptable levels.		

In addition to minor updates to the ICM stipulated in the RRF, the ICM criteria evolved between its introduction in 3GIRM and the publication of the RRF. Over a series of decisions on utility rate filings, the OEB determined that, in some circumstances, utilities could implement the ICM for purposes that were not extraordinary or unanticipated.[24] Because the OEB recognized its acceptance of allowed incremental capital cost recovery that diverged from the original criteria set forth in 3GIRM, the OEB determined a need for two different forms of capital supplement. In 2014, the OEB introduced an additional capital supplement beyond the ICM called the Advanced

[24] Ontario Energy Board. *Filing Requirements for Electricity Transmission and Distribution Applications.* April 12, 2024.

Capital Module ("ACM").[25] The ACM now operates as a capital supplement for distributors requiring support for planned investments. Table 2.4 summarizes the differences between each module.

Table 2.4: Summary of Differences for ICM and ACM

Purpose and Use:
ICM: Used for unforeseen, non-routine, and significant capital projects that arise outside of the regular rate-setting process. ACM: Used for planned capital projects identified and approved at the time of the multi-year rate plan submission.
Project Nature:
ICM: Non-discretionary projects required to maintain reliability and meet regulatory standards. ACM: Planned and discretionary projects that are part of the utility's long-term capital plan.
Approval Timing
ICM: Approval sought as projects arise, outside the regular rate-setting cycle. ACM: Approval sought as part of the multi-year rate application process.
Funding Mechanism:
ICM: Separate rate rider for approved projects. ACM: Costs recovered over the duration of the rate plan through a rate rider.

In addition to revising the UR model to allow for a menu of incentive regulation options, the RRF also introduced a goal of developing new scorecard metrics to assess utility performance on the following items:

1. *Customer Focus*: services are provided in a manner that responds to identified customer preferences;
4. *Operational Effectiveness*: continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives;
5. *Public Policy Responsiveness*: distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the OEB); and
6. *Financial Performance*: financial viability is maintained; and savings from operational effectiveness are sustainable.

In 2014, the OEB issued a report that contained updated guidance on scorecard metrics to be filed by Ontario distributors on an annual basis.[26] Subsequent to this direction, each utility's scorecard is expected to include data for at least five years. A utility may propose measures for which five years of data is not yet available if it commits to collecting and reporting the data through the course of the plan.[27] Figure 2.2 summarizes the metrics currently filed by distribution utilities in annual scorecards. Ontario's existing scorecards are not considered PIMs, as the metrics do not tie to financial incentives. However, the RRF considers the possibility of, at

[25] Ontario Energy Board. *Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module.* EB-2014-0219. September 18, 2014.

[26] Ontario Energy Board. *Report of the Board: Performance Measurement for Electricity Distributors: A Scorecard Approach.* March 5, 2014.

[27] Ontario Energy Board. *Handbook for Utility Rate Applications.* October 13, 2016.

some point, attaching incentives to reward achievement of utility plan objectives or the implementation of truly innovative technologies sometime in the future.[28]

Figure 2.2: Annual Scorecard Metrics[29]

<table>
<tr><th>Performance Outcomes</th><th>Performance Categories</th><th colspan="2">Performance Measures</th></tr>
<tr><td rowspan="6">Customer Focus

Services are provided in a manner that responds to identified customer preferences</td><td rowspan="3">Service Quality</td><td colspan="2">New Residential Services Connected on Time</td></tr>
<tr><td colspan="2">Scheduled Appointments Met on Time</td></tr>
<tr><td colspan="2">Telephone Calls Answered on Time</td></tr>
<tr><td rowspan="3">Customer Satisfaction</td><td colspan="2">First Contact Resolution</td></tr>
<tr><td colspan="2">Billing Accuracy</td></tr>
<tr><td colspan="2">Customer Satisfaction Survey Results</td></tr>
<tr><td rowspan="7">Operational Effectiveness

Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.</td><td>Safety</td><td colspan="2">Public Safety (measure to be determined)</td></tr>
<tr><td rowspan="2">System Reliability</td><td colspan="2">Average Number of Hours that Power to a Customer is Interrupted</td></tr>
<tr><td colspan="2">Average Number of Times that Power to a Customer is Interrupted</td></tr>
<tr><td>Asset Management</td><td colspan="2">Distribution System Plan Implementation Progress</td></tr>
<tr><td rowspan="3">Cost Control</td><td colspan="2">Efficiency Assessment</td></tr>
<tr><td colspan="2">Total Cost per Customer</td></tr>
<tr><td colspan="2">Total Cost per Km of Line</td></tr>
<tr><td rowspan="4">Public Policy Responsiveness

Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).</td><td rowspan="2">Conservation and Demand Management</td><td colspan="2">Net Annual Peak Demand Savings (Percent of target achieved)</td></tr>
<tr><td colspan="2">Net Cumulative Energy Savings (Percent of target achieved)</td></tr>
<tr><td rowspan="2">Connection of Renewable Generation</td><td colspan="2">Renewable Generation Connection Impact Assessments Completed on Time</td></tr>
<tr><td colspan="2">New Micro-embedded Generation Facilities Connected on Time</td></tr>
<tr><td rowspan="4">Financial Performance

Financial viability is maintained; and savings from operational effectiveness are sustainable.</td><td rowspan="4">Financial Ratios</td><td colspan="2">Liquidity: Current Ratio (Current Assets/Current Liabilities)</td></tr>
<tr><td colspan="2">Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio</td></tr>
<tr><td rowspan="2">Profitability:
Regulated Return on Equity</td><td>Deemed (included in rates)</td></tr>
<tr><td>Achieved</td></tr>
</table>

2.3 The changing electricity sector in Ontario

Ontario faces an evolving electricity utility sector. The continued adoption of electric vehicles and other advancements in electrification are expected to increase peak demand levels. The proliferation of distributed energy resources ("DERs") increases the complexity of operating the electric grid. Environmental concerns, including climate change, present challenges to the reliable generation and distribution of energy to consumers. In addition, affordability concerns,

[28] "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach." Report of the Board. Ontario Energy Board. October 18, 2012. P. 64.
[29] Additional detail on Ontario's current scorecards can be found here: https://www.oeb.ca/sites/default/files/uploads/Scorecard_Performance_Measure_Descriptions.pdf

particularly in the wake of the global Covid-19 pandemic, have placed cost pressure on utilities and end use customers alike. The Minister of Energy and Electrification, the Ontario Energy Board, the Independent Electricity System Operator ("IESO"), and other institutions are working to answer questions about how to meet the demands of the energy transition while maintaining affordability. These initiatives provide additional context for the current state of Ontario's utility remuneration model, and where this model could be improved for the purpose of meeting these challenges.

Provincial Developments

The energy transition is a major focus in Ontario, reflecting the region's commitment to harnessing Ontario's clean energy advantage. In recent years, various institutions have issued reports and outlined objectives related to clean energy policy and meeting the rise in electricity demand. In order to focus the jurisdictional scan in this report on possible UR solutions pertinent to the electricity distribution sector in Ontario, we briefly review current developments in Ontario and expectations for the near future.

In December 2023, the Electrification and Energy Transition Panel ("EETP") –a short-term advisory body, established by government, to help Ontario's economy prepare for electrification and the energy transition - issued a report to the Minister of Energy called Ontario's *Clean Energy Opportunity* outlining opportunities and necessary reforms to support Ontario's transition to a clean economy.[30] The report proposes that Ontario should develop and communicate a government-wide commitment to a clean energy economy by 2050. As part of this plan, the EETP proposes enhanced coordination between the OEB, gas and electric distributors, and the IESO for integrated planning of gas and electric resources.

The EETP report makes a number of recommendations, including several directly related to the electricity distribution sector. For example, the report states that the government, IESO, and OEB should support capacity-building for utilities. The report suggests empowering utilities to make investments in the distribution system in advance of having firm customers in place to ensure the distribution system can keep pace with demand. Such investments could assist utilities in supporting EV charger adoption. In addition, the report recommends that the government, OEB and IESO provide support and space for innovative models that incentivizes DER participation "to the benefit of the whole system."

In addition to the work of the EETP, the government of Ontario published the report *Powering Ontario's Growth* in 2023.[31] The report clarifies the government's plan to support electrification by increasing energy efficiency programs in the electricity and natural gas sectors and building new generation and storage, among other initiatives. Within the energy sector, the IESO and the OEB have undertaken several initiatives to integrate DERs in a way that maximizes value to consumers, including the OEB's *Framework for Energy Innovation* and the *IESO's DER Roadmap*. For example, the *Framework for Energy Innovation*, which was completed in 2023, states that electricity distributors are expected to modify their planning and operations to prepare for the impacts of DER adoption on their systems, and that associated costs will be treated the same as other capital and OM&A spending.

[30] Ontario's Clean Energy Opportunity. Report of the Electrification and Energy Transition Panel. *Electrification and Energy Transition Panel.* December 2023.

[31] Ontario. *Powering Ontario's Growth*: *Ontario's Plan for a Clean Energy.* 2023.

The IESO also developed recommendations and scenarios for the energy transition from the transmission and generation perspective in its 2022 report, *Pathways to Decarbonization*.[32] And more recently in its 2024 Annual Planning Outlook Report.[33] These reports expect a need to build infrastructure to support clean electricity generation, including DERs.

Local governments within the province also have policy goals that will affect electricity distributors. All municipalities are required to have an energy plan, and many municipalities have community energy plans. For example, the City of Ottawa's Climate Change Master Plan outlines a framework for how Ottawa will transition to a clean, renewable, and resilient city by 2050.[34] ReCharge Hamilton, a Community Energy and Emissions Plan from the City of Hamilton, is a major component of the city's long-term plan to decarbonize by 2050.[35] Toronto city council has adopted an ambitious TransformTO Net Zero Strategy that aims to reduce community-wide greenhouse gas emissions in Toronto to net zero by 2040.[36]

Considerations for Rate Regulation

Ontario's distributors are expected to make significant capacity investments toward electrification, while accommodating DER adoption and other clean energy connections. At the same time, there is an expectation of reliability and affordability for electricity consumers. Given these changing circumstances, adjustments to the current rate regulation framework may be worth consideration.

2.4 Developments at the OEB

The OEB is engaged currently in several initiatives and proceedings that pertain to utility remuneration and the rate-setting framework. These initiatives and proceedings, alongside exploration of utility remuneration and performance incentive mechanisms, contribute to the on-going evolution of the Renewed Regulatory Framework for Electricity and the OEB's performance-based approach to rate regulation. These initiatives and proceedings include:

- *Total Cost Benchmarking Review* focuses on OEB's total cost benchmarking processes, first implemented in 2013-2014, to determine how utility stretch factors can be updated and improved.
- *Distributor Spending Pattern Analysis* reviews distributor spending and investing behaviors over a rate term to discern drivers of spending during and following the rebasing period. This initiative is expected to contribute to the potential update of the total cost benchmarking process and reveal whether existing or new regulatory incentives are required to increase distributors' productivity gains.

[32] Independent Electricity System Operator. *Pathways to Decarbonization.* December 15, 2022.

[33] Independent Electricity System Operator. *Annual Planning Outlook: Ontario's electricity system needs: 2025-2050.* March 2024.

[34] City of Ottawa. *Climate Change Master Plan.* January 2020; Amended December 2020.

[35] City of Hamilton. *ReCharge Hamilton: A Prosperous, Equitable, Post-Carbon City*. August 2022.

[36] City of Toronto website. *TransformTO Net Zero Strategy.*

- The *Cost of Capital* proceeding, which commenced in March 2024, is the review of cost of capital parameters[37] that regulated electricity and gas utilities can recover through rates and other matters.
- The *Distribution System Operator Study* assesses the need, value, functionalities, opportunities, risks, roles and impact of potential distribution operator system ("DSO") models for Ontario.
- *Incremental Capital Module Policy* consultation was launched in August 2024 to review and evaluate the funding of significant capital investments for discrete projects between cost-of-service applications through the Incremental Capital Module mechanism.

In addition to these initiatives and proceedings, the Toronto Hydro Electric System Limited ('Toronto Hydro') rate setting application for 2025-2029 and Enbridge Gas Inc.'s 2024 rate rebasing and 2025-2028 price cap plan are currently being adjudicated. Furthermore, through the *Framework for Energy Innovation* the OEB invited distributors to propose incentive mechanisms for deploying non-utility owned DER solutions as alternatives to conventional capital investments. The OEB subsequently provided *Filing Guidelines for Incentives for Electricity Distributors to Use Third-Party DERs as Non-Wires Alternatives*, in 2023, identifying the information distributors should include in their applications for incentive mechanisms. This may give rise to future applications for incentive mechanisms. These on-going proceedings and any potential future proceedings may help ensure clean, reliable and affordable energy and inform the potential development of PIMs regime, utility performance assessment activities, and additional incentive rate-making mechanisms.

[37] The cost of capital parameters include the Return on Equity (ROE) and the Long-Term and Short-Term debt rates for cost of service and custom incentive rate-setting applications.

3. JURISDICTIONAL SCAN

CA Energy Consulting initially considered thirteen candidate jurisdictions, with the goal of selecting three to five locations for further examination in this report. These thirteen candidates contained regulated utilities that operated under some form of incentive regulation, including price or revenue cap PBR, other forms of multi-year rate plans ("MYRPs"), and PIMs. These jurisdictions also exhibited diverse industry characteristics. In some locations, the regulated utilities operated as distribution-only companies in unbundled markets for generation services, with electricity system operators managing the transmission grid, while other locations contained vertically integrated utilities with no transmission system operator.

The thirteen candidate jurisdictions were: Alberta, Australia, California, Colorado, Connecticut, Hawaii, Maryland, Massachusetts, Minnesota, New York, North Carolina, Rhode Island, and Great Britain. From this list, we selected Australia, California, Hawaii, New York, and Great Britain, based on the following criteria:

1. Innovations in regulatory frameworks (e.g., the existence of PIMs and other forms of incentive regulation).
2. Similar policy goals relative to Ontario.
3. Diversity in UR model insights relative to other jurisdictions selected for review.
4. Information availability.

The industry organization and regulatory constructs of the five selected jurisdictions do not perfectly match sector conditions in Ontario. However, the UR models of these locations employ alternative regulation tools that differ from those currently in place in the province and that may inform Ontario's efforts to address the evolving electric sector landscape using regulatory innovation.

Our analysis follows a consistent structure across all jurisdictions examined. We begin with a high-level overview, followed by a detailed exploration of the regulatory framework's historical development. This historical context serves as backdrop for understanding the specific policy goals each jurisdiction aimed to address with their UR model. We then provide an overview of the current UR model, highlighting its key features, incentive mechanisms, and regulatory innovations. Where possible, we supplement our findings with observed outcomes, drawing insights from regulators and other stakeholders.[38] Finally, we conclude with key takeaways, contrasting elements of each jurisdiction's utility remuneration model with Ontario's approach. This structured analysis enables a thorough understanding of each system's unique characteristics, evolution, and effectiveness in comparison to Ontario's model.

Table 3.1 summarizes the industry and alternative regulation characteristics of these jurisdictions.

[38] The availability of information on outcomes for the current utility remuneration model and its elements varies between jurisdictions.

Table 3.1: Comparison of Selected Jurisdictions and Ontario

Jurisdiction	Ontario	New York	California	Great Britain	Hawaii	Australia
Number of regulated electric distributors	59	6	6	14	4	13
Regulatory Authority	Ontario Energy Board	New York Public Service Commission	California Public Utilities Commission	Office of Gas & Electricity Markets (Ofgem)	Hawaii Public Utilities Commission	Australian Energy Regulator
System Operator	Independent Electricity System Operator [39]	New York Independent Systems Operator	California Independent Systems Operator	National Grid Electricity System Operator	-	Australian Energy Market Operator
Multi-Year Rate Plans	✓	✓	✓	✓	✓	✓
Revenue Decoupling	(Limited)[40]	✓	✓	✓	✓	✓
Revenue Cap	✓	-	-	-	✓	✓
Price Cap	✓	-	-	-	-	-
Performance Incentive Mechanisms	-	✓	-	✓	✓	✓
PIMs specific to the Energy Transition	(Limited)	✓	-	✓	✓	✓
Earnings Sharing Mechanisms	In some cases.[41]	✓	-	✓	✓	✓[42]
Totex Returns	-	-	-	✓	-	-

[39] In Ontario, the Independent Electricity System Operator is responsible for market operation and resource planning.

[40] Although Ontario does not operate with full revenue decoupling, utilities in the province have the option of applying for a Lost Revenue Adjustment Mechanism ("LRAM"). In addition, for residential customers, distribution charges are recovered through fixed, monthly customer charges, effectively decoupling a portion of distributor revenues from sales volumes.

[41] Utilities can propose earnings sharing mechanisms as part of their Custom IR application. Currently, earnings sharing mechanisms are applied to HydroOttawa, Hydro One, Elexicon, Alectra, and Toronto Hydro.

[42] Typically, Earnings Sharing Mechanisms share earnings beyond a threshold above the utility's allowed return on equity. In Australia, the utility shares gains from capex underspend.

NEW YORK

Key Takeaways

- New York's Reforming the Energy Vision ("REV") approach to utility remuneration aims to facilitate the transformation of the electricity distribution sector, shifting to a more consumer-centered model with three-year multi-year rate plans for each utility.
- REV provides utilities with earning opportunities that match or exceed traditional investments for non-wires-alternative programs. Non-wires alternatives solve system constraints in place of traditional "wires and poles" infrastructure.
- REV has also introduced new earning opportunities that tie a maximum of 100 basis points in total of utility's return on equity to the performance in system efficiency, energy efficiency, decarbonization of end use and customer engagement.
- The performance incentives associated with REV have produced mixed results.

Profile of New York's Electric Utility Sector

Distribution Regulation	
Regulated Utilities	6
Ratemaking regulator	New York Public Service Commission
Transmission Operator	New York Independent System Operator
UR Elements	
Multi-Year Rate Plans	✓
Revenue Decoupling	✓
Revenue Cap	-
Price Cap	-
PIMs	✓
Earnings Sharing Mechanisms	✓

Fuel Mix[43]			
Dual (Gas/Oil)	39.7%	Hydro	22.7%
Nuclear	22.1%	Gas	9.4%
Wind	3.9%	Other	2.2%

Energy Sector Facts	
Total Installed Capacity	40,286.5 MW[44]
Total Generation	124.52 TWh[45]
Rooftop Solar Capacity	5656 MW[46]
Electric Vehicles[47]	121,768[48]
Battery Storage Capacity[49]	396 MW[50]

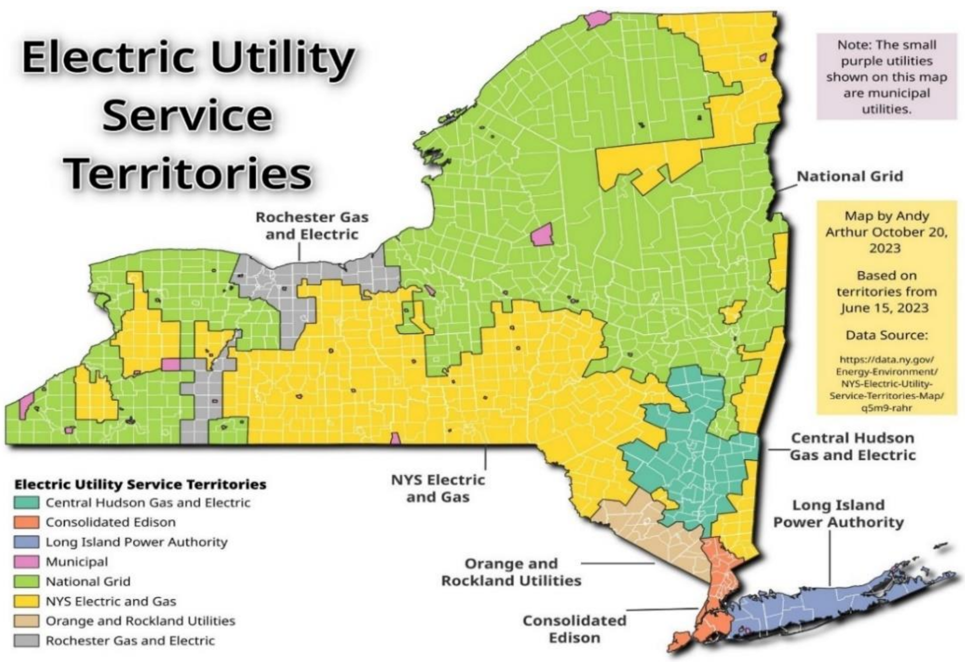
[43] New York ISO, *2024 Power Trends, the New York ISO Annual Grid and Markets Report*. 2024, p49.
[44] U.S. Energy Information Administration. *Table 6.2. A. Net Summer Capacity of Utility Scale Units by Technology and State*. April 2024.
[45] New York ISO, *2024 Power Trends, the New York ISO Annual Grid and Markets Report*. 2024, p49.
[46] New York State Energy Research and Development Authority. *Statewide Distributed Solar Projects*. April 30, 2024. [Accessed on July 2, 2024]
[47] Only all-electric vehicles are included. Plug-in hybrid electric vehicles are not included.
[48] U.S. Department of Energy, Alternative Fuels Data Center. *Electric Vehicle Registrations by State.* June 2024. [Accessed on July 2, 2024]
[49] The capacity refers to total deployed capacity at the end of March 2024.
[50] New York State Department of Public Service. *State of Storage in New York*, April 1, 2024.

3.1 New York

3.1.1 Overview of New York

New York has six large investor-owned utilities and Long Island Power Authority, which cover much of the state's geographic area, as shown in Figure 3.1. The New York Public Service Commission ("NYPSC") regulates the investor-owned utilities ("IOUs") and the New York Independent System Operator ("NYISO") manages the transmission grid with similar responsibilities as Ontario's IESO. As in Ontario, the state's utilities provide distribution services and are unbundled from generation. In recent years, New York has set ambitious targets to transition to a clean energy economy and developed PIMs to address the energy transition. Like Ontario and other jurisdictions in this report, New York's regulatory history shows a trend toward incentive regulation over time, with a particular emphasis on addressing the ongoing clean energy transition.

Figure 3.1: Map of New York's Electric Utility Service Areas[51]



3.1.2 History of Utility Remuneration

Since its inception in 1907 to regulate and oversee New York's electric, gas, water, and telecommunication industries, the New York Public Service Commission ("NYPSC") has implemented several key regulatory reforms moving the state away from traditional cost-of-service regulation. Such early reforms include the adoption of forward test years and Multi-Year Rate Plans ("MYRPs") with earning-sharing mechanisms ("ESMs").

Future Test Years and Multi-Year Rate Plans

[51] Arthur, A. *NYS Electric Utility Service Territories Map*. October 20, 2023.

For decades, New York utilities calculated their revenue requirements based on the company's cost to serve customers, as calculated by actual accounting data from a recent 12-month period (this is known as a "historical test year" approach). However, by definition, the historical test year approach does not capture prospective periods of extraordinary capital expansion and rapidly changing conditions. To provide better aligned utility rates with expenditures, the NYPSC issued an order in 1977 requiring the utilities to include the *projected* operating results for a future 12-month rate period (i.e., a "forward test year").[52] Soon after, during the 1980s, New York adopted Multi-Year Rate Plans,[53] along with ESMs that share over-earnings between the utilities and their ratepayers. While utilities are not required to file a Multi-Year Rate Plan, most utilities operate under a three-year rate plan, which is generally the result of settlement negotiations between all active parties. These rate plans aim to provide incentives for utilities to improve efficiencies and allow the customers to share the efficiency gains.[54]

Industry Restructuring

In 1994, consistent with the commission's goal to encourage competition, reduce consumer prices, and promote technological advancement, the NYPSC began a proceeding to investigate competitive opportunities regarding electric utility services.[55] In 1996, the NYPSC issued an order setting its vision and goals for the state's future regulatory regime, which captured the goals of improved competition and customer choice, as well as the creation of a system operator.[56]

As in Ontario, the industry was subsequently restructured, such that energy generation and retail energy sales became deregulated statewide. Utilities divested their generation assets. Retail competition began, which introduced the opportunity for consumer choice for alternative energy providers (known as "energy services companies") and different pricing options. In the wake of this restructuring, the distribution sector consisted of the six formerly vertically integrated utilities, with rates regulated by the NYPSC.

Revenue Decoupling and Energy Efficiency

The NYPSC also implemented mechanisms to accommodate energy conservation concerns. To mitigate potential incentives to oppose the promotion of energy efficiency, renewable technologies, and distributed generation, the NYPSC issued an order in 2007 requiring utilities to develop and implement mechanisms that true-up forecasted revenues and actual revenues.[57] This practice, known as revenue decoupling, attempts to resolve a mismatch between allowed and realized revenues, such that revenues are generally not impacted by changes in delivery volumes compared to projected sales when rates were approved. The mismatch between forecast and actual revenues can be problematic from a policy perspective if some fixed costs are recovered through volumetric charges, because, in such a scenario, utilities may have a

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[52] State of New York Public Service Commission. *Statement of Policy on Test Periods in Major Rate Proceedings*. November 2023, 1977.
[53] New York State Department of Public Service, Staff Report and Proposal. *Reforming the Energy Vision*. *Case 14-M-0101*. April 24, 2014. p47.
[54] Ibid.
[55] New York State Department of Public Service. *Case 94-E-0952*.
[56] State of New York Public Service Commission. *Opinion No. 96-12, Opinion and Order Regarding Competitive Opportunities for Electric Service*. May 20, 1996.
[57] State of New York Public Service Commission. *Order Requiring Proposals for Revenue Decoupling Mechanisms*. *Case 03-E-0640 & Case 06-G-0746*. April 20, 2007.

disincentive to promote energy efficiency and other activities that may reduce its sales volume. The NYPSC introduced a revenue decoupling mechanism into its rate-regulation framework to reduce this disincentive.

In a 2013 decision, the NYPSC updated the state's Energy Efficiency Portfolio Standards. The decision recognized that energy efficiency and distributed clean energy resources had gradually become a core source of value to electric customers. The decision also acknowledged that integrating load management capabilities into grid management would enhance overall system reliability, efficiency, and resilience while maintaining fair and reasonable rates.[58]

Non-Wires Alternatives

Following the Energy Efficiency Portfolio Standards order, the NYPSC issued a decision regarding Consolidated Edison's 2013 rate case. In this decision, the NYPSC, for the first time, required the utility to proactively seek non-wire solutions to manage system demand growth.[59] The context for this decision was that Consolidated Edison, which serves over three million customers in New York, needed to address an overload condition of the company's electric sub-transmission feeders. The company originally had proposed construction of a new area substation, establishing a new switching station and sub-transmission feeders at a cost of approximately $1 billion.[60] However, following the NYPSC's order, the company proposed the Brooklyn/Queens Demand Management ("BQDM") Program, which proposed a combination of non-traditional utility-side and customer-side solutions along with traditional utility infrastructure investments at a total cost of $200 million. The company proposed the following three earning opportunities for utilities:[61]

1. Earn a return on any deferred BQDM Program costs, akin to the recovery of returns on traditional capital infrastructure investments.
2. Establish an incentive of up to a 100-basis points on the BQDM Program investments.
3. Sharing the annual net savings, which is the difference between the annual carrying cost of the original wired solution proposal and the total annual collections for the BQDM Program.

The NYPSC approved the BQDM program and the first two proposed earning opportunities,[62] providing an example of non-wire solutions (such as distributed generation, energy efficiency, and other innovative technologies) that worked to reduce or eliminate the need for traditional utility infrastructure. The program also set an early example for the state's subsequent UR framework.

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[58] State of New York Public Service Commission. *Order Approving EEPS Program Changes. Case No. 07-M-0548.* December 19, 2013.

[59] State of New York Public Service Commission. *Order Establishing Brooklyn/Queens Demand Management Program. Case 14-E-0302*. December 12, 2014

[60] Ibid.

[61] *Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn/Queens Demand Management Program*. *Case 14-E-0302*. p20-22.

[62] State of New York Public Service Commission. *Order Establishing Brooklyn/Queens Demand Management Program. Case 14-E-0302*. December 12, 2014. p19-21

3.1.3 Overview of the Current Utility Remuneration Model

The Adoption of REV

In 2014, the New York state government introduced a policy known as Reforming the Energy Vison ("REV"), which set new statewide policies for utility regulation. The state promoted REV as a plan to take advantage of the development of clean energy resources and create a cleaner, more resilient, and affordable energy system,[63] with several clean energy goals for 2030, including:[64]

- A 40% reduction in greenhouse gas emissions from 1990 levels;
- 50% generation of New York State's electricity must come from renewable energy sources;
- A 23% decrease in energy consumption of buildings from 2012 levels.

The REV framework was motivated by a concern that the state's energy system could not keep up with the challenges of rising energy bills, more frequent extreme weather, and the state's own goals related to carbon emissions reductions.[65] Building on previous efforts that addressed rising importance of distributed generation, energy efficiency and other innovative technologies, in 2014, the NYPSC initiated a proceeding to address REV policies.[66] The REV proceeding dealt with developing distributed resource markets, and also focused on ratemaking reforms. The goal of the proceeding was to facilitate the transformation of the electricity distribution sector and the sector's ratemaking paradigm, shifting the industry to be more consumer-centered with the assistance of markets and technology. The NYPSC viewed integrating DERs into the electric distribution system as a key component of this transformation.[67] The commission stated six objectives for its REV initiative:

1. Enhanced customer knowledge and tools that will support effective management of the total energy bill.
2. Market animation and leverage of customer contributions.
3. System wide efficiency.
4. Fuel and resource diversity.
5. System reliability and resiliency.
6. Reduction of carbon emissions.

Prior to the adoption of the NYPSC's REV framework, both utilities and consumer advocates advised caution in deviating from the cost-of-service approach to utility revenues. In a cost-of-serve framework, New York utilities' revenue requirement for a given year is determined by the following general formula:

$$RRQ = E + D + T + (r * RB)$$

Where:

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[63] *Reforming the Energy Vision.* March 2016.

[64] Ibid.

[65] Ibid.

[66] New York State Department of Public Service. *Case 14-M-0101.*

[67] State of New York Public Service Commission. *Order Adopting Regulatory Policy Framework and Implementation Plan. Case 14-M-0101.* February 26, 2015

RRQ = the revenue requirement

E = all operating and maintenance expenses, administrative and general expenses, and taxes other than income

D = book depreciation expense

T = income taxes paid to federal and state governments

r = the allowed return on rate base; it is related to cost of debt and cost of equity

RB = the total used and useful capital investment in plant and equipment dedicated to providing utility service.

Both utilities and consumer advocates argued that new sources of revenue from DER markets may take a substantial amount of time to develop. [68,69] The utilities suggested REV should complement the cost-service ratemaking model. The utilities also stated that cost-of-service regulation is necessary for utilities to raise capital in financial markets, recover their costs to fulfill their public service obligations, and make REV-related investments.[70] Other stakeholders emphasized the importance of maintaining the relationship between cost-to-serve and rates for different customer classes.[71,72,73] In response to these concerns, the NYPSC structured the REV reform to maintain some traditional ratemaking principles, stating further that "where it is driven by the success of markets and new technologies," the pace of change will not be artificially restricted.[74]

The REV UR Model

As discussed in Section 3.1.2, most New York distribution utilities operated under a three-year rate plan before REV. The plan length remains unchanged under REV. Most stakeholders accepted three years as the optimal term for a negotiated rate plan as longer term rate plan may entail more risks and uncertainties for both the utilities and the customers and a shorter term

[68] *Initial Comments of the Joint Utilities on the July 20, 2015 Staff White Paper on Ratemaking and Utility Business Models.* Case 14-M-0101. October 26, 2015. The Joint Utilities include the six large investor-owned utilities in New York: Central Hudson Gas & Electric; Consolidated Edison; National Grid; New York State Electric & Gas; Orange & Rockland; Rochester Gas & Electric.

[69] *Initial Comments of Multiple Intervenors on Track 2 White Paper.* Case 14-M-0101. October 26,2015. Multiple Intervenors is an association of large industrial, commercial and institutional energy consumers.

[70] *Initial Comments of the Joint Utilities on the July 20, 2015 Staff White Paper on Ratemaking and Utility Business Models.* Case 14-M-0101. October 26, 2015. p7-9.

[71] *Comments of The City of New York on Staff's Track 2 White Paper.* Case 14-M-0101. October 26, 2015. p11.

[72] *Initial Comments of Multiple Intervenors on Track 2 White Paper.* Case 14-M-0101. October 26, 2015. p51.

[73] *Comments of the Public Utility Law Project of New York, Inc.* Case 14-M-0101. October 27, 2015. Public Utility Law Project represents residential low income consumers. p3

[74] State of New York Public Service Commission. *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework. Case 14-M-0101*. May 19, 2016. p21

rate plan may not be worth the resource spent during negotiation.[75,76,77] Some expressed concerns over changing the plan length during the REV transition period.[78] Utility revenue requirements are set for the three years based on forecasted costs. These rate plans typically include ESMs that split earnings between the utilities and the customers beyond a threshold over the allowed Return on Equity. Previously, the MYRP also included a "net plant" reconciliation mechanism ("claw-back" mechanism) that works to prevent utilities from boosting short-term earnings by delaying needed capital projects. In the old claw-back mechanism, earnings from capital projects that fell below approved levels were returned to customers. Thus, utilities were de facto penalized for underspending relative to their capital forecasts, which created a disincentive to adopt cost-effective DER alternatives to capital investments. The commission reformed the claw-back mechanism under REV to allow utilities to retain the earnings on capital that are reflected in base rates if they adopt DER alternatives to capital projects.[79] The previously established revenue decoupling mechanism still exists.

Under REV, utility revenues consist of the following components:[80]

- A traditional cost-of-service revenue requirement based on cost forecasts.
- Earnings from market-facing platform activities.
- Revenues tied to achievement of alternatives that reduce utility capital spending and provide definite consumer benefits (e.g. non-wires-alternative programs).
- Transitional outcome-based performance measures.

Earnings from market-facing platform activities

Under the REV framework, distribution utilities serve as the coordinator between smart grid technology, DER providers, and energy services companies. In addition to the traditional role of distribution utilities, one of the long-term ambitions of the REV framework is to define distribution utilities as "Distributed System Platforms" ("DSPs"). As a DSP, the utility will provide information and price signals to customers that provides the fair value for energy resources, with the goal of eliminating barriers for cost-effective DER adoption. The revenue required for the utility to fulfill this role will come from the operation and facilitation of distribution-level markets. These revenues are called Platform Service Revenues ("PSRs"). Each utility is required to file a Distributed System Implementation Plan ("DSIP") related the development of its role as a DSP.

Earnings tied to achievement of alternatives that reduce capital spending

The Brooklyn/Queens Demand Management ("BQDM") project described in the previous section provided an example of earning opportunities related to the creation of non-wires solutions that reduce utility capital spending. The BQDM proposal came at the time when the Renew the Energy

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[75] *Initial Comments of Multiple Intervenors on Track 2 White Paper.* Case 14-M-0101. October 26,2015. p42.
[76] *Initial Comments of the Joint Utilities on the July 20, 2015 Staff White Paper on Ratemaking and Utility Business Models.* Case 14-M-0101. October 26, 2015. p31.
[77] *Comments of The City of New York on Staff's Track 2 White Paper.* Case 14-M-0101. October 26, 2015. p35-37.
[78] State of New York Public Service Commission. *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework. Case 14-M-0101*. May 19, 2016. p108.
[79] Ibid, p98-104.
[80] Ibid, p2.

Vision ("REV") proceeding was ongoing. At the time, Consolidated Edison stated that the BQDM program would "provide an important opportunity for stakeholders to learn from an effective test of REV ambitions."[81] The NYPSC also viewed the program as a demonstration of a REV-like demand-side management program that would, at least partially, replace traditional infrastructure investments.[82]

While a "totex" approach, in which both capital and operating expenditures may earn a return, was implemented for the BQDM project, the NYPSC did not adopt the "totex" for the state's distribution utilities in general.[83] As explained in subsequent sections of this report, under the RIIO framework in effect in Great Britain, electricity distributors operate under a "totex" approach. However, the NYPSC cited concerns about technical challenges of a full totex adoption related to differences in accounting standards between the United States and the UK. In addition, the NYPSC cited that distribution utilities in Great Britain do not serve as a DSP, which may give rise to differences in the application of a totex approach. The NYPSC's 2016 REV decision said totex should continue to be explored, and, as Great Britain gains more experience with RIIO, totex will be re-evaluated.[84]

Though the "totex" approach was not adopted, within the current accounting system, New York's utilities can earn a return on some types of REV-related operating investments (for example, contracts to lease software services).[85] In addition, the commission expects to provide utilities with earning opportunities that match or exceed traditional investments for non-wires-alternative programs like the BQDM initiative.

Transitional outcome-based performance measures

New York utilities have been subject to the Reliability Performance Mechanism ("RPM") and the Customer Service Performance Mechanism ("CSPI") for many years. These mechanisms were initially created to prevent excessive spending cuts under multi-year rate plans.[86] The RPM measures overall distribution system reliability, including criteria such as frequency and duration of outages, remote network monitoring system performance and timely replacement of damaged poles. The CSPI measures the company's customer service quality using a broad number of indices. The utilities face negative revenue adjustments if certain performance thresholds across the RPM and CSPI are not met. Because of this financial incentive, these two metrics meet the definition of PIMs.

In addition to the state's existing PIMs, the REV framework also introduced specific earning opportunities based on utility performance, called "Earnings Adjustment Mechanisms" ("EAMs"), which is synonymous with PIMs. The NYPSC has characterized EAMs as providing revenue support for utility outputs during the current period of transition to other forms of market-based revenues that will eventually fulfill each utility's revenue requirement. The Commission stated

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[81] *Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn/Queens Demand Management Program. Case 14-E-0302*. p2.

[82] State of New York Public Service Commission. *Order Establishing Brooklyn/Queens Demand Management Program*. *Case 14-E-0302.* December 12, 2014. p14.

[83] State of New York Public Service Commission. *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework. Case 14-M-0101*. May 19, 2016. p101-p104.

[84] Ibid.

[85] Ibid.

[86] New York State Department of Public Service, Staff Report and Proposal. *Reforming the Energy Vision*. *Case 14-M-0101*. April 24, 2014. p48.

that EAMs must both encourage achievement of new policy objectives and counter implicit negative incentives that the state's ratemaking model provides against REV objectives. The Commission rejected arguments that EAMs should be restricted to items under the utility's direct control or strong influence, stating that an outcome-oriented approach was the most effective route.[87]

While the Commission decides the EAM opportunity areas, each utility can propose their own performance incentives within these identified areas. The Commission provided guidance and direction on structural issues of EAMs in the 2016 REV order, which included generally reward-only earnings, limiting the maximum amount of earnings to be less than 100 basis points total from all new incentives initially.[88] Subsequent orders also provided guidance on metrics utilities should use under some EAM opportunity areas.[89] The financial details of performance incentives are decided in each rate proceeding. Table 3.2 summarizes the Commission's EAM opportunity areas and examples of approved EAMs for New York utilities. Since the adoption of the 2016 REV order, all six investor-owned utilities have proposed and adopted EAMs under some categories described in Table 3.2. The Commission requires each utility to propose performance incentives in system efficiency, energy efficiency, and interconnection, and also welcome proposals related to the decarbonization of end use and customer engagement. [90]

[87] State of New York Public Service Commission. *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework. Case 14-M-0101*. May 19, 2016. p61-65.

[88] Ibid. p60-70.

[89] For example, the order under Case 18-M-0084 required utilities to develop and propose a new "share the savings" EAM related to their EE programs. The order under Case 18-E-0130 required utilities to develop both a peak load reduction metric and a load factor-based metric. The peak reduction targets should set either a specific MW goal for the system peak or aim for a percentage reduction from a predetermined MW value.

[90] Affordability was another the area staff proposed to be an EAM opportunity area. The commission set affordability metrics as scorecards rather than EAMs based on recommendations of low-income advocates. See State of New York Public Service Commission. *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework. Case 14-M-0101*. May 19, 2016. p25.

Table 3.2: EAMs in the State of New York[91,92,93]

EAM Area	Example	Details of approved EAMs
System Efficiency (Mandatory)	Electric System Peak (Con Edison 2020)	Incent the Company to deliver New York Control Area coincident electric system peak reduction. Metric: actual weather normalized coincident system peak in MW Reward: The company will receive 3 to 8 basis point ($4.356 to $11.615 million) if targets are met. Penalty: None
	Locational System Relief Value Load Factor (Con Edison 2020)	Improve load factor of more constrained portions of the distribution system that are not current or likely Non-wires Alternatives areas. Metric: load factor Reward: The company will receive 1 to 5 basis point ($1.452 to $7.259 million) if targets are met. Penalty: None
	DER Utilization (Con Edison 2020)	Incent the company to work with DER providers and expand use of DER. Metric: annualized MWh produced or discharged from incremental DER Reward: The company will receive 3 to 10 basis point ($4.356 to $14.518 million) if targets are met. Penalty: None
Energy Efficiency (EE) (Mandatory)	Sharing the Savings (Con Edison 2020)	Reduce unit costs for the Company's combined electric and gas EE portfolio by reducing the unit cost of lifetime energy savings Metric: unit cost savings relative to the baseline unit cost times non-Low to Moderate Income EE savings Reward: 30% of the savings Penalty: None
	Deeper Energy Efficiency Lifetime Savings (Con Edison 2020)	Achievement of Energy Efficiency (EE) savings from EE measures beyond lighting and behavioral measures. Metric: Lifetime energy savings (in LMMBtu) provide by deeper EE measures in the Company's entire EE portfolio. Reward: The company will receive 2 to 11 basis point ($2.904 to $15.970 million) if targets are met. Penalty: None
Interconnection (Mandatory, but eliminated later)	No actual EAM was implemented.	Each utility negotiated the basis for this EAM in their rate cases, but targets were not established. Please see the next section (Review of REV) for more details.

[91] State of New York Public Service Commission. *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework. Case 14-M-0101*. May 19, 2016. p61-65.

[92] Consolidated Edison Company of New York Case 19-E-0065 & 19-G-0066 Joint Proposal. October 16, 2019.

[93] Central Hudson Gas and Electric Corporation Case 17-E-0459 & 17-G-0460 Joint Proposal. April 18, 2018.

Decarbonization of end uses	Beneficial Electrification	Incent Con Edison to support the adoption of electric vehicles and heat pumps to decrease carbon emissions. Metric: Lifetime CO_2 emissions reductions provided by annual incremental beneficial electrification technologies. Reward: The company will receive 2 to 10 basis point ($2.904 to $14.518 million) if targets are met. Penalty: None
Customer Engagement	Customer Participation in Time of Use rates (Central Hudson 2018)	Incent the Company to increase customer participation in Voluntary Time of Use ("VTOU") rates. Metric: percentage of residential customers that sign up for VTOU rates. Reward: The company will receive $32,500 if participation reaches 1.51% (minimum target) and $162,500 if participation reaches 2.74% (maximum target). Penalty: None

Review of REV

One notable accomplishment of REV was the establishment of earnings opportunities for non-wires alternatives.[94] While the non-wires alternatives utility business model is still in its infancy, partly because these alternatives are not yet cost-competitive in some locations, stakeholders perceive that REV has provided an initial path forward.[95] The state's distributors are working on data sharing and hosting capacity and moving forward with innovative market-enabling demonstration projects,[96] but the original REV vision of utilities being compensated for managing transactions as DSP has yet been fully realized.[97]

The performance incentives associated with REV have produced mixed results. The Regulatory Assistance Project published a report in 2023 that found the three New York IOUs operating under REV (Consolidated Edison, Central Hudson Gas & Electric and National Grid) often either fully achieved the performance target or did not meet the minimum level to receive any incentive.[98] This is notable, as these PIM targets are not generally "all or nothing" incentives, and yet the utilities generally achieved "all or nothing" results. The Regulatory Assistance Project report does not speculate as to the reasons for this result, but it may be worth further examination in case certain PIMs are designed with performance thresholds that are perceived by the utility to be unachievable.

In 2019, the NYPSC decided to eliminate performance incentives under the Interconnection PIM. The NYPSC found that this PIM, which was based on the results of a customer satisfaction survey, suffered from a small sample size of survey data. With a statistically insignificant sample size, the NYPSC found it inappropriate to reward utilities for achievement of the required

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94 Trabish, H. *New York's landmark Reforming the Energy Vision framework remains both vital and unfinished, analysts say.* December 9, 2021.
95 Ibid.
96 Ibid.
97 Ibid.
98 Regulatory Assistance Project. *Improving Utility Performance Incentives in the United States*. October 2023.

threshold.[99] In addition, the need for the Interconnection PIM diminished over time because interconnection processes improved since the REV order was issued, due to multiple efforts including stakeholder engagements.[100]

Figure 3.2: Overview of PIM performance for New York Utilities[101]

PIM Categories	Consolidated Edison			Central Hudson Gas & Electric			National Grid		
	2018	2019	2020	2018	2019	2020	2018	2019	2020
Coincident peak demand savings	100%	100%	100%	0%	0%	0%	100%	100%	45%
DER utilization	100%	100%	0%	0%	100%	100%	4%	0%	0%
Energy-efficiency savings	100%	100%	N/A	100%	100%	100%	39%	100%	100%
Energy intensity of residential customers	100%	0%	N/A	0%	0%	0%	69%	0%	0%
Energy intensity of commercial customers	0%	0%	N/A	0%	0%	100%	100%	33%	100%
Energy intensity of multifamily customers	34%	61%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Beneficial electrification	N/A	N/A	TBD	100%	100%	100%	47%	100%	100%
Customer engagement	N/A	N/A	N/A	0%	0%	0%	N/A	N/A	N/A
Street lighting conversion	N/A	N/A	N/A	N/A	N/A	N/A	0%	65%	22%
Locational system relief value load factor improvement	N/A	N/A	0%	N/A	N/A	N/A	N/A	N/A	N/A
Total incentive Achieved ($M)	$26.2	$36.6	$11.6	$0.7	$1.6	$2.1	$11.3	$12.1	$12.2
Contribution to ROE	N/A	N/A	N/A	1.4%	3.0%	3.9%	6.4%	6.8%	6.9%

Note: Only outcome-based PIMs are reported. "N/A" means "not available," which indicates that the utility did not have a PIM for this category or ROE values were unavailable. "TBD" indicates the result has not yet been reported by the utility for this category of PIM.

3.1.4 Key Takeaways

New York's utilities have been operating under the REV UR model for approximately eight years. The state's UR model was developed to meet the challenges of and find opportunities presented by the rapid increase of distributed energy resources and other technological advancements that have accelerated over the past decade.

The NYPSC's order to administer REV envisioned that distribution utilities would eventually serve as DSPs and earn revenue from the operation and facilitation of the distribution-level market. Though this vision has not been fully realized, the ideas behind this reform may be helpful for Ontario in its consideration of next generation UR models and research into Distribution System Operator models. In addition, REV provides an example of a framework currently in use that

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[99] State of New York Public Service Commission. *Order Eliminating Interconnection Earning Adjustment Mechanisms. Case 14-M-0101 & Case 16-M-0429.* April 19, 2019.

[100] Ibid.

[101] Regulatory Assistance Project. *Improving Utility Performance Incentives in the United States*. October 2023. p12.

encourages utilities to adopt non-wires solutions, which may provide earning opportunities to the state’s utilities, as well as generate savings for customers.

REV also established categories in which the state’s utilities can propose performance incentives associated with the energy transition. While this “propose your own” approach to the creation of PIMs may prove to be too great a regulatory burden for Ontario, if all 59 distributors propose their own approach, some of the proposed or existing PIMs in New York may provide ideas about what categories of performance are important and how PIMs should be structured around these categories.

CALIFORNIA

Key Takeaways

- Each of California's three major investor-owned utilities operate under a four-year multi-year rate plan based on revenue forecasts.
- The utility remuneration model in California does not currently contain any financial performance incentives, but the utilities do operate several programs aimed at achieving policy goals.
- The California Public Utilities Commission mandates that utilities maintain robust energy efficiency portfolios, manage demand response programs, and actively seek opportunities to defer capital investments. This approach differs from the model in Great Britain or New York, which have traditionally relied more heavily on financial incentives to drive similar outcomes.

Profile of California's Electric Utility Sector

Distribution Regulation	
Regulated Utilities	6[103]
Ratemaking regulator	California Public Utilities Commission
Transmission Operator	California Independent Systems Operator
UR Elements	
Multi-Year Rate Plans	✓
Revenue Decoupling	✓
Revenue Cap	-
Price Cap	-
PIMs	-
Earnings Sharing Mechanisms	-

Fuel Mix[102]			
Coal	2.15%	Hydro	10.36%
Natural Gas	36.38%	Biomass	2.15%
		Solar	17.04%
Other Thermal	7.24%	Geothermal	4.67%
Nuclear	9.18%	Wind	10.83%

Energy Sector Facts	
Total Installed Capacity	91,621 MW[104]
Total Generation	216.31 TWh[105]
Rooftop Solar Capacity	15,295 MW[106]
Electric Vehicles	1,516,107 EVs[107,108]
Customer Battery installations	153,980[109]

[102] California Energy Commission. *2022 Total System Electric Generation.*
[103] U.S. Energy Information Administration. *Annual Electric Power Industry Report 2022, Form EIA-861*.
[104] U.S. Energy Information Administration. *Table 6.2. A. Net Summer Capacity of Utility Scale Units by Technology and State*. April 2024.
[105] U.S. Energy Information Administration. *Net generation for all sectors, annual*.
[106] *California Distributed Generation Statistics*. April 30, 2024.
[107] This includes Battery Electric, Plug-in Hybrid and Fuel Cell light-duty electric vehicles.
[108] California Energy Commission. *Light-Duty Vehicle Population in California 2023*. December 31, 2023.
[109] California Energy Commission. *California Energy Storage System Survey, Residential and Commercial Energy Storage Installations.* April 15, 2024.

3.2 California

3.2.1 Overview of California

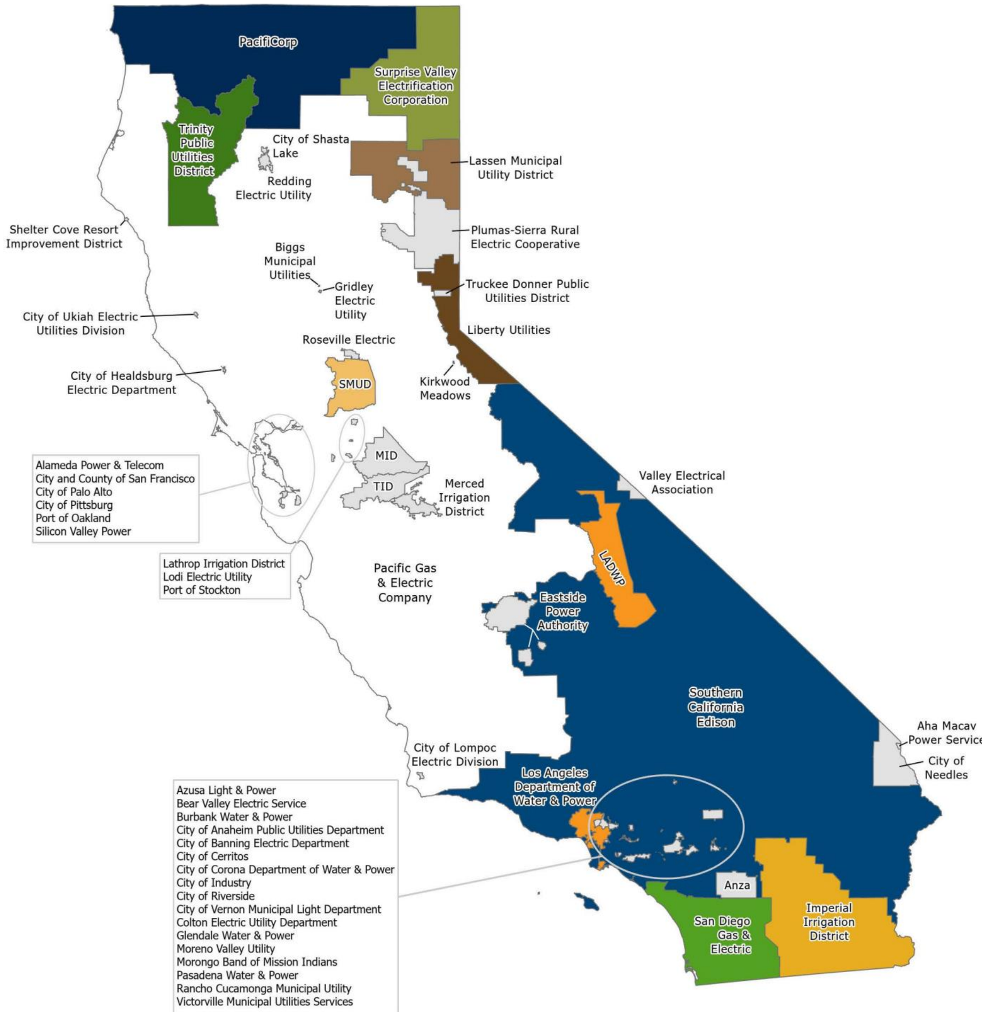
The majority of the electricity in California is distributed by three major investor-owned, utilities ("IOUs"), each of which is vertically-integrated: Pacific Gas & Electric ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas & Electric ("SDG&E").[110] These three utilities together with all other privately owned electric utilities in the state are regulated by the California Public Utilities Commission ("CPUC", or "the Commission"). California's wholesale electric grid is operated by California Independent Systems Operator, which conducts transmission planning, facilitates real-time and day-ahead energy markets, and sets Resource Adequacy requirements.[111]

California's electric industry offers insights into the challenges faced by regulators and utilities as they work to meet ambitious climate and energy goals. It also highlights strategies and regulations developed to address these challenges. Utility compensation in California uses forecasted multi-year rate plans with decoupled revenues, structured to encourage energy efficiency.

[110] According to Form EIA-861 data, these utilities were responsible for serving more than 75% of customers in California in 2022.

[111] Resource Adequacy requires each utility to maintain physical generating capacity and electrical demand response adequate to meet its load requirements, including peak demand and operating reserves.

Figure 3.3: Map of California's Electric Utility Service Areas[112]



3.2.2 History of Utility Remuneration

Evolution of California's UR Model

California's utility regulator has utilized PBR-like mechanisms since early 1980s. The state's utilities have been required to follow a multi-year rate case cycle for almost 40 years.[113] The adoption of multi-year plans subsequently led to discussions on Attrition Rate Adjustment mechanisms[114] to provide utilities with a better chance of achieving their authorized rates of return during years in which they are not permitted to file general rate relief.[115]

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[112] California Energy Commission, *Electric Utility Service Areas, California 2023. June 7, 2023.*

[113] *Resolution ALJ-151*. June 6, 1984.

[114] An Attrition Rate Adjustment is a component included in rate case plans to adjust some elements of the utility's revenue requirement during the course of a rate case cycle. The specific adjustment mechanism can vary between companies and has changed between rate cases.

[115] California Public Utilities Commission. *Decision 85-12-076.*

California's utilities first adopted revenue decoupling in 1981.[116] Revenue decoupling mechanisms were briefly discontinued as part of electric utility sector restructuring in the late 1990s. Following the restructuring, revenue decoupling mechanisms in the form of balancing accounts were reintroduced in PG&E[117] and SDG&E[118] rate cases to adjust for over- and under-collections of revenue. All three major IOUs have continued to operate with revenues decoupled from sales to remove disincentives for promoting energy efficiency.

In the past, the three major IOUs have also implemented PIMs and ESM at various times, however currently the utilities do not operate under any PIMS or ESM.[119,120]

Energy Transition

California has historically been a leader with respect to energy efficiency and GHG reduction initiatives (for example, the California Building Energy Efficiency Standards, first adopted in 1977),[121] and the state continues to advance its energy transition and beneficial electrification goals through legislation. In 2018, the state government established a 2045 goal of powering all retail electricity sold in California with renewable and zero-carbon resources.[122] The governor of California has also issued a target for 100 percent of new cars and passenger trucks sold in California to be "zero emission" by 2035.[123]

To achieve both new and existing energy transition objectives, the CPUC frequently mandates certain actions by utilities, rather than offering financial incentives. These mandates require the state's utilities to undertake socially beneficial activities, allowing them to recover associated costs through revenue collection. Such activities include, but are not limited to, demand response programs, energy efficiency portfolios, and transportation electrification initiatives.

The CPUC has also focused heavily on promoting the adoption of DERs. In 2016, the CPUC released California's "DER Action Plan" to promote DERs,[124] and in April of 2022, the CPUC published an updated "DER Action Plan 2.0" to serve as a roadmap for CPUC decision-makers, staff, and stakeholders as they facilitate forward-thinking DER policy.[125] These plans are used to guide CPUC's policy actions, and they establish a timeline for achieving DER policy goals. Overview of both Action Plans is provided in Figure 3.4 below:

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[116] California Public Utilities Commission. *Decisions 93887 and 82-12-055.*

[117] California Public Utilities Commission. *Decision 04-05-055.*

[118] California Public Utilities Commission. *Decision 05-03-023*, p21.

[119] SDG&E's Earnings sharing mechanism adopted in D.05-03-023 was ended with D.08-07-046. While their Electric Reliability Performance Indicators and associated rewards and penalties were discontinued with CPUC Decision 19-09-051.

[120] California utilities are now required to report 32 safety performance metrics pursuant to CPUC decisions 19-04-020 and 21-11-009.

[121] The California Energy Commission. *Building Energy Efficiency Standards*.

[122] *The 100 Percent Clean Energy Act of 2018, Senate Bill 100*.

[123] Executive Department of State of California. *Executive Order N-79-20.*

[124] California Public Utilities Commission. *California's Distributed Energy Resources Action Plan: Aligning Vision and Action. November 10, 2016.*

[125] California Public Utilities Commission. *Distributed Energy Resources Action Plan: Aligning Vision and Action. April 22, 2022.*

Figure 3.4: Overview of DER Action Plans

DER Action Plan 1.0		DER Action Plan 2.0
2016-2020	Period	2022-2026
1. Rates and Tariffs 2. Distribution Grid Infrastructure, Planning, Interconnection and Procurement 3.Wholesale DER Market Integration and Interconnection	Tracks	1. Load Flexibility and Rates 2. Grid Infrastructure 3. Market Integration 4. DER Customer Programs
1. DERs are able to meet distribution grid needs through planning and sourcing. 2. IOUs are motivated to accelerate deployment of DER regardless of the impact on distribution capacity investment opportunities. 3. Cost effectiveness and valuation frameworks accurately reflect the full grid, renewables integration and GHG value of DERs.	Select Vision Elements*	1. Decisions on budgets and priorities for all ratepayer-funded DER programs are informed by metric and guidelines for cost-effectiveness. 2. End-of-life management programs are in place to ensure collection, safe transport, and recycle or re-use of DERs at end of life. 3. Utilities integrate the anticipated impacts of electrification into distribution planning to maximize public benefits, minimize costs, and optimize deployment of infrastructure and DERs.

* DER Action Plan 1.0 includes a total of 17 vision elements while DER Action Plan 2.0 includes 23 vision elements.

Both plans acknowledge the usefulness of incentives (to customers and utilities) in promoting adoption of DERs, while also highlighting necessity for a holistic approach indicating the importance of ratemaking, performance assessment, demand response programs and other elements to improve affordability, quality and load flexibility through the adoption of DERs.

3.2.3 Overview of Current Utility Remuneration

For California's three major IOUs, General Rate Cases ("GRCs") are divided into two phases. Phase I of a GRC determines the total amount the utility is authorized to collect, while Phase II determines the share of the cost each customer class is responsible for and the rate schedules for each class. Each of the major IOUs files a GRC application every four years.[126] For smaller utilities, authorization and allocation of costs are done in just one phase.[127]

The generic GRC cycle was changed from three-year to four-year cycles with a CPUC decision in January of 2022.[128] The CPUC's reasoning supporting the adoption of a four-year cycle is twofold.

[126] The period between rate applications was three years until 2022. The amount of time between applications increased to four years in 2022 to allow parties dedicate more time implementing risk-mitigation and accountability structures and allows the Commission to shift its resources to implementing expanded utility reporting requirement.
[127] California Public Utilities Commission. *What is a General Rate Case (GRC)?*
[128] California Public Utilities Commission. *Decision 23-11-069*. p684.

The longer cycle allows utilities and stakeholders to dedicate more time to implementing risk-mitigation and accountability structures that were adopted by the CPUC. The longer cycle also enables the CPUC and the staff to shift their focus to monitoring utility spending closer to real-time. The primary concern expressed about extending the three-year ratemaking cycle to four years was the inherent uncertainty of attrition year forecasts. However, a majority of the stakeholders supported a four-year cycle.

During a GRC, a forecasted test year is used to estimate the operational expenses and capital costs used in the revenue requirement calculation. This test year serves as the first year of the GRC. The years following the test year are usually called post-test years or attrition years, and the allowed revenues for those years are set according to the utility's revenue forecasts.

The test year revenue requirement is determined based on the following general formula:

$$RRQ = E + D + T + (r * RB)$$

Where:

RRQ = the revenue requirement

E = all operating and maintenance expenses, administrative and general expenses, and taxes other than income

D = book depreciation expense

T = income taxes paid to federal and state governments

r = the allowed return on rate base; it is a direct input obtained from a Cost of Capital proceeding

RB = the total used and useful capital investment in plant and equipment dedicated to providing utility service.

For post-test year periods, the revenue requirement is determined by applying attrition rate adjustments to reflect the increases in capital costs due to ongoing investments, as well as increases in wages and other expenses due to inflation. Adjustments to the utility's operation and maintenance ("O&M") expenses and capital-related costs are often made separately, with different indices. Specifically, O&M expenses are escalated using a mixture of inflation indexes such as energy-specific indexes in the S&P IHS Markit's indexes forecast. Capital-related costs are also adjusted using an index or a weighted average of indexes such as IHS Markit's Power Planner indexes. Utilities are also sometimes able to adjust certain capital-related costs using budget-based approach if cost growth is not appropriately reflected in an available index. The annual post-test year adjustments are filed by advice letters.[129] Advice letters are formal documents submitted by utilities to the CPUC for approval of routine or non-controversial matters, such as implementing rate changes authorized in general rate cases, requesting approval for new programs, or as compliance filings.

Since the recoverable revenue for the test year is determined during the GRC process, and the subsequent three post-test year allowed revenues are determined largely by exogenous Attrition Rate Adjustment mechanisms, utilities are provided with an incentive to increase their returns through the reduction of expenses over the multi-year rate period.

[129] Ibid, p716.

The Commission has also established a process for rate adjustments for unexpected and uncontrollable events in post-test year ratemaking. The adopted mechanism, called a "Z-factor," is designed to protect both the utility and customers by allowing for rate increases and decreases in the period between GRCs. The Z-Factor mechanism includes nine criteria described by the CPUC to identify unforeseen external events largely beyond utilities' control.[130,131] These criteria are:

1. The event must be exogenous to the utility;
2. The event occurred after late 1989;
3. The costs are beyond the control of the utility management;
4. The costs are not a normal part of doing business;
5. The costs must have a disproportionate impact on the utility;
6. The costs must not be reflected in the escalation factors used in the GRC;
7. The costs must have a major impact on overall costs;
8. The cost impact must be measurable; and
9. The utility must incur the cost reasonably.

Utility remuneration incentive (and non-incentive) programs

California currently lacks PIMs that offer financial rewards for utilities achieve specific outcomes. However, the state's IOUs engage in various programs to support the energy transition. In some instances, utilities manage programs that offer incentives directly to customers.

Self-Generation Incentive Program ("SGIP")

Description: The CPUC's SGIP provides customer incentives to support existing, new, and emerging distributed energy resources. SGIP was first adopted in 2001 with the intent to reduce peak energy demand and the program has been since extended several times. The scope of SGIP has been expanded to address energy transition and GHG emission goals. This program provides residential and non-residential customers with financial incentives for installing eligible generation and battery storage technologies. The collection and distribution of the benefits is administered by California's three major IOUs and Center for Sustainable Energy. Utilities are required to allocate SGIP costs on the basis of the actual benefits resulting from the disbursement of SGIP incentives over the previous three years, and the allocation gets updated annually, on rolling basis.[132] The program has been continuously updated with incentive levels and eligibility requirements changing over time. This program provides incentives to customers rather than to utilities, but it is a major driver of DER adoption in California.

Initial Outcomes: A third-party consultant was contracted to conduct an evaluation of the performance of incentivized SGIP systems for 2021 and 2022. The key findings from the report indicate that the SGIP program has led to significant GHG reductions and customer bill savings

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[130] California Public Utilities Commission. *Resolution E-5287*. September 21, 2023.

[131] As in Ontario, in specific circumstances, utilities are allowed to record certain costs and capital expenses in additional regulatory accounts. Some regulatory accounts, such as memorandum accounts, are set up by utilities to track expenses that utilities may eventually seek to recover with the authorization of the Commission, while other accounts, such balancing accounts, are accounts to track pre-approved expenses and collections and to ensure adequate revenue recovery and avoid under- or over-recovery.

[132] California Public Utilities Commission. *Decision 20-01-021*. January 16, 2020.

for recipients of the incentive.[133] The primary drivers of GHG reductions come from generation and battery storage systems installed by customers.

Efficiency Savings and Performance Incentive Mechanism ("ESPI")

Description: ESPI was adopted in a decision by the CPUC on September 5, 2013, to promote energy efficiency goals. During the time that it was active, the ESPI mechanism offered the state's IOUs financial incentives in four performance categories: energy efficiency savings, ex ante review performance, building and standards energy efficiency programs, and non-resource programs. Each performance category had an incentive cap with a combined maximum earnings potential at 10.85 percent of the energy efficiency program budget. This incentive was applied to programs administered by utilities as part of their energy efficiency portfolios. Aspects of ESPI were updated in subsequent proceedings until an indefinite moratorium was imposed on ESPI in November of 2020 as the CPUC found lacking evidence that ESPI had been effective in achieving all its originally intended purposes.[134] Today, utilities remain responsible for energy efficiency program design and performance to meet adopted energy savings goals and cost effectiveness thresholds, but the ESPI program is no longer active.

Initial Outcomes: As part of the decision approving ESPI in 2013, the CPUC set out to provide incentive rewards directly tied to the performance of the utilities. The intention of the program was to motivate utilities to invest in energy efficiency programs instead of devoting scarce resources to supply-side procurement on which they earn a return. The annual performance reward calculations indicated that utilities would commonly receive only a portion of the capped reward. However, this does not show that the utilities underperformed compared to the counterfactual of no ESPI rewards. As described above, a moratorium on ESPI program was imposed in 2020 indicating lacking evidence of effectiveness as a reason to discontinue ESPI. In fact, CPUC noted that imposing a moratorium on the payment of ESPI rewards would improve cost effectiveness, since the incentive awards were included in the costs.[135]

Integrated DER ("IDER") Incentive Pilot

Description: As part of IDER incentive pilot PG&E, SDG&E and SCE were required to identify one project (and up to three additional projects) where the deployment of DER on the system would displace or defer the need for capital expenditures or traditional distribution infrastructure. The utilities would receive a financial incentive of 4 percent pre-tax of annual payment for the DER.[136] Due to the scope of the pilot program, smaller DER providers were not able to pursue competitive solicitations. This program faced a timeline issue related to deferring planned distribution projects with a shorter timeframe than the solicitation process. (Many planned distribution projects with closer forecasted in-service dates were not deferrable by distributed energy resources sourced through a solicitation project because of the time required to select deferral opportunities, launch a solicitation, evaluate bids, request Commission approval, and construct and interconnect a distributed energy resources project through to commercial

[133] Verdant Associates. *Self-Generation Incentive Program 2021-2022 SGIP Impact Evaluation*. May 29, 2024.
[134] California Public Utilities Commission. *Decision 20-11-013*.
[135] Ibid.
[136] California Public Utilities Commission. *Decision 16-12-036.*

operation.) These and other issues were addressed in CPUC Decision 21-02-006, in which the CPUC adopted pilots to test two frameworks for procuring DERs:[137]

1. Five-year DER distribution deferral tariff pilot named Partnership Pilot; and
2. Three-year standard offer contract ("SOC") pilot for procuring DERs to defer distribution investments.

As part of the Partnership Pilot, utilities contract aggregators that are responsible for providing deferral services with Behind-the-Meter resources.[138] To provide the deferral service, aggregators engage customers of utilities. The aggregators are compensated by the utilities for installing DERs, reserving specific amounts of capacity and energy during specified timeframe, and for performance according to contracted criteria.[139] The rewards for customers are determined by the aggregators. With the SOC pilot the utilities seek out In-Front-of-the-Meter resources as part of a solicitation process to achieve deferral of distribution needs. SOC pilot is similar to the original format of deferral service procurement under IDER.

Initial Outcomes: Both SOC and Partnership Pilots were initially included as part of Distribution Investment Deferral Framework ("DIDF").[140] In 2023, an Administrative Law Judge ruled to discontinue SOC pilot on the grounds of limited success in procuring and to protect ratepayer funds.[141]

Distribution Investment Deferral Framework

DIDF is an ongoing annual process to identify, review, and select opportunities for competitively sourced DERs to defer or avoid utility traditional distribution capital investments. DIDF was established in CPUC Decision 18-02-004. Many of the IDER elements were used as the foundation for DIDF. Major IOUs are required to file annual Grid Needs Assessment and Distribution Deferral Opportunity Reports ("DDOR"), and in the DDOR reports, the utilities identify potential distribution deferral opportunities. An example illustration of the process is provided in Figure 3.5.

[137] California Public Utilities Commission. *Decision 21-02-006.*

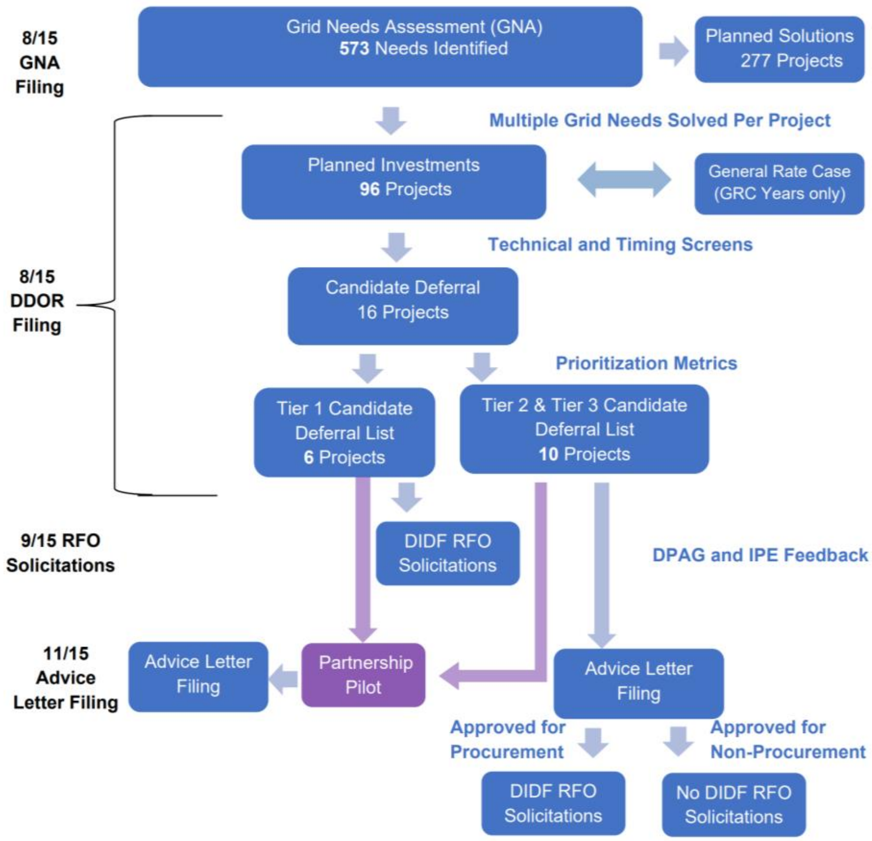
[138] The aggregator decides how it will arrange the services necessary to defer some or all of the planned distribution project that would otherwise be carried out by the utility.

[139] Ibid.

[140] DIDF is an ongoing annual process to identify, review, and select opportunities for competitively sourced DERs to defer or avoid utility traditional distribution capital investments. DIDF was established in CPUC Decision 18-02-004.

[141] *Administrative Law Judge's Ruling on Recommended Reforms for the 2023 Distribution Investment Deferral Framework Process, The Partnership Pilot and the Standard-Offer-Contract Pilot*. May 19, 2023.

Figure 3.5: Illustration of Process to Identify Deferral Opportunities[142]



Other Measures and Initiatives:

The CPUC has also employed other tools to incentivize the adoption of DERs. These include net energy metering for solar customers, electrification rates for customers with qualifying technologies, demand response programs for peak load reductions, and vehicle-to-grid pilot programs. A brief description of these initiatives and tools is provided in Table 3.3.

[142] *PGE's 2023 Distribution Deferral Opportunity Report*. August 15, 2023

Table 3.3: Summary of Measures and Initiatives to Promote DER Adoption

Innovative Ratemaking	Net Energy Metering and Net Billing Tariff ("NBT")
Pricing that reflects time variant and location-based marginal costs is important to ensure proper incentives to customers adopting DER technologies. While time-variant time-of-use ("TOU") rates are now very common for customers in California, IOUs have more recently started to offer electrification TOU rates with higher fixed and lower volumetric charges. A step further is offering dynamic and real time pricing rates to customers to mirror the movements in the wholesale markets and even better align incentives to cost causation.	With the recent adoption of NBT, California is now currently in their third iteration of Net Energy Metering tariffs. NBT requires customers to be on a specific "electrification"[143] TOU rate, and credits are calculated based on an avoided cost calculation in contrast to customer retail rates under first two iterations. The primary objective of NBT is to support the adoption of energy storage technologies in addition to customer-sited generation.[144]
Vehicle to grid ("VGI") pilot programs	**Demand Response ("DR")**
On December 21, 2020, the CPUC issued a decision 20-12-029, which authorized the IOUs to spend up to $35 million on VGI pilots. The purpose of these pilots is to overcome barriers to VGI commercial implementation. The structure of the VGI pilots may differ, but broadly CPUC wants to address the possibility of using EVs for demand response, battery backup, load shifting, grid resiliency and charging based on real-time electricity prices.	DR programs encourage reductions, increases, or shifts in electricity consumption by customers in response to economic or reliability signals. CPUC indicates that DR programs can provide benefits to ratepayers by reducing the need for construction of new generation and the purchase of high-priced energy.[145]

3.2.4 Key Takeaways

California's utility regulation model presents a comprehensive approach to balancing efficiency, innovation, and consumer protection. The state's long-standing experience with PBR elements has resulted in a sophisticated system that includes multi-year rate plans and revenue decoupling mechanisms. These features work in tandem to drive operational efficiencies between rate cases while promoting energy conservation measures, creating a dynamic regulatory environment that adapts to changing market conditions and policy objectives.

A key aspect of California's rate-regulation framework is its focus on mechanisms other than financial incentives to achieve energy transition goals. The CPUC mandates that utilities maintain robust energy efficiency portfolios, manage demand response programs, and actively seek opportunities to defer capital investments. This approach differs from the models found in other jurisdictions reviewed in this report, which have begun testing the use of financial incentives to drive similar outcomes. California's strategy places a greater emphasis on regulatory requirements and utility obligations, offering a different perspective on how to achieve energy transition objectives.

[143] Electrification rates generally have a fixed daily or monthly charge coupled with lower time-variable rates during off-peak hours.

[144] California Public Utilities Commission. *Decision 22-12-056.* December 15, 2022

[145] California Public Utilities Commission. *Decision 23-12-005*. December 14, 2023

While California has previously implemented financial incentive mechanisms such as the IDER and ESPI programs, the current regulatory landscape has shifted away from providing PIMs for these specific goals. This evolution in California's approach contrasts with the use of financial incentives in other jurisdictions and provides an example of how regulatory programs drive utility performance and innovation.

GREAT BRITAIN

Key Takeaways

- Great Britain operates under a five-year revenue cap framework known as "RIIO-ED2" (the second generation of "**R**evenue using **I**ncentives to deliver **I**nnovation and **O**utputs" for electricity distributors).
- A unique feature of Great Britain's RIIO approach is that it allows distribution utilities to obtain a return on both capital expenditures and a portion of operating expenditures, through a "totex" mechanism. The totex approach attempts to counter-balance a perceived capital spending bias.
- RIIO-ED2 contains financial incentives for utility performance in the form of "Output Delivery Incentives" ("ODIs"), which adjust the utility's allowed rate of return depending on the achievement of pre-specified metrics.
- The current approach uses a mix of forecasts and inflation adjustments to set annual revenue requirements. The revenue-setting approach is considered more complex than other jurisdictions in this report.

Profile of Great Britain's Electric Utility Sector

Regulated Utilities	
Distributed Utilities	14
Ratemaking regulator	Office of Gas and Electricity Markets ("Ofgem")
Transmission Operator	National Grid Electricity System Operator
UR Elements	
Multi-Year Rate Plans	✓
Revenue Decoupling	✓
Revenue Cap	-
Price Cap	-
PIMs	✓
Earnings Sharing Mechanisms	✓

Fuel Mix[146]			
Coal	1.28%	Hydro	1.65%
Nuclear	13.02%	Gas	31.71%
Wind	26.10%	Other	21.98%
Solar	4.26%		

Energy Sector Facts	
Total Installed Capacity	111 GW
Total Generation	318.6 TWh
Electric Vehicles	1.1 million
Customer Battery installations	10,000+ batteries

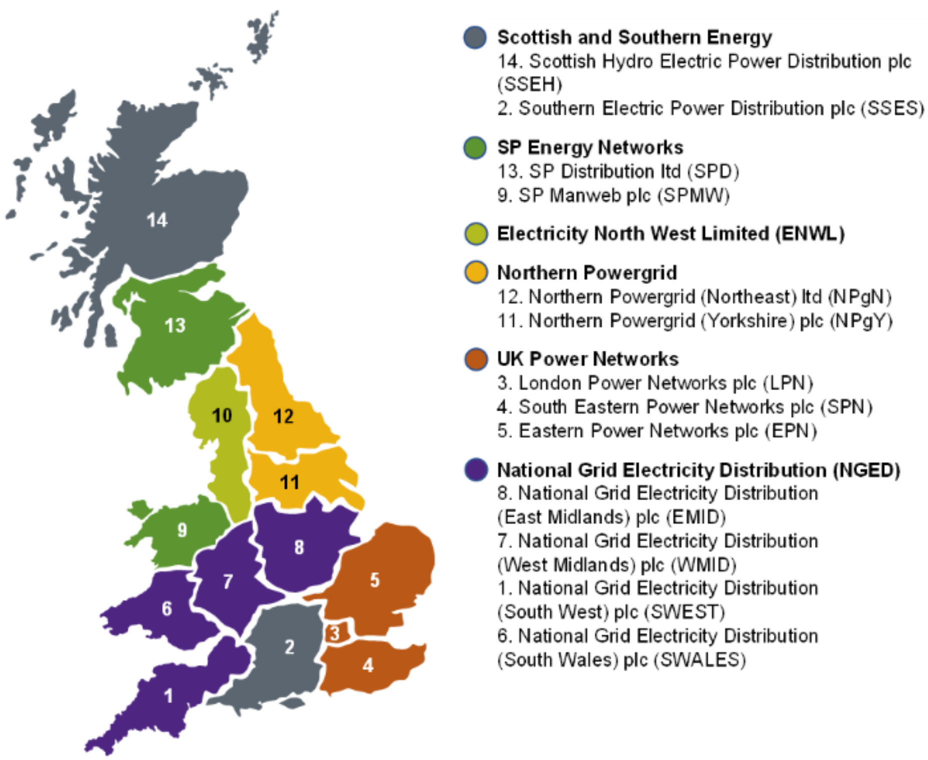
[146] Our World in Data. *Electricity production in the United Kingdom 2023.*

3.3 Great Britain

3.3.1 Overview of Great Britain

Great Britain has 14 electricity distributors ("DNOs") owned by six different groups, shown in Figure 3.6.The nation's transmission grid is operated by the National Grid Electric System Operator ("ESO"), which has many of the same responsibilities at Ontario's Independent Electricity System Operator ("IESO"). The unbundled nature of the industry, along with its unique utility remuneration model, makes it a worthwhile jurisdiction for review in this report.

Figure 3.6: Map of Great Britain Electric Utility Service Areas[147]



3.3.2 History of Utility Remuneration

Early Incentive Regulation and RPI-X

Electric utilities in Great Britain were owned by the state until the 1980s.[148] In 1979, Prime Minister Margaret Thatcher's government sold state-owned enterprises and carried out a series of industry privatization reforms, including among the electric utility sector. The new structure of the national electricity industry was introduced under the Electricity Act 1989, which resulted in the creation of twelve independent regional electric companies.[149] This legislation also created

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147 Ofgem.RIIO-ED2 Final Determinations Core Methodology Document. November 30, 2022.

148 Mandel, B.*A primer on utility regulation in the United Kingdom: Origins, aims, and mechanics of the RIIO model. November 2014*.

149 Liu, J., Wang, J., & Cardinal, J. (2022). *Evolution and reform of UK electricity market*. Renewable & Sustainable Energy Reviews, *161*, 112317.

the regulatory body that would become the nation's Office of Gas and Electricity Markets ("Ofgem").

The privatization of the electric industry in Great Britain occurred during a time of innovation in the economic theory of regulation. The concept of price caps was introduced to Great Britain in 1983 by Stephen Littlechild,[150] and were first used to regulate British Telecommunications in the wake of privatization.[151] Price cap regulation of the nation's privatized electric utilities soon followed, in the form of a regulatory construct dubbed "RPI-X." This general form of the price cap formula, where the allowed annual growth in prices equals sector inflation minus productivity growth, was eventually adopted by various incentive regulation frameworks around the world, including in Ontario.

Distribution price controls began with a calculation of allowed revenues.[152] Subsequent to the establishment of allowed revenues, prices were capped at RPI-X, where an average X factor was set each year. In practice, the application of RPI-X regulation in Great Britain involved some complexity beyond a simple annual price adjustment, including efficiency assessments of operating expenditure, profitability assessments, and scrutiny of forward-looking capital and operating expenditure plans.[153] Over time, the Office of Gas and Electricity Markets ("Ofgem") modified the RPI-X approach, expanding the formula to allow for the passthrough of costs beyond a utility's control (e.g., fuel costs) through a "Y" factor, and included reopeners that triggered rate reviews to address unforeseen circumstances.[154]

Assessment of RPI-X and the Evolution to RIIO

Ofgem touted the successes of RPI-X regulation in delivering real value to consumers over its 20 year existence, stating that the regulatory construct delivered a 50 percent reduction in electricity distribution costs since 1990, *in real terms*, improved quality of service in the form of a reduced number and duration of power cuts, and delivery of new investment in excess of £1bn a year.[155] Nevertheless, Ofgem recognized looming changes in the industry that would require "significant action […] to deliver both security of supply and environmental objectives at affordable prices longer term, given the nature and scale of challenges."[156] Through a working group by the name of "Project Discovery," Ofgem pressed for regulatory innovation that would meet these challenges.

In 2010, Ofgem determined it would move away from RPI-X to a new model known as RIIO ("**R**evenue using **I**ncentives to deliver **I**nnovation and **O**utputs"). The fifth and final form of RPI-X, known as the Fifth Distribution Price Control Review ("DPCR5") began in 2010 and ended in 2015. RIIO-ED1 ("Revenue using Incentives to deliver Innovation and Outputs for Electricity

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150 Littlechild, S. *Regulation of British Telecommunications Profitability, Report to the Secretary of State*. February 1983.

151 Littlechild, S. (2009). *RPI-X Regulation: Ofgem's RPI-X@20 Review and the Scope for More Customer Involvement.* Network, 34.

152 Ofgem. *Regulating Energy Networks for the Future: RPI-X@20. History of Energy Network Regulation*. February 27, 2009

153 Burns. P., Weyman-Jones, T. *The long-run level of X in RPI-X regulation: Bernstein and Sappington revisited*. July 10, 2008.

154 McHarg, Aileen. *Evolution and Revolution in British Energy Network Regulation: From RPI-X to RIIO*. Energy Networks and the Law: Innovative Solutions in Changing Markets. February 2012.

155 Ofgem. *Electricity Distribution Price Control Review: Initial Consultation Document*. March 28, 2008. p9.

156 Ofgem. *Project Discovery: Options for Delivering Secure and Sustainable Supplies*. February 3, 2008.

Distributors") began in 2015, spanning eight years until 2023. The current rate plan, the second generation of RIIO for electric distribution utilities, known as RIIO-ED2, will cover the five-year period from 1 April 2023 to 31 March 2028.

3.3.3 Overview of the Current Utility Remuneration Model

Today, Great Britain is split into 14 electricity distribution areas, which are operated by investor-owned Distribution Network Operators ("DNOs"). Each of the UK's DNOs are regulated under the RIIO-ED2 framework (spanning years 2023-2028). The RIIO-ED2 framework is a price control framework that sets several components of allowed revenue over the rate plan period, in which some components incorporate specific incentives. In this way, RIIO differs from the prior RPI-X approach, as well as the I-X price caps in Ontario, as the RIIO approach focuses on setting allowed revenues for each company rather than prices.

RIIO-ED2 began when the eight-year RIIO-ED1 rate plan period ended (in 2023) and largely follows the same conceptual approach as RIIO-ED1, with some updates. This means that all of the nation's electricity distributors established new base revenues in 2023, with each utility's five year revenue trajectory set according to a utility-specific set of inputs.

Regulatory Design Process and Goals of the RIIO-ED2 Framework

A consultation period that spanned 2022 and into 2023 informed Ofgem's final determinations for RIIO-ED2. During this period, DNOs submitted lengthy comments on the proposed elements of Ofgem's second generation framework. Many of these comments were detailed criticisms of specific components. However, some broad issues recurred across DNO filings, including issues with financial security under funding reductions.[157] Some DNOs also stated that the incentives to produce outputs did not reflect value of outputs, and that those incentives should be higher.[158] Similarly, there was concern about whether the RIIO-ED2 outputs reflect the wants of end use customers.[159]

Several DNOs expressed concerns about the lack of transparency and the high levels of complexity involved in the design of RIIO-ED2.[160] Given the increased frequency and severity of storms, DNOs raised concerns about funding for system hardening and resiliency.[161]

The RIIO-ED2 Challenge Group was an independent group comprised of energy sector experts and consumer advocates with specialist knowledge of the electricity distribution sector and economic regulation. The group filed a report offering comments on the RIIO-ED2 draft determination, including concerns about some of the incentives and financial elements of the framework. The Challenge Group advocated for changes to the use of distribution networks,

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[157] See, for example, Draft Determination Response, Scottish & Southern Electricity Networks, August 2022.
[158] See, for example, "Executive Summary," UK Power Networks, August 25, 2022.
[159] See, for example, "Draft Determination Response Letter," Western Power Distribution, August 25, 2022.
[160] See, for example, "RIIO-ED2 Draft Determinations: Overview Response," Electricity Northwest, August 2022.
[161] See, for example, "Draft Determination Response," Scottish & Southern Electricity Networks, August 2022.

stating that a “step change is needed” to improve existing DNO network utilization and to free up capacity.[162]

Various stakeholders also argued that the allowed returns were too high.

Ultimately, some changes were made to the RIIO-ED1 framework to address the changing environment of the electricity distribution sector. Environmental sustainability and customer affordability primarily motivated these updates, though some of the concerns of the DNOs were addressed in Ofgem’s list of policies for RIIO-ED2. In its final determination for RIIO-ED2, Ofgem clearly identified five policy objectives and concrete actions under the second generation of RIIO that would address these objectives. These goals, along with some of the concrete actions aimed at achieving these goals, are summarized in Table 3.4, below.

Table 3.4: Goals and Policies Under RIIO-ED2

RIIO ED2 Goal	Policy Examples
Facilitating the energy transition to Net Zero.	An initial totex funding package of £22.2bn, recovered through rates, for operating, maintaining, and enhancing the local distribution electricity distribution networks to ensure they are prepared to support the transition to net zero.
	Investment of £3.2bn in network upgrades to support the rollout of EVs, heat pumps and the connection of more local, low carbon generation including solar and wind.
	Uncertainty mechanisms (“UM”) that allow investment to adapt quicky to support higher volumes of low carbon technologies if networks are faced with sharper uptakes in demand for new connections.
Supporting a smarter, more flexible energy system.	A new framework of outputs and incentives for Distribution System Operation (“DSO”) with clearer executive level accountability for neutral decision-making between DSO and DNO business activities.
	A new DSO financial output delivery incentive to drive DNOs to more efficiently develop and use their network, including considering flexible and smart alternatives to defer the need for reinforcement and ultimately reduce customer bills.
	Funding to improve the DNOs’ monitoring of their networks, including through the installation of network monitoring equipment and through improved use of data analytics
Reliability, plus faster connections to low carbon technologies.	Package of financial and reputational incentives to drive behavioral changes.
	Strengthening quality of service targets in key customer priority areas, including reliability, customer service, and improvements in the time it takes to connect minor connection customers to the network.
	Funding for maintaining network assets so that networks remain resilient, including in relation to severe weather and cybersecurity.

[162] Ofgem. *RIIO-2 Challenge Group: Response to Draft Determinations*. August 2022.

RIIO ED2 Goal	Policy Examples
Delivering low cost to customers.	Higher share of any costs saved to be shared with consumers.
	Reduced cost of equity allowance.
	"The Return Adjustment Mechanism" - to protect consumers and companies against significant deviations in performance.
Ensuring vulnerable customers are not left behind in the energy transition.	Inclusion of a combination of stronger, enforceable License Obligations to hold DNOs to account for delivering minimum standards of service and treating all customers fairly.
	New consumer vulnerability incentive framework with stretching targets and common metrics to drive further improvements in services.

The RIIO-ED2 UR Model

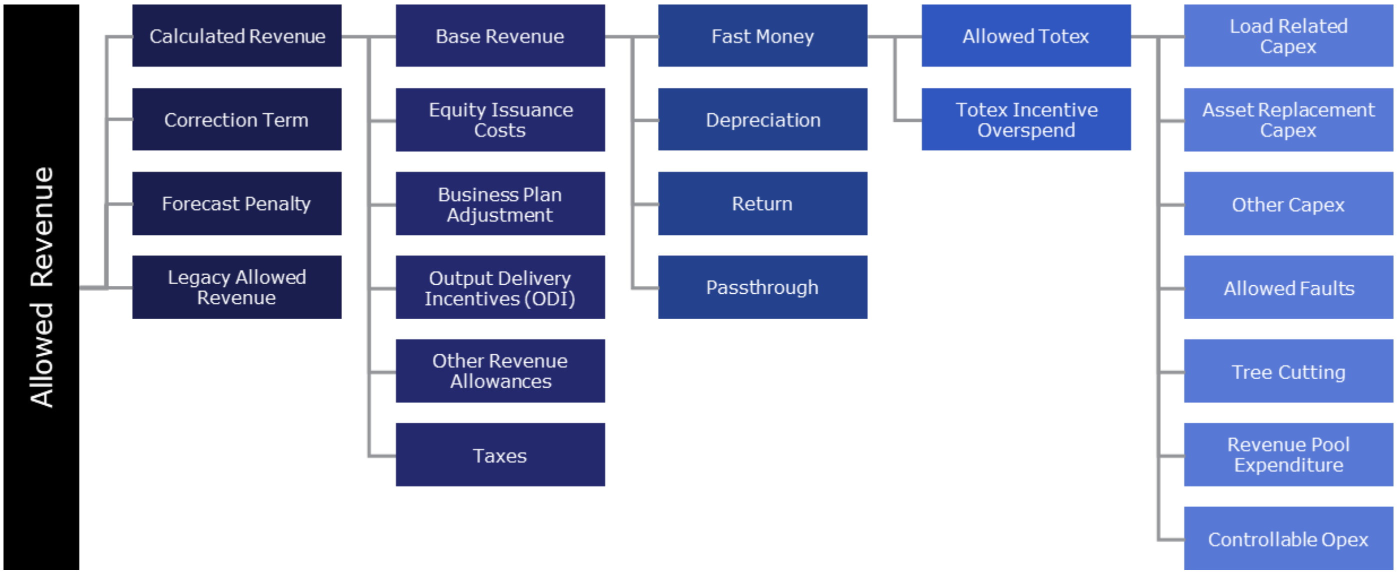
The RIIO-ED2 utility remuneration model uses a forecast approach to setting revenues in which each utility provides forecast revenue needs over the five-year term.[163] This forecast is adjusted by the rate of inflation and according to performance on incentive targets over the price control term. The incentives within RIIO-ED2 arise from how revenues are calculated. The "Allowed Revenue" of each DNO consists of a "Calculated Revenue" component, which is the largest component, a "Correction Term" that trues up allowed revenues in a manner akin to revenue decoupling, and two other true-ups: a forecast penalty, and a legacy allowed revenue amount.

The Calculated Revenue consists of "Base Revenue," equity issuance costs, Output Delivery Incentives ("ODIs")—which provide additional revenues based on performance, like PIMs—other revenue allowances, and taxes. The Base Revenue component is the sum of "Fast Money," depreciation, return, and passthrough (Y Factor) costs, where Fast Money consists of the portion of capex and opex excluded from depreciation.

Figure 3.7 provides an overview of the components of the allowed revenue for utilities under RIIO-ED2.[164]

[163] Ofgem. *ED2 Price Control Financial Handbook*. February 3, 2023.
[164] Ofgem. *ED2 Price Control Financial Model*. January 26, 2024.

Figure 3.7: Allowed Revenue Components



Some aspects of the UR methodology under RIIO-ED2 are common to traditional revenue requirement calculations conducted in North America. For example, the revenue requirement contains depreciation, taxes, and an allowed return. However, the RIIO-ED2 approach differs from traditional rate of return regulation in several respects. The sections below describe elements of RIIO related to utility remuneration and which may be relevant to the Ontario electricity distribution sector.

Distributor Business Plans

Nearly two years before the RIIO-ED2 price control period began, each DNO was required to submit a business plan that contained the activities that they intend to undertake in RIIO-ED2, and their associated costs. These business plans included performance targets across a broad range of categories, factors that give rise to cost differences during the control period, historical returns, and profits distributed to investors.[165] To generate these business plans, each DNO engaged with stakeholders to understand the perspectives of different industry parties prior to the beginning of RIIO-ED2.[166] Subsequent to the DNO business plan filings, Ofgem organized hearings and collected evidence on the business plan proposals between 2021 and 2022.

Ofgem assessed each business plan to determine the allowed revenue and set performance targets for the regulatory period. As such, the DNO business plans in RIIO-ED2 are crucial documents that guide the strategic direction, investment decisions, and performance commitments of DNOs. They ensure alignment with regulatory objectives, drive accountability and performance, foster customer and stakeholder engagement, and support innovation and sustainability. The plans form the basis for regulatory approval and funding.

165 Ofgem. *RIIO-ED2 Business Plan Guidance.* September 30, 2021.
166 Ofgem. *Enhanced Stakeholder Engagement Guidance for RIIO-ED2*. July 30, 2020.

Cost Efficiency Incentive Elements of RIIO-ED2

Electricity distributors face incentive pressures from several elements of the RIIO-ED2 framework. The framework is designed to provide cost efficiency incentives, as well as financial incentives for providing certain outputs.

Cost efficiency incentives arise from the multi-year rate plan structure of RIIO-ED2. In one respect, this mirrors the Ontario approach to regulation because Great Britain's revenue-based multi-year rate plan, like a price cap plan, lengthens the amount of time between rate applications. A longer period between rate applications is expected to reduce administrative and regulatory costs both for the utilities and for the regulator. Depending on its structure, a multi-year rate plan can provide additional cost incentives if it allows the utility to keep the benefits from cost efficiency gains over time.

The RIIO multi-year rate plan approach differs from Ontario, however, as it focuses on an inflation-adjusted revenue forecast, rather than an exogenous price cap index. Rather than relying on a price cap formula to encourage cost efficiency, distributors under the framework forecast their revenue requirement over a five-year period in current dollars and then recover an inflation adjusted amount based on this forecast. If a DNO manages to reduce its expenditure below the allowed level in a given year, it retains a portion of the savings, sharing the rest with consumers through a "Rate Adjustment Mechanism" ("RAM").[167] Conversely, if costs exceed the allowance, the DNO bears a portion of the excess costs. The RIIO-ED2 framework defines the earnings sharing according to a factor called the "efficiency incentive rate," which differs between distributors.

A "forecast penalty," which levies a financial charge on utilities with a substantial deviation between forecast and actual revenues, discourages inflated revenue requirement projections.

The Totex Approach

As under the first generation RIIO approach, distributors obtain a return on total expenditures ("totex"), which contains elements of both capital spending ("capex") and operating spending ("opex"). The totex approach attempts to counter-balance a perceived incentive for utilities to exhibit a capital bias in spending, since capital spending accompanies an allowed return. A portion of totex, under the name "Slow Money" is capitalized over time, incorporated into the annual depreciation expense. The remainder of totex spending, called "Fast Money" is incorporated into the allowed revenue as an expense. A sharing factor called the Totex Incentive Mechanism determines companies' exposure to under or overspends compared to our totex allowances.

The totex approach to setting returns differs from the traditional approach to setting utility returns, in which only capitalized expenditures earn a return. Totex has also been adopted in Italy as a component of utility regulation,[168] but is not currently in use in North America.

Output Incentive Elements of RIIO-ED2

Outputs (common to all DNOs or "bespoke"—specific to a given DNO) for RIIO-ED2 are aimed at meeting the needs of consumers and network users, maintaining a safe and resilient network,

[167] RAMs are analogous to "earnings sharing mechanisms" in North American incentive regulation plans.
[168] "Totex Ratemaking Could Help Keep Rates Affordable Through the Clean Energy Transition." Rebane, Kaja, Cara Goldenberg, David Posner. July 13, 2022. https://rmi.org/totex-ratemaking/

and delivering an environmentally sustainable network.[169] RIIO-ED2 explicitly focuses on utility outputs using both mandates and incentives. The framework contains three different forms of output regulation:

1. "License Obligations," which are mandates that each utility is required to fulfill. There are also longer standing obligations placed upon the DNOs through statutory instruments that have been put in place, notably in relation to Guaranteed Standards of Performance.

2. "Price Control Deliverables are outputs that each utility has been granted funding to produce. If the utility does not generate the required outputs associated with a given Price Control Deliverable, it must refund customers accordingly.

3. "Output Delivery Incentives" ("ODIs") provide distributors with a financial incentive to produce certain outputs. In this sense, ODIs operate like PIMs.

Table 3.5 summarizes the output components of the RIIO-ED2 framework.

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[169] Ofgem. *RIIO-ED2 Final Determinations Core Methodology Document.* November 30, 2022

Table 3.5: Summary of RIIO-ED2 Framework Output Components[170]

Mechanism	Definition	Metrics
License Obligations	Minimum standards that the utility must achieve.	Treating domestic customers fairly
		Digitalization of data
		Publication of the smart optimization platform
Price Control Deliverables	Specify the deliverable for the funding allocated and the mechanism to refund customers in the event that an output is not delivered.	Network asset risk metric
		Cyber resilience information technology
		Cyber resilience operational technology
Output Delivery Incentives	Reputational and financial incentives that drive service improvement.	Annual environmental report
		Distribution system operation
		Customer satisfaction survey
		Complaints metric
		Time to connect
		Major connections incentive
		Consumer vulnerability incentive
		Technology business management taxonomy for classifying digital/IT spend
		Collaborative project with networks to develop a new regulatory reporting methodology
		Annual vulnerability report
		Interruptions incentive scheme
		Network asset risk metric

ODIs operate by adjusting the allowed return of utilities according to the performance on each metric. Each utility has a "baseline" allowed ROE. The ODI incentive structure then adjusts this baseline by a maximum upward adjustment of 2.65% and a maximum downward adjustment of -4%, so that the possible range of return is between 1.5% and 8.8%. Figure 3.8 provides a visual representation of how the ODIs interact with the allowed rate of return on equity. The bar on the left side of the graph depicts the utility's range of possible returns before the "Rate Adjustment Mechanism" ("RAM") shares returns with customers. The righthand bar shows the tighter range of returns after sharing returns. The orange band, reflecting totex over- or underspend, is an illustrative example of the effect on returns of deviations in totex spending from the forecast.[171]

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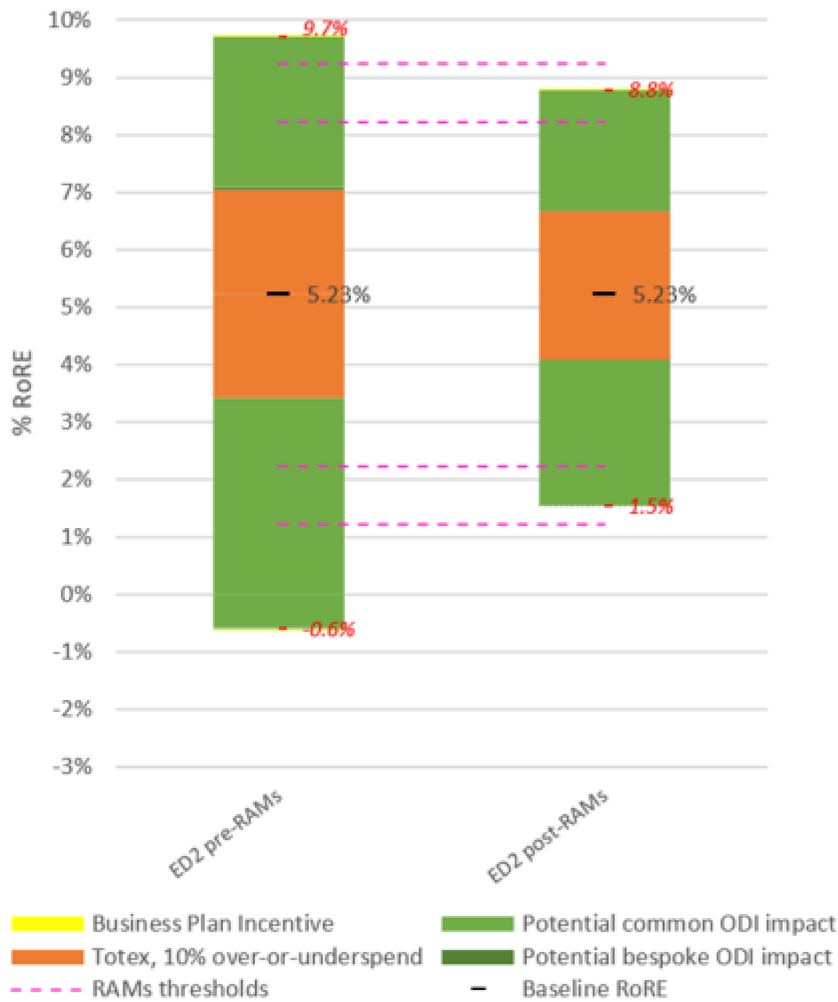
[170] Ofgem. *RIIO-ED2 Final Determinations Finance Annex.* November 30, 2022.

[171] Ibid.

Figure 3.8: Example of ODI Interaction with allowed Rate of Return On Equity[172]



Uncertainty Mechanisms and Correction Term

As a five-year MYRP, the RIIO-ED2 framework relies on Ofgem to set ex ante totex allowances for the DNOs. Ofgem only sets allowances where there is a need for and certainty of the proposed work, and where there is sufficient certainty on the efficient cost of delivery. Where uncertainty remains, "uncertainty mechanisms" are used.

The five categories of UMs are:

i. *Volume drivers* - Adjust allowances in line with the actual volume of work delivered, where the volume of certain types of work that will be required over the price control is uncertain (but where the cost of each unit is stable).
ii. *Re-opener mechanisms* - Decide, within a price control period, on additional allowances to deliver a project or activity once there is more certainty on the needs case, project scope or quantities.

[172] Ofgem. *RIIO-ED2 Final Determinations Finance Annex.* November 30, 2022, p. 72.

iii. *Cost pass-through mechanisms* - Adjust allowances for costs incurred by the DNO over which they have limited control and that, in general, we consider the full cost of which should be recoverable (e.g. business rates).

iv. *Indexation* - Provide network companies and consumers some protection against the risk that realized prices are different to those that were forecasted when setting the price control, e.g. general price inflation or cost pressures.

v. *Use-it-or-lose-it allowances* - Adjust allowances where the need for work has been identified, but the specific nature of work or costs are uncertain.

Ofgem has implemented 37 common UMs of which 21 are automatic and 16 are administrative reopeners.[173]

In addition to the uncertainty mechanisms, allowed revenues are adjusted each year of the price control period with a "correction term," which is applied to adjust the revenue allowances for DNOs to true-up actual costs and revenues from the previous year. This mechanism helps to correct any discrepancies between forecasted and actual values, with the goal of maintaining fairness and accuracy in the financial framework. This mechanism operates like a decoupling mechanism: the difference between actual and allowed revenue from the prior year is applied to the current year, adjusted for an interest rate.

An Assessment of RIIO

RIIO-ED1 (2015-2023)

The RIIO-ED1 framework, which shared many characteristics with RIIO-ED2, ended 2023.

While different parties have differing views on the successes and shortcomings of the first generation of RIIO, Ofgem published annual statistics related to utility performance that can assist with evaluating the outcomes of the rate-regulation framework. These annual reports provided information on service quality and customer satisfaction with distributors over time.[174] The findings of the 2023 (and final) annual performance report on RIIO-ED1 did not clearly show whether the output incentives under the framework caused improved performance.

Under RIIO-ED1, a financial incentive by the name of Incentive on Connections Engagement was enacted to provide DNOs with rewards or penalties based on the average time between receiving a request for quote to connecting its customers. The incentive was initiated in April 2015. Figure 3.9, below, charts the results of this metric for each of the six electric distribution groups operating under RIIO-ED1. The figure shows mixed results. In some years, distributors improved connection times, while in other years, connection times worsened. No distributor exhibited a clear change in the trend of its connection times over the eight-year RIIO-ED1 term, which might have indicated utilities reacting to the incentive. The reason for the mixed nature of these results is not clear, but Ofgem has committed to exploring what can be done to speed up the time to connect under RIIO-ED2.

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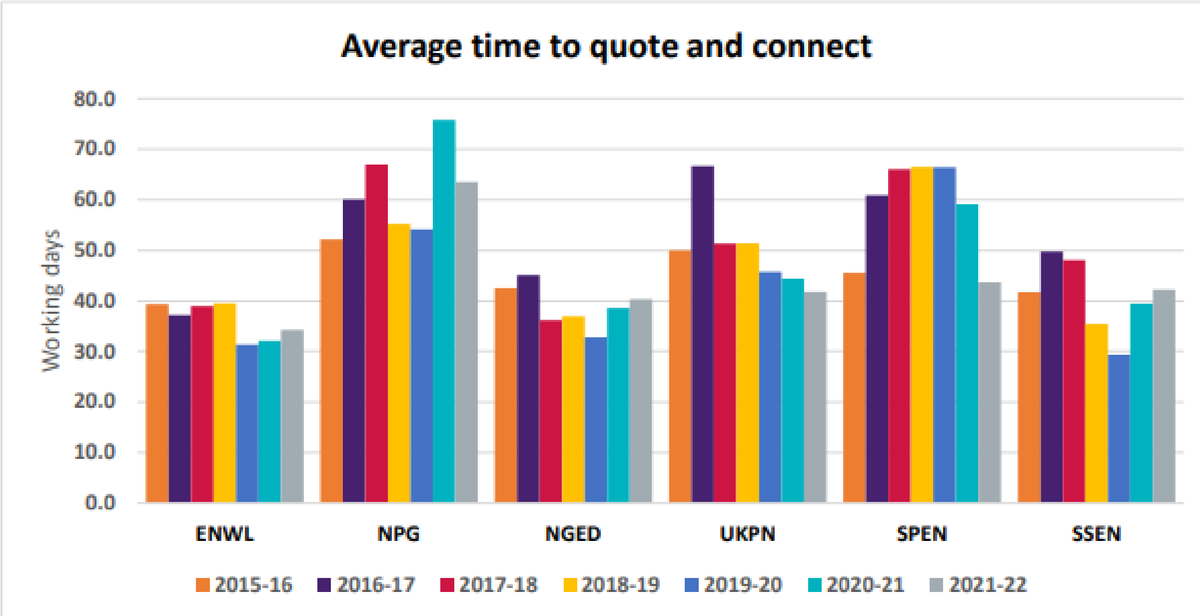
[173] Economic Consulting Associates. *An overview of Ofgem's latest electricity distribution price controls (RIIO-ED2).* February 2023.

[174] Ofgem. *RIIO-1 Electricity Distribution Annual Report 2021-22 and Regulatory Financial Performance Annex to RIIO-1 Annual Reports.*

Figure 3.9: Average Time to Quote and Connect[175]

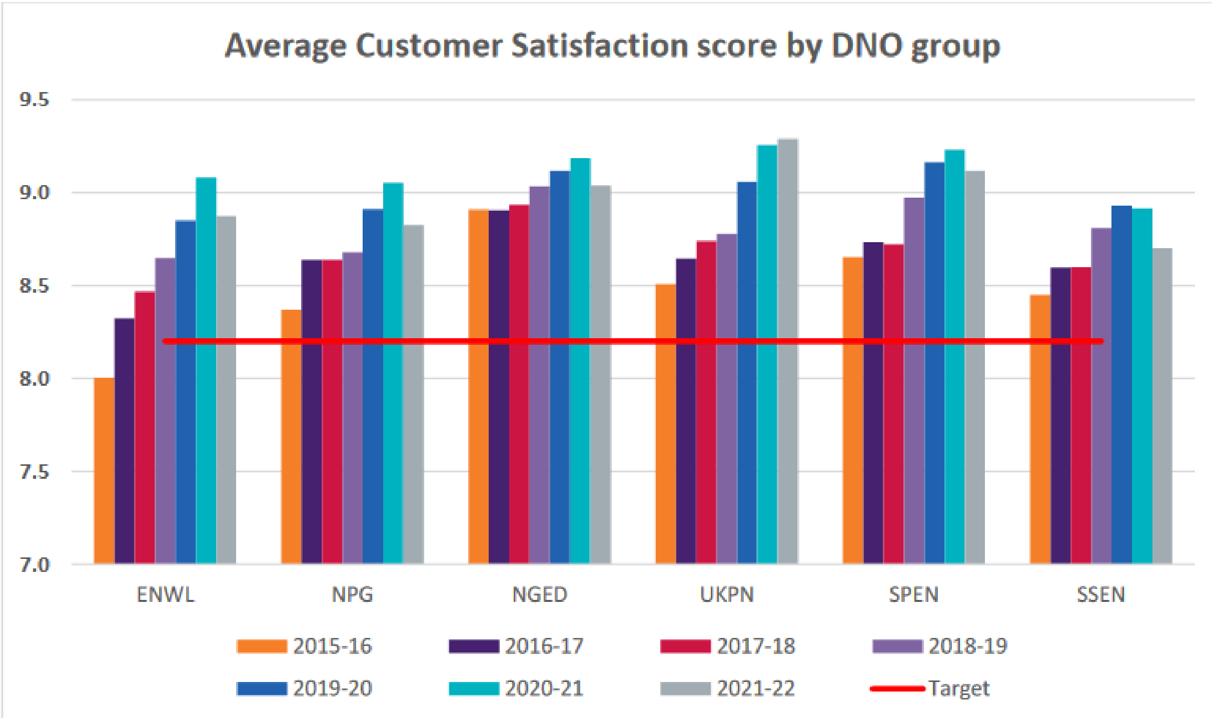


RIIO-ED1 also included a customer satisfaction incentive for distributors, which was set according to a Customer Satisfaction Survey and a complaints metric.[176] Figure 3.10 shows an upward trend in customer satisfaction scores over the RIIO-ED1 period, with all utilities exceeding the target customer satisfaction scores after the first year of the incentive.

175 Ofgem. *RIIO-1 Electricity Distribution Annual Report 2021-22 and Regulatory Financial Performance Annex to RIIO-1 Annual Reports*, p. 4.

176 Ofgem. *RIIO-ED1: Final determinations for the slow-track electricity distribution companies. Final Decision.* November 28, 2014.

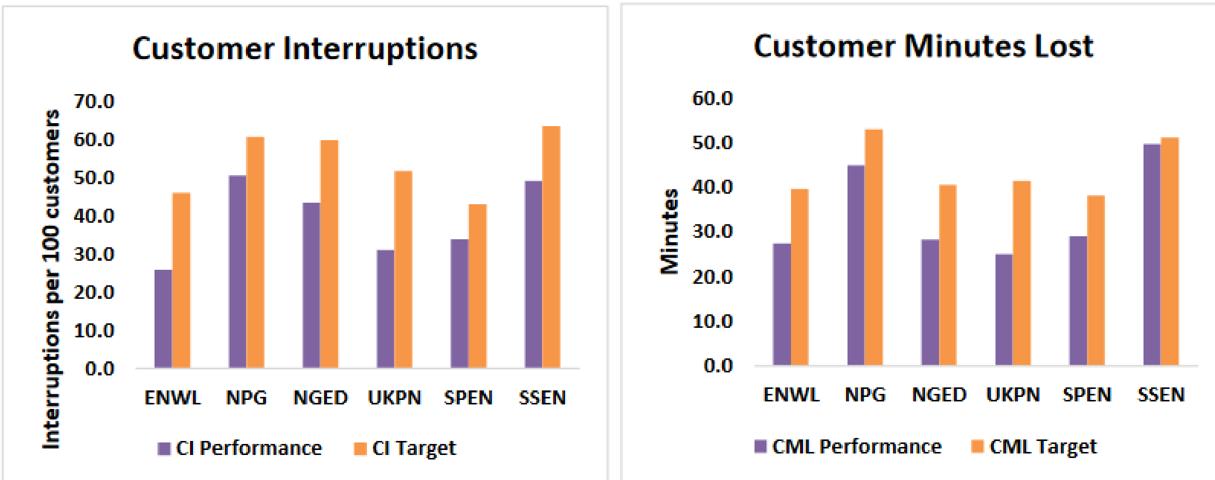
Figure 3.10: Average Customer Satisfaction Score by DNO Group[177]



Another financial incentive, the Interruptions Incentive Scheme ("IIS") under RIIO-ED1 focused on targets for the frequency and duration of both planned and unplanned interruptions.[178] The DNO was rewarded or penalized depending on whether it achieved or failed to achieve certain targets. Figure 3.11 shows that each distributor achieved its target in the 2021-2022 period—and this result was generally consistent with prior years of the framework—except that in 2019 one utility failed to meet its "Customer Minutes Lost" target.[179]

[177] Ofgem. *RIIO-1 Electricity Distribution Annual Report 2021-22 and Regulatory Financial Performance Annex to RIIO-1 Annual Reports*, p. 5.
[178] Ofgem. *Guide to the RIIO-ED1 electricity distribution price control*. January 18, 2017.
[179] Ofgem. *RIIO-ED1 Annual Report 2019-20.* March 11, 2021.

Figure 3.11: Customer Interruptions and Customer Minutes Lost[180]



RIIO-ED2 (2023-2028)

RIIO-ED2 began in April 2023, which is not enough time to make substantive assessments on its success relative to other regulatory models. However, based on Final Determinations proposals, Ofgem calculated that domestic consumers will experience average savings of £4.67 (2021/21 prices) a year/per household based on medium typical domestic consumption values, compared to the average bill in RIIO-ED1.

3.3.4 Key Takeaways

Although RIIO-ED2 bears a passing resemblance to Ontario's rate-regulation framework, as it involves a five-year rate application cycle for over a dozen distributors in an unbundled environment, the RIIO approach in its entirety constitutes a substantially different UR model from what exists in Ontario today. Rather than capping rates using an inflation and productivity price cap (or revenue cap) formula, DNOs under RIIO forecast their revenues over a five-year period and may collect additional revenues through a number of additional mechanisms. An annual inflation rate adjusts a portion of British utilities' allowed revenues each year, but the full calculation of allowed revenue consists of many different components, including PIMs (or "Output Incentives"), a "correction term" akin to decoupling, uncertainty mechanisms, a forecast penalty, and earnings sharing.

The RIIO approach includes incentive regulation tools that were specifically designed to address industry issues related to the energy transition. Some of these, like targeted PIMs and revenue decoupling, are comparatively discrete tools that can be borrowed without an overhaul of Ontario's current UR approach. Other features of the RIIO model, like the Totex method of combining certain portions of capex and opex, may, in theory, be possible to implement in Ontario, but would require careful consideration in the context of both the goals of the regulatory construct and the means of calculating allowed revenue.

To address specific objectives related to the energy transition, Ofgem also explicitly allowed utilities to collect additional revenues to fund certain investments (see Table 3.5, above). This

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180 Ofgem. *RIIO-1 Electricity Distribution Annual Report 2021-22 and Regulatory Financial Performance Annex to RIIO-1 Annual Reports, p. 6.*

constitutes a more traditional approach to supporting investment according to the cost-to-serve, as opposed to designing PIMs or alternative approaches that incent utilities to take desired actions. In some cases, this direct approach may be more efficient.

Finally, RIIO has many components and adjustment mechanisms, which contributes to regulatory complexity. Such complexity has the potential to be contentious and possibly lead to prolonged rate-proceedings to determine the application of each component in each utility's specific circumstances. This could be a particularly noteworthy for Ontario, a province with 56 utilities.

HAWAII

Key Takeaways

- Three investor-owned, vertically integrated utilities in Hawaii operate under a five-year revenue cap based on an "I-X" formula, where I is an inflation measure and X represents productivity.
- A portion of utility revenue is set by eight Performance Incentive Mechanisms ("PIMs"), which provide financial incentives for the achievement of certain policy objectives and the provision of enhanced customer service.
- Hawaii's process for designing PIMs may be instructive. The Hawaii PUC began with a set of specific goals at the outset of its PBR design process, and then crafted the UR framework around those goals.

Profile of Hawaii's Electric Utility Sector

Regulated Utilities	
Integrated Utilities	4 (3 under PBR)
Ratemaking regulator	Hawaii Public Utilities Commission
Transmission Operator	(None)
UR Elements	
Multi-Year Rate Plans	✓
Revenue Decoupling	✓
Revenue Cap	✓
Price Cap	-
PIMs	✓
Earnings Sharing Mechanisms	✓

Fuel Mix[181]			
Petroleum	74.1%	Renewables	22.4%

Energy Sector Facts	
Total Installed Capacity	3,247 MW[182]
Total Generation	9.47 TWh[183]
Residential Solar Capacity	1,268 MW[184]
Electric Vehicles	32,586[185]
Customer Battery Installations	4,819[186]

[181] U.S. Energy Information Administration. *U.S. Energy Atlas With Total Energy Layers.*
[182] U.S. Energy Information Administration. *Table 6.2. A. Net Summer Capacity of Utility Scale Units by Technology and State*. April 2024.
[183] U.S. Energy Information Administration. *Net generation for all sectors, annual*.
[184] Hawaiian Electric. *Cumulative Installed PV*. March 31, 2024
[185] Hawaii Department of Business, Economic Development & Tourism. *Monthly Energy Trends.* June 7, 2024.
[186] Hawaii Department of Business, Economic Development & Tourism. *Solar PV Battery Installations in Honolulu 2022 Update.* May 2023.

3.4 Hawaii

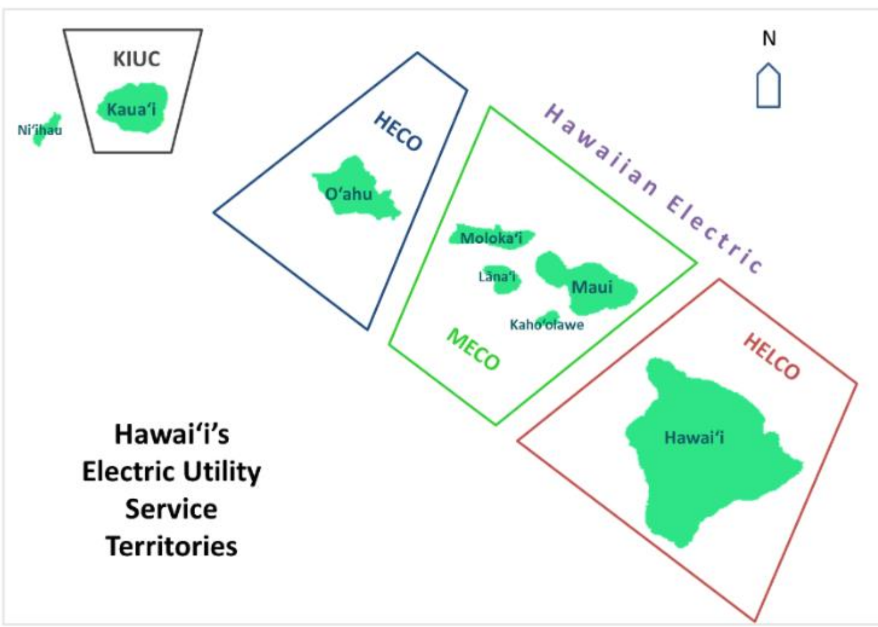
3.4.1 Overview of Hawaii

Four regulated utilities operate in the state of Hawaii, across several islands:

- Hawaii Electric Light Company ("HELCO")
- Hawaiian Electric Company ("HECO")
- Kauai Island Utility Cooperative ("KIUC")
- Maui Electric Company ("MECO")

Collectively, HECO, MECO and HELCO are known as the "HECO Companies" and serve about 95% of the State's population.[187] Each of Hawaii's six main islands has its own electrical grid, not connected to any other island, which means although the utilities send electricity from generating stations to population centers over transmission lines, there is no transmission system operator. This also means that each utility is fully integrated, generating, transmitting, and distributing electricity to end users. This means that each utility is also responsible for system planning and reliability, dispatch and grid operations, and resource adequacy.

Figure 3.12: Map of Hawaii's Electric Utility Service Territories[188]



The island situation of the utilities also gives rise to a unique power mix relative to the rest of the United States, with nearly 75% of power generation fueled by petroleum.[189] Relatedly, average electricity prices in Hawaii have historically been more than double the national average, and have fluctuated over the years in a manner similar to the fluctuations in the price of oil.[190] Small

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187 Hawaii Public Utilities Commission. *Energy.* August 2021.

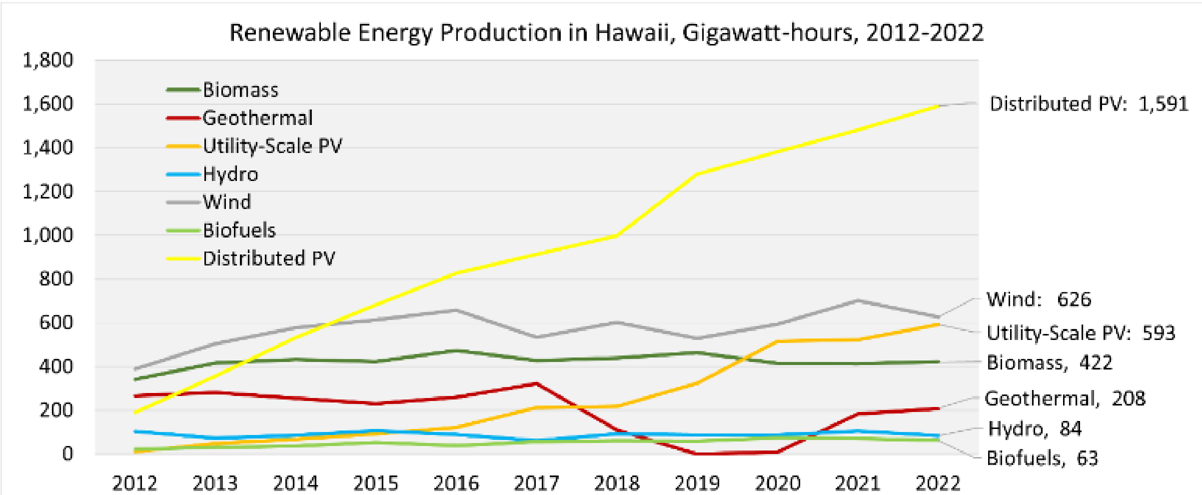
188 Hawaii State Energy Office. *Hawai'i's Energy Facts & Figures*. 2020

189 U.S Energy Information Administration. *Hawaii State Profile and Energy Estimates.* June 20, 2024.

190 Hawaii State Energy Office. *Hawai'i's Energy Facts & Figures*. 2020

scale solar and utility scale solar combined currently constitute 20% of the island's electricity generation, having grown substantially in the past decade.

Figure 3.13[191]



The current PBR framework in Hawaii bears some resemblance to Ontario, as the utilities operate under a five-year indexed cap, though some key components of the framework differ. This jurisdiction is particularly helpful to examine because the Hawaii Public Utility Commission ("Hawaii PUC") undertook a lengthy regulatory process to design its current PBR framework, addressing many of the same energy transition challenges arising in Ontario. The PUC's investigation led to the implementation of a wide array of PIMs, in addition to other PBR elements.

3.4.2 History of Hawaii's Utility Remuneration Model

Though categorized by some as a "traditional cost-of-service" model, Hawaii's pre-2021 regulatory framework for the state's IOUs incorporated many elements of PBR. The HECO companies operated under a three-year multi-year rate plan, along with revenue decoupling and an earnings sharing mechanism. The utilities also had several PIMs, including PIMs rewarding successful implementation of new renewable programs and procurement of utility-scale renewable generation.[192]

Another feature of the HECO utility remuneration model that existed prior to its current PBR framework, was a "revenue adjustment mechanism" ("RAM"), which allowed the company to recover adjusted costs for inputs that were already approved by the regulator. For example, the RAM allowed recovery for increases in operating expenses, payroll taxes, depreciation, and changes in taxes due to changes in tax laws, among other items.

Nevertheless, in 2018, the Hawaii PUC instituted a proceeding to investigate a more comprehensive PBR framework for the state, citing "a significant transition from predominantly centralized fossil-fuel-based generation systems towards increasingly distributed and renewable generation systems."[193] The PUC recognized that this evolution would change the role of the

[191] Hawaii State Energy Office. *Driving the Transition*. 2023

[192] Public Utilities Commission of the State of Hawaii Docket No. 2018-0088, Decision and Order No. 35411.

[193] Ibid, page 1.

electric utility in some respects, including the type of operations and services provided, the proportion of the utility-owned generation resources, and the nature of the utility's relationship with customers. The PUC stated that PBR would adapt the rate-regulation framework of the state to meet these industry changes.

At the outset of its PBR proceeding, the PUC defined a set of specific goals to be considered in the construction of the first generation PBR framework. Table 3.6, below, shows the PBR Goals and Outcomes.

Table 3.6: Regulatory Goals Set by the State of Hawaii

Goal	Regulatory Outcome	
Enhance Customer Experience	Traditional	Affordability
		Reliability
	Emergent	Interconnection Experience
		Customer Engagement
Improve Utility Performance	Traditional	Cost Control
	Emergent	DER Asset Effectiveness
		Grid Investment Efficiency
Advance Societal Outcomes	Traditional	Capital Formation
		Customer Equity
	Emergent	GHG Reduction
		Electrification of Transportation
		Resilience

In addition, the PUC sought to design a regulatory framework with an incentive structure to encourage utility performance irrespective of the nature of its investments—meaning an investment in capital expenditures or investment in efficiency measures. Similarly, the PUC discussed concerns about a "capital bias" in utility investment and set a goal of encouraging the efficient allocation of resources between capital and operating expenses. The PUC briefly considered the totex approach, but did not pursue it, citing implementation difficulties related to GAAP accounting.[194]

3.4.3 Overview of Current Utility Remuneration

Hawaii's current PBR framework was designed to maintain financially healthy utilities while supporting the state's clean energy goals. The PBR framework was specifically initiated to address the state's energy transition from fossil-fuel based power generation to a paradigm of renewable generation and DERs,[195] as prior to the investigation into PBR by the Hawaii PUC, the state set a goal of 100% renewable power generation by 2045.[196]

Hawaii's PBR framework is widely discussed as an example of the return of PBR to the regulation of utilities in the United States. The PBR plan centers around a five year I-X revenue cap for the state's three IOU, employing a number of PIMs aimed at addressing specific policy goals. While

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[194] "Staff Proposal for Updated Performance-Based Regulations." Public Utilities Commission of the State of Hawaii. February 7, 2019.

[195] Public Utilities Commission of the State of Hawaii. *Docket No. 2018-0088, Decision and Order No. 35411*.

[196] See Hawaii Revised Statutes ("HRS") § 269-92.

PIMs and revenue caps are not new concepts, Hawaii's PBR approach signaled a renewed interest in using these tools to address regulatory roadblocks brought on by the energy transition.

HECO's Revenue Cap Framework

The HECO UR model consists of common PBR tools. The utilities face a five-year rate-stay out period, with a revenue cap mechanism based on the following formula:

$$Revenue_t = Revenue_{t-1} * (1 + I - X - CD) + EPRM + Z$$

Where:

$Revenue_t$ = allowed revenue in year t

I = inflation, (equal to GDP-PI)

X = productivity (set equal to zero percent)

CD= consumer dividend (set equal to 0.22 percent)

EPRM = costs allowed to be recovered under the Exceptional Projects Recovery Mechanism

Z= costs associated with exogenous, one-time events

The formula adjusts revenues each year by the percentage change in GDP-PI (the Gross Domestic Product Price Index) minus a pre-determined percentage called the "stretch factor."[197] Each year, depending on circumstances, the utility's allowed revenue may be adjusted by several additional components, including cost trackers, a Z factor, PIMs, and a capital recovery mechanism.

The Hawaiian utilities have cost trackers that allow for the recovery of costs pertaining to fuel and purchased power, pensions, demand-side management, renewable energy infrastructure program. These costs are recovered outside of the allowed revenue that is adjusted by the inflation-based revenue cap. The Z factor, as in Ontario, provides the utility with an opportunity to review and recover prudently incurred costs that address events beyond the control of the utility.[198]

The PBR framework also contains a provision for additional revenue related to capital expenditures. In particular, the Exceptional Project Recovery Mechanism ("EPRM") is a -mechanism that allows the utility to file for cost recovery of projects that meet certain criteria. It provides recovery of allowed revenues for the net costs of these approved "Eligible Projects" placed in service during HECO's five-year revenue cap period, provided that cost recovery is not already covered by another effective recovery mechanism.[199] Eligible Projects include infrastructure necessary to connect renewable energy projects, projects that encourage clean

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[197] Although the PUC referred to HECO's revenue cap as an "I-X" revenue cap because an X factor was considered, the X factor was arbitrarily set to equal zero in the final decision. For this reason, the Hawaii revenue cap is not truly an "I-X" revenue cap, as it does not incorporate industry productivity.

[198] HECO's exogenous costs must exceed a threshold of $4 million to be eligible for Z factor cost recovery. This is equivalent to 0.14% of the company's total allowed revenue.

[199] Hawaii Public Utilities Commission. *In the Matter of the Application of Hawaiian Electric Company, Inc. For Approval to Commit Funds in Excess of $2,500,000 (excluding customer contributions) for the PZ.005125 – Kahe-Waiau 138 kV Undergrounding Project and to Recover Costs through the Exceptional Project Recovery Mechanism. Decision and Order No. 38451 Docket No. 2021-0086*. p62.

energy choices or conservation, utility scale generation and storage, grid modernization, and other similar projects.

Conceptually, the EPRM is akin to Ontario's ICM and ACM mechanisms, which provide for the recovery of capital-related costs beyond the scope of a utility's price cap. However, Hawaii's EPRM can also recover O&M expenses related to Eligible Projects, meaning this mechanism is not exclusively used for capital expenditures.

To reduce excessive use of the EPRM and to incorporate the unique circumstances of each utility operating under PBR, the Commission considers EPRM treatment on a case-by-case basis. Each project must demonstrate both eligibility and the exceptional nature of the project.[200] Some illustrative examples of eligible projects include: infrastructure necessary to connect renewable energy projects, utility scale generation and storage which aids in increasing the share of renewable energy on the grid, grid modernization projects, and service contracts with third-parties.[201] The PUC stated that EPRM should be reserved for projects that are extraordinary in nature and do not reflect "business as usual" investments or expenses.[202] While the concept is fairly simple and straightforward, the EPRM serves as an example of a mechanism that is not automated, requiring potentially significant regulatory resources to function effectively.

Additional components of the PBR plan include off-ramp and an earnings sharing mechanism ("ESM"). The off-ramp corresponds to an ROE trigger, allowing the utility to reconsider aspects of its PBR framework if its realized ROE falls below a certain threshold. Hawaii's off-ramp policy also includes other potential triggers, including regulator discretion. The ESM distributes to customers a portion of revenues earned outside of a band around the Company's authorized ROE.

HECO's PIMs and Scorecard Metrics

HECO reports a broad set of metrics, with dozens of different metrics currently active.[203] Like Ontario, many of these metrics are merely reported (i.e., "scorecard" metrics), rather than PIMs offering financial incentives, though the companies have eight PIMs currently in effect. Under the current UR model, HECO must balance different objectives of its UR model as it strives to achieve metrics goals while attempting to find cost efficiencies. Its success in this pursuit remains an open question—as the cost of administering more metrics may deteriorate cost efficiencies, even as other goals of the PBR framework may be achieved.

PIMs

A working group appointed by the PUC assisted with the conceptualization and design of Hawaii's current PIMs. Comments and proposals were also submitted by HECO and several other stakeholders, which the PUC considered in its final decision. Given the energy transition goals underpinning the state's PBR framework, many of the approved PIMs pertain to incorporating renewables and DERs onto the grid.

[200] Hawaii Public Utilities Commission. *Order 38451*, p63.

[201] Hawaii Public Utilities Commission. *Instituting a Proceeding To Investigate Performance-Based Regulation. Decision and Order 37507 Docket 2018-0088, Appendix A*. p4-6.

[202] Hawaii Public Utilities Commission. *Order 37507*. p. 87.

[203] Hawaiian Electric. *Performance Scorecards and Metrics.*

HECO's PIMs aim to achieve both energy transition goals and affordability for customers. To accelerate renewable energy adoption, the Renewable Portfolio Standard-Accelerated ("RPS-A") rewards utilities for exceeding clean energy goals, incentivizing faster integration of renewable sources like solar and wind. To facilitate the energy transition from the perspective of grid management, the PUC implemented PIMs that address challenges arising from a changing grid. For example, the Interconnection Approval PIM encourages faster approval processes for connecting new renewable energy systems to the grid.

The Grid Services PIM is designed to promote DER asset effectiveness, as well as grid investment efficiency, by incenting the expeditious acquisition of Grid Services capabilities from DERs. Grid Services include "Load Build"—in which entities provide energy to the grid when generation is needed—and "Load Reduction"—in which entities reduce usage to relieve capacity constraints. Grid Services also includes Fast Frequency Response ("FFR").[204] Traditionally, FFR services were provided by spinning reserves, which are backup generators that can quickly ramp up power production. More recently, however, FFR services might be obtained from battery storage systems and "smart inverters" that quickly adjust power output based on grid frequency. This PIM existed prior to the 2021 implementation of Hawaii's revenue cap framework, but was modified to include load reduction, as the PUC cited a "critical need for peak reduction" across Hawaii's service territories.[205]

To encourage affordability and equity, the Low-to-Moderate Income Energy Efficiency PIM pushes utilities to collaborate with energy efficiency programs, helping low-income residents participate in the energy transition by offering them ways to manage their energy use and potentially save money.

Table 3.7 presents HECO's current PIMs, describing the metrics, rewards, penalties, and desired outcomes.

[204] Hawaii Public Utilities Commission. *DPS Phase 3 D&O Summary.*
[205] Hawaii Public Utilities Commission. *Order 38429.* p60.

Table 3.7: List of PIMs in Hawaii[206]

Performance Incentive Mechanism	Details
RPS-A (Renewable Portfolio Standards)	Incent Hawaiian Electric to accelerate the achievement of its Renewable Portfolio Standards goals Metric: Companies' annual compliance with the RPS Reward for exceeding the RPS target: $20/MWh in 2021 and 2022, $15/MWh in 2023, and $10/MWh for the remainder of the MRP. Penalty: as prescribed in the RPS The Commission has increased the potential reward in the early years of the MRP to encourage further acceleration of renewable development associated with the upcoming retirements of fossil-fueled plants and support post-COVID economic recovery. Regulatory outcomes: DER Asset Effectiveness, Customer Engagement, Interconnection Experience, Cost Control, Affordability, Grid Investment Efficiency, and GHG Reduction.
Grid Services PIM	Incent the expeditious acquisition of grid services capabilities from DERs. Metric: kW capacity of grid services acquired Reward: companies will receive a one-time award on per kW basis depending on the grid services acquired and the service territory it will serve Penalty: None Regulatory outcomes: Promote DER Asset Effectiveness and Grid Investment Efficiency
Interconnection Approval PIM	Metric: Number of business days it takes the companies to complete all steps within the companies' control to interconnect DER systems <100kW in size Three tiers of targets with financial rewards and penalties to encourage incremental improvement Maximum annual reward is $3 million for all companies, calculated on a target revenue basis. Maximum annual penalty will be set for $900,000 for all companies, calculated on a target revenue basis. Regulatory outcome: Interconnection Experience
Low-to-Moderate Income Energy Efficiency PIM	Incent collaboration between Hawaiian Electric and Hawaii Energy to deliver energy savings for low- and moderate-income customers. Metric 1: Residential Hard-to-Reach Energy Savings Beyond Hawaii Energy's Target Reward structure: $/kwh reward factor times the amount of kWh energy verified savings

[206] Hawaii PIMs References:
- Public Utilities Commission of the State of Hawaii. *Docket No. 2018-0088, Decision and Order No. 37507.*
- Public Utilities Commission of the State of Hawaii. *Docket No. 2018-0088, Decision and Order No. 37787.*
- Public Utilities Commission of the State of Hawaii. *Docket No. 2013-0141, Decision and Order No. 34514.*

Performance Incentive Mechanism	Details
	Metric 2: Residential Hard-to-Reach Peak Demand Reduction Beyond Hawaii Energy's Target Reward structure: $/kW reward factor times the amount of kW peak demand verified savings Metric 3: Affordability & Accessibility program Customers Served Beyond Hawaii Energy's Target Reward structure: $/customer reward factor times the verified number of customers served. Total reward capped at $2 million annually. Regulatory outcome: Customer Equity, Customer Engagement, Affordability
Advanced Metering Infrastructure ("AMI") Utilization PIM	Incent acceleration of the number of customers with advanced meters enabled to support time-varying rates and next generation DER programs. Metric: percentage of total customers with advanced meters delivering at least two of the three benefits ("Customer Authorization", "Energy Usage Alert", "Program Participation") Maximum annual reward: $2 million Regulatory outcome: Customer Engagement, DER Asset Effectiveness, Grid Investment Efficiency
SAIDI/SAIFI PIMs	(Penalties only) Maximum revenue exposure: 20 basis points on earnings Regulatory outcome: Reliability The utility (HECO) proposed symmetric award/penalty, while the consumer advocate supports penalty only. The HECO companies proposed expressing maximum financial incentive amounts for the PIMSs based on percentage of T&D revenue requirements, while the consumer advocate proposed financial incentive amounts based on basis points on earnings. The commission finds using "basis points on earnings" provides a more direct and meaningful context for considering the appropriate magnitudes of the financial incentives.
Call Center PIM	Metric: the percentage of calls answered within thirty (30) seconds. Maximum revenue exposure: +/- 8 basis points on earnings Regulatory outcome: Customer Engagement

The HECO companies have had mixed success in meeting its PIMs objectives. In 2022 and 2023, HECO exceeded the PIM connection time threshold for its Interconnection Approval PIM. HECO achieved its renewable generation threshold for the RPS-A PIM in 2022, but not in 2023. None of the three HECO IOUs achieved the SAIFI, Call Center, or AMI Utilization PIMs thresholds in 2022 or 2023. In some cases when PIM thresholds were not achieved, HECO cited forces beyond the Company's control as presenting obstacles to achievement of the PIMs.[207]

[207] "Notice Transmittal to Update Target Revenue through the Major Project Interim Recovery Adjustment Mechanism, Exceptional Project Recovery Mechanism, and Calculation of 2022 Performance Incentive

Scorecards

In addition to PIMs, "reported metrics" were put in place as part of the first generation PBR plan to track several dozen dimensions of HECO's service.[208] These metrics differ from PIMs, in that they do not correspond with financial incentives for the utility, much like the existing scorecard metrics in Ontario. These scorecard metrics cover affordability, cost control, customer engagement, electrification of transportation, greenhouse gas reduction, resiliency, and many other categories.

It is not clear how the Hawaii PUC will use these metrics to inform the evaluation of HECO's first generation PBR framework, or whether the metrics will inform the design of the second generation PBR framework.

3.4.4 Key Takeaways

The PBR framework for HECO took effect on June 1, 2021, so the state's current UR model is relatively new, and the efficacy of the plan remains a topic of speculation. HECO's revenue cap is particularly restrictive, as it adjusts allowed revenues only by the rate of economy-wide inflation—not for an X factor based on sector productivity. In addition, the PUC has also been highly selective in approving HECO's requests for revenue support through the EPRM. It remains to be seen whether the companies can operate with the restrictive revenue cap in place while business input requirements and costs increase.

Hawaii's process for designing PIMs may be instructive for Ontario. The Hawaii PUC began with a set of specific goals at the outset of its PBR design process, and then crafted the UR framework around those goals. As part of the development process of HECO's PIMs, the PUC conducted a thorough stakeholder engagement process with a working group, and subsequently allowed comments on proposed PIMs designs through an open docket. This methodology for designing the PIMs allowed for input from diverse perspectives about what different groups deemed important and feasible, as well as the value of achievement in different performance categories.

HECO has had mixed success in achieving its PIMs goals. As with any PIM, it is possible that the PIM design does not adequately capture the cost of achieving the performance goal. For example, if HECO has PIMs with performance thresholds that the company believes will never be achieved, or if the reward is too low, there may be no *de facto* incentive associated with the PIM. It is also possible that external factors beyond management's influence may hinder the achievement of certain PIMs in a given year, or that management prioritized other efforts for reasons not clear in the public record.

Hawaii's first-generation five-year revenue cap ends in 2025, and the Hawaii PUC has indicated that it plans to assess the UR model prior to implementing a second-generation framework. More evaluative information will likely arise from that process. However, a major hurdle in evaluating the state's PBR framework is that the island of Maui experienced devastating wildfires in 2023. Given this massive, unexpected event, simple assessments of utility performance may be difficult to gauge wholistically—particularly if using a "before and after" methodology.

Mechanism and Shared Savings Mechanism Financial Incentives," Hawaiian Electric Companies, June 1, 2023.

[208] Hawaii Public Utilities Commission. *Order No. 37507, Docket 2018-0088*.

AUSTRALIA

Key Takeaways

- Electricity distributors in Australia operative under a five-year rate plan with revenue cap.
- Australia has implemented seven Performance Incentive Mechanisms ("PIMs") to address three key areas: cost-efficiency, service quality, and customer engagement.
- The cost-efficiency and service quality PIMs work in conjunction with one another to balance cost efficiency and service quality to ensure efforts to reduce operational and capital expenditures don't compromise reliability.
- Cost-efficiency PIMs also provide incentives for utilities to pursue non-wire solutions to manage peak demand.

Profile of Australia's Electric Utility Sector

Distribution Regulation	
Regulated Utilities	13 (see Figure 3.14)
Ratemaking regulator	Australian Energy Regulator
Transmission Operator	Australian Energy Market Operator
UR Elements	
Multi-Year Rate Plans	✓
Revenue Decoupling	✓
Revenue Cap	✓
Price Cap	-
PIMs	✓
Earnings Sharing Mechanisms*	✓

Fuel Mix[209]			
Black Coal	46.90%	Hydro	7.60%
Brown Coal	17.00%	Gas	5.40%
Wind	14.10%	Other	0.60%
Solar	8.30%		

Energy Sector Facts	
Total Installed Capacity	77,683 MW[210]
Total Generation	185 TWh[211]
Rooftop Solar Capacity	18,012 MW[212]
Electric Vehicles	130,000 EVs[213]
Customer Battery installations	101,877[214]

*Typically, ESMs share earnings beyond a threshold above the utility's allowed ROE. In Australia, the utility shares gains from capex underspend.

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[209] AEMO NEM Dashboard fact sheet. *National Energy Market fuel mix June 24, 2023 – June 15, 2024*.
[210] Australian Energy Regulator. *State of the Energy Market 2023. p37*
[211] Ibid., p70
[212] Australia Energy Regulator. *Generation Capacity as of June 30, 2023, State of the Energy Market 2023*.
[213] Electric Vehicle Council. *State of Electric Vehicles*. July 2023.
[214] Clean Energy Regulator. *Small-scale installation postcode data as of June 21, 2024*.

3.5 Australia

3.5.1 Profile of Electricity Distribution in Australia

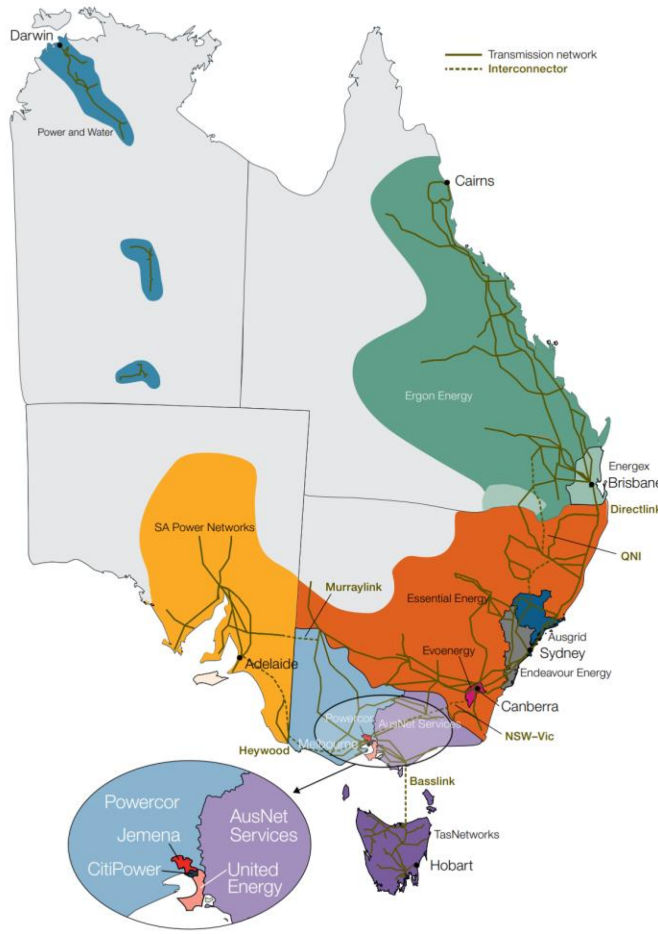
Electric utilities in Australia, as in Ontario, operate in an unbundled environment where distribution-only utilities face rate regulation by a regulatory authority. These distributors operate under a form of incentive regulation, implemented through multi-year rate plans along with incentive mechanisms that provide rewards and penalties for the achievement of specific performance objectives. Such mechanisms may lend perspective to Ontario in its evaluation of possible utility remuneration methods.

Australia's national energy system, encompassing all states and territories except Western Australia, is governed by three major market bodies: the Australian Energy Market Commission ("AEMC"), the Australian Energy Market Operator ("AEMO"), and the Australian Energy Regulator ("AER"). (Western Australia is separately regulated by Economic Regulation Authority of Western Australia.[215]) The AEMC develops the rules by which the markets must operate, the AEMO manages day-to-day operations of the markets, and the AER monitors performance and compliance with rules. Within this regulatory construct, Distribution Network Service Providers ("DNSPs") operate as regulated natural monopolies responsible for the physical delivery of electricity, while retailers compete in a largely deregulated market to purchase wholesale electricity and sell it to end consumers, with both entities overseen by the AER to ensure efficiency and customer protection.[216]

[215] Unless otherwise stated, 'Australia' in this report refers to all Australian states and territories excluding Western Australia.

[216] In Australia, utilities are commonly referred to as "networks". Distribution utilities are specifically termed Distribution Network Service Providers (DNSPs).

Figure 3.14: Service Territory Map of Eastern Australia[217]



3.5.2 History of Utility Remuneration

Evolution of Australia's UR Model

Until 1991, Australia's electricity sector was entirely under state government control, with all aspects—generation, transmission, distribution, and retail—managed by public entities. In the years that followed, as in Ontario and Great Britain, the industry underwent substantial deregulation, leading to a more market-oriented approach.[218] Deregulation reforms culminated at a national level in the establishment of the National Electricity Market in 1998.[219] Today, the National Electricity Market is an interconnected power system that operates across five Australian states and one territory, facilitating the wholesale trading of electricity between generators and retailers in a competitive market structure.

In 2005, the AER was established to oversee wholesale and retail energy markets, as well as energy utilities. As part of its mandate, the AER was tasked with administering an incentive regulation construct to simulate competitive market conditions where possible.[220] To achieve this

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[217] Australian Energy Regulator. *State of the Energy Market 2023*. p. 82.

[218] Deregulation and Reform of the Electricity Industry in Australia, Felix Karmel, February 2018

[219] Australian Energy Market Commission. *National Electricity Market, A Case study in successful microeconomic reform*.

[220] National Electricity Rules, Chapter 6, Part D, Clause 6.10.2, June 30, 2005 version.

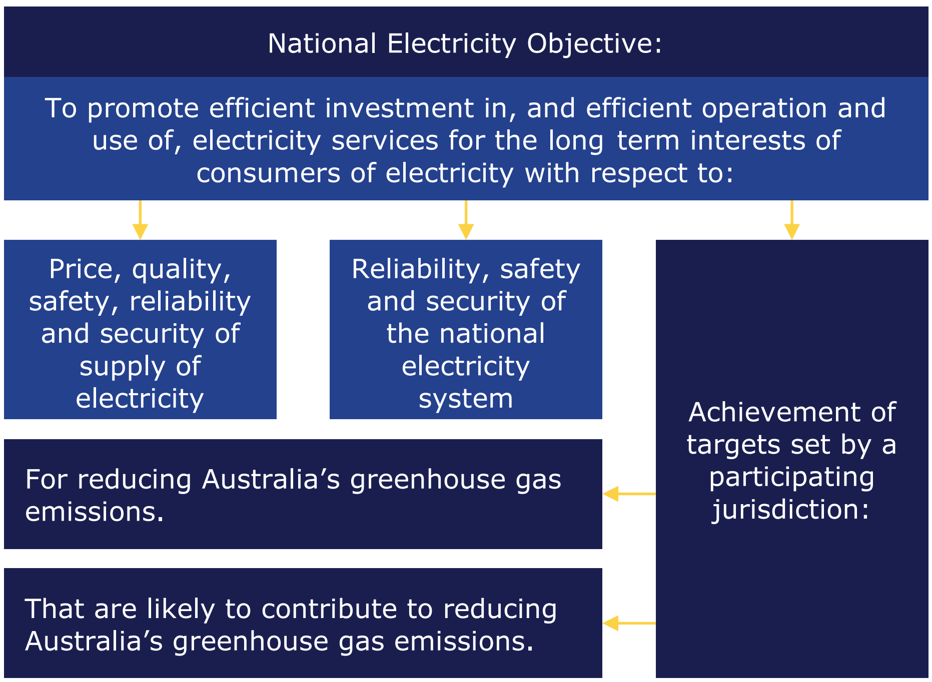
goal, the jurisdiction regulated by AER adopted a variant of the inflation minus X formula,[221] with the flexibility to consider individual utility performance incentives.[222]

Over time, the AEMC also introduced incentive schemes aimed at providing additional cost efficiency and service quality incentives. These incentive schemes are described in more detail in the next section.

Energy Transition

Australia's Climate Change Act 2022 set targets to reduce greenhouse gas emissions by 43% below 2005 levels by 2030 and achieve net zero by 2050. Following this legislative change, Australia's National Electricity Objective ("NEO"), summarized in Figure 3.15 below, was amended to align with these climate goals by including emissions reduction as a key objective.[223]

Figure 3.15: Summary of Australia's National Electricity Objective



The inclusion of emissions reduction goals in Australia's NEO set out a clear environmental objective that the AER must consider when regulating utilities. This prompted the AER to release guidance on the operationalization of the new NEO. The guidance included expected changes to DNSP expenditure forecast assessments, cost benefit analyses, and consumer energy resources to account for value of emissions reduction. Considering the relative recency of these changes, shifts in the regulatory approach are likely to happen in the future, however the AER has already

[221] It is worth noting that the application of the X-Factor in Australia differs from its use in other PBR frameworks. While in many jurisdictions the X-Factor serves as a productivity offset to the rate of sector inflation, in Australia, it functions only as a price adjustment mechanism. Its primary purpose is to smooth out revenue streams and minimize significant year-to-year fluctuations. The X-Factor is determined for each adjustment year to achieve this smoothing effect without impacting the Net Present Value of the total revenue collected over the entire ratemaking period. Importantly, the X-Factor in the Australian context does not directly correlate with actual sector productivity growth. Instead, it serves as a financial tool to enhance stability and predictability in the regulatory framework.

[222] National Electricity Rules, Chapter 6, Part D, Clause 6.10.5, June 30, 2005 version.

[223] National Electricity (South Australia) Act 1996, Historical version 21.9.2023 to 7.5.2024.

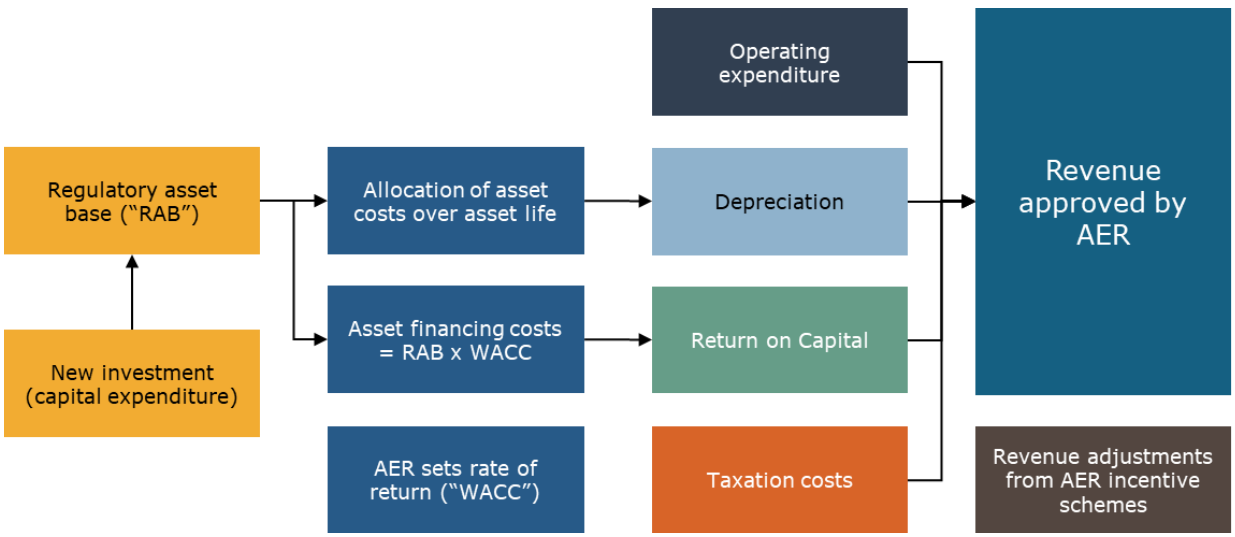
taken steps and has developed an interim value of emissions reduction, which was applied in the recent determinations.[224]

3.5.3 Overview of Current Utility Remuneration

Setting the Revenue Requirement in Australia

The AER regulates Australian distribution utilities through a forecasted multi-year revenue approach, setting the maximum amount of revenue they can earn from customers through electricity distribution determinations (i.e., rate cases). The determinations for distribution utilities follow a five-year cycle. Revenues are determined and set for five years until the following determination. Since its establishment, the AER has used a "building block approach" in determining the revenue requirement for their utilities. Figure 3.16 shows the "building blocks" that the AER uses to determine the allowed revenue for distribution utilities. The utilities are allowed to recover operating expenditures, depreciation, and taxation costs, as well as a return on the approved asset base consisting of existing asset stock and new investments.[225] The final approved revenue for each year also includes adjustments from AER incentive schemes.

Figure 3.16: Australia's Electricity Distribution Utility Revenue Requirement Model[226]



Once the allowed revenues are set for a 5-year period, the utility is incentivized to keep its actual costs below the forecasted costs to retain part of the benefit. To minimize year-to-year swings in prices, the approved revenues are smoothed out across the 5-year period.

During the 5-year multi-year rate plan term, utilities are required to submit to the AER an annual pricing proposal that contains the utility's proposed rates for the following year, incorporating

224 Australian Energy Regulator. *Valuing emissions reduction – Final guidance and explanatory statement*. May 2024

225 The rate of return is calculated at the time of the determination and is updated annually. The calculation steps are described in detail in Rate of Return Instrument reports.

226 Australian Energy Regulator. *Final Decision: Ausgrid Electricity Distribution Determination 2024 to 2029*. April 2024

adjustments for incentive scheme rewards or penalties, inflation, and revenue decoupling (for under- or over-recovery of revenue due to fluctuations in energy consumption).[227]

Summary of Australia Incentive Schemes

The AER has developed and implemented seven incentive schemes to address three key areas: cost-efficiency, service quality, and customer engagement. Table 3.8 provides an overview of each scheme, including detailed descriptions, performance assessments, and stakeholder feedback and concerns, where applicable.

Table 3.8: List of Incentive Schemes (or PIMs) in Australia[228]

Performance Incentive Mechanism	Details
Efficiency benefit sharing scheme ("EBSS")	To promote operational expense efficiency and incentivize revealing true opex costs. <u>Reward</u>: Companies retain the benefit of outperforming against opex forecasts over a six-year period. <u>Penalty:</u> Companies incur the cost of underperforming against opex forecasts over a six-year period. <u>Regulatory outcomes:</u> The goal of the incentive is to act as an efficiency carryover mechanism, allowing the utility to retain the gains from cost efficiencies between rebasing periods.[229] The rewards provided by the EBSS mean that utilities have an incentive to reveal their true opex costs in forecasts. The AER benchmarks each utility's performance against other utilities, and if a utility is materially inefficient, the AER typically adopts a lower opex forecast than the revealed actual opex costs. A recent review conducted by the AER indicates that customers have benefited from EBSS. The 2023 review revealed that opex per customer had decreased by 30 percent since 2011/12. The AER suggests that this significant improvement in efficiency can be largely attributed to the implementation of incentive schemes.[230] Some stakeholders argue that emphasis should be placed on benchmarking to prevent utilities from being rewarded for average or low levels of productivity,[231] but the AER has decided to maintain its current EBSS approach, citing its effectiveness in driving opex efficiency.

[227] Ausgrid. *Statement of reasons: Ausgrid's Annual Pricing Proposal*. May 2024

[228] "Incentive Schemes" is a broader term used by the AER that encompasses PIMs and other regulatory tools. Some schemes listed, such as the Efficiency Benefit Sharing Scheme ("EBSS") and Capital Expenditure Sharing Scheme ("CESS"), operate differently from traditional PIMs but fall under the broader category of Incentive Schemes.

[229] Under a typical MYRP, cost efficiency incentives decline as the rebasing period approaches. The EBSS works to address this issue by allowing the utility to retain the efficiency savings for a period after the efficiency was achieved. This is done through an incremental efficiency gain, which is calculated as the difference between underspend in the relevant year less the underspend in the previous year. The incremental efficiency gain in each year is then carried forward for an additional five years and to allow the utility to benefit from its operational efficiencies across different rate periods.

[230] Australian Energy Regulator. *Final Decision: Review of incentive schemes for networks*. April 2023.

[231] Ibid.

Performance Incentive Mechanism	Details
Capital Expenditure Sharing Scheme ("CESS")	To incentivize utilities to undertake efficient capital expenditure and share efficiency benefits with customers. The CESS also provides a mechanism to share capital-related efficiency gains and losses between utilities and customers. The most recent version of the CESS applies a 30:70 utility-customer sharing ratio for underspends of up to 10 percent, and a 20:80 sharing ratio for underspends exceeding 10 percent. <u>Reward</u>: Companies retain the benefit of outperforming against capex allowance over a six-year period. <u>Penalty:</u> Companies incur the cost of underperforming against capex allowance over a six-year period. <u>Regulatory outcomes</u>: The AER indicated that capex has decreased significantly from 2011/12 by around 50 percent per customer indicating that CESS might have driven capital expenditure efficiency gains.[232] Stakeholders have expressed concerns about CESS that mirror those raised about EBSS, advocating that there should be more emphasis on benchmarking and that poor performance should not be inadvertently rewarded.[233] A key issue highlighted during the review process is underspend that does not result of genuine efficiency gains. This can occur due to over-forecasted capex stemming from information asymmetry, and deferral of capex to later periods. The AER has implemented an adjustment mechanism to account for capex deferrals.[234]
Service target performance incentive scheme ("STPIS")	To promote reliability and safety and ensure expense reductions do not impact service quality. Reliability is measured by a combination of System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI") and Momentary Average Interruption Frequency Index ("MAIFI"). Reliability targets are typically based on the level of reliability achieved by a utility over a recent period. These targets are then updated every 5 years as part of the regulatory determination process. <u>Reward/Penalty:</u> The rewards for improving reliability (and the penalties for declines in reliability) are based on the value that customers place on improved reliability. The AER conducts a Values of Customer Reliability study to determine how different customer groups value reliability. These values are updated annually based on inflation and changes in customer preferences. <u>Regulatory outcome:</u> According to the AER, between 2006 and 2020, the average duration of outages was reduced by 26 minutes (18 percent). There has been an increase in outage duration from 2017 to 2020. The frequency of interruptions has also declined from 2006 to 2020.[235]
Demand management incentive ("DMIS")	To encourage utilities to find lower cost solutions relative to direct network investments, including non-wire solutions to manage peak electricity demand. <u>Regulatory outcome:</u> (see DMIAM outcomes)

[232] Ibid.

[233] Ibid.

[234] Australian Energy Regulator. *Capital Expenditure Incentive Guideline for Electricity Network Service Providers*. April 2023

[235] Australian Energy Regulator. *Final Decision: Review of incentive schemes for networks*. April 2023.

Performance Incentive Mechanism	Details
Demand management innovation allowance mechanism ("DMIAM")	Offers utilities support for pioneering demand management initiatives. This program focuses on funding research and development projects that show promise in reducing long-term network costs. To access DMIAM funding, utilities are required to identify eligible projects for researching, developing, or implementing demand management capability or capacity.[236] <u>Regulatory outcome:</u> Every two years, the AER reports the innovative initiatives implemented by utilities under the DMIS and DMIAM frameworks. This report details the financial incentives received by utilities and quantifies the estimated customer benefits stemming from these initiatives. Their analysis reveals that since the inception of these two mechanisms, customers have gained approximately $50 million in advantages through the strategic deferral of capex and the application of non-network solutions to mitigate peak demand.[237]
Consumer Service Incentive Scheme ("CSIS")	To promote utility engagement with customers. Utilities consult with their customers to identify opportunities for service improvement and then set targets and incentives to improve those services based on customers' preferences. <u>Reward/Penalty:</u> The utilities may be financially penalized or rewarded depending on how they perform against these customer service targets. As part of the determination process, utilities are allowed to design and propose incentive designs which are then approved or denied by the AER.[238,239] <u>Regulatory outcome:</u> The AER is responsible for assessing the annual CSIS performance and approving rewards for utilities. In 2024, the AER approved a total of $5.98 million in rewards to utilities for improving their customer service in line with the proposed metrics.[240] The AER has also suspended a customer complaint metric for one utility, indicating reporting issues as a reason for suspension.[241]
Export Service Incentive Scheme ("ESIS")	The primary aim of the ESIS is to foster engagement between utilities and their customers, aligning export services with customer needs and preferences.[242] This approach recognizes the evolving landscape of energy generation and consumption, particularly with the rise of residential solar and other small-scale renewable technologies. The adoption of ESIS remains in its early stages. While several utilities have shown interest in the concept, no formal ESIS incentive designs have been officially proposed or implemented.

236 If funding is approved by the AER, the utilities are required to submit a compliance report each year.

237 Australian Energy Regulator. *Demand Management Incentive Scheme (DMIS) payments for 2020-21 and 2021-22*. May 2023.

238 Australian Energy Regulator. *Final Decision, Endeavour Energy Electricity Distribution Determination 2024 to 2029.* April 2024.

239 For example, three Victorian utilities proposed to track metrics on communication and outages in place of an existing STPIS telephone answering parameter to address customer preferences more holistically. Another distributor in Victoria suggested four key metrics to monitor customer communication regarding outages, as well as satisfaction with connections and complaint resolution.

240 Australian Energy Regulator. *Assessment of Customer Service Incentive Scheme 2022-23.* May 13, 2024.

241 Australian Energy Regulator. *AER Decision: AusNet Services Customer Service Incentive Scheme performance parameter suspension for 2022-23 regulatory year*. May 2024

242 In Australia "export services" generally include services the utilities provide to their customers to allow them to export energy back to the grid.

3.5.4 Key Takeaways

Australia's rate-regulation framework for distribution utilities offers a perspective that could inform the evolution of Ontario's utility remuneration model. As in Ontario, electricity distributors in Australia operate under an incentive-based framework designed to mimic, at least partially, cost efficiency competitive market incentives. In both jurisdictions, distributors are governed by five-year rate plans.

The AER's incentive schemes show how PIMs can be designed to work in conjunction with one another to balance cost efficiency (via EBSS and CESS) and service quality (via STPIS), such that efforts to reduce operational and capital expenditures don't compromise reliability. Australia's rate-regulation framework also demonstrates flexibility by allowing utilities to propose tailored incentive schemes within a structured framework.

Australia has been working to proactively address energy transition goals through regulation. The Australian UR model has long provided conservation compatibility through revenue decoupling, which separates allowed revenues from output to remove disincentives for utilities to promote energy efficiency. Building on this foundation, the AER implemented additional initiatives to encourage utilities to pursue innovative means of meeting consumer demand while minimizing environmental impact through the DMIS, DMIAM, and ESIS. These mechanisms offer non-wires solutions incentives that may ultimately reduce utility investments in physical plant.

4. SUMMARY AND CONCLUSIONS

This report offers insight into the diversity of UR models currently in place in five jurisdictions across three continents. The findings include examples of regulatory bodies working to facilitate innovation within the electricity industry while maintaining financial stability among the constituent utilities. Within these regulatory models, we find mechanisms designed to improve reliability, resiliency, customer choice, and service quality through financial incentives. We also find diverse approaches to rate-regulation frameworks intended to improve utility cost efficiencies and customer affordability. Many of the regulatory tools described in this report were specifically designed to address the industry's transition to renewables and DERs, as well as the electrification of the economy.

Multi-year rate plans across jurisdictions

All five jurisdictions employed some form of multi-year rate plan ranging from three to five years in length. No two multi-year rate plan were exactly alike. In Hawaii, utilities operate under an inflation-based revenue cap that cover nearly the entire utility revenue requirement. The other four jurisdictions employ a form of forecast-based revenue cap, adjusted by different mechanisms. The UR models of all five jurisdictions focus on setting allowed revenues, rather than capping prices, as it is done in Ontario. In one of these cases (Great Britain) the UR model changed from a price cap to a revenue cap after the regulator determined an overhaul was necessary to improve incentives for innovation in energy networks.

Economic literature generally agrees that traditional cost-of-service regulation provides minimal incentives for cost efficiency, and that multi-year rate plans can be designed to improve efficiency incentives. However, not all multi-year rate plans provide equally powerful incentives. For example, longer price control periods generally impose stronger incentives. In addition, to the extent that utilities can collect revenues over time through cost trackers, cost efficiency incentives are reduced. Relative to other jurisdictions, Ontario's current price cap model (or revenue cap, under the Custom IR option) provides a typical PBR period length of five years and a relatively low proportion of cost recovery through trackers.

Performance incentive mechanisms

Four of the jurisdictions (all but California) have implemented PIMs. In some cases, these PIMs are penalty-only (see for example Hawaii's SAIDI/SAIFI PIMs). Others may be symmetrical or reward-only. In all cases, the PIMs were put in place to align the utility's incentives with policy goals without mandating action by the utility. However, in some cases, as in California and Great Britain, mandates are used instead of financial incentives, requiring certain actions while providing revenue recovery as in a traditional rate-regulation framework. In California, these mandates include demand response programs aimed at reducing system peak loads. In Great Britain, funding has been specifically provided to facilitate the transition to net zero carbon emissions and support a smarter, more flexible energy system. Our research in this report has not determined the conditions under which a PIM might be preferred over the "mandated programs plus funding" approach.

Although California does not currently utilize PIMs, certain programs in the state may be instructive. First, the creation and subsequent retirement of the Efficiency Savings and Performance Incentive Mechanism ("ESPI") program provided an example of a mechanism that served as a bridge to meet specific policy goals. In Ontario, temporary programs could be used or piloted to accomplish targeted objectives. Second, as exemplified by the Self-Generation Incentive Program ("SGIP"), incentive programs could be applied to customers rather than to utilities, if deemed more appropriate.

Combining operating and capital expenditures via totex

Although some jurisdictions (e.g., New York and Hawaii) considered adopting a UR model that would provide a rate of return to operating expenses, only one jurisdiction, Great Britain has adopted a form of totex cost recovery. Under the totex approach, a subset of operating expenditures is grouped together with capital, earning an annual rate of return in an effort to balance a perceived capital spending bias. In both New York and Hawaii, regulators cited accounting issues with transitioning to totex.

Takeaways for Ontario

This report does not make recommendations for adopting the UR models described herein or suggest that the OEB make broad changes to the existing framework for rate-regulation in Ontario. However, each jurisdiction practices some form of regulation that could be added incrementally to the province's current incentive regulation model. For example, PIMs could be designed to address specific goals. In other cases, specific policy-oriented programs with funding may be better suited. To the extent that Ontario ultimately seeks a more comprehensive change to the status quo, each of these five jurisdictions may offer lessons about balancing incentives, oversight, and regulatory complexity.

Ontario's distributors are expected to make significant capacity investments toward electrification, while accommodating DER adoption and other clean energy connections. At the same time, there is an expectation of reliability and affordability for electricity consumers. The achievement of some of these diverse policy objectives may be aided by modifying the current rate-regulation framework. While the RRF does not currently contain explicit provisions related to PIMs, the 2012 RRFE Report considered the possibility of attaching incentives or penalties to achievement of utility plan objectives or the implementation of truly innovative technologies sometime in the future.

The OEB is already undertaking several initiatives related to its rate-setting framework. There may be an opportunity to complement these regulatory changes, with incremental additions to the existing model to address specific goals, without a need for comprehensive changes to the RRF.

APPENDIX A: GLOSSARY OF ABBREVIATIONS

Abbreviated Term	Full Term	Abbreviated Term	Full Term
3GIRM	3rd Generation Incentive Regulation	DSPs	Distributed System Platforms
ACM	Advanced Capital Module	EAMs	Earnings Adjustment Mechanisms
AEMC	Australian Energy Market Commission	EBSS	Efficiency Benefit Sharing Scheme
AEMO	Australian Energy Market Operator	EE	Energy Efficiency
AER	Australian Energy Regulator	EETP	Electrification and Energy Transition Panel
BQDM	Brooklyn/Queens Demand Management	EPRM	Exceptional Project Recovery Mechanism
CAIDI	Customer average interruption duration index	ESIS	Export Service Incentive Scheme
Capex	Capital Expenditures	ESMs	Earnings Sharing Mechanisms
CESS	Capital Expenditure Sharing Scheme	ESO	Electric System Operator
CPUC	California Public Utilities Commission	ESPI	Efficiency Savings and Performance Incentive Mechanism
CSIS	Consumer Service Incentive Scheme	EV	Electric Vehicle
CSPI	Customer Service Performance Mechanism	FEI	Framework for Energy Innovation
DDOR	Distribution Deferral Opportunity Reports	FFR	Fast Frequency Response
DERs	Distributed Energy Resources	GHG	Greenhouse Gases
DIDF	Distribution Investment Deferral Framework	GRCs	General Rate Cases
DMIAM	Demand Management Innovation Allowance Mechanism	HECO	Hawaiian Electric Company
DMIS	Demand Management Incentive	HELCO	Hawaii Electric Light Company
DNOs	Distribution Network Operators	ICM	Incremental Capital Module
DNSPs	Distributed Network Service Providers	IDER	Integrated Distributed Energy Resources
DPCR5	Fifth Distribution Price Control Review	IESO	Independent Electricity System Operator
DR	Demand Response	IOUs	Investor-Owned Utilities
DRRCE	Distribution Resilience Responsiveness and Cost Efficiency	IPI	Input Price Inflation
DSIP	Distributed System Implementation Plan	IR	Incentive Regulation
DSO	Distribution System Operator	KIUC	Kauai Island Utility Cooperative

Abbreviated Term	Full Term	Abbreviated Term	Full Term
LMI	Low-to-Moderate Income	REV	Reforming the Energy Vision
MECO	Maui Electric Company	RIIO	Revenue using Incentives to deliver Innovation and Outputs
MYRPs	Multi-Year Rate Plans	ROE	Return on Equity
NBT	Net Billing Tariff	RPM	Reliability Performance Mechanism
NEO	National Electricity Objective	RPS-A	Renewable Portfolio Standards
NWS	Non-wires Solutions	RRF	Renewed Regulatory Framework
NYISO	New York Independent System Operator	RRFE	Renewed Regulatory Framework for Electricity
NYPSC	New York Public Service Commission	SAIDI	System average interruption duration index
O&M	Operating and Maintenance	SAIFI	System average interruption frequency index
ODIs	Output Delivery Incentives	SCE	Southern California Edison
OEB	Ontario Energy Board	SDG&E	San Diego Gas & Electric
Ofgem	Office of Gas and Electricity Markets	SGIP	Self-Generation Incentive Program
Opex	Operating Expenditures	SOC	Standard Offer Contract
PBR	Performance Based Regulation	STPIS	Service Target Performance Incentive Scheme
PG&E	Pacific Gas & Electric	Totex	Total Expenditures
PIM	Performance incentive mechanism	TOU	Time-of-Use
PSRs	Platform Service Revenues	UM	Uncertainty Mechanism
PUC	Public Utilities Commission	UR	Utility remuneration
PULP	Public Utility Law Project of New York	VDER	Value of Distributed Energy Resources
RAB	Regulatory Asset Base	VGI	Vehicle-to-grid
RAM	Rate Adjustment Mechanism	WACC	Weighted Average Cost of Capital