Performance-based Regulation and Legislative Recommendations for Prince Edward Island

A Research Report on Performance-Based Regulatory Frameworks

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Executive Summary

Prince Edward Island's *Electric Power Act* (Chapter E-4, consolidated December 2017) operates under a traditional cost-of-service regulatory framework administered by the Island Regulatory and Appeals Commission (IRAC). This framework, while containing some demand-side management (DSM) provisions (Section 16.1), lacks the modern regulatory tools needed to address capital expenditure bias, integrate renewable energy at scale, promote non-wires alternatives (NWAs), or tie utility earnings to performance outcomes such as reliability (SAIDI/SAIFI) (Prince Edward Island, 2017; Island Regulatory and Appeals Commission [IRAC], 2025).

A jurisdictional scan of leading regulatory frameworks worldwide reveals a clear global trend: regulators are moving toward performance-based regulation (PBR), totex approaches, and mandated NWA screening to ensure that large capital projects are rewarded on the basis of outcomes delivered to customers rather than mere size of investment (Regulatory Assistance Project [RAP], 2019; Utility Dive, 2019). This report examines eight jurisdictions and provides specific legislative recommendations for amending PEI's *Electric Power Act*.

The urgency of reform is underscored by PEI's *Net-zero Carbon Act* commitment to net-zero emissions by 2040. This is a target that demands rapid expansion of renewable energy, aggressive demand management, and a utility regulatory model aligned with clean energy outcomes rather than one that rewards capital accumulation (Natural Resources Canada, 2025; Spencer, 2025). PEI's 2025 ten-year energy strategy explicitly calls for the modernization of regulatory processes to respond to an evolving energy system (Atlantica Centre for Energy, 2026; Canadian Renewable Energy Association [CanREA], 2025).

This report identifies ten legislative amendments to PEI's Electric Power Act drawn from proven approaches in the United Kingdom, Australia, New York, Hawaii, Ontario, Nova Scotia, New Zealand, and British Columbia.

1. Introduction: PEI's Current Regulatory Landscape

1.1 Overview of PEI's Electricity System

Prince Edward Island occupies a distinctive position in Canada's energy landscape. As the country's smallest province by land area, PEI has pursued one of the most ambitious climate agendas in the world, committing to achieve net-zero greenhouse gas emissions by 2040. This is a target that would make it the first province in Canada to do so (Natural Resources Canada, 2025; Devries, 2026). In 2023, PEI's total greenhouse gas emissions were 1.59 megatonnes of CO_2 equivalent, and under the province's *Net-zero Carbon Act*, this must fall below 1.2 megatonnes by 2030 and reach net-zero by 2040 (Devries, 2026).

PEI's electricity system is characterized by several structural features that make its regulatory context both challenging and urgent. The province is a net importer of electricity, sourcing approximately 69% of its electricity supply from New Brunswick via two submarine transmission cables under the Northumberland Strait (Canada Energy Regulator [CER], 2024). Maritime Electric Company, Limited (MECL), an indirect wholly owned subsidiary of Fortis Inc., holds the exclusive franchise for electricity service across the island, with the exception of the City of Summerside, which operates its own municipal utility. PEI Energy Corporation, a provincial Crown corporation, owns approximately 73 MW of installed wind generation capacity and the submarine cables leased to Maritime Electric (Government of Prince Edward Island, n.d.; Doane Grant Thornton LLP, 2025).

Roughly 99% of electricity generated on PEI comes from wind farms, and the province has an estimated generating capacity of 441 megawatts (CER, 2024). However, despite this renewable generation profile, PEI remains highly dependent on imported power creating a dependency that exposes the province to both supply security risks and market volatility. The current Energy Purchase Agreement with NB Power, executed in March 2019 and expiring December 31, 2026, supplies approximately 54.9% of Maritime Electric's firm capacity requirements (Doane Grant Thornton LLP, 2025). PEI's 2025 energy strategy projects a 27% electricity supply deficit by 2033 as electrification accelerates (CanREA, 2025; Spencer, 2025).

1.2 The Island Regulatory and Appeals Commission (IRAC) and the Electric Power Act

The Island Regulatory and Appeals Commission (IRAC), constituted under the *Island Regulatory and Appeals Commission Act* (R.S.P.E.I. 1988, Cap. I-1.1), is the provincial regulator responsible for overseeing Maritime Electric's generation, distribution, and transmission operations under the *Electric Power Act*. Under this legislative mandate, IRAC approves electric rates, capital

expenditures, capital budget variances, transmission line changes, and energy efficiency programs (IRAC, 2025). The Commission's stated role is to ensure that ratepayers receive safe and reliable service at rates that are reasonable, publicly justifiable, and non-discriminatory (IRAC, 2025).

The *Electric Power Act* (Chapter E-4, last consolidated December 20, 2017) establishes a traditional cost-of-service (COS) regulatory model (Prince Edward Island, 2017). Under this model, the Commission determines rate base on the 'prudent original cost' of assets 'used and useful' (Section 21), authorizes a return on investment computed against the rate base (Section 24), and reviews annual capital budget submissions (Section 17). Maritime Electric is currently authorized to earn a return on equity of 9.35%, with a ceiling of 9.7% under certain conditions (CBC News, 2023; IRAC, 2023).

In practice, IRAC has increasingly moved toward multi-year rate-setting in recent rate proceedings, approving rates for two-to-three-year periods to provide stability for customers—a partial step toward multi-year rate plans (IRAC, 2025). However, these multi-year rate orders remain within the traditional cost-of-service framework and do not incorporate the performance incentives, totex neutrality, or NWA screening requirements that characterize modern performance-based regulatory (PBR) systems.

1.3 Structural Tensions in the Current Framework

PEI's current regulatory framework creates several structural tensions that undermine the province's clean energy and affordability objectives. First, the cost-of-service model creates a well-documented capital expenditure bias: because every dollar of approved capital expenditure earns a regulated return while operating expenditure is simply passed through, Maritime Electric has a financial incentive to prefer capital-intensive infrastructure solutions over potentially cheaper operational solutions, DSM programs, or third-party non-wires alternatives (Regulatory Assistance Project, 2022; AEMC, 2017). This dynamic is illustrated most acutely in Maritime Electric's current application before IRAC (Docket UE20742) for a $334 million capital program to build on-island combustion turbines for security of supply—a project that has drawn significant public opposition from advocates calling for a comprehensive alternatives analysis, including renewables-first and community/cooperative models (Action Network, 2024; Energy Democracy Now, 2025).

Second, the existing reliability regulation framework (Section 39) imposes a maximum penalty of $5,000 per avoidable interruption exceeding 15 minutes, an amount so modest as to provide minimal financial deterrent (Prince Edward Island, 2017). The severe impact of post-tropical storm Fiona in September 2022 which knocked out power to nearly all 83,000 Maritime Electric customers, with restoration times averaging one week and extending up to three weeks in some

areas exposed the inadequacy of the province's reliability incentive structure (Campbell, 2024; CBC News, 2023). A consultant retained by IRAC found that insufficient vegetation management prior to Fiona significantly extended restoration times, illustrating how the absence of financial incentives tied to reliability outcomes can lead to systematic under-investment in resilience (CBC News, 2025).

Third, the Act contains no requirement for Maritime Electric or IRAC to screen capital budget applications against non-wires alternatives. This is a glaring gap. International best practices have demonstrated screening mandates can be worth hundreds of millions of dollars in deferred or avoided infrastructure costs (New York State DPS, 2025; IESO, 2023). Fourth, the Act does not decouple utility revenue from electricity sales volume, creating a financial incentive for Maritime Electric to promote electricity consumption rather than efficiency. This is in direct conflict with DSM objectives and the Net Zero 2040 target (Hawaii PUC, 2024; RAP, 2019).

1.4 The Case for Reform

PEI's October 2025 ten-year energy strategy explicitly acknowledges the need to modernize regulatory processes (Atlantica Centre for Energy, 2026; Spencer, 2025). The strategy calls for 'strengthened consumer protections, upgrades to infrastructure and regional collaboration' while projecting a 27% electricity supply deficit by 2033 and noting that electricity demand growth on PEI 'outstrips generation capacity' (CanREA, 2025). It also recommends the creation of an energy consumer advocate to represent Islanders' interests in regulatory proceedings. This implicitly acknowledges the inadequacy of the current framework to balance utility and ratepayer interests (Spencer, 2025).

Doane Grant Thornton LLP's 2025 independent review of PEI's energy system found that the province lacks an Independent System Operator (ISO), that PEI Energy's submarine cables are a critical infrastructure asset requiring enhanced regulatory treatment, and that the existing regulatory structure needs reform to address the province's evolving energy needs (Doane Grant Thornton LLP, 2025). The review noted that PEI tied for second place with Quebec in Efficiency Canada's 2025 national energy efficiency report card—a signal that the province's demand-side programs have been effective, but that this progress is being achieved despite the regulatory framework rather than because of it (Atlantica Centre for Energy, 2026).

Against this backdrop, this report presents a jurisdictional scan of eight leading regulatory frameworks and ten legislative recommendations for modernizing PEI's Electric Power Act. The recommendations draw on proven approaches while accounting for PEI's unique circumstances: a small island jurisdiction, a single dominant utility, ambitious climate targets, and critical dependence on interprovincial energy imports.

Section 2: Jurisdictional Scan — International Regulatory Precedents

This section provides a rigorous, technically detailed analysis of eight international regulatory jurisdictions whose performance-based frameworks offer structural precedents for the reform of Prince Edward Island's Electric Power Act. For each jurisdiction, the analysis addresses: (A) the seminal architectural features of the framework; (B) the precise mechanics and operationalization of each feature, including governing formulas, numerical parameters, and data inputs; (C) documented guardrails and known failure modes with regulatory corrections; and (D) the specific significance of each feature to PEI's regulatory context, mapped to provisions of the Electric Power Act and grounded in PEI-specific financial and operational data.

2.1 United Kingdom — RIIO Framework (Ofgem)

A. Seminal Features

The United Kingdom's Revenue = Incentives + Innovation + Outputs (RIIO) framework, administered by the Office of Gas and Electricity Markets (Ofgem), constitutes the most architecturally comprehensive performance-based regulatory system deployed at scale to date. Introduced in 2010 and now entering its third iteration (RIIO-3, commencing April 2026 for transmission and gas distribution, with electricity distribution following under RIIO-ED3 from April 2028), RIIO replaced the RPI-X price cap regime that had governed British network utilities since 1990 (Ofgem, 2010). Four seminal features distinguish RIIO from cost-of-service antecedents.

The first is the Totex Sharing Mechanism (TIM), which eliminates the categorical distinction between capital expenditure (capex) and operating expenditure (opex) by consolidating them into a single "Totex" envelope. Prior to RIIO, regulated utilities could add capex directly to their Regulatory Asset Value (RAV), earning an authorized return on every pound capitalised, while opex was simply passed through to customers with no comparable return benefit. This capex bias was identified by Ofgem as a fundamental misalignment between utility incentives and consumer welfare (Ofgem, 2010).

The second is the Output Delivery Incentive (ODI) framework, a portfolio of performance incentives tied to six output categories: reliability and availability, customer service, connections, safety, social obligations, and environmental performance. ODIs solve the problem that multi-year price caps create a tension between cost control and service quality: without explicit quality incentives, a utility maximizing under-spend against its allowance would naturally allow service levels to deteriorate (Ofgem, 2022a).

The third feature is the Business Plan Incentive (BPI), which replaces the earlier Information Quality Incentive (IQI) under RIIO-2 and beyond. The BPI is designed to solve the problem of information asymmetry: utilities have private knowledge of their efficient cost level, and without a mechanism to reward honest disclosure, rational utilities will submit inflated business plans to secure generous allowances (Oxera, 2021).

The fourth is the Network Innovation Allowance (NIA) and Strategic Innovation Fund (SIF), collectively constituting a ring-fenced mechanism to fund demonstration projects that the normal regulatory settlement would not incentivize because the returns are uncertain or accrue to the system rather than the individual network (Ofgem, 2022b).

B. Mechanics and Operationalization

Under the Totex Incentive Mechanism, Ofgem sets an ex ante Totex allowance for the five-year control period (RIIO-ED2 covers April 2023 to March 2028) based on benchmarked efficient costs assessed through a combination of top-down econometric models. The efficient benchmark set at the 85th percentile under RIIO-ED2, tightened from the 75th percentile under RIIO-ED1 (Oxera, 2022a) and bottom-up review. The allowed Totex for all Distribution Network Operators (DNOs) under RIIO-ED2 was set at £22.2 billion in 2020/21 prices against submitted costs of £25.2 billion, representing an 11.8% reduction (Oxera, 2022b). An ongoing efficiency target of 1.2% per annum is applied as a post-modelling adjustment, rising to 1% per annum under RIIO-3 (Ashurst, 2025).

The Totex sharing mechanism then distributes actual over- or under-spend against the allowance according to a pre-set sharing factor. The key numerical parameters for the RIIO-ED2 TIM are:

- Sharing factor: Approximately 45–55% retained by the company on under-spend; the remainder returned to customers through lower future revenues (Ofgem, 2022a).
- Fast money / slow money split: A predetermined fraction of Totex is expensed immediately (fast money) and the remainder is capitalized into the RAV (slow money), regardless of whether the underlying spend is capex or opex. This preserves the directional neutrality of the Totex approach.
- Ongoing efficiency: 1.2% per annum under RIIO-ED2; 1.0% per annum under RIIO-3 (Ashurst, 2025).
- Regulatory period: Five years under RIIO-ED2 (2023–2028); five years under RIIO-3 (2026–2031 for T&GD).

The ODI framework assigns performance targets to each output category and translates deviations into financial rewards or penalties expressed in basis points of Return on Regulated

Equity (RoRE). Under RIIO-ED1, the reliability incentive (calibrated using customer-willingness-to-pay surveys for SAIDI and SAIFI improvements) was capped at ±250 basis points of RoRE per year, equating to approximately 1–2% of allowed revenues (Economic Consulting Associates, 2023). Under RIIO-ED2, Ofgem introduced Price Control Deliverables (PCDs). These are specific, funded deliverables with refund mechanisms if not delivered. The PCD also retained the broader ODI financial incentives.

The BPI rewards DNOs that submit high-quality, cost-transparent business plans. Where Ofgem has high confidence in its own independent cost assessment, it assigns a higher company sharing factor, allowing the company to retain more of any efficiency gains; where confidence is lower, the sharing factor is lower (Oxera, 2021). The NIA provides a ring-fenced allowance of approximately 0.5–1% of allowed revenue — totalling approximately £68 million across all DNOs under RIIO-ED2 (Economic Consulting Associates, 2023) — for innovation projects that must meet Ofgem's governance criteria, share learning, and demonstrate potential consumer benefit.

C. Guardrails and Known Failure Modes

RIIO incorporates several explicit guardrails. Uncertainty mechanisms and re-openers allow mid-period adjustments for costs that are genuinely unforeseeable (cyber-security obligations or new government policies) without reopening the entire settlement. This preserves the incentive properties of the price control while protecting both the utility and consumers from extreme variance (Ofgem, 2022a). The annual Time Value of Money (TVOM) adjustment, applied using the WACC, ensures that inter-temporal revenue shifts are neutral to both parties.

The most significant documented failure mode in RIIO is the excess profit problem identified during RIIO-1. The UK National Audit Office (NAO) reported that network companies collectively outperformed Totex allowances by substantially more than Ofgem had intended, earning returns well above the authorized level, owing primarily to allowances that had been set too generously at the outset of the period and to an IQI mechanism that proved insufficiently effective at eliciting accurate cost forecasts (Ofgem, 2010). In response, Ofgem tightened the efficient benchmark from the 75th to the 85th percentile under RIIO-ED2, replaced the IQI with the BPI, and increased the ongoing efficiency challenge from approximately 0% per annum under some RIIO-1 controls to 1.2% per annum under RIIO-ED2 (Oxera, 2022a). A second documented distortion which is specific to Australia's equivalent scheme rather than RIIO itself involves asymmetric incentive weight between SAIDI and SAIFI, discussed in Section 2.2.

D. Significance to PEI

The RIIO Totex Sharing Mechanism maps directly onto the most structurally consequential gap in PEI's Electric Power Act: Section 21, which establishes Maritime Electric's rate base as the primary vehicle through which the company earns its authorized return. Under the current framework, any expenditure capitalized to rate base earns the authorized return of 9.35% (baseline) to 9.70% (ceiling) on the full capital value over the asset's life, while opex or third-party contracted solutions generate no comparable return for shareholders (Island Regulatory and Appeals Commission [IRAC], 2022). This asymmetry directly explains the logic of the $334 million application in IRAC Docket UE20742 for on-island combustion turbines: as a large capital project, it would expand Maritime Electric's rate base, whereas demand-side management, energy storage contracts, or non-wires alternatives that could address the same supply risk would not (IRAC, 2023).

A Totex framework, adapted for PEI's single-utility context by amending Section 21 of the Electric Power Act to authorize IRAC to set a combined Totex allowance rather than separate capex and opex envelopes, would remove this asymmetry. Under a 50% sharing factor. Which is conservative by RIIO standards, Maritime Electric would retain half of any efficiency gain from selecting a $50 million demand-side or storage solution over a $334 million capital alternative, providing a direct financial incentive that the current rate-base structure systematically suppresses.

RIIO is highly transferable to PEI in structural logic but requires scaling to a small, single-utility jurisdiction. The benchmarking exercise that underpins the efficient Totex allowance under RIIO relies on comparison across multiple DNOs; with only one distribution company in PEI, IRAC would need to rely on comparator benchmarking against other small Canadian utilities (Nova Scotia Power, NB Power distribution) or on detailed bottom-up engineering review. The five-year price control period is directly applicable and would reduce the frequency of contested rate hearings, which impose significant regulatory cost on a small jurisdiction.

2.2 Australia — AER Service Target Performance Incentive Scheme (STPIS)

A. Seminal Features

The Australian Energy Regulator's (AER) Service Target Performance Incentive Scheme (STPIS) is the most precisely calibrated reliability incentive mechanism in the comparative literature, distinguished by its direct use of consumer willingness-to-pay data, which is expressed through the Value of Customer Reliability (VCR) to set incentive rates that are economically grounded rather than arbitrarily capped (AER, 2018). The STPIS applies to electricity distribution network service providers (DNSPs) across the National Electricity Market (NEM) and constitutes an add-

on to the revenue determination framework governed by the National Electricity Rules. Three seminal features define the STPIS.

The first is the s-factor mechanism, a symmetric reward-and-penalty structure tied to actual SAIDI and SAIFI performance relative to distributor-specific historical targets. The s-factor directly solves the problem that incentive rate-setting under pure price-cap regulation creates no financial stake in maintaining or improving reliability: a utility facing only a price cap and no quality incentive will rationally trade off service quality against cost, particularly under spending pressure (AER, 2018).

The second is the VCR-based incentive rate. Rather than setting the financial reward-per-unit-of-reliability-improvement by regulatory judgment, the STPIS derives the incentive rate from periodic AER surveys of consumer willingness to pay for improvements in supply reliability expressed in dollars per megawatt-hour of unserved energy (AER, 2019). This provides an explicit economic foundation for the magnitude of incentives.

The third is the ±5% revenue-at-risk cap, which limits the total financial exposure of the STPIS to a defined fraction of the distributor's annual forecast revenue. This cap solves the problem of excessive rate volatility that could result if raw VCR-based incentives were allowed to produce unbounded penalties in years of poor reliability performance which is a particular risk for distributors exposed to severe weather events (AER, 2023a).

B. Mechanics and Operationalization

The STPIS s-factor mechanism works as follows. At the beginning of each five-year regulatory control period, the AER sets distributor-specific reliability targets for both SAIDI (System Average Interruption Duration Index, measured in minutes per customer per year) and SAIFI (System Average Interruption Frequency Index, measured in interruptions per customer per year), calculated as the average of the distributor's normalized performance over the preceding five regulatory years (AER, 2018). Each year of the regulatory period, actual normalized SAIDI and SAIFI are compared to these targets. The financial incentive is calculated as:

Revenue Adjustment = Incentive Rate × (Target – Actual Performance) × Customer Numbers

Where the incentive rate is derived from the VCR. Key parameters under STPIS Version 2.0 (applicable from 2018 onwards) include:

- Revenue at risk: Default cap of ±5% of annual forecast revenue across all STPIS components (AER, 2023a). For distributors with strong reliability performance, the AER has approved caps of ±4.5% (Endeavour Energy, 2024-29 period) to reflect lower marginal incentive value where reliability is already high (AER, 2023b).

- SAIDI/SAIFI incentive weight: Under STPIS Version 2.0, weights were revised from equal weighting (50:50) to 40:60 (SAIFI:SAIDI) across all NEM jurisdictions, effective from 2020 to 2022 depending on regulatory period (AER, 2023c).
- VCR basis: The 2019 VCR values (escalated annually to current CPI) are applied to calculate incentive rates by network segment (residential, commercial, industrial). The AER published updated 2024 VCR values under a revised methodology (AER, 2024).
- Customer service component: ±0.5% of Maximum Allowable Revenue for the telephone answering parameter; distributors may replace this with a Customer Service Incentive Scheme (CSIS) where approved (AER, 2023b).
- Major Event Day (MED) exclusion: Events exceeding a threshold derived from the 2.5-beta method (or AER-approved Box-Cox transform) are excluded from the SAIDI/SAIFI calculation, isolating the incentive to controllable performance (AER, 2018).

The AER calculates each distributor's STPIS financial outcome annually, using data from the distributor's Category Analysis Regulatory Information Notice (RIN). Where a distributor outperforms its SAIDI target, the positive s-factor is converted to a revenue addition in the following year; underperformance results in a revenue reduction. The annual adjustment is subject to the ±5% cap, with any excess carried forward or absorbed depending on the cumulative position within the regulatory period.

C. Guardrails and Known Failure Modes

The STPIS's most significant documented failure mode, and the most instructive for PEI — occurred prior to the 2018 amendment. Under STPIS Version 1.0, the incentive weights for SAIDI and SAIFI were equal (50:50). Because SAIFI (frequency of interruptions) is more directly controllable by distributors through investment in automated switching and sectionalizing equipment than SAIDI (duration), distributors were observed to optimise heavily on reducing interruption frequency while allowing average restoration times to remain elevated or even increase (AER, 2023c). The AER identified that this produced a perverse outcome: customers experienced fewer outages but when outages occurred, they lasted longer. In response, STPIS Version 2.0 reduced the weight on SAIFI to 40% and increased SAIDI to 60%, and raised the MED threshold definition from outages exceeding one minute to outages exceeding three minutes, aligning the measure with what consumers actually experience as a meaningful supply interruption (AER, 2018).

The MED exclusion mechanism itself creates a secondary guardrail risk: distributors could theoretically manipulate the classification of outage-cause to qualify more events as major events (and thus excluded from the incentive calculation). The AER addresses this through prescriptive MED classification rules and annual RIN auditing requirements.

D. Significance to PEI

PEI's Electric Power Act, in its current form, establishes in Section 39 a regulatory penalty mechanism of up to $5,000 per interruption for reliability violations. This is a cap that has remained nominally fixed and which bears no relationship to the economic cost of unserved energy to Maritime Electric's approximately 83,000 to 86,000 customers (IRAC, 2022). The consequence is that Maritime Electric's financial stake in reliability performance above the $5,000 penalty threshold is effectively zero. Post-tropical storm Fiona (September 2022) left essentially all PEI customers without power for an average restoration period of approximately one week, representing an enormous economic cost to the island economy that the existing penalty regime did not and could not capture (Government of Prince Edward Island, 2022).

An STPIS-equivalent mechanism for PEI would replace the flat-rate Section 39 penalty structure with a revenue-at-risk mechanism anchored to a PEI-specific VCR survey. Applying the STPIS framework at even a conservative ±2% revenue-at-risk level which is below the Australian default of ±5% against Maritime Electric's annual revenues would create a financial stake in the order of millions of dollars per year, dwarfing the current $5,000 cap and creating meaningful incentives for investment in resilience, automated switching, and storm hardening.

The SAIDI/SAIFI weighting lesson from Australia is directly applicable: PEI should design any reliability incentive with a deliberate weighting toward SAIDI (duration) rather than SAIFI (frequency), given that PEI's most severe reliability problem as evidenced by Fiona is the duration of restoration after major events rather than the frequency of minor interruptions.

2.3 New York — Reforming the Energy Vision (REV)

A. Seminal Features

New York's Reforming the Energy Vision (REV), initiated by the New York Public Service Commission (NYPSC) in April 2014 and operationalized through a series of orders culminating in the May 2016 Track Two Order and subsequent Value of Distributed Energy Resources (VDER) proceedings, represents the most ambitious attempt by a North American jurisdiction to reconstitute the utility business model around distributed resource integration rather than centralized infrastructure investment (NYPSC, 2016). REV does not constitute a single mechanism but rather an interlocking set of four seminal features.

The first is the Distribution System Platform (DSP) model, which reconceives the regulated distribution utility as a market operator. The model facilitates transactions between distributed energy resource (DER) providers and consumers. The DSP model solves the structural problem that traditional utilities have financial incentives to resist or delay DER interconnection because

DERs reduce throughput, reduce rate base growth opportunities, and add operational complexity without compensating revenue (NYPSC, 2016; Wikipedia, 2024).

The second is the Earnings Adjustment Mechanism (EAM), New York's version of performance-based incentives. EAMs provide utilities with financial rewards for achieving specific policy outcomes for energy efficiency, DER interconnection and customer engagement, that the traditional cost-of-service model would not compensate and might actively disincentivize (RMI, 2016).

The third is the Value of Distributed Energy Resources (VDER) mechanism, also termed the Value Stack, which provides a granular, location- and time-specific compensation structure for DER output that goes beyond simple net energy metering (NEM) by reflecting the actual grid services provided by each DER resource (NYSERDA, 2021).

The fourth is Revenue Decoupling, which severs the link between a utility's financial performance and its throughput of electricity, eliminating the "throughput incentive" that makes utilities structurally opposed to energy efficiency investment (Utility Dive, 2015).

B. Mechanics and Operationalization

The DSP model is operationalized through Distributed System Implementation Plans (DSIPs), which each New York utility is required to file, outlining how it will develop the distribution grid as a platform for DER market participation. DSIPs must include hosting capacity maps — data showing where the distribution grid can absorb DER connections without costly upgrades — and market-enabling strategies. Platform Service Revenues (PSRs) allow utilities to earn revenue from facilitating DER transactions, including by monetizing Non-Wires Alternatives (NWAs) to defer or avoid traditional capital investment (NYPSC, 2016).

EAMs are metric-based financial adjustments that are applied to the utility's revenue requirement. The NYPSC established initial EAMs in 2016 covering system efficiency, energy efficiency, data access, and DER interconnection. EAM rewards are not funded by rate base additions but by verified improvements in policy outcomes, creating a direct substitute for the capex earnings stream. The interconnection EAM, for example, rewards utilities for meeting timeliness standards set by the Standard Interconnection Requirement (SIR) and for achieving high developer satisfaction scores (Utility Dive, 2017).

The VDER Value Stack compensates DER generators through bill credits calculated using multiple components:

- Energy value (E): Based on NYISO day-ahead locational marginal prices at the time of injection.

- Capacity value (ICAP): Based on the NYISO spot capacity auction price, not the monthly auction, rewarding DERs that provide capacity during peak periods.
- Demand Reduction Value (DRV): Based on system injections between 2:00 PM and 7:00 PM on non-holiday weekdays from June 1 to August 31 — the peak demand window.
- Environmental value: Reflecting the social cost of avoided carbon.
- Community Credit (CC): Increased from $0.02/kWh to $0.05/kWh for qualifying community distributed generation projects (NYSERDA, 2021).

Revenue decoupling under REV employs a Revenue Balancing Account (RBA) mechanism: actual revenues are reconciled against allowed revenues annually, with any shortfall or surplus returned to or collected from customers in subsequent rate years, ensuring that the utility's net revenue is independent of whether customers consume more or less electricity (Utility Dive, 2015).

The Brooklyn-Queens Demand Management Program (BQDM) represents the most cited concrete example of REV mechanics in operation. Consolidated Edison identified a projected need for approximately $1 billion in substation investment to serve load growth in Brooklyn and Queens. Rather than capitalize this investment to rate base, ConEd deployed a combination of solar, batteries, demand response, and energy efficiency solutions, which earned revenue through the NWA compensation mechanism while avoiding the capital expenditure (Wikipedia, 2024).

C. Guardrails and Known Failure Modes

REV's most significant documented limitation is implementation completeness. As of 2021, analysts described two critical unfinished elements: the earnings incentive structure for DSP market operation, and the utility business model transformation more broadly (Utility Dive, 2021). The VDER mechanism, while theoretically comprehensive, proved complex for DER developers to navigate, with uncertainty about compensation rates discouraging investment in some project categories (Energy Toolbase, 2024). The 2019 Climate Leadership and Community Protection Act (CLCPA), which established far more ambitious renewable energy targets than the original REV framework anticipated, partially superseded REV's graduated DER market development approach with direct procurement mandates.

The DSP concept raised contested governance questions. One was whether utilities or independent third parties should operate the distribution platform, that were not fully resolved, with the NYPSC ultimately determining that only utilities could perform system planning and market administration functions (Utility Dive, 2021). This creates a conflict-of-interest risk where the regulated entity acts simultaneously as infrastructure owner, market operator, and DER competitor.

D. Significance to PEI

REV's most directly transferable feature for PEI is the Non-Wires Alternative compensation mechanism, which maps onto PEI's structural gap in Section 24 of the Electric Power Act. Section 24 governs the process by which IRAC approves capital projects but contains no explicit requirement to screen capital alternatives against lower-cost non-capital solutions before approval. The contested $334 million RICE engine application in Docket UE20742 illustrates this gap precisely: IRAC must evaluate whether the capital project is prudent and whether the costs are reasonable, but has no legislative mandate requiring Maritime Electric to demonstrate that DSM, storage, or demand response alternatives were formally evaluated and found inadequate before proceeding with a capital application (IRAC, 2023).

Revenue decoupling is the single highest-value short-term reform PEI could implement. Maritime Electric's current revenue structure, governed by Section 17 of the Electric Power Act, ties the company's ability to recover its revenue requirement to electricity throughput. Because Maritime Electric earns its target ROE only when it sells enough electricity to recover its revenue requirement, any investment in energy efficiency or conservation by Maritime Electric's own DSM programs directly reduces its cost recovery. A Revenue Balancing Account, requiring no more than a targeted amendment to Section 17, would eliminate this perverse incentive at minimal regulatory cost.

The DSP model, while ambitious for a small jurisdiction like PEI, is not without transferable elements. Maritime Electric's hosting capacity mapping (knowing where the distribution grid can absorb rooftop solar and EV charging without costly upgrade) is a function the company should be incentivized to perform and publish regardless of whether PEI develops a full DER market. An amendment to Section 24 or a new Section 24.1 could require biennial hosting capacity disclosure as a condition of rate approval.

2.4 Hawaii — Performance-Based Regulation (PBR) Framework

A. Seminal Features

Hawaii's Performance-Based Regulation (PBR) framework, implemented through the Hawaii Public Utilities Commission's (HPUC) Decision and Order in Docket No. 2018-0088 (effective January 1, 2021), constitutes the most integrated PBR framework adopted by a North American small-island utility system to date (Hawaii Public Utilities Commission [HPUC], 2020). Hawaiian Electric Companies (HECO) share important structural characteristics with Maritime Electric in that they are the sole electric utilities on their respective islands, are subsidiaries of a publicly traded holding company, and face a long-term requirement to transition from imported fossil

fuel dependence to high penetration renewable energy. The PBR framework is organized around four seminal features.

The first is the Multi-Year Rate Plan (MRP) governed by the Annual Revenue Adjustment (ARA) formula, which determines allowed revenues for each year of a five-year control period without a rate case. The MRP solves the problem of regulatory lag — the gap between when costs are incurred and when they are recovered through rates while simultaneously reducing the transaction cost of annual rate filings (HPUC, 2020).

The second is the Earnings Sharing Mechanism (ESM), a symmetric mechanism that shares deviations of actual Return on Equity (ROE) from the authorized target with customers above and below a defined deadband. The ESM solves the problem that a multi-year rate plan creates: if the utility outperforms its revenue forecast due to factors within management control, shareholders would receive windfall profits without the ESM's redistributive function (SEC, 2021).

The third is the Performance Incentive Mechanism (PIM) portfolio, which creates explicit financial rewards and penalties tied to specific policy outcomes such as renewable energy achievement, customer engagement, DER integration, and interconnection experience. PIMs solve the problem that the ARA formula alone creates incentives for cost control but not for policy-aligned investment (HPUC, 2020).

The fourth is the Revenue Balancing Account (RBA), which decouples HECO's revenue from electricity sales volume, eliminating the throughput incentive that would otherwise make HECO financially opposed to its own customers' energy efficiency investments (Ulupono Initiative, 2021).

B. Mechanics and Operationalization

The ARA formula governs annual revenue adjustments throughout the MRP period. Its structure is:

ARA = I − X + Z − Customer Dividend

Where the components are defined as follows:

- I Factor (Inflation): The GDP Price Index, updated annually. This indexes allowed revenues to economy-wide inflation, ensuring that HECO's purchasing power for labour and materials is maintained without requiring a full rate case (HPUC, 2020).
- X Factor (Productivity): An annual productivity offset initially set at 0% under MRP-1, reflecting the HPUC's determination that insufficient benchmarking data existed to set a non-zero productivity challenge for HECO at the time of implementation (SEC, 2021).

- Z Factor (Exogenous Events): A post-implementation adjustment for events outside HECO's control (e.g., natural disasters, legislative changes to tax law). Z-Factor adjustments require HPUC approval and are intended to be genuinely exogenous rather than a mechanism for cost recovery of management decisions (HPUC, 2020).
- Customer Dividend: A fixed annual downward adjustment of 0.22%, compounded annually, plus a flow-through of pre-PBR savings from management audit recommendations. The Customer Dividend ensures that customers receive a share of the efficiency benefits that the MRP is designed to generate (SEC, 2021).

The ESM parameters are:

- Target ROE: 9.5%, the authorized ROE for HECO as of MRP-1 implementation (SEC, 2021).
- Deadband: ±300 basis points around the target ROE. Actual ROE between 6.5% and 12.5% produces no ESM adjustment (SEC, 2021).
- Sharing above the deadband: Earnings above 12.5% ROE are shared 50:50 between shareholders and customers, flowing to customers through a bill credit mechanism.
- Sharing below the deadband: Losses below 6.5% ROE are similarly shared, protecting HECO from extreme adverse outcomes.
- Re-opener triggers: Credit rating downgrade below investment grade, or actual ROE below 5% or above 14%, triggers a mandatory HPUC review of the PBR framework (SEC, 2021).

PIMs under MRP-1 cover five areas: customer engagement and DER asset effectiveness (reward only, no penalty); accelerated renewable portfolio standard achievement (reward only, with statutory penalties applying separately); interconnection experience (symmetric rewards and penalties); energy efficiency for low-to-moderate income customers; and data accessibility. PIMs are calibrated to be material but not so large as to create excessive volatility in HECO's earnings.

C. Guardrails and Known Failure Modes

The Hawaii PBR framework's most significant guardrail is the ESM deadband, which provides a 600-basis-point corridor within which HECO bears full risk without customer redistribution, creating strong incentives for efficient operation while protecting consumers from the consequences of cost shocks that may be outside management control. The re-opener mechanism provides a further safety valve.

The framework's principal documented limitation is the X-Factor being set at zero under MRP-1. Setting X = 0 means that the ARA formula provides no productivity challenge: HECO's allowed revenues increase with inflation without any requirement to become more efficient over time.

This was acknowledged by the HPUC as a transitional compromise pending the development of better benchmarking data (Ulupono Initiative, 2021). For PEI, where IRAC would face the same benchmarking challenge for a single utility, this provides an important precedent: a zero X-factor in the initial MRP period is not a design failure but a deliberate regulatory choice that can be revisited in subsequent plan periods as data accumulates.

D. Significance to PEI

The Hawaii PBR framework is arguably the single most transferable international precedent for PEI, for reasons that go beyond the formal structure of its mechanisms. Hawaiian Electric and Maritime Electric are structurally near-identical: both are monopoly island utilities, both are subsidiaries of publicly traded holding companies (HECO under HEI; Maritime Electric under Fortis Inc.), both depend heavily on imported energy purchased under long-term supply agreements (PEI's NB Power Energy Purchase Agreement, which expires December 31, 2026), and both face a statutory net-zero target with a 2040–2050 horizon (Government of Prince Edward Island, 2022; SEC, 2021).

The ARA formula directly addresses PEI's Section 17 gap. Maritime Electric's current revenue requirement is set through periodic cost-of-service rate cases before IRAC, a process that is resource-intensive for a small regulator and that creates a structural lag between cost changes and rate adjustments. An ARA formula keyed to CPI and a PEI-specific productivity factor, combined with a Z-factor for genuinely exogenous events (such as the post-expiry NB Power replacement costs), would enable multi-year rate predictability while retaining IRAC's ability to intervene through the re-opener mechanism.

The ESM is directly applicable to the PEI context. Maritime Electric's current authorized ROE is 9.35% (baseline), with a ceiling of 9.70% and a floor of 9.00% (IRAC, 2022). An ESM with a ±300 basis-point deadband around the 9.35% target, producing a corridor of 6.35% to 12.35%. This would be well-suited to PEI's risk profile. Above 12.35%, shareholders and customers would share excess returns; below 6.35%, customers would share in recovery costs. This symmetric structure is less volatile than the current framework, under which Maritime Electric can earn up to 9.70% without any customer-sharing obligation.

2.5 Ontario — Ontario Energy Board (OEB) Incentive Rate-Setting

A. Seminal Features

The Ontario Energy Board (OEB) administers Canada's most mature incentive regulation framework for electricity distribution, having operated performance-based rate-setting since the late 1990s and implementing a comprehensive Renewed Regulatory Framework for Electricity (RRFE) in 2012, with ongoing updates through the 2013 benchmarking methodology

and subsequent rate-setting parameters (OEB, 2013). Ontario's framework governs over 60 licensed electricity distributors, including Hydro One Networks — the province's dominant transmitter and distributor — and provides the most direct domestic Canadian precedent for PEI given its regulatory heritage under common law, federal-provincial energy jurisdiction structures, and comparable utility scale at the individual distributor level. Three seminal features define the OEB incentive regulation framework.

The first is the Price Cap Incentive Rate-Setting (Price Cap IR) mechanism, a multi-year index-based approach under which annual rate adjustments are determined by a formula combining an inflation factor (I) and a productivity offset factor (X), applied mechanically between periodic cost-of-service rebasing exercises (OEB, 2013). The Price Cap IR solves the problem of regulatory drag and frequent rate cases while providing a continuous efficiency incentive.

The second is the differentiated Stretch Factor, which assigns each distributor to one of five efficiency tiers based on its cost ranking relative to sector benchmarks, with higher-cost distributors assigned a higher X-factor component (the stretch factor ranges from 0.0% to 0.6%) (OEB, 2013). The stretch factor solves the problem that a uniform X-factor would apply the same efficiency challenge to already-efficient utilities and to high-cost, inefficient utilities, providing no additional incentive for the latter to close the performance gap.

The third is the Custom Incentive Rate-Setting (Custom IR) mechanism, designed for large, capital-intensive utilities — most notably Hydro One — where the standard Price Cap IR formula does not adequately capture the capital cycle of a major transmission or distribution system. Custom IR includes a Capital Factor (C-Factor) that allows capital expenditures above the index-based formula to be included in the revenue requirement, subject to OEB scrutiny and a capital-specific stretch factor (Aird Berlis, 2020).

B. Mechanics and Operationalization

The Price Cap IR formula determines the annual rate adjustment as:

Rate Change = I − X

Where:

- I (Inflation Factor): The Industry Price Index (IPI), a composite of labour and materials cost indices. For the 2025 rate year, the OEB set the inflation factor at 3.60% (EPCOR, 2025).
- X (Productivity-Offset Factor): The sum of a sector-wide productivity factor (set at 0.00% for the 2025 rate year, consistent with the OEB's determination that the appropriate industry total factor productivity value is zero) and a distributor-specific stretch factor

ranging from 0.00% (most efficient quintile) to 0.60% (least efficient quintile) (OEB, 2013; EPCOR, 2025).

- Net formula: A distributor in the median efficiency tier with a stretch factor of 0.15% and the 2025 inflation factor would receive a rate increase of 3.45% = 3.60% − (0.00% + 0.15%) (EPCOR, 2025).
- Rebasing frequency: Distributors operating under Price Cap IR rebase their cost-of-service every five years (or on IRAC request), at which point their base revenue requirement is reset and a new IR term begins (OEB, 2016).

Under the Custom IR methodology approved for Hydro One Networks, the revenue cap index (RCI) formula is:

RCI = Inflation Factor + Capital Factor − Productivity Factor

For Hydro One's 2024 transmission revenue requirement, this resulted in a total RCI of 4.56%, reflecting a higher capital factor driven by the company's major transmission investment program (OEB, 2024). The OEB added an incremental capital stretch factor of 0.15% to the Custom IR for both Hydro One transmission and distribution, intended to incentivize productivity gains on the capital plan (Aird Berlis, 2020).

The OEB benchmarks distributor costs using econometric modelling updated periodically by Pacific Economics Group LLC. Distributors are ranked by their normalized cost per customer, with the resulting efficiency scores determining stretch factor tier assignment. The 2024 benchmarking update informed the 2025 stretch factor assignments (EPCOR, 2025).

The OEB also administers a Lost Revenue Adjustment Mechanism (LRAM) that compensates distributors for revenues lost due to conservation and demand management programs, partially decoupling revenues from throughput within the Price Cap IR structure (OEB, 2024a).

C. Guardrails and Known Failure Modes

The OEB framework includes guardrails through the combination of the stretch factor's efficiency-tier assignment, the rebasing mechanism, and the OEB's Innovation Sandbox (launched in 2019), which allows pilot projects outside the standard regulatory framework on a monitored basis. The stretch factor itself is a guardrail against the risk of regulatory capture: distributors cannot remain in the most-efficient quintile indefinitely, as rebasing periodically resets the cost benchmark.

The most significant documented limitation of the OEB incentive regulation framework is a partial failure of capex-bias mitigation. The Price Cap IR formula provides an efficiency incentive on operating costs through the I − X structure but does not neutralize the incentive to add

capital to rate base. Between rebasings, a distributor can earn its authorized ROE on capital additions made through system upgrades without those additions being subject to the same X-factor challenge applied to operating costs. The OEB acknowledged this gap in its 2023 Annual Report, identifying the review of capex incentive structures as a priority workstream (OEB, 2024b). Separately, Ontario's approximately 60-distributor landscape, with many very small utilities — has limited the benchmarking precision of the productivity analysis, a problem PEI would share in even more acute form.

D. Significance to PEI

The OEB Price Cap IR framework is the most directly domestically relevant precedent for PEI's reform agenda because it operates within the Canadian regulatory, legal, and accounting framework that IRAC already uses. Section 17 of PEI's Electric Power Act, which governs Maritime Electric's rate-setting process, could be amended to incorporate an explicit I − X formula modelled on the OEB approach, transitioning from a cost-of-service rate case to a multi-year index-based settlement between rebasings. For a small regulator like IRAC, with fewer staff and resources than the OEB — the mechanistic annual rate adjustment that Price Cap IR provides would substantially reduce regulatory burden.

The differentiated stretch factor concept is directly applicable to PEI, with the important adaptation that, with only one distribution company, the tier assignment cannot be based on inter-distributor benchmarking. Instead, IRAC could assign Maritime Electric's stretch factor based on a comparison to a basket of comparable Canadian utilities which serve other small, rural-heavy, single-province utilities and update the assignment periodically as benchmarking data accumulates. Even a stretch factor of 0.15%, the lowest non-zero tier in Ontario would, applied to Maritime Electric's annual O&M expenditures, generate a meaningful efficiency incentive that the current framework entirely lacks.

The OEB's Non-Wires Solutions Guidelines (published March 2024) and the Framework for Energy Innovation (published March 2023) also represent transferable policy instruments for PEI. The OEB's NWS Guidelines establish a formal process under which distributors can propose non-capital alternatives to infrastructure investment, analogous to the DSM screening mandate that PEI's reform agenda requires under Section 16.1 of the Electric Power Act (OEB, 2024b).

2.6 Nova Scotia — UARB (Now Nova Scotia Energy Board) Framework

A. Seminal Features

Nova Scotia's regulatory framework for electricity, administered historically by the Utility and Review Board (UARB) and, following the passage of Bill 404 in April 2024 and the April 1, 2025 transfer of energy regulatory jurisdiction, now governed by the newly constituted Nova Scotia

Energy Board represents the most proximate domestic comparator for PEI given geographic, demographic, and structural similarities: Nova Scotia Power (NSPI), a subsidiary of Emera Inc., is a vertically integrated, investor-owned monopoly utility serving a predominantly rural island and peninsula jurisdiction under a traditional cost-of-service regulatory compact (FactSet, 2024). The framework's relevance to PEI derives not primarily from its innovations; the UARB framework is less advanced in performance incentives than the other eight jurisdictions surveyed but from its documented failure modes and the Nova Scotia government's recognition of these failures as requiring legislative correction. Three features are seminal.

The first is the Fuel Stability Plan, a multi-year mechanism that smooths fuel cost recovery through a deferral account rather than immediate pass-through, providing customers with rate predictability while allowing NSPI to manage inter-year fuel cost volatility (Emera, 2022). The fuel stability plan demonstrates a low-complexity form of multi-year rate planning that is directly accessible to small regulators.

The second is the legislated ROE cap, introduced through Bill 212 (November 2022), which limits NSPI's return on equity to 9.25% on an equity ratio of 40% (Emera, 2022). The ROE cap addresses the specific failure mode of cost-of-service regulation in a high-investment environment: without a cap, NSPI's extensive capital investment programs (Maritime Link recovery, storm restoration, grid modernization) would generate returns potentially well above what a competitive market would allow.

The third is the structural reform represented by the Energy Modernization Act (Bill 404), which in 2024 replaced the UARB's energy jurisdiction with a standalone Nova Scotia Energy Board, separating electricity regulation from the UARB's heterogeneous portfolio of non-energy regulatory functions (insurance, motor vehicles, fire safety) and establishing the groundwork for a specialized, expertise-focused energy regulator (FactSet, 2024).

B. Mechanics and Operationalization

Nova Scotia Power has historically filed rate cases infrequently once in approximately a decade as of 2024, with the UARB adjudicating a General Rate Application (GRA) that determines the revenue requirement and ROE for the forward period (FactSet, 2024). The fuel cost is handled separately through a Fuel Adjustment Mechanism and three-year Fuel Stability Plan, under which NSPI operated with an average annual overall rate increase of 1.5% for 2020 through 2022 to recover fuel costs (Emera, 2022).

The February 2023 UARB decision on NSPI's 2022 GRA approved substantially as settled, established the key parameters currently in effect:

- Authorized ROE: 9.25%, capped by Bill 212 (Emera, 2022).

- Equity ratio: 40%, capped by Bill 212 (Emera, 2022).
- Non-fuel rate increase cap: 1.8% between the decision date and end of the rate period, pursuant to Bill 212 (Emera, 2022). Despite this cap, the 14% overall rate increase (6.9% annually for 2023 and 2024) reflects fuel cost pass-through above the non-fuel cap (Ainvest, 2025).
- Storm cost recovery rider: A three-year rider approved to recover extraordinary storm restoration costs, including Hurricane Fiona (September 2022), which caused approximately $115 million in total restoration costs, of which $91 million was capitalized (Emera, 2022).
- Decarbonization deferral account: Established to manage the cost of coal plant retirements without immediate rate impact (Ainvest, 2025).

The Maritime Link regulatory framework, administered separately through NSPI's subsidiary Nova Scotia Power Maritime Link Inc., involves annual UARB review of recovery costs. For 2023, the UARB approved $163.7 million in Maritime Link costs which represented financing, operation, and maintenance of the undersea cable to Newfoundland for recovery from ratepayers (CBC News, 2022).

C. Guardrails and Known Failure Modes

Nova Scotia's most significant documented regulatory failure mode is the inadequacy of traditional cost-of-service regulation. Without a multi-year price plan, performance incentives, or NWA screening mandate to drive decarbonization investment at the pace required by the province's 80% renewable by 2030 target. The Clean Electricity Solutions Task Force, established in April 2023, concluded that the UARB lacked the specialized expertise, scope of jurisdiction, and institutional mandate to oversee the energy transition, and recommended the creation of the Nova Scotia Energy Board precisely because the UARB's broad multi-sector portfolio diluted its energy regulatory focus (FactSet, 2024).

The absence of explicit performance incentives on NSPI, beyond the blunt instrument of the legislated ROE cap has been identified as a structural deficiency. NSPI has no financial stake in outperforming its reliability targets or in adopting innovative technology solutions, and the ROE cap, while protecting consumers from excess profits, does not create the positive incentive for efficiency improvement that performance incentive mechanisms provide.

D. Significance to PEI

Nova Scotia's experience is instructive for PEI primarily through negative example. The Nova Scotia regulatory regime, traditional COS, infrequent rate cases, no multi-year price plan, no NWA mandate, no performance incentives closely mirrors PEI's current framework and has

produced the same failure modes: a utility with a financial incentive to invest capital, limited incentive to minimize costs or adopt alternatives, and a regulator that is structurally reactive rather than proactive (FactSet, 2024).

The legislative response, Bill 212's ROE cap and Bill 404's creation of a standalone energy board demonstrates that small Atlantic Canadian jurisdictions are capable of enacting targeted regulatory reform when political will exists. PEI's reform agenda, focused on amending the Electric Power Act to incorporate an ROE-sharing mechanism (analogous to Hawaii's ESM) and multi-year rate planning (analogous to British Columbia's MRP), is directly informed by Nova Scotia's experience.

Maritime Electric's authorized ROE of 9.35% (IRAC, 2022) is 10 basis points higher than the 9.25% cap legislated for NSPI. If Nova Scotia Power, a substantially larger and more diversified utility than Maritime Electric (serving approximately 540,000 customers versus Maritime Electric's 83,000–86,000), justifies a capped ROE of 9.25%, the PEI reform argument for tightening Maritime Electric's ROE band through an ESM with a target of 9.35% and sharing above 12.35% has strong precedential support from the immediately adjacent provincial jurisdiction.

2.7 New Zealand — Default Price-Quality Path (DPP)

A. Seminal Features

New Zealand's Default Price-Quality Path (DPP) framework, administered by the Commerce Commission under Part 4 of the Commerce Act 1986, constitutes one of the most rigorous implementations of a revenue cap combined with binding quality standards in any comparative jurisdiction. The DPP currently governs 17 electricity distribution businesses (EDBs) subject to price-quality regulation under DPP3 (April 2020 to March 2025) and, effective April 1, 2025, DPP4 under final decisions published by the Commerce Commission in November 2024 (Commerce Commission, 2024). Three seminal features distinguish the New Zealand DPP.

The first is the Revenue Cap with Wash-Up, which replaces the price cap used in earlier DPP iterations. Under a revenue cap, distributors are permitted to recover a specified total revenue from prices charged to consumers. Any over-recovery or under-recovery relative to the allowed revenue is "washed up" — returned to or recovered from consumers in the subsequent regulatory period through the use of a wash-up account with an NPV-neutral interest rate adjustment (Commerce Commission, 2019). The revenue cap solves the problem that price caps create: a distributor with a price cap will earn more or less than the allowed revenue depending on whether actual throughput differs from forecast, creating systematic revenue variability that neither consumers nor investors can easily predict.

The second is the Revenue-Linked Quality Incentive Scheme (QIS), a scheme under which distributors face financial adjustments to their allowed revenue based on SAIDI performance relative to a target derived from historical averages. The QIS provides a direct economic signal for reliability investment without recourse to a punitive penalty regime (Commerce Commission, 2024a).

The third is the Customised Price-Quality Path (CPP) option, which allows individual distributors, particularly those with materially different investment profiles from the DPP norm to apply for a bespoke regulatory path with higher capital allowances, subject to rigorous consumer consultation and Commission scrutiny. The CPP option solves the problem of average allowances being inappropriate for outlier utilities. This is also a problem that PEI faces as a small island with an unusually severe natural disaster exposure and a rapid planned energy transition (Commerce Commission, 2019).

B. Mechanics and Operationalization

Under DPP3 (2020–2025), the revenue cap is set for each EDB at the beginning of the period, based on the Commerce Commission's determination of the efficient revenue requirement: starting price, regulatory asset base (RAB), weighted average cost of capital (WACC), depreciation, and forecast capital and operating expenditures. The 10% annual limit on revenue increases from prices provides rate shock protection, and the 90% voluntary undercharging limit prevents distributors from building up large wash-up credits that could produce sharp future increases (Commerce Commission, 2019).

The QIS under DPP4 (commencing April 2025) has been simplified relative to DPP3 following consultation. Key parameters include:

- Incentive measure: SAIDI only (unplanned). The SAIFI revenue-linked incentive has been removed under DPP4 to reduce complexity and following evidence that the dual-metric approach created operational gaming analogous to the Australian pre-2018 problem (Commerce Commission, 2024a).
- Incentive rate derivation: Based on the Value of Lost Load (VoLL) at $25,000/NZD per MWh, discounted for the interaction with the Independent Reliability Incentive Scheme (IRIS) and the effect of quality standards, producing an effective QIS incentive rate of approximately $5,200/NZD per MWh of unserved energy (Commerce Commission, 2024a).
- Planned interruption incentive rate: Further discounted by 50% (to approximately $2,600/NZD per MWh) for planned interruptions, reflecting that consumers place less value on avoiding planned outages with 24-hour advance notice than unplanned outages (Commerce Commission, 2024a).

- Revenue at risk: A combined planned-unplanned cap of 2% of total revenue, set endogenously based on historical performance data rather than arbitrarily (Commerce Commission, 2024a).
- SAIDI target: Set at the distributor-specific historical average; SAIDI cap for the QIS is the compliance standard (approximately 1.5 standard deviations above historical average for unplanned interruptions) (Commerce Commission, 2019).

Quality standards under the DPP operate independently of the QIS. The unplanned reliability standard is set at 1.5 standard deviations above the historical average (so that distributors can breach it roughly 7% of years by chance alone); a separate extreme event standard is set at three times the major event boundary. Failure to meet quality standards triggers a Quality Standards Violation (QSV) — a revenue reduction separate from the QIS financial adjustment (Commerce Commission, 2024a).

C. Guardrails and Known Failure Modes

New Zealand's DPP framework incorporates extensive consultative guardrails, including requirements for distributors to consult with consumers during CPP applications and mandatory information disclosure under Part 4 of the Commerce Act. The wash-up mechanism itself is a guardrail against the revenue over-collection problem that price caps create.

The most significant documented adaptation in New Zealand's DPP evolution was the removal of the SAIFI revenue-linked incentive under DPP4. The Commerce Commission concluded that maintaining a revenue-linked incentive for both SAIDI and SAIFI created complexity without proportionate benefit, and that distributors were focusing disproportionate management attention on the easier-to-influence SAIFI metric (Commerce Commission, 2024a). This mirrors Australia's experience and confirms a general principle for small-jurisdiction PBR design: fewer, well-designed metrics outperform complex multi-metric schemes.

The CPP mechanism has produced its own unintended outcome: Aurora Energy, one of New Zealand's most under-invested distributors, was placed on a CPP after the Commerce Commission identified severe reliability concerns — with customers experiencing SAIDI values several multiples above the national average — arising from decades of deferred capital investment under the DPP's conservative allowances. The Aurora CPP (running to March 2026) allows substantially higher capital allowances but required consumers to fund large rate increases. This illustrates the risk that revenue cap frameworks set too tightly can defer network deterioration onto future consumers at higher ultimate cost (Commerce Commission, 2019).

D. Significance to PEI

New Zealand's DPP framework is relevant to PEI through two distinct channels. First, the revenue cap with wash-up is a technically superior form of revenue control to the price cap implied by PEI's current cost-of-service framework: it eliminates the throughput risk that Maritime Electric currently faces, reduces the over- and under-collection variance across years, and provides a more stable basis for utility financial planning. An amendment to Section 17 of the Electric Power Act to authorize IRAC to set a revenue cap with an annual wash-up mechanism rather than a revenue-requirement-plus-throughput structure would capture these benefits at relatively low regulatory cost.

Second, the SAIDI-only QIS design under DPP4, derived from VoLL-based incentive rates, is the technically strongest precedent for replacing PEI's flat $5,000 penalty cap under Section 39 of the Electric Power Act with an economically grounded revenue-at-risk mechanism. New Zealand's approach of capping the QIS at 2% of revenue, rather than Australia's ±5% may be more appropriate for PEI given its limited regulatory capacity and Maritime Electric's small revenue base, where a ±5% revenue adjustment could create excessive rate volatility for residential customers.

The Aurora CPP lesson is directly cautionary for PEI: the post-Fiona regulatory environment, in which Maritime Electric is seeking approval for $334 million in capital investment partly in response to identified vulnerability (IRAC, 2023), may represent a similar risk of regulatory framing that large capital approval is the appropriate response to systemic under-investment. The NWA screening process embedded in a reformed PEI framework requiring Maritime Electric to formally evaluate and document demand-side and storage alternatives before capital applications would serve the same corrective function as the Commerce Commission's rigorous CPP scrutiny.

2.8 British Columbia — BCUC Multi-Year Rate Plan (MRP)

A. Seminal Features

The British Columbia Utilities Commission (BCUC) administers one of the longest-standing performance-based rate-setting frameworks in Canada for FortisBC Inc. (FBC), the electricity distributor serving the southern interior of British Columbia, and FortisBC Energy Inc. (FEI), the natural gas distributor. The BCUC-FortisBC MRP relationship is particularly instructive for PEI because FBC is a subsidiary of Fortis Inc., the same parent company as Maritime Electric meaning that the regulatory tools, cost structures, and management incentive frameworks that FBC operates under are directly applicable to its PEI affiliate (FortisBC, 2024). The BCUC has regulated FBC under PBR-type plans since 1996, with five-year MRPs operating for 2014–2019

and 2020–2024, and a three-year Rate Framework approved for 2025–2027 (BCUC, 2024). Three seminal features define the BCUC MRP framework.

The first is the Index-Based O&M Formula, which governs the controllable portion of the utility's operating costs. Rather than approving detailed operating budgets in annual proceedings, the MRP allows O&M costs per customer to increase annually according to an inflation index less a fixed productivity adjustment, creating a direct efficiency incentive on the largest controllable cost category (FortisBC, 2019).

The second is the Service Quality Indicators (SQI) Framework, which establishes minimum performance thresholds across a range of customer service and reliability metrics. Unlike the reward-and-penalty ODI structure of RIIO or the revenue-linked QIS of New Zealand's DPP, the SQI framework under the BCUC MRP is primarily compliance-based: FBC must report annually on SQI performance and must maintain SQI levels above defined floors as a condition of rate approval. SQIs solve the problem that pure index-based rate-setting creates a cost-reduction incentive that could, without a quality floor, be satisfied by allowing service levels to deteriorate (FortisBC, 2019).

The third is the 50/50 Earnings Sharing Mechanism, which shares variances from the allowed ROE equally between shareholders and customers. This mechanism, approved by the BCUC as part of the 2020–2024 MRP and continued under the 2025–2027 Rate Framework, provides a symmetric risk-sharing structure that moderates both windfall profits and extreme losses relative to the authorized return (FortisBC, 2024).

B. Mechanics and Operationalization

The 2020–2024 MRP for FBC set the controllable O&M revenue requirement using the following formula:

O&M Allowance = (Base O&M per Customer × Inflation Index) × Forecast Customers

Where:

- Base O&M per Customer: Established by reference to 2019 actual O&M expenditure per customer, rebased at the beginning of the MRP term (FortisBC, 2019).
- Inflation Index: A weighted average of Average Weekly Earnings for B.C. (AWE:BC) for labour costs and Consumer Price Index for B.C. (CPI:BC) for other costs, reflecting the actual cost drivers of utility operations rather than a general economy-wide deflator (FortisBC, 2019).

- Customer count: Forecast annually, ensuring that O&M allowances scale with actual customer growth, which is an important adaptation for utilities in growing service territories.
- Productivity adjustment: An embedded challenge within the index, as the AWE:BC-weighted composite typically grows below the rate of O&M expenditure growth in the absence of efficiency measures, creating real-terms cost pressure.

Capital expenditures under the 2020–2024 MRP were handled through a forecast approach, similar to traditional cost-of-service for major sustainment and growth capital, rather than an index-based formula. This hybrid structure reflects the BCUC's determination that capital expenditures are too project-specific and lumpy to be accurately governed by a formula approach, particularly given FBC's significant infrastructure renewal program (FortisBC, 2024). The 2025–2027 Rate Framework continues this hybrid structure.

The 50/50 ESM operates as follows:

- Authorized ROE: Set by the BCUC's 2023 Generic Cost of Capital proceeding (GCOC Stage 1 Decision, Q3 2023), which updated FBC's deemed equity component to 41% and debt component to 59% (FortisBC, 2024).
- Sharing mechanism: Variances from the allowed ROE whether positive (above allowed) or negative (below allowed) are shared 50:50 between shareholders and customers. The customer share flows through a rate adjustment in the following year.
- ROE automatism: The BCUC determined in the 2023 GCOC that neither a formulaic ROE automatic adjustment mechanism nor specific criteria for future cost of capital proceedings are warranted; the approved ROE will remain in effect until otherwise determined by the BCUC (FortisBC, 2024).

SQIs under FBC's MRP are updated with each rate plan. The 2025–2027 Rate Framework proposes an updated SQI set designed to maintain service levels through FBC's infrastructure renewal period, with annual reporting obligations and potential rate implications for sustained SQI failures (BCUC, 2024).

C. Guardrails and Known Failure Modes

The BCUC MRP's primary guardrail is the five-year — now three-year — term structure, which limits the period over which any formula drift can create material misalignment between allowed and efficient costs, followed by a mandatory rebasing. The hybrid capital approach (forecast-based rather than index-based) prevents the formula from producing inadequate capital allowances for a system with large, lumpy investment requirements.

The framework's most significant limitation is the absence of a revenue-linked reliability incentive. FBC's SQI framework creates compliance obligations but not financial rewards for reliability outperformance. This means that FBC, like Maritime Electric under PEI's current framework, has no financial incentive to invest in reliability improvements beyond the minimum required to avoid SQI violation. The 2025–2027 Rate Framework application acknowledged this and proposed an updated SQI set, but did not include revenue-linked reliability incentives comparable to Australia's STPIS or New Zealand's QIS (BCUC, 2024).

A second limitation is that the hybrid capital approach. With forecast-based capital approval, it preserves elements of capex bias. FBC can and does seek approval for capital projects in the rate-setting process, with approved capital additions flowing into the rate base on which it earns its authorized ROE. The O&M index disciplines operating costs but leaves capital expenditure subject to the same structural incentive as traditional cost-of-service regulation.

D. Significance to PEI

The BCUC MRP is the most operationally proximate international precedent for PEI for a simple structural reason: Maritime Electric is a Fortis Inc. subsidiary, and the same parent company's other regulated subsidiary, FBC — operates under a BCUC-approved MRP with an index-based O&M formula and 50/50 earnings sharing. This means that Maritime Electric's management and financial systems are already calibrated to operate within a Fortis corporate framework that is accustomed to MRP-type regulation. IRAC could, in principle, design a PEI MRP that draws directly on the BCUC's MRP structure, adapted to PEI's size and reliability context, reducing the regulatory design burden substantially.

The AWE:CPI-weighted inflation index used in FBC's O&M formula is directly transferable to PEI. Maritime Electric's operating cost structure, dominated by labour (line workers, metering, customer service) and materials (transformer oil, wire, poles) mirrors FBC's. An O&M index based on a PEI-specific labour index (Statistics Canada's Prince Edward Island average weekly earnings) and CPI-PEI would provide a credible, data-based formula that IRAC could administer mechanically between rebasings.

The BCUC 50/50 ESM provides a direct template for a PEI earnings sharing mechanism under a reformed Section 17. Maritime Electric's current authorized ROE band (9.00%–9.70%, with a 9.35% target) is wider than the simple authorized ROE that an ESM would anchor to. A BCUC-style reform would set a single target ROE say, 9.35% and share all variances 50:50. Applied to Maritime Electric's equity base, a 50-basis-point outperformance (earning 9.85% rather than 9.35%) would result in approximately half of the excess being returned to customers through a rate credit in the following year, creating a direct incentive for cost control while ensuring customers benefit from efficiency gains.

3. Comparative Framework

Table 1 compares the regulatory features of the eight reviewed jurisdictions against PEI's current framework.

Table 1: Comparative Regulatory Framework Summary

Feature	UK (RIIO)	Australia (AER)	New York (REV)	Hawaii (PBR)	Ontario (OEB)	Nova Scotia (UARB)	New Zealand (DPP)	BC (BCUC)	PEI
Multi-Year Rate Plan	✅ 5–8 yrs	✅ 5 yrs	✅ 3 yrs	✅ 5 yrs	✅ 5 yrs	Partial	✅ 5 yrs	✅ 3 yrs	❌ Annual
Totex / Capex-Opex Neutral	✅ Full Totex	Under Review	Partial	Partial	Under Review	❌	Under Review	Partial	❌
SAIDI/SAIFI Incentives	✅ Financial	✅ Financial	✅ Reporting	✅ PIMs	✅ Targets	✅ Standards	✅ Financial	✅ Financial	❌ Basic Penalty
NWA Screening Mandate	✅	❌ Formal	✅ Mandated	✅	✅ (IESO)	❌	Emerging	Partial	❌
Revenue Decoupling	✅ Revenue Cap	✅ Revenue Cap	✅	✅ Explicit	Price Cap	❌	Revenue Cap	Revenue Cap	❌
DSM Integration	✅ Totex	Separate	✅ Platform	✅ PIMs	✅ CDM Targets	✅ Perf. Targets	✅ Statutory	✅ NEB Adder	Partial (S.16.1)
Innovation Incentive	✅ NIA/ SIF	✅ STPIS	✅ REV Pilots	✅ Pilot Process	Emerging	❌	✅ Allowance	✅ Pilot	❌

Source: Compiled by author from jurisdictional review. See references.

4. Analysis of PEI's Electric Power Act — Gaps and Barriers

4.1 Current Regulatory Framework

PEI's *Electric Power Act* establishes a traditional cost-of-service model with the following structural features (Prince Edward Island, 2017; IRAC, 2025):

1. **Rate Base Approach (Section 21):** The Commission determines rate base on 'prudent original cost' of assets 'used and useful.' This inherently rewards capital investment, every dollar of approved capex earns a regulated return, while opex is simply passed through (Prince Edward Island, 2017; RAP, 2022).
2. **Return on Investment (Section 24):** The utility earns annually 'such return as the Commission considers just and reasonable, computed by using the rate base.' Combined with the common equity requirements of Section 12.1 (35–40% equity ratio), this creates a classic capex bias (Prince Edward Island, 2017; Gomero, 2025).
3. **Capital Budget Process (Section 17):** Annual capital budget submission and approval process with no requirement to test alternatives. Section 17(4.1) states that 'no public utility shall recover any expenditures on improvements or additions to its property that have not first been approved by the Commission,' but the Commission has no explicit mandate to require NWA screening (Prince Edward Island, 2017; IESO, 2023).
4. **DSM Provisions (Section 16.1):** The Act contains relatively modern DSM provisions (added in 2013) allowing the Commission to order a public utility to prepare energy efficiency and demand-side resources plans for up to 5-year terms. However, DSM costs are not integrated into the rate base or totex framework — they exist as a parallel process with no binding performance targets (Prince Edward Island, 2017; NSUARB, 2022).
5. **Renewable Energy Cost Recovery (Section 24(2)):** The Commission must allow recovery of expenditures 'reasonably and prudently incurred' for compliance with the Renewable Energy Act, but this is framed as a pass-through rather than a performance incentive (Prince Edward Island, 2017; Prince Edward Island, 2016).
6. **Service Monopoly (Sections 2.1–2.2):** Maritime Electric holds the exclusive franchise for service provision across PEI (except Summerside), limiting competitive pressure (Prince Edward Island, 2017; Doane Grant Thornton LLP, 2025).
7. **Reliability Regulation (Section 39):** Only provides for a penalty of up to $5,000 per avoidable interruption exceeding 15 minutes. No positive incentive for reliability improvement, no SAIDI/SAIFI targets (Prince Edward Island, 2017; AER, 2018).

5. Recommended Legislative Amendments to the Electric Power Act

5.1 Introduce a Performance-Based Regulation Framework

Amend Section 24 (Return on Investment) and add new Section 24.1:

Add provisions authorizing the Commission to:

- (a) Establish a multi-year rate plan of 3–5 years duration, incorporating an Annual Revenue Adjustment formula that accounts for inflation, productivity, and a customer dividend factor (modelled on Hawaii's ARA: I Factor − X Factor + Z Factor − Customer Dividend) (Hawaii PUC, 2024).
- (b) Implement Performance Incentive Mechanisms (PIMs) that provide incremental revenue opportunities or penalties based on the utility's achievement of specified outcomes including: (i) reliability improvement (SAIDI/SAIFI targets), (ii) renewable energy integration, (iii) DSM achievement, (iv) customer service quality, and (v) cost efficiency (OEB, 2025b; Hawaii PUC, 2024).
- (c) Establish an Earnings Sharing Mechanism (ESM) to protect both the utility and customers from excessive earnings or losses under the PBR framework, modelled on Hawaii's tiered deadband structure (Hawaii PUC, 2024).

Rationale: This draws on Hawaii's PBR model (particularly appropriate for island jurisdictions), Ontario's evolving PIMs framework, and the UK's RIIO output categories. It aligns utility profit incentives with provincial policy goals including Net Zero 2040 (Natural Resources Canada, 2025; OEB, 2025b; Ofgem, 2024).

5.2 Adopt a Total Expenditure (Totex) Approach

Amend Section 21 (Rate Base) to add subsection (5) authorizing the Commission to adopt a total expenditure approach in which:

- (a) Controllable capital expenditure and operating expenditure are combined into a single 'total expenditure' category for the purpose of setting efficiency targets and allowances;
- (b) A predetermined capitalization rate, set by the Commission based on its best estimate of efficient expenditure shares, determines how total expenditure is allocated between rate base additions and pass-through costs (RAP, 2022).

- (c) Efficiency incentives apply symmetrically to all categories of expenditure, ensuring the utility is financially neutral between capital and operating solutions (Commerce Commission NZ, 2022; AEMC, 2017).

Amend Section 17 (Capital Budget) to require that:

- (d) Any capital budget submission must demonstrate that the proposed expenditure represents the most cost-effective solution when compared against alternative approaches including operating expenditure, demand-side management, non-wires alternatives, and third-party contracting (Ofgem, 2024; RAP, 2022).

Rationale: This directly addresses capex bias. The UK's RIIO totex model has demonstrated that utilities respond to this incentive structure by seeking the most cost-effective solution (Utility Dive, 2019; Gomero, 2025). New Zealand's Commerce Commission is working to achieve capex/opex neutrality through parallel incentive schemes, and the Australian Energy Market Commission's Total Expenditure Frameworks report evaluated similar options (AEMC, 2017; Commerce Commission NZ, 2022).

5.3 Mandate Non-Wires Alternative (NWA) Screening

Add new Section 17.2 (Non-Wires Alternatives Assessment):

(1) Where the Commission receives a capital budget application under Section 17 for any improvement or addition to property with an estimated cost exceeding a threshold amount to be set by regulation:

- (a) The public utility shall conduct and file a non-wires alternatives assessment demonstrating that the proposed capital investment has been evaluated against feasible alternatives including energy efficiency programs, demand response, distributed generation, energy storage, and other distributed energy resources (IESO, 2023; New York State DPS, 2025).
- (b) The non-wires alternatives assessment shall include: (i) an hourly load characterization of the identified need; (ii) screening of potential NWA options by need type; (iii) economic comparison of the capital investment and feasible NWA alternatives over the expected useful life of the proposed asset; and (iv) consideration of optionality value, where deferral of the capital investment creates value through avoided risk of stranded assets (IESO, 2023).

(2) The Commission shall not approve a capital budget item to which this section applies unless it is satisfied that the public utility has conducted a thorough non-wires alternatives assessment and that the proposed investment represents the most cost-effective solution for ratepayers.

(3) Where a non-wires alternative is approved:

- (a) The public utility shall be entitled to recover NWA project costs on the same basis as capital costs would be recovered under Section 24, ensuring financial neutrality between capital and NWA solutions (New York State DPS, 2025).
- (b) The Commission may authorize shareholder incentives for successful NWA implementation, including enhanced incentives for delivery under budget (New York State DPS, 2025).

Rationale: Modelled on New York's REV NWA framework and Ontario's IESO Guide to Assessing Non-Wires Alternatives (New York State DPS, 2025; IESO, 2023). The BQDM program's deferral of a $1 billion substation through 52 MW of distributed resources demonstrates the potential scale of savings available through NWA screening (ORNL, 2019; Utility Dive, 2017). This recommendation is directly applicable to Maritime Electric's current application (Docket UE20742) for fossil-fuel generation, where public advocates have called for a full alternatives analysis (Action Network, 2024; Energy Democracy Now, 2025).

5.4 Strengthen DSM Provisions (Amend Section 16.1)

Amend Section 16.1 to add the following provisions:

- **(a) Cost-Effectiveness Testing:** Require that DSM plans include cost-effectiveness testing using at a minimum the Total Resource Cost (TRC) test, with provision for a Non-Energy Benefits (NEB) adder of at least 15% to account for benefits not captured in the TRC such as reduced infrastructure investment, environmental benefits, and job creation (Government of BC, 2008; NSUARB, 2022).
- **(b) DSM Performance Targets:** Require the Commission to establish binding performance targets for cumulative annual energy savings and cumulative annual peak demand savings, with a minimum of 90% achievement constituting substantial compliance. Establish a separate performance target for low-income and underserved community programs (NSUARB, 2022).
- **(c) DSM Cost Recovery Parity:** Provide that expenditures on approved DSM programs shall be eligible for inclusion in rate base on the same basis as capital expenditures, or alternatively, that the utility shall be entitled to earn a return on DSM investments equivalent to the return authorized on rate base assets, ensuring financial neutrality (New York State DPS, 2025).
- **(d) Portfolio-Level Evaluation:** Require portfolio-level evaluation of DSM programs rather than measure-by-measure assessment, ensuring that programs supporting

education, technology innovation, and community engagement are evaluated in the context of the overall portfolio (Government of BC, 2008).

- **(e) Integration with IRP:** Require that DSM plans be integrated with a comprehensive Integrated Resource Plan (see Recommendation 5.6).

Rationale: The current Section 16.1 provides a framework for DSM plans but lacks critical elements: cost-effectiveness testing, binding targets, cost recovery parity, and integration with broader resource planning (Prince Edward Island, 2017; Energy Regulation Quarterly, 2024). Nova Scotia's UARB has demonstrated the effectiveness of binding DSM performance targets in reducing provincial electricity demand by more than 5% through efficiency programs—achieving leadership status among Canadian provinces (Energy Regulation Quarterly, 2024; NSUARB, 2022).

5.5 Establish Revenue Decoupling

Add new Section 20.1 (Revenue Decoupling):

(1) The Commission shall establish a revenue decoupling mechanism that sets target revenue for the public utility that is not linked to the volume of electricity sales.

(2) The revenue decoupling mechanism shall include:

- (a) An annual true-up mechanism that adjusts rates to ensure the utility recovers its authorized revenue requirement regardless of changes in sales volumes;
- (b) A customer dividend or bill impact cap to ensure that decoupling adjustments do not result in unreasonable rate volatility.

Rationale: Revenue decoupling is a foundational element of PBR frameworks in Hawaii, the UK, New Zealand, and other jurisdictions (Hawaii PUC, 2024; Commerce Commission NZ, 2022; Ofgem, 2024). Without decoupling, the utility retains a financial incentive to increase electricity sales, which directly conflicts with DSM objectives and renewable energy goals. Hawaii's experience demonstrates that revenue decoupling was a critical 'first step' in evolving its regulatory construct—and PEI's context is directly comparable as an isolated island system with ambitious renewable targets (E Source, 2022; Hawaii PUC, 2024).

5.6 Mandate Integrated Resource Planning (IRP)

Add new Section 16.2 (Integrated Resource Plan):

(1) The Commission shall, by order, require each public utility to prepare and submit, at intervals not exceeding 3 years, an Integrated Resource Plan.

(2) An Integrated Resource Plan shall:

- (a) Evaluate all feasible supply-side and demand-side resources on a consistent and comparable basis, including renewable energy, energy efficiency, demand response, energy storage, distributed generation, and traditional generation and transmission assets;
- (b) Include a 'least-cost' analysis that considers reliability, safety, environmental costs, carbon pricing, and avoided infrastructure costs (modelled on Vermont's statutory requirement) (CNEE, 2025).
- (c) Assess the potential for non-wires alternatives to defer or avoid capital investments;
- (d) Incorporate scenario analysis addressing high and low demand growth, varying renewable energy penetration levels, carbon price trajectories, and technology cost trends;
- (e) Be subject to public consultation and Commission approval.

Rationale: PEI currently has no statutory IRP requirement (Prince Edward Island, 2017). Vermont requires regulated utilities to submit a 'least-cost integrated plan' every three years, where 'least-cost' includes reliability, safety, and environmental costs needed to meet energy demand (CNEE, 2025). An IRP requirement ensures that resource decisions are made holistically rather than on a project-by-project basis, which is the current approach under Section 17, and would provide the analytical foundation needed to evaluate Maritime Electric's major capacity applications (IRAC, 2025; Doane Grant Thornton LLP, 2025).

5.7 Modernize Reliability Regulation

Amend Section 39 (Interruption of Service) and add new Section 39.1:

- **(a) SAIDI/SAIFI Targets:** Require the Commission to establish SAIDI and SAIFI performance targets for each public utility, with targets based on historical performance averages adjusted for annual improvement expectations (modelled on Ontario's 2025 methodology) (OEB, 2025a).
- **(b) Financial Incentive Scheme:** Establish a revenue-linked quality incentive scheme providing financial rewards for performance exceeding targets and financial penalties for underperformance, with incentive magnitude calibrated to customers' willingness to pay for reliability improvements (modelled on Australia's STPIS and New Zealand's DPP quality incentive) (AER, 2018; Brattle Group, 2018).

- **(c) Duration/Frequency Balancing:** Ensure that the incentive scheme appropriately weights both the frequency and duration of outages, avoiding the Australian experience where distributors focused on reducing short interruptions while average restoration times increased (AER, 2018).
- **(d) Reporting and Transparency:** Require annual public reporting of SAIDI, SAIFI, CAIDI, and MAIFI metrics, with benchmarking against comparable Canadian utilities.
- **(e) Increase Maximum Penalty:** Update the $5,000 per-interruption penalty ceiling in Section 39(1) to reflect current economic conditions, indexed to inflation.

Rationale: Maritime Electric currently records SAIFI and CAIDI performance but has no financial incentive scheme tied to reliability improvement (Maritime Electric, 2022). The existing $5,000 penalty cap is inadequate as either a financial deterrent or an incentive for improvement—a reality made plain by the Fiona event and subsequent findings about vegetation management underinvestment (Campbell, 2024; CBC News, 2023). Ontario's newly established distributor-specific SAIDI/SAIFI targets provide a directly transferable model (OEB, 2025a).

5.8 Enable Renewable Energy and DER Integration

Amend Section 1 (Definitions) to add:

- "distributed energy resource" means any resource deployed on the distribution system or at a customer site, including distributed generation, energy storage, electric vehicles, demand response, and energy efficiency;
- "non-wires alternative" means any electrical grid investment or project that uses non-traditional solutions, including distributed energy resources, to defer or replace the need for traditional utility infrastructure investments.

Amend Section 3 (Duties of Public Utilities) to add:

- (e) facilitate the cost-effective integration of renewable energy and distributed energy resources in accordance with the province's renewable energy and emissions reduction targets;
- (f) consider and, where cost-effective, implement non-wires alternatives before pursuing traditional infrastructure investments.

Amend Section 24(2) (Renewable Energy Cost Recovery) to expand beyond simple pass-through:

The Commission shall allow a public utility to earn a return on investments in renewable energy integration measures, distributed energy resources, and enabling infrastructure (including smart grid, advanced metering, and energy storage) on the same basis as investments in traditional

utility property, provided such investments are demonstrated to be cost-effective and consistent with the utility's approved Integrated Resource Plan (Prince Edward Island, 2024; Prince Edward Island, 2016).

Rationale: The current Act's definitions and duty provisions were written for a traditional centralized utility model. Modernizing definitions and duties ensures that IRAC has clear legislative authority to consider and approve DER-related investments. The broader suite of DERs — solar, storage, demand response, EVs — requires legislative recognition within the *Electric Power Act* itself, separate from the *Renewable Energy Act* (Prince Edward Island, 2024; Prince Edward Island, 2016; IRAC, 2025).

5.9 Community and Third-Party Participation

Amend Section 2.1 (Service Restriction) to add provisions allowing:

- (a) Community renewable energy projects to sell electricity to or through the public utility without being classified as a public utility themselves, subject to Commission-approved interconnection standards;
- (b) Third-party providers of non-wires alternatives to participate in competitive procurement processes administered by the public utility under Commission oversight.

Rationale: Maritime Electric's February 2025 application for utility-scale community renewable energy generation projects demonstrates emerging interest in community energy models (Maritime Electric, 2025). However, the current Act's service restriction framework creates barriers to third-party and community participation. New York's REV platform model demonstrates how opening the distribution system to competitive participation drives innovation and cost reduction (New York State DPS, 2025; Utility Dive, 2017).

5.10 Preamble and Purpose Amendment

Amend the Preamble to add:

AND WHEREAS the regulation of public utilities should support the province's climate change and emissions reduction objectives, facilitate the cost-effective integration of renewable energy and distributed energy resources, and ensure that infrastructure investments represent the least-cost solution when all feasible alternatives are considered;

AND WHEREAS the regulatory framework should align the financial incentives of public utilities with the achievement of reliable, affordable, and sustainable electricity service;

Rationale: The current preamble references reasonable rates, efficient regulation, and cost-effective DSM. Adding explicit references to climate objectives, renewable integration, DER facilitation, and incentive alignment provides interpretive guidance to IRAC and signals legislative intent for the modernization of utility regulation (Natural Resources Canada, 2025; Spencer, 2025). This approach mirrors Nova Scotia's experience where legislative policy direction provided the foundation for the UARB's catalytic role in electricity system transformation (Energy Regulation Quarterly, 2024).

6. Implementation Considerations

6.1 Sequencing

Based on jurisdictional experience, the following phased implementation sequence is recommended (Hawaii PUC, 2024; E Source, 2022):

- **Phase 1 — Immediate (Year 1):** Preamble amendment, definitions update, NWA screening mandate, reliability reporting requirements, IRP mandate.
- **Phase 2 — Medium-Term (Years 1–2):** Revenue decoupling, DSM provision strengthening, enhanced reliability incentives.
- **Phase 3 — Full PBR Transition (Years 2–4):** Multi-year rate plan, totex framework, PIMs design and implementation.

Hawaii's experience demonstrates that PBR is a '10-year evolution' of the regulatory construct, with decoupling as a first step (E Source, 2022; Hawaii PUC, 2024). PEI should plan for iterative implementation rather than a single comprehensive reform.

6.2 IRAC Capacity

PBR and totex regulation require greater regulatory capacity for benchmarking, performance monitoring, and incentive calibration (OEB, 2025b; Doane Grant Thornton LLP, 2025). Given PEI's small size, the Commission may benefit from: (a) shared analytical resources with other Atlantic Canadian regulators; (b) adoption of standardized methodologies (e.g., Ontario's benchmarking models); and (c) phased implementation allowing capacity building. The Atlantica Centre for Energy's 2026 analysis of PEI's energy strategy notes that the province is already watching Nova Scotia's work on an Independent Energy System Operator for potential lessons on regulatory modernization (Atlantica Centre for Energy, 2026).

6.3 Stakeholder Engagement

All jurisdictions reviewed emphasize the importance of structured stakeholder engagement in PBR design (OEB, 2025b; Hawaii PUC, 2024; Ofgem, 2024). Ontario's APBR consultation with working groups, Hawaii's two-year collaborative process, and the UK's enhanced engagement requirements for RIIO business plans all demonstrate that successful implementation requires structured input from ratepayer advocates, environmental groups, industry participants, and the utility. PEI's October 2025 energy strategy recommendation for a consumer advocate role reflects awareness of this requirement (Spencer, 2025; CanREA, 2025).

6.4 Compatibility with the Renewable Energy Act

The proposed amendments are designed to complement PEI's existing *Renewable Energy Act* and its regulations (Prince Edward Island, 2024; Prince Edward Island, 2016). The IRP and NWA screening requirements would provide a structured process for evaluating renewable energy investments alongside other resource options, while the totex approach would ensure financial neutrality between purchasing renewable energy under the Minimum Purchase Price framework and investing in utility-owned alternatives.

6.5 The Summerside Exemption

The City of Summerside Electric Utility Exemption Regulations exempt Summerside from most regulatory provisions of the *Electric Power Act* (Prince Edward Island, 2004). Any amendments should consider whether Summerside should be brought within the modernized framework or whether its exemption should be updated to ensure consistency with new DSM and NWA requirements. Summerside has, notably, operated as an innovator in municipal renewable energy, with a solar farm and wind generation capacity that has pushed its renewables share above 65% of local demand—a demonstration of what community-level renewable integration can achieve (Spencer, 2025).

7. Conclusion

The jurisdictional scan presented in this report demonstrates a clear global consensus: modern electricity regulation must move beyond cost-of-service models that inherently reward capital accumulation toward performance-based frameworks that reward efficient outcomes for customers (RAP, 2019; Utility Dive, 2019; Ofgem, 2024). PEI's *Electric Power Act*, while containing some modern provisions in Section 16.1 on DSM, retains a fundamentally traditional structure that creates capex bias, lacks reliability incentive mechanisms, provides no NWA screening requirement, and does not decouple utility revenue from sales volume (Prince Edward Island, 2017; IRAC, 2025).

The timing of reform is urgent. PEI faces a projected 27% electricity supply deficit by 2033, an expiring Energy Purchase Agreement with NB Power at the end of 2026, a $334 million fossil-fuel capacity application before IRAC that lacks a mandatory alternatives analysis, and a legislated net-zero target by 2040 that demands a fundamental reorientation of the utility regulatory model (CanREA, 2025; Doane Grant Thornton LLP, 2025; Action Network, 2024; Natural Resources Canada, 2025).

The ten recommendations in this report provide a comprehensive pathway for legislative modernization, drawing on proven approaches from comparable jurisdictions—particularly Hawaii's PBR framework (which shares PEI's island geography and single-utility structure), Nova Scotia's DSM performance target approach (which shares PEI's Atlantic Canadian regulatory context), and Ontario's benchmarking methodology (which provides a transferable template for SAIDI/SAIFI target-setting) (Hawaii PUC, 2024; Energy Regulation Quarterly, 2024; OEB, 2025a). Implemented in a phased sequence that builds regulatory capacity while delivering immediate consumer protections, these reforms offer PEI a credible pathway to an electricity regulatory framework fit for the energy transition.

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About Energy Democracy Now! Co-operative Limited

Energy Democracy Now! Co-operative Limited is a community-based advocacy organization working to put Islanders in charge of their energy future. Founded and incorporated in 2023, we believe the climate crisis demands more than small fixes — it requires a bold shift from corporate control of fossil fuels to renewable energy that is owned, governed, and guided by local communities.

We're building a future where decisions about energy on PEI are made transparently, with health, fairness, and community well-being at the centre.

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