Canadian Regulatory Jurisprudence on Deferral Accounts

Case Studies and Precedent Analysis for IRAC Docket UE20742

Supplement to Energy Democracy Now! Comments on Maritime Electric's Dispatchable Generation Application

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1. Introduction and Purpose

This supplementary report provides a comprehensive review of Canadian regulatory jurisprudence governing deferral accounts in the utility sector. It is filed in connection with IRAC Docket UE20742, specifically addressing Maritime Electric Company, Limited's (MECL) request for approval of a Work-in-Progress (WIP) Deferral Account to commit approximately USD $34.72 million in ratepayer funds before the completion of regulatory review, environmental assessment, or municipal approvals for its proposed 100 MW diesel-fired generation facility.

This analysis draws on decisions from six Canadian regulatory jurisdictions: the Ontario Energy Board (OEB), the Alberta Utilities Commission (AUC), the Nova Scotia Utility and Review Board (NSUARB), the British Columbia Utilities Commission (BCUC), the Manitoba Public Utilities Board (PUB), and the Island Regulatory and Appeals Commission (IRAC) itself. Together, these decisions establish a clear body of jurisprudence that Canadian regulators have consistently applied to limit the use of deferral accounts as vehicles for transferring planning risk, cost overruns, and financial exposure onto ratepayers.

For context on EDN's broader arguments concerning MECL's capacity deficit framing, the status of demand-side management on PEI, and the Commission's findings in Order UE25-07A regarding MECL's confidentiality overreach, readers are directed to EDN's earlier submission and related correspondence filed in this proceeding. Those arguments are not repeated here.

2. Foundational Principles: The Purpose and Limits of Deferral Accounts

Across Canadian jurisdictions, regulators have consistently identified deferral accounts as mechanisms designed to address a narrow set of circumstances in rate-setting. The Ontario Energy Board, in its foundational *Guidelines for Variance and Deferral Accounts* (2005), defines **a deferral account as a tool for tracking costs of a project or program that the utility could not forecast when its current rates were set.**[1] A variance account, by contrast, tracks the difference between forecast and actual costs for items already included in rates. The OEB has emphasized that **deferral accounts should only capture costs that are "unforeseen, extraordinary, or beyond management control."**[1]

The Alberta Utilities Commission, in its Performance-Based Regulation framework, has similarly held that regulated rate option providers **may apply for deferral accounts only when there is genuine difficulty in establishing a reasonable forecast for expenses or revenue.**[2] This principle was reinforced in AUC Decision 26505-D01-2021, where the Commission noted that if final rates have been approved, deferral accounts cannot be retroactively used to revisit those rates except in limited and extraordinary circumstances, such as the COVID-19 pandemic.[2]

In British Columbia, the Auditor General's 2019 report on rate-regulated accounting at BC Hydro warned that **the accumulation of billions of dollars in regulatory deferral accounts represents an effective debt owed by ratepayers,** and cautioned against the use of such accounts to defer costs without independent regulatory oversight.[3] The report noted that by 2018, BC Hydro's net regulatory asset balance had grown

to billions of dollars, creating significant intergenerational equity concerns as current ratepayers' costs were being shifted to future ratepayers.[3]

3. Ontario: Prudence Disallowances and Risk Allocation

3.1 OPG Darlington Refurbishment – EB-2016-0152

The OEB's decision in the Ontario Power Generation rate application EB-2016-0152 is directly relevant to MECL's deferral account request. In this proceeding, OPG sought recovery of approximately $4.8 billion in rate base additions associated with the Darlington Nuclear Generating Station refurbishment, along with the continuation of a Capital Revenue Variance Account (CRVA) to track cost variances during the multi-year refurbishment program.[4]

The OEB took OPG to task for its management of two nuclear-related capital projects: the Auxiliary Heating System (AHS) and the Operations Support Building (OSB). Intervenors proposed rate base disallowances ranging from $14.4 million to $53.1 million for the AHS project and $7 million to $14.9 million for the OSB project, based on evidence of poorly developed estimates, flawed contractor selection, and weak day-to-day risk management.[4] The OEB ultimately imposed approximately $33 million in cost disallowances across these two projects, finding that OPG's management failures were "apparent" and that ratepayers should not bear the full cost of project management deficiencies.[5]

The Darlington precedent establishes that even **where a regulator accepts the need for a capital project, it retains full authority to disallow costs attributable to poor planning, flawed procurement, or management failures**. MECL's request for a WIP deferral account that would commit ratepayer funds before the Commission has had the opportunity to assess the prudence of MECL's procurement approach (including the sole-source ProEnergy contract) directly engages this principle.

3.2 Ontario Rate Smoothing Deferral – Cautionary Lesson

Ontario's experience with rate smoothing through cost deferral provides a critical cautionary precedent. Under the provincial government's Fair Hydro Plan, OPG was directed to defer more than $1 billion in nuclear costs over a five-year period. Ontario's Financial Accountability Officer found that the interest costs associated with this deferral would amount to approximately $116 million over the five-year period, potentially rising to $470 million by the time the deferred amounts were fully repaid, with future ratepayers bearing the accumulated burden.[5]

MECL's proposed WIP deferral account similarly front-loads financial commitments while deferring the regulatory reckoning. The Ontario experience demonstrates that carrying costs on deferral balances compound significantly over time and that the true cost to ratepayers substantially exceeds the nominal amounts deferred. IRAC should consider the full lifecycle cost of any deferral mechanism, including carrying charges.

3.3 OEB EPCOR Decision – Risk Sharing Between Utility and Ratepayers

In EB-2023-0140, EPCOR sought to shift all volume variance risk for mass market customers onto ratepayers through its deferral account structure. The OEB dismissed EPCOR's motion, finding that the Board's original decision appropriately balanced the interests of ratepayers and the utility. The OEB specifically noted that the IRM Decision "sought to balance the interests of ratepayers and the utility" and that there was "no error of law or fact that arises as result of such balancing."[6] The OEB used a 300-basis point limitation on financial relief as a dead band threshold, consistent with its broader approach to ensuring utilities bear an appropriate share of risk.[6]

MECL's deferral account proposal effectively assigns 100% of the pre-approval financial risk to ratepayers and 0% to the utility's shareholders. The EPCOR precedent confirms that regulators routinely impose risk-sharing mechanisms, and that a proposal assigning no risk to the utility is inconsistent with regulatory practice across Canada.

4. Alberta: Deferral Accounts Cannot Correct Historical Planning Failures

4.1 AUC Decision 26589-D01-2021 – ENMAX Historical Costs

In Decision 26589-D01-2021, the Alberta Utilities Commission denied ENMAX Power Corporation's attempt to use a transmission access charge deferral account (TACDA) to recover $10.27 million in historical costs arising from a calculation error in its previous rate filings for the years 2015 through 2019. **The Commission held that deferral accounts cannot be used to correct "historical and previously approved amounts."**[7] As a result, the full $10.27 million was denied recovery from ENMAX's customers.[7]

This decision establishes the principle that deferral accounts are forward-looking instruments and cannot be used to retroactively shift costs that arose from a utility's own planning or calculation failures. MECL's capacity need has been known for years; the urgency that now drives the deferral account request is a product of MECL's own failure to plan adequately, not an unforeseeable external event.

4.2 AUC Decision on ENMAX Green Line LRT – Type 1 Capital Denied

In a separate proceeding, ENMAX Power Corporation filed a Type 1 Capital Tracker Treatment Application to recover costs associated with infrastructure relocation required by the City of Calgary's Green Line LRT expansion. The AUC had previously granted a placeholder funding mechanism to alleviate ENMAX's cash flow concerns, with the explicit understanding that ENMAX risked a cost disallowance if the expenditure was later deemed ineligible.[8]

On November 24, 2021, the Commission denied ENMAX's application, finding that the project did not meet the criteria for a Type 1 capital expenditure and that the Green Line expansion was not an out-of-

the-ordinary cost relative to ENMAX's usual operations. The Commission ordered ENMAX to refund $5.37 million already collected through the placeholder mechanism and disallowed $25.18 million in rate base additions.[8]

This case demonstrates the AUC's willingness to both deny capital tracker treatment and order refunds of amounts already collected under placeholder mechanisms. It confirms that pre-approval collection of funds through deferral-like mechanisms does not create an entitlement to recovery. IRAC should be alert to the risk that approving MECL's WIP deferral account could create a fait accompli that constrains future regulatory options.

4.3 AltaLink 2024 – Deferral Account Denied for Insufficient Substantiation

In its 2024–2025 General Tariff Application (Decision 28174-D01-2024), AltaLink Management Ltd. requested approval of a wildfire damages deferral account along with $49.52 million in increased wildfire mitigation expenditures. The Commission denied both requests, finding that AltaLink had not fully substantiated the need for the expenditures and had not demonstrated the likelihood that its asset deficiencies would cause ignition events triggering wildfires. The Commission also denied the $11 million in expenses associated with AltaLink's Salvage allocation study for 2022 and 2023.[9]

The AltaLink decision illustrates that regulators will deny deferral account requests where the utility has not provided sufficient evidentiary substantiation. MECL's deferral account request **similarly lacks independent verification of cost estimates, as the ProEnergy proposal is the only option presented**, and the Commission itself has noted MECL's confidentiality overreach has impeded proper regulatory scrutiny.

4.4 ATCO Electric Enforcement – Penalties for Deferral Account Misconduct

In AUC Decision 29109-D01-2024, the Commission approved a settlement agreement arising from enforcement proceedings against ATCO Electric Ltd. ATCO admitted to failing to clearly identify and explain accrual amounts in deferral account applications and to failing to present all material facts fully and accurately regarding a capital project. Under the settlement, ATCO agreed to refund customers $4.0 million and to pay administrative penalties totalling $3.0 million.[10]

The ATCO enforcement action demonstrates that Canadian regulators take deferral account integrity seriously and are prepared to impose significant financial penalties for failures of transparency and accuracy. In the context of MECL's application, where the Commission has already rebuked MECL for "sweeping confidentiality requests" and unauthorized redactions (Order UE25-07A), this precedent underscores the importance of full disclosure in any deferral account proceeding.

5. Nova Scotia: Deferral Limitations and Financial Risk

5.1 NSUARB 2024 Decision 116 – Carrying Costs on Deferral Accounts

In Decision 2024 NSUARB 116 (M11411), the Nova Scotia Utility and Review Board addressed the treatment of deferral account carrying costs in the context of Nova Scotia Power's operations. The Board explicitly confirmed that carrying costs of non-regulated deferral assets will not be added to deferral amounts recovered from ratepayers.[11] The Board further emphasized its established practice under Accounting Policy 6900 that deferral treatment should generally be applied for before costs are incurred, not retroactively.[11]

Relevance to MECL: MECL's WIP deferral account proposal implicitly assumes that ratepayers will bear carrying costs on the deferred balance. The NSUARB's position that carrying costs on non-regulated deferral assets should not be passed to ratepayers provides a direct precedent for IRAC to impose similar limitations if any deferral is approved. Moreover, the NSUARB's strong preference for prospective deferral applications – filed before costs are incurred – is directly at odds with MECL's proposal to commit funds before obtaining Commission approval.

5.2 NSUARB 2023 GRA Decision – Risks of Compounding Deferrals

In the 2022–2024 General Rate Application decision (2023 NSUARB 12, M10431), the Board approved a settlement agreement between Nova Scotia Power and key stakeholders but explicitly refused to approve additional fuel cost deferrals beyond those contemplated in the settlement. The Board stated that further deferral "would run the very real risk of compounding rate pressures in the future and reducing the flexibility that may be available to manage those costs in a reasonable timeframe."[12]

This decision was issued against the backdrop of Nova Scotia Power's Fuel Adjustment Mechanism (FAM) balance having grown to approximately $395 million by the end of 2023, a level that NS Power itself acknowledged endangered its financial health by reducing its cash flow to debt metric. S&P Global Ratings subsequently downgraded NS Power, placing it in what the utility described as the bottom 10% of North American regulated utilities.[13]

Relevance to MECL: The NS Power experience provides a vivid illustration of how deferred costs can accumulate to levels that threaten both ratepayer affordability and utility financial health. MECL's proposed $334.2 million gas plant, funded through a combination of rate base additions and deferral mechanisms, risks creating a similar compounding dynamic on a much smaller system. PEI has fewer ratepayers over which to spread costs, making the per-capita burden of any cost overrun or stranded asset significantly higher.

6. British Columbia: Regulatory Independence and Deferral Account Reform

6.1 BC Hydro Rate Smoothing Account Write-Off

The British Columbia experience with BC Hydro's regulatory deferral accounts provides perhaps the most dramatic cautionary precedent in Canadian regulation. Under the previous provincial government's 10 Year Rates Plan, BC Hydro was directed to defer costs into a rate smoothing regulatory account, effectively suppressing rate increases in the near term while accumulating a growing balance that ratepayers would eventually need to repay.[14]

A comprehensive government review in 2019 found that this approach had fundamentally undermined the integrity of the rate-setting framework. The government accepted the recommendation that BC Hydro cease using the rate smoothing regulatory account and wrote off the entire $1.1 billion balance, meaning that these deferred costs would not be recovered from ratepayers.[14] The review concluded that **regulatory deferral accounts, when used without independent oversight, create an "effective debt" for ratepayers that distorts the true cost of utility service.**[3]

The BC Hydro write-off demonstrates the ultimate risk of deferral mechanisms that are approved without sufficient safeguards: either ratepayers bear a burden they should not, or the utility (and by extension the public purse) absorbs a massive write-down. MECL's WIP deferral account, if approved without conditions, could create a similar situation on PEI where the Commission faces a choice between imposing imprudent costs on ratepayers or requiring a write-off that threatens utility financial health.

6.2 BCUC – "Used and Useful" Standard for Capital Cost Recovery

In its review of BC Hydro's Fiscal 2020–2021 Revenue Requirements Application, the BCUC denied the recovery of capital expenditures associated with electric vehicle charging infrastructure from ratepayers, finding that these assets were "not used and useful" to deliver electricity to ratepayers.[15] The BCUC directed BC Hydro to remove all capital expenditures for EV charging infrastructure from rate base, irrespective of the broader policy justification for EV adoption.[15]

Separately, in the FortisBC Inc. 2023 Annual Review, the BCUC removed $27.959 million of the Corra Linn Dam project from FortisBC's 2023 rate base after finding that the project was not substantially complete by year-end and therefore did not qualify for inclusion.[16]

The "used and useful" standard is directly relevant to MECL's WIP deferral account. **Work-in-progress assets are, by definition, not yet "used and useful"; they are assets under construction that have not yet provided any service to ratepayers.** The BCUC's insistence on this standard reinforces the principle that ratepayers should not be required to fund assets before those assets are providing value. MECL's proposal to commit $34.72 million before the project has received any approvals, let alone entered service, represents a significant departure from this principle.

6.3 BCUC – Site C Hydroelectric Project Cost Review Reserved

In its 2023–2025 rates decision, the BCUC approved BC Hydro's rate increases but directed a different treatment for Site C costs than what BC Hydro had proposed, specifically reserving the right to review and potentially disallow costs associated with the project in any future BCUC review.[17] This reservation

ensures that ratepayers are not automatically committed to absorbing all costs from a major capital project, regardless of whether those costs were prudently incurred.

The BCUC's reservation of its authority to review and potentially disallow Site C costs is a model for how IRAC should approach MECL's deferral account request. Even if IRAC approves some form of preliminary expenditure, **it should explicitly preserve its full authority to conduct a prudence review and to disallow any costs found to have been imprudently incurred, including costs arising from the sole-source procurement, inadequate alternatives analysis, or failure to consider BESS and other options.**

7. Manitoba: Capital Project Cost Overruns and Regulatory Oversight

Manitoba's experience with Manitoba Hydro's major capital projects provides cautionary context for MECL's proposal. In its 2019 General Rate Application, Manitoba Hydro requested a 3.5% rate increase, which was itself scaled down from an initially contemplated increase of nearly 8%. The Manitoba Public Utilities Board approved only a 2.5% increase and directed that additional revenue be funnelled into a deferral account to address ongoing construction costs.[18]

The PUB's then-Vice Chair was quoted emphasizing that the deferral mechanism **"sends a really strong efficiency signal to Manitoba Hydro that when you have cost overruns, when you're not running your business as well as you should, you can't rely exclusively on Manitoba ratepayers to foot the bill."**[18] This principle was applied in the context of significant cost overruns on the Keeyask Generating Station and the Bipole III transmission line, both of which came in substantially over their original budgets.

In its Order No. 101/23, the PUB further confirmed its approach of considering both the utility's short-term revenue needs and long-term projections, explicitly to avoid rate shock for consumers, while using deferral account balances strategically for debt reduction rather than as open-ended cost recovery vehicles.[19]

The Manitoba precedent is particularly instructive because it involves a Crown-owned utility with a large capital construction program – a situation somewhat analogous to MECL's proposal, albeit at a different scale. The PUB's insistence that **the utility, not ratepayers, bear the primary financial consequences of cost overruns and planning failures is directly applicable to IRAC's assessment** of MECL's deferral account request.

8. IRAC's Own Precedent: Order UE25-07A

The Commission's own recent Order UE25-07A (March 10, 2026), issued in the present docket, provides important context for the deferral account question. In that order, the Commission found that "the importance of the public's understanding of the requested deferral account, and the potential rate impacts of the required initial payments, outweighs MECL's concerns respecting confidentiality."[20]

The Commission ordered that the dollar amounts of MECL's Full Notice to Proceed payment, Long Lead Procurement Payment, and total required financial commitment are not confidential, specifically so that

the public can understand the rate impact of the deferral account request.[20] The Commission further stated: "the starting point for regulatory proceedings is full and fair transparency to rate-payers. While the Commission appreciates the reality of commercial sensitivity, rate-payers are entitled to know the impact to their electricity rates that may result from regulatory filings."[20]

Relevance: IRAC's own statements in this proceeding establish a high transparency standard for the deferral account assessment. This standard is fully consistent with the principles emerging from the cross-jurisdictional analysis above: regulators across Canada require full disclosure, independent scrutiny, and demonstrated prudence before permitting utilities to pass costs to ratepayers through deferral mechanisms.

9. Principles Emerging from Canadian Jurisprudence

The cross-jurisdictional analysis above yields the following principles that IRAC should apply in assessing MECL's WIP deferral account request:

Principle 1 – Deferral accounts are for unforeseen costs, not planning failures. The OEB and AUC have consistently held that deferral accounts are designed for costs that are unforeseen, extraordinary, or beyond management control. MECL's capacity need has been known for years; the urgency of the current request is a product of MECL's own planning timeline, not an external shock.[1][7]

Principle 2 – Prudence review must precede cost recovery. In every jurisdiction surveyed, regulators have preserved their authority to conduct prudence reviews of costs booked to deferral accounts. The OEB's Darlington decision imposed $33 million in disallowances even for a project whose need was legislatively mandated.[4][5] The BCUC reserved Site C cost review authority.[17] IRAC should explicitly state that any deferral approval does not prejudge the prudence of the underlying expenditures.

Principle 3 – Risk must be shared between utility and ratepayers. The OEB (EPCOR), AUC (ENMAX Green Line), and Manitoba PUB all rejected proposals that placed 100% of cost risk on ratepayers. MECL's proposal assigns all pre-approval commitment risk to ratepayers and none to shareholders.[6][8][18]

Principle 4 – Deferral accounts cannot create faits accomplis. The AUC's willingness to order refunds of amounts already collected under placeholder mechanisms (ENMAX Green Line) demonstrates that pre-approval spending does not guarantee cost recovery. IRAC should be explicit that MECL proceeds at its own risk with any expenditure made before Commission approval.[8]

Principle 5 – Carrying costs compound and must be controlled. Ontario's $470 million in projected carrying costs on deferred nuclear costs, and the NSUARB's explicit prohibition on passing carrying costs for non-regulated deferral assets to ratepayers, demonstrate that the true cost of deferral substantially exceeds the nominal amounts deferred.[5][11]

Principle 6 – Transparency is non-negotiable. The ATCO enforcement action ($7 million in penalties and refunds), the BCUC's insistence on removing government-imposed restrictions on regulatory oversight,

and IRAC's own Order UE25-07A all establish that deferral account integrity requires complete transparency.[10][14][20]

Principle 7 – "Used and useful" is the standard for cost recovery. The BCUC's denial of BC Hydro's EV charging costs and removal of FortisBC's incomplete project from rate base confirm that assets not yet providing service to ratepayers should not generally be recovered through rates.[15][16]

10. Recommendations to the Commission

Based on the foregoing analysis, Energy Democracy Now! respectfully submits that the Commission should:

(a) Deny MECL's WIP deferral account request in its current form, as the level of pre-approval financial commitment sought is, to EDN's knowledge, unprecedented in Canadian regulatory practice and is inconsistent with the foundational principles governing deferral accounts across all surveyed jurisdictions.

(b) If the Commission determines that some form of preliminary expenditure authorization is warranted, impose conditions consistent with the principles identified in this submission, including: a prudence review requirement for all expenditures before recovery, with the burden of proof on MECL; no carrying costs on deferral balances until the project demonstrates net ratepayer benefit; shareholder liability for a minimum of 50% of costs if the project is cancelled or denied; independent third-party verification of all costs; and quarterly public reporting of all transactions.

(c) Explicitly state that any expenditure MECL incurs prior to full Commission approval of the generation project is at MECL's own risk and does not create any presumption of cost recovery from ratepayers, consistent with the AUC's approach to placeholder funding mechanisms.

(d) Require MECL to complete a comprehensive alternatives analysis, including grid-forming BESS, demand-side management, and virtual power plant options, before any deferral account is established, consistent with the IRP best practices identified in EDN's primary submission.

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