Nova Scotia Energy Board

IN THE MATTER OF the *More Access to Energy Act*, SNS 2024, c. 2, Sch. B, (the "MAEA")

and

IN THE MATTER OF an application by the Nova Scotia Independent Energy System Operator for an Order or Orders made pursuant to Section 29 of the *Act* for the review of its proposed expenditure and revenue requirements and the fees it proposes to charge for the fiscal year between April 1, 2027 and March 31, 2028.

IESO Nova Scotia – Proposed Expenditures, Revenue Requirement, and Fees Application

November 5, 2026

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[1] IESO Nova Scotia is appending the redacted Consumer Advocate and Small Business Advocate annual reports as filed with the Board in M12776.

1 Introduction

1.1 Overview

This is the Revenue Requirement, Proposed Expenditures, and Fees application (the "Application") of the Nova Scotia Independent Energy System Operator (IESO Nova Scotia) for the fiscal period beginning on April 1, 2027 and ending March 31, 2028, submitted to the Nova Scotia Energy Board ("NSEB" or the "Board") for approval in compliance with Section 29 of the *More Access to Energy Act* (the "MAEA" or the "Act").

This is the third application in which IESO Nova Scotia seeks approval of its proposed revenue requirements under s.29 of the MAEA. IESO Nova Scotia is Nova Scotia's not-for-profit independent energy system operator, a small organization established under the MAEA with a significant mandate. The organization was stood-up in December 2025 with administration and operational staffing for Phase 1 functions (i.e. System Planning, Interconnection Request Management, and Energy Procurement). As such, at the time of this filing, IESO Nova Scotia has less than a full year of operational experience behind it.

Nevertheless, IESO Nova Scotia has accomplished much in its nascent phase, with much more work ahead as it takes on the important task of transforming the Nova Scotia energy system. IESO Nova Scotia is growing to achieve its legislative mandate and learning from its operational and regulatory experience with a focus on continuous improvement and efficiency. This Application and the revenue requirement, proposed expenditures, and fees proposed for approval herein, reflect IESO Nova Scotia's work in achieving its mandate in fiscal year 2027/2028 and beyond, as well as improvements based on lessons learned and NSEB direction.

In accordance with IESO Nova Scotia's mandate, this Application is seeking approval from the NSEB for:

- Proposed Expenditures associated with:
  - capital costs (capital work in progress) for 2026/2027, 2027/2028, 2028/2029, and 2029/2030 for the proposed Phase 2 Control Centre in the amount of $48.99M.
- Total Revenue Requirement for 2027/2028 of $15.19M associated with:
  - amortization expense related to capital costs for its Phase 2 Control Centre, for one month of 2027/2028 (March 2028) in the amount of $0.38M;
  - amortization expense related to other capital cost categories in the amount of $0.05M
  - ongoing Operating, Maintenance, and Administration (OM&A) costs in the amount of $14.76M.
- IESO Nova Scotia's Net Revenue Requirement Deferral Variance Mechanism (DVM) Guidelines and Accounting Policies as it relates to approval of variances under the DVM.
- Fees[2] associated with:
  - The underlying fee recovery mechanism for which IESO Nova Scotia applied for Board approval in M13007;
  - All eligible revenue requirements;
  - Variances from the 2025/2026 revenue requirement application (M12412) calculated via the DVM.[3]
  - And in the amounts of:
    - True-Up Option 1:
      - NS Power - $1,218,112
      - Berwick Electric Commission - $5,024
      - Riverport Electric Light Commission - $1,171
      - Town of Mahone Bay - $2,034

[2] Fees are subject to applicable HST.

[3] Subject to the outcome of NSEB approval of either True-up Option 1 or 2 as noted in IESO Nova Scotia's Fee Recovery Mechanism Application (M13007) which is currently before the Board.

    - Town of Antigonish - $10,907
- Or True-Up Option 2:
    - NS Power - $1,246,595
    - Berwick Electric Commission - $5,034
    - Riverport Electric Light Commission - $1,171
    - Town of Mahone Bay - $1,991
    - Town of Antigonish - $11,035
- Alternatively, fees beginning on April 1, 2027 as requested in M13007 and reasserted in section 4.5 in alignment with s.29(3) of the MAEA, in the event Fees for fiscal year 2027/2028 are not approved by the NSEB by March 31, 2027.

Given IESO Nova Scotia's not-for-profit status, NSEB approval of its proposed expenditures, revenue requirements, and fees on a timely basis is of critical importance for the organization to continue to carry-out its important legislatively mandated work. IESO Nova Scotia's ability to do so assumes fees sought via its Fee Recovery Mechanism application (M13007) are received in full by March 31, 2027 as requested, and commercial funding is received to complete Phase 2 Project work facilitated through NSEB approval of those proposed expenditures in this Application. As such, IESO Nova Scotia respectfully requests NSEB approval for all of the above by March 31, 2027, in alignment with IESO Nova Scotia's fiscal year as established by the MAEA. If in the event the NSEB believes it is unable to do so, then IESO Nova Scotia respectfully requests that the Board provide a Decision by December 31, 2026 regarding fees beginning on April 1, 2027 in alignment with s.29(3) as requested in M13007 and again in section 4.5 below.

1.2 Background

This is the third Application in which IESO Nova Scotia seeks approval of its proposed revenue requirements under s.29 of the MAEA, but is the first such application in which approval is sought for other proposed expenditures under s. 29 of the MAEA. Section 29 requires IESO Nova Scotia to submit its proposed expenditure and revenue requirements for the fiscal year at least 90 days before the beginning of each fiscal year, for review.

Pursuant to subsection 29(4) of the MAEA, the Nova Scotia Energy Board may either (a) approve the proposed expenditure and revenue requirements and the proposed fees, or (b) may refer them back to the IESO Nova Scotia for further consideration with the Energy Board's recommendations.

IESO Nova Scotia is a not-for-profit body corporate established upon the proclamation of certain sections of the MAEA on October 24, 2024. As the Board is aware from previous hearings, the organization has progressed from Board of Directors, with no employees or officers, for the first several months of 2025, to a maturing organization carrying out system planning, energy resource procurement, and interconnection processes under the scope of its Phase 1 operations. Important milestones in that development are:

- The appointment of the Board of Directors in February of 2025;
- The hiring of the President and CEO on August 18, 2025;
- The hiring of the balance of the senior leadership team in October and November 2025;
- The transitioning of 21 system planning employees from NS Power in December 2025;
- Hiring of additional Phase 1 staff for a total of 40 employees to date.

The MAEA introduced a suite of fundamental reforms to the province's energy sector, which, among other things, mandated a transfer of certain system functions from the incumbent utility, Nova Scotia Power (NS Power), to the not-for-profit independent system operator, IESO Nova Scotia.

The proclamation of the MAEA contemplated a phased transition; while system planning, procurement, and other objects came into force on October 24, 2024, responsibility for real-time energy dispatch and related functions was not immediately transferred. IESO Nova Scotia understands from the Province of Nova Scotia that IESO Nova Scotia should prepare for proclamation of subsections 9(b)(c)(d)(e) and sections 75 to 85 (excluding section 84) of the MAEA as soon as possible. These additional responsibilities have been collectively referred to as "Phase 2".[4] Accordingly, IESO Nova Scotia has pursued a phased transition of the system operator functions from NS Power, commencing with Phase 1 (independent energy procurement, system planning, and generation interconnection functions), followed by Phase 2 (independent energy dispatch operations and related functions).

Work underway or completed by IESO Nova Scotia in this short Phase 1 timeframe has been substantial and includes the following:

- Commencement of and continued progress on IESO Nova Scotia's inaugural Integrated Resource Plan.

[4] It is also referred to as the "Independent Grid Operations (IGO) Program" in the 2027/2028 Plan.

- Completed the first Cluster System Impact Study for the Nova Scotia system, comprising four wind generation facilities, as well 9 System Impact Studies and 1 Feasibility Study.
- Supported the commissioning of three transmission-connected BESS facilities and six transmission-connected wind farms.
- Worked with the NS Department of Energy and its Procurement Administrator to inform the procurement approach and develop the Feasibility Study and Deliverability Assessment process being used for the Green Choice 2 wind procurement, launched in September 2026.
- Supported the Atlantic Canada Offshore Wind Grid Integration and Transmission Study, led by Net Zero Atlantic, as a member of the Technical Committee
- Progressed Resource Adequacy and Transmission Adequacy studies required under NERC and NPCC reliability standards.
- Participated in NERC and NPCC committees, task forces, and working groups aligned to IESO-NS's functional roles of Resource Planner, Transmission Planner, and Planning Coordinator.
- Entered into agreement with New Brunswick Power for capacity from its RIGS program with New Brunswick Energy and Utility Board approval.
- Launch of the Fast-Acting Generation procurement process which is ongoing.
- Launch of the technology neutral capacity procurement process which is ongoing.
- Reached agreement with NS Power on interim administration of the Standard Generator Interconnection Procedures (SGIP) and submitted agreement to NSEB.
- Developed proposed amendments to the Transmission System Interconnection Procedures (TSIP – successor to the SGIP) and initiated stakeholder engagement ahead of filing.
- Completed Phase 2 Control Centre options analysis and report by IBM consulting.
- Completed IESO Nova Scotia value case analysis and report by FTI consulting.
- Submission of its 2025/2026 Revenue Requirement Application and NSEB approval.

- Submission of its 2026/2027 Revenue Requirement and Fees Application with NSEB proceeding concluded subject to issuance of the Board's Decision and Order.
- Submission of its Fee Recovery Mechanism Application with NSEB proceeding currently underway.
- Completed its first external financial audit.
- Published its first Annual Report and submitted it to the Minister and the NSEB.
- Published its first two quarterly reports and submitted them to the NSEB.
- Submitted the first 10-Year System Outlook Report the NSEB with a corresponding NSEB proceeding underway.
- Provided comments on quarterly NERC reliability standards applications to the NSEB.
- Submission of this 2027/2028 Revenue Requirement, Proposed Expenditures, and Fees Application.
- Implemented and carried out regular intervenor engagement sessions aligned with quarterly reporting, and well as program and application specific intervenor engagement sessions.

This work has been completed by a small and dedicated team at IESO Nova Scotia. IESO Nova Scotia continues to mature as an organization, with much more work ahead in both its responsibilities under the Act and in creating an organization to match. That growth is primarily related to IESO Nova Scotia taking on Phase 2 responsibilities, including the following:

- Ownership and administration of the Market Rules and Open Access Transmission Tariff (OATT).
- Day-ahead forecasting and planning activities.
- Control Centre Operations including North American Electric Reliability Corporation (NERC) Transmission Operator (TOP) and Balancing Authority (BA) roles.
- Settlement activities.

IESO Nova Scotia has developed a transition plan to achieve the transfer of energy dispatch and grid operations functions over several fiscal years. Within that transition plan, IESO Nova Scotia

will assume responsibility for real-time energy dispatch by establishing an independent energy control center, which is expected to be operational in March 2028.[5]

As IESO Nova Scotia continues to grow, so does its institutional experience as Nova Scotia's first independent system operator. It is important to note that, at the time of this filing, the organization has only been stood up under Phase 1 operations for less than a full calendar year. As such, IESO Nova Scotia acknowledges that there is still much benefit to be gained from further experience and growth. With this in mind, IESO Nova Scotia views this Application within the framework of a nascent organization focused on continuous improvement, so that each s.29 application incorporates improvements year-over-year, resulting in the NSEB and stakeholders being better able to assess the reasonableness of IESO Nova Scotia's revenue requirement, proposed expenditures, and fees. Accordingly, as noted in IESO Nova Scotia's reply to closing in last fiscal year's revenue requirement application (M12663), IESO Nova Scotia believes a forward-looking approach is a reasonable framework, focused on continuous improvement, to assess this Application as well as intervenors' forthcoming comments.

To that end, and as described in the sections that follow, this Application addresses various NSEB direction, and increases transparency and evidentiary detail where possible and commensurate to the materiality of IESO Nova Scotia's proposed expenditures and revenue requirement in these early days of IESO Nova Scotia's operations.

1.3 Material Changes in the Application

The Board and parties will note that this Application differs in some respects from the prior applications for the 2025/2026 and 2026/2027 fiscal years. The material changes or additions fall under several categories described below.

[5] The target transition date for Phase 2A of March 2028 was identified following the design and planning work described in this Application and replaces the aspirational transition date referenced in prior matter before the NSEB, before this necessary work was undertaken.

Presentation of OM&A Expenditures in the Revenue Requirement

As IESO Nova Scotia matures as an organization and gains valuable experience and feedback in the regulatory process, it is committed to improving the quality and presentation of its evidence in those processes.

In this Application, in Section 3.4, IESO Nova Scotia presents OM&A expenses in its revenue requirements in a manner that is more closely aligned to functions performed. That portion of the evidence also provides the details of how the 2025/26 and 2026/27 revenue requirements have been recharacterized in the updated reporting framework. This will enable the Board to evaluate cost categories on a consistent basis across prior fiscal years and the forecast test period.

Further detail of proposed OM&A expenses appears in Section 3.4 of this Application.

Phase 2 Control Centre Project and Phase 2A and 2B Capital Costs

As noted above, IESO Nova Scotia plans to assume responsibility for real-time energy dispatch and related functions over several fiscal years. The Phase 2 Control Centre project is itself planned in three sub-phases, as follows:

- **Phase 2A** – Will establish the IESO Nova Scotia physical control centre, as required to fulfil the organization's mandate under the MAEA, enable independent Balancing Authority (BA)/Transmission Operator (TOP) operations, and create defined physical and cyber boundaries
- **Phase 2B** - Introduces province-wide settlement, as required by the MAEA, market participant communication workflows, additional analytics, and enhanced transparency capabilities.
- **Phase 2C** – Delivers enhanced operational processes and capabilities that further optimizes both the economic and reliability aspects of the grid. This will include exploring the opportunity and benefits of an independent Energy Management System (EMS).

The capital costs associated with Phase 2 are planned to occur across the three sub-phases, over a period of around 5 years.

Accordingly, as part of this Application, in addition to detail on its proposed 2027/28 revenue requirements, IESO Nova Scotia provides detail of all three sub-phases of the Phase 2 Control Centre project, and seeks Board approval of:

- The Phase 2A capital costs in the amount of $40.91 million;
- The Phase 2B capital costs in the amount of $8.08 million;
- Forecast amortization in the amount of $0.38 million with respect to Phase 2A capital costs.

IESO Nova Scotia is not seeking approval for Phase 2C costs or activities at this time. Phase 2C is not strictly required to take on its initial mandate under the MAEA, and it is believed that there would be benefit to customers in the short term by delaying the investment until IESO Nova Scotia has actual operating experience to enable it to further validate, refine, and optimize the enhancement plans to maximize the anticipated benefits for customers over the longer term. IESO Nova Scotia intends to justify any proposed future Phase 2C scope and expenditures in a future revenue application with more advanced development and scoping, while taking into consideration regional electricity market circumstances as they develop.

Further detail on the Phase 2 Control Centre project, including the options analysis and capital and operating expenditure forecasts for the proposed option, appears in Section 3.2 of this evidence.

Amortization Expense Related to Capital Assets in Service

Amortization, consisting of capital asset depreciation and interest expense, is now a line-item expense in the revenue requirements, due to capitalization of information technology assets and the transmission control centre forecast to be placed in service in March 2028. IESO Nova Scotia also forecasts interest expense related to the debt incurred to fund these capital expenditures. Further detail of depreciation policies and calculation of depreciation expense appears in section 3.3.

Revenue Requirement Variances from FY 2025/26

In Board matter M12412, the Board approved the creation of a Net OM&A Deferral and Variance Account with respect to the 2025/2026 fiscal year, and directed IESO Nova Scotia to develop and file guidelines and policies related to the account prior to recovery of any variances and

no later than the filing of this Application. In Board matter M12663, IESO Nova Scotia sought approval of a new Net Revenue Requirement Deferral and Variance Mechanism (DVM).

Although the NSEB's approval of the new DVM is pending, IESO Nova Scotia has calculated the forecast to actual variance for fiscal year 2025/2026 on the basis of the DVM, as it is merely an extension of the OM&A Deferral and Variance Account, and the resulting variance calculation is the same under either variance calculation methodology. Likewise, guidelines have been developed and provided in this Application for the DVM, and Accounting Policies and a description of Financial Controls are also included in this Application, per NSEB direction in M12412.

IESO Nova Scotia presents its evidence with respect to the variances from the approved 2025/2026 revenue requirements and proposed disposition of the (positive) variance in Section 4.3.

Approval of Fees

In Board matter M13007, IESO Nova Scotia applied for approval of a fee recovery mechanism to recover approved revenue requirements and variances from those revenue requirements. At the time of filing this Application, a decision in M13007 has not yet been rendered.

In this Application, IESO Nova Scotia presents its proposed fees for fiscal year 2027/2028 based on the methodology it proposed in M13007. To the extent the Board alters that methodology in its final decision, adjustments to the proposed fees may be necessary.

The proposed fees and supporting evidence appear in Section 4.

1.4 Process

This Application reflects a more detailed budgeting process than was possible for IESO Nova Scotia's first two revenue requirement applications. The organization has developed three annual budgets within approximately 18 months while simultaneously establishing its operations and advancing the transition of additional system operator responsibilities. As a result, the budgeting process and supporting level of detail have evolved quickly, although IESO Nova Scotia recognizes that its forecasts will continue to be refined as the organization gains additional operating experience.

The 2025/2026 budget was developed at a high level by the Board of Directors before the organization had management or employees in place. The 2026/2027 budget was subsequently developed by management by scaling the prior-year budget and incorporating known changes. Building on that work, the proposed 2027/2028 budget was developed through a bottom-up process led by IESO Nova Scotia's leadership and informed by the organization's 2026/2027 budget, and the priorities and workplan set out in IESO Nova Scotia's 2027/2028 Business Plan. Available contracts, invoices, quotes, market information, estimates and other supporting documentation were also considered in developing significant budget items.

The consolidated budget was reviewed by the Audit and Risk subcommittee of the IESO Nova Scotia Board, and finally approved by the full independent IESO Nova Scotia independent Board of Directors on October 29, 2026.

The process also included the development and integration of two related financial components:

- an OM&A budget for the continued delivery of IESO Nova Scotia's existing responsibilities and the commencement of system operations; and
- a capital plan, principally associated with the Phase 2 Control Centre project and other capital additions.

These components were developed together so that the proposed revenue requirement reflected not only departmental operating needs, but also the expected in-service timing of capital assets, related amortization, applicable financing costs, and the cash requirements associated with the organization's capital program. Project costs directly attributable to developing the Phase 2 Control Centre were identified and treated as capital costs where appropriate, rather than included in current-period OM&A.

As part of this process, IESO Nova Scotia revised the presentation of its OM&A cost categories. Employee compensation is now included within the functional department responsible for the work, rather than presented as two separate organization-wide categories. The revised categories are intended to align costs more closely with the functions performed, improve management visibility and accountability, better articulate and track expenditures, and respond to IESO Nova Scotia's understanding of the information sought by the NSEB during the

prior revenue requirement proceeding. To provide a meaningful year-over-year comparison, the 2026/2027 budget was reallocated and restated using the new categories.

In addition to the detailed 2027/2028 budget, management prepared indicative outlooks for 2028/2029 and 2029/2030 in response to the NSEB's direction to provide multi-year forecasts. Those outlooks incorporate known changes, including the expected full-year effect of the transfer of system operations and the elements of the Phase 2 Control Centre entering service, anticipated staffing requirements, inflation and other identifiable cost drivers. The outlooks are necessarily less precise than the 2027/2028 budget and are expected to change as the Phase 2 project advances and IESO Nova Scotia gains further operating experience.

1.5 Update and Compliance with Board Orders and Directives

In its Decision dated February 25, 2026 in Board Matter M12412, the Board provided a number of specific directives for action by IESO Nova Scotia. The directives and IESO Nova Scotia's response to each appear in Figure 1 below.

Figure 1: NSEB Direction

NSEB Directive	IESO Nova Scotia Response
Accounting Policies "The Net OM&A Deferral and Variance Account is approved. However, specific guidelines and accounting policies must be developed and approved before there is a recovery of Net Ongoing OM&A amounts from the Deferral and Variance Account. IESO Nova Scotia is directed to include these specific guidelines and accounting policies, and a description of the financial controls it has adopted, no later than its application for the 2027/2028 revenue requirement."	Attached in Appendix 1 IESO Nova Scotia's accounting policies have been finalized as incorporated in the 2025-2026 audited financial statements. They are provided herein for the NSEB's review and approval as it relates to approval of variances under the DVM. Notably, they provide the foundation on which capital expenditures are treated and depreciated.

Financial Controls "The Net OM&A Deferral and Variance Account is approved. However, specific guidelines and accounting policies must be developed and approved before there is a recovery of Net Ongoing OM&A amounts from the Deferral and Variance Account. IESO Nova Scotia is directed to include these specific guidelines and accounting policies, and a description of the financial controls it has adopted, no later than its application for the 2027/2028 revenue requirement."	**A**ttached in Appendix 2 Financial controls are in place at IESO Nova Scotia. The attached description of financial controls provides a reviewable version of those controls.
DVM Guidelines "The Net OM&A Deferral and Variance Account is approved. However, specific guidelines and accounting policies must be developed and approved before there is a recovery of Net Ongoing OM&A amounts from the Deferral and Variance Account. IESO Nova Scotia is directed to include these specific guidelines and accounting policies, and a description of the financial controls it has adopted, no later than its application for the 2027/2028 revenue requirement."	Attached in Appendix 3 The DVM guidelines have been developed and shared with stakeholders for their feedback in advance of the filing of this Application. They are provided herein for the NSEB's review and approval as it relates to approval of variances under the DVM. They describe in further detail the treatment of variances related to forecast versus actual expenditures in a prior fiscal year. The guidelines have been developed for the Net Revenue Requirement DVM proposed under M12663, which are an extension of the OM&A Deferral and Variance Account approved by the NSEB in M12412.
Business Plan "The Board directs that minimum filing requirements will apply to IESO Nova Scotia's future applications, including: …	Attached in Appendix 4 IESO Nova Scotia's business plan is attached for the NSEB's review and includes: a detailed workplan of IESO Nova Scotia's planned activities in the period covered by the revenue requirement application connecting each activity to the

• An annual business plan that includes: - a detailed workplan of IESO Nova Scotia's planned activities in the period covered by the revenue requirement application connecting each activity to the achievement of IESO Nova Scotia's objects in the *More Access to Energy Act*; - timelines for activities expected to span more than one year; - an analysis of the past year's results, including reasons for failing to complete activities in the prior business plan and the reasons for any adjustments to timelines for longer-term activities;"	achievement of IESO Nova Scotia's objects in the *More Access to Energy Act*; timelines for activities expected to span more than one year; and an analysis of the past year's results and reasons for any adjustments to timelines for longer-term activities.
Historical Costs and Forecasts. "The Board directs that minimum filing requirements will apply to IESO Nova Scotia's future applications, including: … • Up to five years of actual audited historical financial results as they become available; • Three years of projected financial results;	Historical costs have been provided for actuals for fiscal year 2025/2026, which are the only full fiscal year actuals available at this time. Please refer to section 4.3. A three-year forecast, along with a description of material assumptions is provided as well. Please refer to section 3.5.
Assumptions and Expenditures Support **"**The Board directs that minimum filing requirements will apply to IESO Nova Scotia's future applications, including: • Formal support for all significant assumptions and expenditures in the application, such as quotes, any referenced market information, correspondence from discussions surrounding	IESO Nova Scotia has provided descriptions of assumptions for all cost categories and provided support, where available and appropriate, for significant expenditures.

estimates, market data supporting employee salaries, etc.;"	
Stakeholder Engagement "The Board directs that minimum filing requirements will apply to IESO Nova Scotia's future applications, including: … • Details of engagement activities with Indigenous groups and stakeholders."	Please refer to section 1.6 below.
Quarterly Reporting "IESO Nova Scotia is directed to file quarterly reports starting on May 15, 2026, including updates about the status of Phase 1 and 2 of the transition of the system operator functions from NS Power to the IESO, as well as reporting about staffing, facilities and technology, regulatory compliance matters, on any material changes to the transition timeline or to forecast costs, and further items as outlined in the Board's decision."	IESO Nova Scotia has provided two quarterly reports to the NSEB to date: May 15, 2026 and August 21, 2026. While the quarterly reporting obligation was resulting from IESO Nova Scotia's 2025/2026 Revenue Requirement Application, which fiscal year has now concluded, IESO Nova Scotia recognizes during active development and evolution towards implementation of the MAEA, that the NSEB and intervenors may find value in this quarterly reporting. Accordingly, IESO Nova Scotia will continue to proactively provide these reports to the NSEB, whether or not ordered in this Application.

1.6 Stakeholder Engagement

Regulatory Stakeholders

Over the course of the last fiscal year and into fiscal year 2026/2027, IESO Nova Scotia has accelerated work on regulatory stakeholder engagement. Engagement has occurred both formally and informally, and on specific projects and proceedings via general or quarterly report updates.

Since the submission of its 2026/2027 Revenue Requirement Application, IESO Nova Scotia has held stakeholder engagement sessions for the following regulatory items:

- Quarterly Report dated May 15, 2026
- Quarterly Report dated August 21, 2026
- Fee Recovery Mechanism Application (M13007) dated July 31, 2026

The Fee Recovery Mechanism stakeholder engagement process provided multiple pieces of application relevant documentation in advance, including presentations, studies, models, and responses to stakeholder questions, over three sessions from May to July 2026. Those details were described in IESO Nova Scotia's update to the NSEB on July 6, 2026 as well as in the corresponding application.

In addition to the foregoing, IESO Nova Scotia held three stakeholder engagement sessions regarding this Application, held on September 17, 2026, October 1, 2026, and October 22, 2026. Stakeholders were provided with presentation materials, previews of the structure and content of the application, reconciliations with the last fiscal year application cost categories, previews of indicative budgets by cost category, and advance review of the DVM Guidelines. Stakeholders were also given the opportunity to ask questions and provide feedback on certain aspects of the application.

It is IESO Nova Scotia's intention to continue to engage with regulatory stakeholders on significant regulatory initiatives and applications in advance of filing, as well as on the quarterly reports for regular updates on general IESO Nova Scotia work and matters.

General Stakeholders

Throughout both last fiscal year and the 2026/2027 fiscal year to date, IESO Nova Scotia has invested significant time and energy into engaging with a broad range of stakeholders. This includes, but is not limited to, industry stakeholders, from market participants and electricity sector partners to large industrial electricity consumers; elected officials and staff at the municipal, provincial, and federal levels of government; advocacy groups and non-governmental organizations; representatives from interested communities; and individual Nova Scotians.

Stakeholder engagement has pertained to a number of topics, including but not limited to the province's electricity infrastructure needs, specific energy resource procurements both ongoing

and planned, and increasing stakeholder awareness of the Integrated Resource Plan process and opportunities to participate.

IESO Nova Scotia has worked to be responsive to the unique needs of its many stakeholders. Engagement formats have ranged from formal opportunities such as presentations to municipal councils, community meetings, open house information sessions, and industry conferences, to informal settings such as drop-in office hours and one-on-one conversations with residents in communities where projects are being proposed.

Engagement with stakeholders — from industry to community to government — will continue to be a priority throughout the 2027/2028 fiscal year and beyond.

Indigenous Communities and Organizations

Over the course of IESO Nova Scotia's first year of operations, as well as throughout the 2026/2027 fiscal year to date, the organization has worked to initiate and build relationships with Mi'kmaw communities and organizations across the province.

Engagement has focused to date on introducing the independent system operator and its role in the province's energy system going forward, inviting and supporting Mi'kmaw participation in Nova Scotia's Integrated Resource Plan process for the first time, and sharing information on proposed energy infrastructure projects.

IESO Nova Scotia's engagement with Mi'kmaw communities and organizations, including Kwilmu'kw Maw-klusuaqn (KMK) and the Assembly of Nova Scotia Mi'kmaw Chiefs, Wskijinu'k Mtmo'taqnuow Agency, Ltd. (WMA), the Confederacy of Mainland Mi'kmaq, the Mi'kmaw Economic Benefits Office, the Native Council of Nova Scotia, and a number of First Nations leaders including Chiefs and Councils, has included written correspondence, in-person and virtual meetings, presentations and structured engagement sessions, and ongoing dialogue.

To support and further enhance this relationship-building work, IESO Nova Scotia has engaged a Mi'kmaw-owned firm to co-develop an organization-wide Indigenous Relations Framework. This Framework will guide IESO Nova Scotia's continued engagement and collaboration with Mi'kmaw communities and organizations in the work of building the province's energy future.

1.7 Requested Approvals

IESO Nova Scotia seeks the following approvals from the Board by March 31, 2027:

1. Approval of Phase 2 Control Centre project Phases 2A and 2B and corresponding capital work in progress proposed expenditures in the total amount of $48.99 million (please refer to section 3.2);
2. Approval of the revenue requirements for the 2027/28 fiscal year in the amount of $15.19 million (please refer to Sections 3.3 and 3.4);
3. Approval of IESO Nova Scotia's DVM Guidelines and Accounting Policies as it relates to approval of variances under the DVM;
4. Approval of a positive overall variance of $343k via Net Revenue Requirement Deferral and Variance Mechanism with respect to the 2025/2026 fiscal year (please refer to section 4.3); and
5. Approval of fees[6] for fiscal year 2027/2028 (please refer to section 4):
    - True-Up Option 1:
        - NS Power - $1,218,112
        - Berwick Electric Commission - $5,024
        - Riverport Electric Light Commission - $1,171
        - Town of Mahone Bay - $2,034
        - Town of Antigonish - $10,907
    - Or True-Up Option 2:
        - NS Power - $1,246,595
        - Berwick Electric Commission - $5,034
        - Riverport Electric Light Commission - $1,171
        - Town of Mahone Bay - $1,991
        - Town of Antigonish - $11,035
6. In the event Fees for fiscal year 2027/2028 are not approved by the NSEB by March 31, 2027, approval of fees beginning on April 1, 2027 under s.29(3) of the MAEA as requested in M13007 (please refer to section 4.5).

[6] Fees are subject to applicable HST.

1.8 Structure of the Application

The balance of the Application is structured as follows:

- **Section 2: IESO Nova Scotia Business Plan and Linkage to Proposed Expenditures and Revenue Requirement**
- **Section 3: Proposed Expenditures and Revenue Requirement**
  - **Section 3.1: Introduction** - Summary of proposed expenditures and revenue requirement
  - **Section 3.2**: **Proposed Expenditures** – Costs related to capital work in progress for the Phase 2 Control Centre project.
  - **Section 3.3: Amortization** – Costs related to Information Technology and Phase 2 Control Centre capital asset depreciation and interest expense, forming one part of IESO Nova Scotia's revenue requirement.
  - **Section 3.4: OM&A** – Costs regarding various categories of operational expense, forming the other part of IESO Nova Scotia's revenue requirement.
- **Section 4: Fees** – Calculation of fees based on IESO Nova Scotia's revenue requirement.
- **Section 5: Conclusion** – Summation of the Application
- **Section 6: Relief Sought** – Enumeration of the approvals sought from the NSEB.

2 IESO Nova Scotia Business Plan and Linkage to Proposed Expenditures and Revenue Requirement

2.1 Role of the Business Plan

IESO Nova Scotia's 2027/2028 Business Plan (Appendix 4) is filed with this Application in accordance with the Board's direction in M12412. The Business Plan establishes the work IESO Nova Scotia intends to undertake during the fiscal year, identifies the expected timing of that work, and connects the organization's planned activities to its objects and responsibilities under the *More Access to Energy Act* ("MAEA"). It also reports on progress in prior years and identifies activities that form part of longer-term initiatives extending beyond 2027/2028.

The Business Plan and this Application are complemented by IESO Nova Scotia's 2027/2028 Plan, published on IESO Nova Scotia's website.[7] The Business Plan, the 2027/2028 Plan, and this Application serve related but distinct purposes. The Business Plan and the 2027/2028 Plan describe what IESO Nova Scotia intends to deliver and why that work is required. This Application identifies the capital expenditures, operating costs and other revenue requirement components necessary to deliver that work, together with the supporting cost estimates, assumptions and evidence. Read together, the documents demonstrate how the organization's proposed expenditures and revenue requirement support the discharge of its legislative mandate.

The Business Plan and the 2027/2028 Plan are organized around six annual enterprise priorities for 2027/2028:

1. complete the successful transition of system operations;
2. advance system reliability, building on the Integrated Resource Plan;
3. strengthen system-user engagement, transparency and access;
4. build external trust and shape energy policy to benefit Nova Scotians;
5. progress important regulatory outcomes; and
6. build a strong organization where people want to work and grow.

These priorities are not separate from IESO Nova Scotia's statutory responsibilities. They translate the objects of the MAEA into a practical annual workplan and form the basis on which the organization has allocated resources and developed its 2027/2028 budget. The sections below summarize the relationship among the MAEA, the Business Plan and the costs for which approval is sought in this Application.

2.2 Legislative Mandate and Business Plan

The MAEA established IESO Nova Scotia as an independent, not-for-profit energy system operator and assigned it responsibilities for electricity system planning, the procurement of energy resources, transmission interconnection functions and, following the next stage of the

[7] https://www.ieso-ns.ca/reports-and-resources/

statutory transition, the real-time operation of the province's bulk electricity system. IESO Nova Scotia's mandate also includes responsibilities related to reliability, competitive market development, settlements, regional coordination, demand and resource forecasting, public information, and the diversification of Nova Scotia's electricity supply.

IESO Nova Scotia has implemented this mandate in phases. The first major transfer of responsibilities was completed on December 1, 2025, when IESO Nova Scotia assumed responsibility for transmission planning, integrated resource planning, transmission interconnection processes and the procurement of new electricity resources (Phase 1). The next major stage is the transfer of real-time system operations and associated responsibilities from Nova Scotia Power to IESO Nova Scotia (Phase 2).

The 2027/2028 Business Plan reflects both dimensions of the organization's work:

- the continued performance and development of responsibilities already transferred to IESO Nova Scotia, including planning, procurement and interconnection work; and
- the establishment of the people, facilities, technology, processes, commercial arrangements and compliance capabilities required to assume real-time system operations.

Accordingly, the Business Plan is both an annual operating plan and a transition plan. It provides for the continued delivery of IESO Nova Scotia's existing responsibilities while advancing the further institutional and operational changes contemplated by the MAEA.

2.3 Business Plan Priorities and Cost Linkages

2.3.1 Complete the Successful Transition of Independent Grid Operations

The first and most significant enterprise priority for 2027/2028 is to establish the capabilities required for IESO Nova Scotia to assume real-time system operations from NS Power while maintaining reliability throughout the transition.

The Business Plan and the 2027/2028 Plan identify the principal components of this work as:

- repurposing and refurbishing an existing facility to establish a dedicated independent control centre;

- implementing the operational and information technology required to support real-time system operations;
- developing operational processes and transferring necessary institutional knowledge;
- recruiting, transferring and training the required workforce;
- establishing the compliance framework necessary to perform the BA and TOP functions;
- updating the Market Rules, Market Procedures and Open Access Transmission Tariff;
- completing testing, readiness assurance and cutover activities; and
- developing the settlement, reporting and market-participant capabilities required to support the independent operating model.

This priority directly advances, among other objects, the authority to enter into agreements respecting the operation of the transmission system, direct the operation of the IESO-controlled grid, establish and enforce reliability criteria, maintain the adequacy and reliability of the bulk electricity system, administer settlement-related activities, and carry out the other functions necessary to operate as an independent energy system operator.

The proposed capital expenditures for Phases 2A and 2B of the Control Centre project are the principal costs associated with this priority. IESO Nova Scotia is seeking approval of approximately $48.99 million in capital work in progress for these phases across the 2026/2027, 2027/2028, 2028/2029, and 2029/2023 fiscal years. Those expenditures include the control centre facility, operational and information technology, cybersecurity, reliability compliance, program integration, transition support, training and the settlement and market-administration capabilities necessary to establish the proposed operating model.

The 2027/2028 revenue requirement also includes one month of forecast operating and amortization costs associated with the planned March 2028 in-service date. These costs are reflected principally in the System Operations, Information Technology, Facilities, Finance and supporting corporate cost categories. Together, the proposed capital and operating expenditures provide the financial resources required to implement the next major stage of the MAEA mandate.

2.3.2 Advance System Reliability, Building on the Integrated Resource Plan

The second enterprise priority concerns IESO Nova Scotia's responsibility to plan for Nova Scotia's future electricity needs and procure the resources necessary to maintain reliability at the best possible cost.

IESO Nova Scotia expects to complete its inaugural Integrated Resource Plan before the beginning of the 2027/2028 fiscal year. The focus in 2027/2028 will therefore move from developing the plan to advancing its near-term action and procurement items. Planned work includes:

- implementing priority actions identified through the Integrated Resource Plan;
- continuing the competitive procurement for fast-acting generation;
- advancing procurement steps following the technology-neutral capacity Request for Qualifications;
- overseeing the New Brunswick capacity arrangement and other contracted resources;
- undertaking transmission and resource-adequacy planning;
- monitoring the development and delivery of procured programs; and
- beginning preparatory work for subsequent planning cycles.

These activities support IESO Nova Scotia's MAEA objects relating to power-system planning, procurement of energy resources, reliability and adequacy, regional coordination, diversification of supply, achievement of system-wide energy-source objectives, and the collection and publication of information regarding Nova Scotia's electricity needs.

The costs associated with this priority are included primarily in the System Planning and Procurement category of the proposed OM&A revenue requirement. The category includes the employees, technical expertise, modelling tools, external advisory support and procurement resources required to carry out independent system resource and transmission planning, conduct competitive procurements, administer interconnection studies and oversee the progress of contracted resources. Related enabling costs are also included in Information Technology, Legal and Regulatory, Communications and Stakeholder Engagement, and Corporate Services.

Energy-resource contract costs and eligible contract-administration or settlement costs that are properly recoverable under section 30 of the MAEA are not included in this section 29

revenue requirement merely because the Business Plan refers to the underlying procurement or project. Those costs will be addressed through the applicable statutory cost-recovery process. The expenditures in this Application relate instead to the organizational activities required to plan, conduct procurements, support projects before contract execution where applicable, and carry out IESO Nova Scotia's ongoing planning and oversight responsibilities.

2.3.3 Strengthen System-User Engagement, Transparency, and Access

The third enterprise priority is intended to improve how existing and prospective system users connect to, participate in and receive information about Nova Scotia's bulk electricity system.

Planned activities include:

- continuing work to update the Transmission System Interconnection Procedures;
- completing interconnection studies and supporting the commissioning of new transmission-connected facilities;
- identifying and implementing improvements to interconnection processes;
- updating the Market Rules, Market Procedures and Open Access Transmission Tariff;
- establishing structured forums through which market participants can provide input into proposed changes; and
- developing improved information-sharing and participant-facing capabilities.

This work supports the MAEA objects relating to interconnection agreements, competitive market development, efficient system planning, connection of new resources, public access to system information, and the performance of IESO Nova Scotia's statutory duties in an open and competitively neutral manner.

The associated costs are distributed across the System Planning and Procurement, System Operations, Information Technology, Communications and Stakeholder Engagement, and Legal and Regulatory cost categories. They include the technical resources required to conduct interconnection studies, regulatory and legal support for revised procedures and market instruments, stakeholder engagement, and the proposed capital investment in an interconnection portal. They also include elements of the Control Centre project associated with market-participant communications, settlements, reporting and information access.

2.3.4 Build External Trust and Shape Energy Policy to Benefit Nova Scotians

The fourth enterprise priority supports the relationships, transparency and public accountability necessary for IESO Nova Scotia to discharge its independent mandate effectively.

IESO Nova Scotia will continue participating in regional and North American reliability activities; complete required transmission- and resource-adequacy assessments; provide input concerning reliability standards; issue quarterly and annual reports; strengthen engagement with the Mi'kmaq and other stakeholders; and improve public access to understandable information about the electricity system and the decisions facing the province.

These activities are connected to IESO Nova Scotia's responsibilities to coordinate with authorities outside Nova Scotia, participate in the development of reliability standards, maintain and report on system adequacy, make relevant system information public, and perform its statutory functions transparently and in the public interest. Engagement is also a practical requirement for effective planning, procurement, market development and implementation of the operational transition.

The corresponding costs are reflected principally in Communications and Stakeholder Engagement, with related costs in System Planning and Procurement, Legal and Regulatory, and Corporate Services. The requested funding supports public and stakeholder communications, Mi'kmaw engagement, development of an Indigenous Relations Framework, public education, required reporting, and IESO Nova Scotia's participation in reliability and policy processes. These activities are intended to support informed participation and confidence in IESO Nova Scotia's decisions, rather than promotion of the organization for its own sake.

2.3.5 Progress Important Regulatory Outcomes

The fifth enterprise priority concerns the regulatory approvals, reporting and cost-recovery arrangements required to fund and oversee IESO Nova Scotia's work.

The Business Plan includes completion of this Application and its associated proceeding, preparation of the 2028/2029 revenue requirement application, advancement of revised interconnection procedures, and continued implementation of improved budgeting, financial-control, reporting and stakeholder-engagement practices.

These activities support IESO Nova Scotia's general obligation to exercise its powers and perform its statutory duties, as well as the specific requirements of section 29 of the MAEA. They also provide the Board and stakeholders with the evidence required to assess whether IESO Nova Scotia's proposed expenditures, revenue requirements and fees are reasonable.

The related costs are included primarily in Legal and Regulatory and Finance. They include the cost of preparing and participating in regulatory proceedings, Board and intervenor-related proceeding costs, external legal and expert support, financial reporting, audit, financing and the development and maintenance of appropriate accounting policies, controls, risk-management practices and deferral and variance mechanisms. These costs provide the governance and regulatory foundation needed for IESO Nova Scotia to undertake its substantive planning, procurement and operational work.

2.3.6 Build a Strong Organization Where People Want to Work and Grow

The sixth enterprise priority recognizes that IESO Nova Scotia can discharge its mandate only if it is able to attract and retain talented individuals with the requisite knowledge, capability, and commitment to undertake specialist activities within its unique mandate.

IESO Nova Scotia plans to implement employee and leadership development initiatives, identify critical roles and knowledge, establish succession and knowledge-transfer arrangements, and recruit and prepare the workforce required for its expanding responsibilities. This is particularly important as specialized operational responsibilities and institutional knowledge are transferred from Nova Scotia Power and IESO Nova Scotia prepares to operate a control centre on a continuous basis.

These activities are enabling requirements that support the performance of IESO Nova Scotia's objects under section 9 of the MAEA. They are not independent ends. A properly qualified and trained workforce is necessary to maintain reliability, conduct planning and procurement, administer market and interconnection processes, comply with applicable reliability standards, and operate the electricity system safely and effectively.

The associated costs are reflected in compensation across the functional cost categories and in the Human Resources category, including recruitment, training, professional development, succession planning and organizational support. A portion of employee costs directly attributable to the development of the Control Centre project is proposed to be capitalized to the Project rather than recovered as current-period OM&A, consistent with IESO Nova Scotia's

accounting policies. This treatment helps align cost recovery with the period over which the resulting assets will provide service.

2.4 Overall Alignment of the Application with the Business Plan

The costs sought in this Application can be grouped into three broad categories, each of which supports the Business Plan and the MAEA mandate:

1. **Proposed capital expenditures**
   These costs establish the facilities, systems and capabilities required to transfer real-time system operations and related settlement and market-administration functions to IESO Nova Scotia. They are principally associated with the first enterprise priority and the implementation of the uncompleted operational elements of the MAEA mandate.

2. **Amortization and financing-related costs**
   These expenses reflect the use of capital assets in delivering IESO Nova Scotia's mandate, including information technology assets and one month of depreciation associated with Control Centre assets expected to enter service in March 2028. They also reflect the financing arrangements required by a not-for-profit organization undertaking a material capital program without shareholder funding.

3. **OM&A revenue requirement**
   These expenses support the continued delivery of IESO Nova Scotia's existing planning, procurement, interconnection, regulatory and corporate responsibilities, while also providing for initial operation of the control centre beginning in March 2028. The proposed 2027/2028 OM&A requirement is approximately $14.76 million, slightly below the total $14.85 million filed for in 2026/2027, notwithstanding the organization's expanding work program. This reflects, among other things, the completion or reduction of certain establishment and transition activities and the capitalization of costs directly attributable to development of the Control Centre project.

The aggregate revenue requirement is therefore expected to remain broadly consistent with the 2026/2027 request in 2027/2028, even as IESO Nova Scotia undertakes a substantial capital program and prepares to assume real-time system operations. A larger operating-cost and revenue requirement increase is forecast to occur in 2028/2029, when the revenue requirement will include a full year of system-operation costs. A material portion of those future costs

relates to functions and responsibilities currently carried out by NS Power that are expected to transfer to IESO Nova Scotia, rather than wholly new functions for the provincial electricity system.

2.5 Summary

The Business Plan and 2027/2028 Plan establish the operational basis for this Application. It identifies the work required to continue performing the responsibilities already transferred to IESO Nova Scotia and to implement the next stage of the Province's independent system-operator model. The proposed expenditures and revenue requirement provide the resources necessary to carry out that work.

In summary:

- the MAEA establishes IESO Nova Scotia's objects and responsibilities;
- the Business Plan translates those statutory responsibilities into annual priorities, activities and milestones;
- the proposed expenditures and revenue requirement provide the people, facilities, systems, services and supporting capabilities required to complete those activities; and
- the fees proposed in this Application provide the mechanism through which Board-approved revenue requirements would be recovered.

IESO Nova Scotia submits that the proposed expenditures and revenue requirement are therefore appropriately connected to its Business Plan, necessary to advance its mandate under the MAEA, and reasonable in light of the scope and timing of the work to be completed during 2027/2028.

3 Proposed Expenditures and Revenue Requirement

3.1 Introduction

In this section, IESO Nova Scotia provides the background, drivers, and descriptions of its proposed expenditures, revenue requirement, and fees for the NSEB's review and approval. Section 29 of the MAEA provides the following:

Proposed expenditure and revenue requirements

> **29 (1)** The IESO shall, at least 90 days before the beginning of each fiscal year, submit its proposed expenditure and revenue requirements for the fiscal year

and the fees it proposes to charge during the fiscal year to the Energy Board for review.

(2) Where the IESO is unable to make its submission under subsection (1) within the time required under that subsection, the IESO shall file its proposed expenditure and revenue requirements for the fiscal year and the fees it proposes to charge during the fiscal year to the Energy Board for review as soon as possible.

(3) Until the Energy Board approves the proposed expenditure and revenue requirements for the fiscal year and the fees the IESO proposes to charge during the fiscal year, the fees approved for the previous fiscal year remain in effect unless the Energy Board orders otherwise.

(4) The Energy Board may approve the proposed expenditure and revenue requirements and the proposed fees or may refer them back to the IESO for further consideration with the Energy Board's recommendations.

(5) The IESO shall not, without the approval of the Energy Board,

(a) establish, eliminate or change any fees it has established;

or

(b) eliminate or change any fees established by a predecessor that remain in effect.

(6) The Energy Board may hold a hearing before exercising its powers under this Section.

s.3 of the MAEA further defines revenue requirement as follows:

"revenue requirements" means the annual amount of revenue required to cover projected operation, maintenance and administrative expenses, amortization expenses, taxes and payments in lieu of taxes, interest and other financing expenses, and a reasonable return on equity;

To date, IESO Nova Scotia has applied for revenue requirement approval only related to its Operational, Maintenance, and Administration (OM&A) expenses. However, revenue requirement, as noted in the s.3 definition of the term, includes more than just OM&A. Notably, revenue requirement includes amortization, which is the allocation of the cost of an in-service capital asset over its estimated useful life, but not the capital work in progress expense leading up to the in-service date of the underlying asset. This distinction is important, as it establishes that the MAEA contemplated IESO Nova Scotia capital expenditures, and that capital work in progress falls outside of revenue requirement and into proposed expenditures under s.29.

This is consistent with how capital expenditures are treated in the electricity system industry and corresponding accounting standards: capital work in progress expense is not considered

revenue requirement and therefore not subject to recovery via fees or rates, but nevertheless often approved by regulators where statutorily required. s.29 of the MAEA clearly identifies the requirement of NSEB approval of proposed expenditures - it necessarily follows then that IESO Nova Scotia's capital work in progress also requires Board approval. Therefore, s.29 applications must seek approval of proposed expenditures related to expense such as capital work in progress, which is not eligible for recovery via revenue requirement and associated fees. This Application seeks NSEB approval of proposed expenditures related to the capital work in progress expense of IESO Nova Scotia's Phase 2 Control Centre build-out.

Likewise, the definition of revenue requirement in s.3 of the MAEA includes amortization as noted, and therefore this Application is seeking approval of amortization expense for the following capital assets expected to be in-service in IESO Nova Scotia's fiscal year 2027/2028: various Information Technology (IT) assets and the assets related to the Phase 2 Control Centre.

While IESO Nova Scotia has had various IT assets under its ownership from the outset, it has not sought amortization approval of such until this Application, as prior IT asset costs were covered by a Provincial grant as described in prior s.29 proceedings. The Provincial grant has been expended, and as such, going forward, new IT assets will have amortization expense required to be recovered under revenue requirement and through corresponding fees. Amortization expense is also being sought for the Phase 2 Control Centre project for the month of March 2028, as the in-service date of the new control centre is expected to be at the beginning of March 2028.

In the sections that follow, IESO Nova Scotia describes its proposed expenditures regarding its Phase 2 Control Centre project, and its revenue requirement related to both amortization and OM&A expense, and the overall costs sought for approval for each.

3.1.1 Summary of Proposed Expenditures and Revenue Requirement

The Application includes the following costs associated with Proposed Expenditures and Revenue Requirement:

- Proposed Expenditures associated with:
  - capital costs (capital work in progress) for 2026/2027, 2027/2028, 2028/2029, and 2029/2030 for the proposed Phase 2 Control Centre in the amount of $48.99M.
- Total Revenue Requirement for 2027/2028 of $15.19M associated with:

- amortization expense related to $40.91 million in capital costs for its Phase 2 Control Centre – Phase 2A, for one month of 2027/2028 (March 2028) in the amount of $0.38M;
- amortization expense related to other capital cost categories in the amount of $0.05M;
- ongoing Operating, Maintenance, and Administration (OM&A) costs in the amount of $14.76M.

Proposed Expenditures sought for approval in this Application are exclusively related to the capital work in progress for IESO Nova Scotia's Phase 2 Control Centre Project. These costs will be treated as a capital investment and recovered through amortization of the costs in accordance with IESO accounting policies.

Revenue Requirement is comprised of 1) amortization associated with one month of Control Centre in-service as well as various other IT assets, and 2) ongoing OM&A expenditures.

- Amortization expense is $0.43 million with no comparable amount included in the 2026/27 application. The majority of the estimated amortization, at $0.38 million, relates to the Phase 2 Control Centre which is projected to be in service for March 2028. The remainder of amortization of $0.05 million relates to capital investment for software and computer hardware.
- The proposed OM&A costs of $14.76 million for 2027/28 represent a continuation of IESO Nova Scotia's responsibilities under the MAEA as part of its Phase 1 activities, with an incremental portion related to one month of projected Control Centre operations in March 2028. This represents a decrease of $0.09 million from the OM&A costs in the 2026/27 revenue requirement application (M12663).

The projected decrease in OM&A costs is the result of the conclusion of the current IRP process and lower consulting costs with the completion of the first phase of the IESO transition. These lower costs are offset by higher interest expense as overall debt increases, one month of operating costs for the system operator function, and higher cost for public education.

Details of the proposed expenditures, amortization, and OM&A follow in the sections below.

3.2 Proposed Expenditures - Phase 2 Control Centre

IESO Nova Scotia's proposed expenditures in this Application are exclusively related to the capital work in progress costs of its Phase 2 Control Centre[8] build-out (the "Project"). This work is being carried out consistent with IESO Nova Scotia's strategic priority "Complete the Successful Transition of System Operations" referenced in section 2.3.1. above.

IESO Nova Scotia has a legislative mandate to take on the control centre activities related to its requirement to direct the operations of the IESO Nova Scotia-controlled grid. However, given the potential significant costs and a range of potential system operation options, IESO Nova Scotia engaged FTI Consulting, Inc. ("FTI") to undertake a value analysis to identify the potential areas of benefit and disbenefit, and the potential magnitude of those benefits and disbenefits that might be delivered by moving to an independent system operator model from a vertically integrated utility model. This information was in turn used by IBM to assist in the determination of the most appropriate option for control centre operations, one that delivered the best balance of potential value for cost. This work is described in more detail below, and the corresponding reports by IBM and FTI are provided in Appendices 6 and 7.

The total Project has an anticipated total capital spend estimate of $75.4 million (an AACE Class 3 estimate) in capital over a five-year period to implement in three phases: 2A, 2B and 2C. IESO Nova Scotia is seeking NSEB approval for Phases 2A – Operational Control and 2B – Settlement Capabilities of the proposed Phase 2 Control Centre project, and associated capital expenditures in the amount of $48.99 million, spanning IESO Nova Scotia's 2026/2027, 2027/2028, 2028/2029, and 2029/2030 fiscal years. Approval of Phases 2A and 2B is sought together because they comprise the minimum operational, settlement, and information-management capabilities required for IESO Nova Scotia to perform its statutory mandate under the MAEA. While Phase 2A transfers operational control of the bulk electricity system, Phase 2B establishes the settlement, participant administration, and reporting capabilities necessary to independently support and administer those operations. Phases 2A and 2B are collectively referred to as Steady State 1.

The projected benefits of the Project are substantial, resulting in a positive net present value (NPV) of $219 million based on IBM's and FTI's options and benefit analyses. This comes from anticipated annual benefits of $21 million per year from 2029/30, which are anticipated to

[8] Also referred to as the Independent Grid Operations (IGO) Program.

increase to $41 million per year after implementation of Phase 2C forecast for 2031/2032. Sensitivity analyses conducted by IBM show that the Project remains a positive net benefit across of range of circumstances.

There is an urgency in completion of this work on a timely basis. While IESO Nova Scotia has diligently progressed the necessary analysis and work in determining the scope and benefits of the Project, immediate execution of the planned Control Centre is necessary for the transition of system dispatch and transmission operation functions under the MAEA before the May 2028 deadline contemplated for transferring assets. As noted in the introduction, IESO Nova Scotia expects that the relevant sections of the MAEA will be proclaimed in the near future, and understands it is the intent of the Province that IESO Nova Scotia move forward expeditiously with its proposed control centre configuration. This is evidenced by the Province's addition of $10 million to its line-of-credit to IESO Nova Scotia to provide interim cashflow support enabling IESO Nova Scotia to progress on the Project, as well as the Province's letter of support, both provided in Appendix 5. As such, IESO Nova Scotia is projecting related capital expenditures in fiscal year 2026/2027 for preparatory and early implementation work to keep the Project moving forward.

Notwithstanding receiving additional financing from the Province via its line-of-credit, IESO Nova Scotia, as a new not-for-profit corporation, does not have funds directly available to complete the Project. Accordingly, the organization plans to secure additional necessary commercial funding. In the absence of NSEB approval of these costs, IESO Nova Scotia may lack the ability to secure this funding. As a result, IESO Nova Scotia believes that it is a practical necessity that the Board approve Phases 2A and 2B of the Phase 2 Control Centre project in a timely fashion to enable it to fulfill its provincially-legislated mandate as set out in the MAEA.

3.2.1 Introduction

Requirements of the More Access to Energy Act

The *More Access to Energy Act* (MAEA) requires the transition of system operator responsibilities from Nova Scotia Power Incorporated (NS Power) to IESO Nova Scotia. In accordance with the objectives of the MAEA, and the transition of independent operational control of the Nova Scotia's integrated electricity system, IESO Nova Scotia must establish a control centre with the personnel, systems and business processes necessary to carry out its statutory responsibilities. The corresponding Project as described herein, together with supporting

analysis as set-out in Appendix 6 – *IBM Control Centre Options Analysis* and Appendix 7 – *FTI IESO Nova Scotia Value Case Report*, provides the evidentiary basis for the proposed expenditures associated with the Phase 2 Control Centre.

Phase 2 Control Centre

Following the successful implementation of Phase 1 in December 2025, IESO Nova Scotia undertook a comprehensive assessment of options for establishing independent operational control of Nova Scotia's integrated electricity system. That work focused on identifying a robust value for money approach that appropriately balances reliability, implementation risk, cost and customer value while advancing the long-term objectives of an independent system operator. Based on that assessment, IESO Nova Scotia is pursuing the implementation pathway identified in IBM's *Control Centre Options Analysis* (Appendix 6) as Scenario 4 – Enhanced Independence ("Scenario 4").

Scenario 4 involves establishing an independent control room space within NS Power's Atlantic Data Centre which will be transferred to IESO Nova Scotia, and the progressive transfer of operational responsibilities of IESO Nova Scotia though a combination of independent infrastructure and enhanced shared systems. Rather than duplicating all systems and infrastructure from the outset, Scenario 4 uses a phased implementation approach (Phases 2A, 2B, and 2C), that allows IESO Nova Scotia to assume key operational responsibilities while building toward advanced operational functionality over time. This includes both the transfer of operational decision-making responsibilities and the supporting settlement and market-administration functions required for an independent system operator.

With support from independent expert advisors IBM and FTI, IESO Nova Scotia evaluated a comprehensive range of technical and physical options for Phase 2. Five strategic scenarios were assessed using a scorecard methodology, with Scenario 4 receiving the highest overall score and emerging as the best option. The primary considerations in choosing Scenario 4 were that it:

(i) Achieves a high level of operational independence through the use of a separate control room space;

(ii) Avoids the significantly higher costs associated with constructing a new, fully independent control center; and

(iii) Captures synergies and cost efficiencies through the use of selected shared NS Power systems; and

(iv) implements appropriate enhancements supporting IESO Nova Scotia's operational independence and overall economic benefits.

IESO Nova Scotia also considered options that offered either lower-costs or greater independence. However, Scenario 4 emerged as the most prudent balance between independence, cost, risk, and expected benefits.

3.2.2 Options Analysis

To develop the option selection process, select an option, and prepare budget estimates, IESO Nova Scotia engaged the expert support of FTI and IBM. FTI was engaged to develop a value framework and to quantify the benefits and disbenefits of transferring from a vertically integrated utility model to an independent system operator model. IBM was engaged to develop and assess long-term operating model options (by way of five strategic scenarios that went from the most simple with limited anticipated benefits to building a new control facility with new control systems within it), recommend an option, and recommend a pathway to implementation of the selected option. IBM was also engaged to support the budget development process and to develop an AACE Class 3 estimate of the Control Centre costs for the recommended option.

IBM developed five options for IESO Nova Scotia's Control Centre as noted in **Figure 2** below.

Figure 2: IBM Strategic Scenarios[9]

Strategic Scenarios	1 IESO-Lite Near-term planning role only	2 Shared Operations Shared facilities and systems	3 Minimum Independence Limited tactical investments	4 Enhanced Independence Enhanced Capability	5 Full Market Operations Fit for future market evolution
Control Centre Facility	NSP Operates	Ragged Lake (RAL)	Atlantic Data Centre (ADC)	ADC	Purpose built Control Room
EMS/SCADA	NSP Operates	Current SCADA and EMS shared	Current SCADA & EMS shared	Current SCADA shared EMS owned by IESO	Independent SCADA & EMS - new vendor selection
Dispatch / redispatch	Day ahead – NSP dispatches based on rules set by NS-IESO	Dispatch by IESO based on improved rules in recently deployed NSP optimizer (ECCPO)	Dispatch by IESO based on improved rules in recently deployed NSP optimizer (ECCPO)	Enhance ECCPO (SCED-Lite) to the full extent of its capabilities	Robust SCED implemented combination with other real-time optimization features
Market mechanisms	Generators provides day ahead P x Q pairs	Generators provide P x Q pairs	Generators provide P x Q pairs	Generators provide P x Q pairs	Enabled for wholesale market operation
Other Capabilities	N/A	N/A	Enhance reliability/scalability capabilities to manage more renewables	Further enhance reliability capabilities (potential current vendor limitation)	Further enhance reliability capabilities (no specific vendor limitation)
CAPEX ($) (1)	1.97M (LO) / **2.6M (MID)** / 3.68M (HI)	30.83M (LO) / **41M (MID)** / 57.54M (HI)	33.05M (LO) / **44M (MID)** / 62.7M (HI)	51.22M (LO) / **68M (MID)** / 95M (HI)	125.5M (LO) / **167M (MID)** / 234.4M (HI)
Benefits ($) (2)	24M (LO) / **63M (MID)** / 101M (HI)	84M (LO) / **312M (MID)** / 538M (HI)	84M (LO) / **312M (MID)** / 538M (HI)	171M (LO) / **620M (MID)** / 1068M (HI)	312M (LO) / **1068M (MID)** / 1859M (HI)
Timeline	6-12 Months	12-15 Months	15-18 Months	2-3 Years	3-5 Years

(1) Rough Order of Magnitude (ROM). Low and High represents a -25% to +40% Class 4 estimate. IBM Analysis. All UDC costs included at a 5% rate
(2) Expected benefits were calculated over a 25-year horizon (2026-2050) and expressed in 2025 present value. For consistent comparison across options, benefits were normalized to a 12-year present value basis for the evaluation

Blue text: new or improved capabilities vs previous scenario

Source: IBM Report, Figure 4.

Scenario 1 - IESO Lite: Scenario 1 represents the lowest-independence model. Under this approach IESO Nova Scotia would perform planning, monitoring and advisory functions while NS Power retained responsibility for real-time BA and TOP operations. No independent control centre or operational systems would be established. While relatively low cost and simple to implement, this scenario would not meet the requirements of the MAEA or satisfy long-term objectives for operational independence, transparency, or direct operational accountability, but was developed to understand the floor of what the lowest cost approach would be before understanding the magnitude of potential benefits that may or may not be available.

[9] **Day-ahead P×Q pairs**: This refers to the day-ahead submission of power (P) and quantity (Q) pairs by generators, indicating their planned generation output and associated costs for the next day. These pairs are used for scheduling and dispatch purposes.
SCADA (Supervisory Control and Data Acquisition): SCADA is a system used for real-time monitoring and control of industrial processes, including power generation and transmission. It collects data from sensors and equipment, processes it, and provides operators with the information needed to manage the system.
EMS (Energy Management System): EMS is a software platform used by utilities to monitor, control, and optimize the performance of the electrical grid. It includes applications for automatic generation control, network modeling, power flow analysis, and contingency analysis.
NSP optimizer (ECCPO): ECCPO stands for Economic Capacity and Constraint Portfolio Optimization. It is a tool used by Nova Scotia Power (NSP) to optimize the dispatch of generation resources based on economic and operational constraints.
SCED (Security Constrained Economic Dispatch): SCED is a method used to determine the most cost-effective generation dispatch while ensuring the security and reliability of the power system. It takes into account various constraints such as transmission limits and generation availability.
SCED-lite: SCED-lite refers to a simplified version of SCED that provides basic optimization capabilities without the full complexity of a complete SCED implementation. It is used for initial optimization and dispatch decisions.

Scenario 2 - Shared Operations: Scenario 2 achieves a faster transition than later options by leveraging NS Power's existing operational systems and control room infrastructure. IESO Nova Scotia personnel would utilize shared systems and facilities, minimizing implementation cost and timeline but retaining substantial operational, cyber and governance dependencies on NS Power. While technically feasible, this model would add material operational inefficiencies for both NS Power and IESO Nova Scotia as there would not be room to co-locate supporting control resources due to footprint constraints, this would also limit future flexibility for both organizations and challenge the independence of IESO Nova Scotia.

Scenario 3 - Minimum Independence: Scenario 3 introduces an independent IESO Nova Scotia control room location while continuing to utilize NS Power-hosted EMS and SCADA environments. This model improves physical separation, future optionality, and organizational independence but is missing incremental investments to deliver incremental benefits.

Scenario 4 - Enhanced Independence (selected option): Scenario 4 introduces an independent EMS environment, enhanced operational optimization capabilities, stronger cyber segregation and greater operational autonomy. It delivers a level of independence sufficient to support the long-term legislative intent of the MAEA while avoiding the material cost and implementation complexity associated with a full wholesale market model. Importantly, it does not preclude those evolutions in the future, but allows a more timely, lower risk transition now, and allows time to better understand the costs and benefits of moving to a full standard market design model in Nova Scotia.

Scenario 5 - Full Market Operations: Scenario 5 builds upon Scenario 4 by introducing a full Market Management System, real-time market operations and day-ahead market functionality. It also includes a brand new control facility for IESO Nova Scotia. While this option provides maximum market capabilities and potential for benefits, it also carries significantly greater cost, delivery complexity, organizational change requirements and implementation risk. With the fast-moving dynamics in the energy system in the province and broader region, it is possible that requirements could evolve quicker than the solution could be developed, increasing the risk of stranded assets. This scenario would not be delivered within the transfer timelines contemplated by the MAEA, but was developed as the ceiling to see what a solution focused on delivering the maximum benefits might look like.

These scenarios were scored under the 6 strategic scoring areas with corresponding weightings as shown in **Figure 3** below:

Figure 3: 6 Strategic Scoring Areas



Scenario 4 – Enhanced Independence scored the highest, balancing operational factors with costs and benefits, as shown in **Figure 4** below. As a result, it is the Project scenario sought for approval in this Application.

Figure 4: Strategy Scenario Scoring Results

Strategic scenario scoring results

Scored dimensions	Weight	1 IESO-Lite	2 Shared Operations	3 Minimum Independence	4 Enhanced Independence	5 Full Market Operations
Reliability / Operability / Compliance	20%	1.5	3.0	3.0	4.1	4.5
Independence / Transparency	20%	1.5	2.3	2.9	3.8	4.5
Future Optionality	10%	1.5	1.9	2.3	3.6	2.9
Implementation Risk	15%	4.5	2.8	2.9	2.3	1.5
Technical Score (Weighted)	65%	1.4	1.7	1.8	2.3	2.3
CAPEX Costs (Present Value)	25%	5.0	4.1	4.0	3.4	1.0
Benefits (Present Value)	10%	1.0	2.0	2.0	3.2	5.0
Net Value Delivery (Weighted)	35%	1.4	1.2	1.2	1.2	0.8
TOTAL WEIGHTED SCORE	100%	2.8	2.9	3.0	3.5	3.1
					Highest Scoring Scenario	

3.2.3 Scope

Scenario 4

Scenario 4 establishes a dedicated IESO Nova Scotia Control Centre at the Atlantic Data Centre.[10] Scenario 4 also provides the operating model through which IESO Nova Scotia will assume responsibility for the operation of Nova Scotia's bulk electricity system. While the establishment of the Control Centre is a major component of the Project, the scope of the work extends beyond the physical facility. It also includes operational capabilities, business processes, compliance activities, and technological systems required for IESO Nova Scotia to perform its functions as the NERC defined BA and TOP for Nova Scotia, and to fulfill its statutory mandate as an independent electricity system operator under the MAEA.

As the BA, IESO Nova Scotia will be responsible for maintaining the real-time balance between electricity supply and demand across Nova Scotia's integrated electricity system. As the TOP, IESO Nova Scotia will be responsible for the reliable operation of the transmission system, including directing power flows, coordinating outages, and responding to system events. Together, these functions ensure that electricity is delivered safely and reliably across the province. To perform these responsibilities, IESO Nova Scotia requires a number of operational capabilities, business processes, and supporting technology systems.

[10] The Atlantic Data Centre is currently under NS Power ownership but will be transferred to IESO Nova Scotia.

Nine core capabilities are required for IESO Nova Scotia to operate the energy system reliably, which are summarized in **Figure 5** below which also details the proposed approach to key systems looking to balance independence with cost.

Figure 5: Core Capabilities

CAPABILITY	OPERATIONAL PURPOSE	SCENARIO 4 APPROACH	PRINCIPAL SYSTEM
1. SCADA & Monitoring	Provides operators with real-time visibility into the electricity system so they can monitor system conditions and respond to events as they occur.	**Shared**	SCADA platform, telemetry, alarms, historian and monitoring systems.
2. Energy Management System (EMS), Training and Simulation	Provides the analytical and decision-support tools needed to safely operate the electricity system, assess reliability, and train operators.	**Transfer/Shared**	EMS applications, state estimator, contingency analysis, power flow analysis, operator training simulator.
3. Dispatch/ Redispatch	Supports operational decisions regarding which generating resources should operate and how generation is adjusted to maintain reliability and balance supply and demand.	**Transfer**	ECC Optimization Tools (ECCPO), dispatch workflows and supporting operational tools.
4. Market Management & Settlement	Supports participant interactions, settlements, reporting, and other commercial processes associated with operating the electricity system.	**Transfer**	Settlement systems, participant interfaces, web portals, and supporting workflows.
5. Operational Forecasting	Provides forecasts of demand, generation output, weather conditions, and other inputs necessary for reliable system operation.	**Transfer**	TruePower, Enverus, and other forecasting services.
6. Intertie Management	Supports the scheduling and coordination of energy imports and exports with neighbouring jurisdictions.	**Transfer**	OATI Interchange Energy Flow Scheduling (IEFS) and e-tagging systems.

7. Outage Coordination	Coordinates planned maintenance and outages to ensure work can be completed without compromising system reliability.	**Shared**	Sun-Net iTOA and supporting outage management processes.
8. Training Systems	Supports operator certification, compliance training, and simulation activities required for reliable system operations.	**Shared**	Qlarity and other training platforms.
9. Reporting & Analytics	Provides operational, participant, regulatory, and management reporting and supports transparency and accountability.	**Build New**	Reporting and analytics capabilities developed for IESO Nova Scotia.

Importantly, independence under the MAEA is not achieved solely through transferring operational decision-making authority. It also requires IESO Nova Scotia to have independent access to the information, participant interactions, settlement processes, reporting capabilities, and contractual data that support those decisions. Accordingly, Scenario 4 includes both operational capabilities and the settlement and market-administration capabilities required to support transparent and independent system operations.

For example, the real-time monitoring capability is supported through Supervisory Control and Data Acquisition ("SCADA") systems, which collect and display information regarding system conditions across the transmission network. Under Scenario 4, certain SCADA infrastructure would continue to be shared with NS Power, reflecting NS Power's continuing ownership and operation of transmission facilities and associated telemetry infrastructure.

Scenario 4 also includes the transfer of dispatch optimization capabilities through the Economic Capacity and Constraint Portfolio Optimization ("ECCPO") tool. ECCPO assists operators in making generation dispatch decisions and balancing supply and demand across the electricity system. Scenario 4 proposes to utilize the full capabilities of the existing ECCPO platform while maintaining and enhancing it within IESO Nova Scotia's independent operating environment.

Accordingly, Scenario 4 provides IESO Nova Scotia with an independent operational environment while continuing to leverage selected existing infrastructure where doing so is prudent and cost-effective. In particular, Scenario 4:

- Creates a new standalone independent control facility for IESO Nova Scotia;
- Establishes an independent EMS environment operated by IESO Nova Scotia;
- Transfers key dispatch and optimization capabilities to support independent system operations;
- Introduces generator-submitted price and quantity ("PQ") pairs reflecting marginal operating costs;
- Establishes independent reporting and transparency mechanisms; and
- Creates a cyber-secure operational environment with reduced dependence on NS Power systems.

Phased Approach

Scenario 4 will be implemented through a phased transition. This is a risk balanced approach that will help accelerate early deliverables while allowing more time to refine later deliverables to maximize value. As noted, the recommended phased transition consists of three phases: Phase 2A - Operational Control, Phase 2B - Settlement, and Phase 2C - Enhanced Independence. Each phase progressively transfers operational responsibilities, systems and capabilities from NS Power to IESO Nova Scotia.

- **Phase 2A - Operational Control:** Establishes the core capabilities required for IESO Nova Scotia to independently operate and dispatch the electricity system. During this phase, IESO Nova Scotia assumes the BA and TOP functions and begins operating from a separate control center, while continuing to rely on certain shared or NS Power hosted systems.
- **Phase 2B - Settlement:** Expands IESO Nova Scotia's operation independency by transferring market settlement and related market administration functions. This phase includes the development of independent settlement capabilities, participant workflows, market interfaces, reporting processes, and the internal support functions required to administer those activities.
- **Phase 2C - Enhanced Independence:** Enhances the independent functionality and benefits established in Phases 2A and 2B. Phase 2C introduces some additional technological independence advanced capabilities with projected additional benefits.

Under the phased implementation approach, Phases 2A and 2B collectively comprise **Steady State 1**, while Phase 2C represents **Steady State 2**.

Within Steady State 1, IESO Nova Scotia assumes responsibility for operating and dispatching the electricity system, administering market settlements, and carrying out related market administration functions, while continuing to rely on certain shared NS Power systems and infrastructure. Steady State 1 therefore establishes the core operational and administrative capabilities required for IESO Nova Scotia to fulfill its mandate as an independent system operator under the MAEA.

Together, Phases 2A and 2B comprise the independent operating model for IESO Nova Scotia. Phase 2A provides the capability to operate and dispatch the electricity system, while Phase 2B transfers responsibility for the information, contractual quantities, pricing data, settlements, reporting, and participant administration functions necessary to independently support those operations. Together, these phases provide the functional capabilities required for IESO Nova Scotia to carry out its mandate under the MAEA.

Steady State 2 extends this foundation by introducing additional technology independence, cybersecurity segregation, operational flexibility, and advanced system capabilities. While Steady State 1 enables IESO Nova Scotia to meet its core responsibilities, Steady State 2 provides a longer-term target operating model designed to support future system complexity, increased operational maturity, and Nova Scotia's evolving energy transition requirements.

A phased approach to implementation is prudent because it allows IESO Nova Scotia to progress toward its long-term target operating model while managing implementation complexity, preserving reliability, and reassessing future phases before committing to them. Given the complexity of establishing a new independent system operator and control centre, a phased approach enables IESO Nova Scotia to establish an initial operating capability and assume key responsibilities before completing the full build-out of the organization and supporting infrastructure. Additional capabilities can then be achieved over time as they are implemented in subsequent phases.

The phased approach also provides flexibility to refine and update cost estimates, Project scope, and implementation requirements as operational experience is gained and additional information becomes available.

At this time, IESO Nova Scotia is requesting approval of expenditures relating to **Steady State 1 (Phases 2A and 2B)**, which are supported by AACE Class 3 estimates. Estimates for Phase 2C are also provided, based on the best information available at the time of filing, but will be subject to future refinement as planning advances and implementation requirements become better defined.

IESO Nova Scotia is seeking approval of both Phases 2A and 2B at this time because together they comprise Steady State 1 and are designed to be implemented as an integrated operating model. Evaluating the phases together provides the most accurate assessment of the costs, benefits, and level of independence achieved through the implementation of Steady State 1.

3.2.4 Costs

IESO Nova Scotia retained IBM to provide expert support in the development of the Phase 2 Control Centre budget and associated cost estimates. The Phase 2 Control Centre has an estimated capital cost of approximately $75.4 million across all three phases over a five-year implementation period. The Phase 2 Control Centre will also incur operational costs once it is in-service. IESO Nova Scotia retained IBM to provide expert support in the development of the budget for the Project. For additional details see: Appendix 6 – IBM Control Centre Options Analysis.

Capital costs applied for approval in this Application represent the expenditures required to establish Steady State 1, including both the operational capabilities established through Phase 2A and the settlement and market administration capabilities established through Phase 2B, for total of $49.0 million in capital costs. Together, these capabilities form the functional requirements for IESO Nova Scotia to operate as an independent system operator under the MAEA. Accordingly, many of the capital investments described below support the implementation of Steady State 1 as a whole and should not be viewed as supporting only a single phase of the Project.

Figure 6 below provides a breakdown of total capital costs of the Project by Phases and cost categories.

Figure 6: Cost Breakdown

(All costs in $M)	Total	Phase 2A	Phase 2B	Phase 2C
IT Costs	$ 20.6	$ 0.8	$ 5.9	$ 13.9
Program Integration	$ 11.4	$ 9.0	$ 1.0	$ 1.4
Control Center Build	$ 9.0	$ 9.0	$ -	$ -
NERC Compliance	$ 6.4	$ 6.4	$ -	$ -
Cyber Security	$ 4.6	$ 1.4	$ -	$ 3.2
NSP Support Costs	$ 5.7	$ 4.2	$ -	$ 1.5
Other	$ 2.8	$ 2.0	$ -	$ 0.8
Direct Capex	**$ 60.5**	**$ 32.8**	**$ 6.9**	**$ 20.8**
Contingency (15%)	$ 9.1	$ 4.9	$ 1.0	$ 3.2
Capitalized Interest	$ 5.8	$ 3.2	$ 0.2	$ 2.4
Total Capex	**$ 75.4**	**$ 40.9**	**$ 8.1**	**$ 26.4**

The cost estimates are organized into two categories: (i) capital costs associated with establishing the facilities, technology systems, compliance framework, and supporting infrastructure required for Phase 2 implementation and (ii) capitalized interest associated with financing project expenditures during the implementation period and contingency.

Figure 7 below provides a proposed expenditure profile by fiscal year.

Figure 7: Cost Profile by Year

(All costs in $M)	26/27	27/28	28/29	29/30	Future Years	Total
Capex – Phase 2A	$ 10.3	$ 30.6	-	-	-	$ 40.9
Capex – Phase 2B	-	$ 1.3	$ 5.4	$ 1.4	-	$ 8.1
Capex – Phase 2C	-	-	$ 1.9	$ 7.9	$ 16.6	$ 26.4
Total Capex	$ 10.3	$ 31.9	$ 7.3	$ 9.3	$ 16.6	$ 75.4

As shown in **Figures 6 and 7** above, total capex for Phases 2A and 2B is $49.0 million, and represents the total proposed expenditures sought for approval in this Application.

Control Center Build

Control Centre Build includes the design, construction, fit-out, physical security systems, and commissioning of the IESO Nova Scotia Control Centre at the Atlantic Data Centre. This includes the dedicated control room, supporting facilities, and operating workforce environment

required for IESO Nova Scotia to independently conduct real-time operation of Nova Scotia's bulk electricity system and assume BA and TOP responsibilities.

The estimate was developed by IBM based on identified facility requirements, including hardware, workstations, video wall technology, servers, construction activities, and commissioning requirements. Costs were informed by analogous control centre projects, vendor information, and professional judgment.

Control Centre Build costs are primarily associated with Phase 2A and establish the physical foundation for Steady State 1. The selection of the Atlantic Data Centre as the Control Centre and transfer to IESO Nova Scotia enables IESO Nova Scotia to assume operational control of the electricity system and exercise its BA and TOP responsibilities independently of NS Power. As the operational hub for Steady State 1, the Control Centre supports the operational, settlement, reporting, and market administration capabilities implemented through Phases 2A and 2B. The Control Centre is therefore a foundational component of IESO Nova Scotia's transition to an independent system operator under the MAEA, providing the infrastructure required to support both the operational capabilities established through Phase 2A and the settlement and market administration functions established through Phase 2B.

IT Costs

IT Costs include the configuration and implementation of shared platforms, transferred platforms, communications, interfaces, and other technology systems required to support Phase 2 operations. This includes operational technology and business systems necessary to support the capabilities transferred to IESO Nova Scotia under Scenario 4, including operational, settlement, reporting, and market administration functions.

IBM developed the IT cost estimate using a capability-based assessment approach. Required capabilities were broken-down into major workstreams, including EMS and SCADA systems, cybersecurity, telecommunications, market systems, data and analytics capabilities, and other supporting technology requirements. Capital costs were estimated using a combination of vendor information, NS Power-provided cost information, IBM estimates, analogous utility projects, and planning-level implementation assumptions.

NERC Compliance

NERC Compliance includes compliance program and procedure development, audit readiness, certification activities, and the documentation required for IESO Nova Scotia to assume BA and TOP functions. This work supports certification by NERC and Northeast Power Coordinating Council (NPCC), which is a pre-requisite for the transfer of activities, and includes the development of procedures and documentation aligned with applicable reliability and cybersecurity standards. The estimate was developed by IBM using industry benchmarks, analogous compliance projects, past project experience, and professional judgment.

NERC Compliance activities are primarily associated with Phase 2A, as IESO Nova Scotia must establish the compliance framework required to assume BA and TOP responsibilities and commence independent operations. These compliance activities support the establishment of Steady State 1 and provide the regulatory foundation for the operational and administrative capabilities implemented through Phases 2A and 2B.

Cyber Security

Cyber Security includes the security architecture, network controls, monitoring, identity management, and other cybersecurity controls required to support IESO Nova Scotia's independent operating environment. This work includes the cybersecurity measures necessary to support BA and TOP functions and to satisfy applicable NERC CIP requirements. The estimate was developed by IBM using vendor information, industry benchmarks, analogous projects, and professional judgment.

Cyber Security activities are required throughout Steady State 1 and Steady State 2. Phases 2A and 2B establish the cybersecurity architecture, controls, monitoring capabilities, and supporting security enhancements required to support the operational, settlement, reporting, and market administration functions comprising Steady State 1.

Program Integration

Program Integration includes program management, design authority, process development, change management, quality assurance, and program administration. This category covers the resources and activities required to coordinate the design, delivery, and quality assurance of

the Phase 2 program, including oversight of vendors, system integrators, and related project workstreams.

The Program Integration estimate was developed by IBM using a bottom-up assessment of the work required to coordinate and deliver the various Phase 2 workstreams. The estimate is based on detailed design and implementation activities, internal resource planning, external system integrator inputs, and IBM's experience with similar projects.

Program Integration activities are required throughout all phases of implementation to coordinate project delivery, manage dependencies between workstreams, oversee vendors and system integrators, and support the phased transition from NS Power to IESO Nova Scotia.

NS Power Support Costs

NS Power Support Costs represent incremental costs associated with support provided by NS Power to facilitate the implementation of Phase 2, including system transition activities, knowledge transfer, handover activities, reconfiguration of shared and transferred systems, and operational readiness activities required to support the transfer of responsibilities to IESO Nova Scotia. These costs reflect NS Power's role in supporting the phased transition contemplated by Scenario 4. The estimate was developed by IBM based on cost information and estimates provided by NS Power.

During Steady State 1, these activities support the transfer of operational, settlement, reporting, and market administration capabilities to IESO Nova Scotia while continuing to leverage selected shared systems and infrastructure.

Other

Other costs cover internal IESO Nova Scotia effort, third-party vendor costs for systems to be transferred or shared, training coordination, market changes and miscellaneous implementation items. This category captures costs that do not fall within the other defined cost categories but are required to complete the scope of Phase 2 implementation.

The estimate was developed by IBM using vendor information, industry benchmarks, past project experience, and professional judgment.

Interest

Interest reflects financing costs associated with capital deployed during the delivery period. It represents the estimated carrying cost on capital expenditures incurred between the point of investment and the point at which the associated assets become operational.

The estimated financing costs were developed by IBM based on the estimated timing of project spend and an estimated rate of 5.0%.

As capital investment increases through the phased implementation of Phase 2, associated financing costs are capitalized until the relevant assets are placed into service.

Contingency

A contingency of 15% is applied to direct capital costs to account for estimate uncertainty and variation within the expected range of a Class 3 AACE estimate. Contingency is applied to direct capital costs only and does not apply to operating costs or capitalized interest.

The contingency amount was developed by IBM based on AACE Class 3 estimates and reflects the planning-level nature of the Project at this stage of development. IBM identified an expected estimate accuracy range after contingency of -15% to +20% for the overall capital program.

Contingency is applied across all phases of implementation and reflects the uncertainty associated with planning-level cost estimates, procurement activities, detailed design, and implementation requirements that will be further refined as the Project progresses.

3.2.4.1 Class of Estimate

The Control Centre cost estimates were developed by IBM as a Class 3 Budgetary Estimate in accordance with AACE estimating standards. The estimate after contingency carries an expected accuracy range of -15% to +20%.

Cost estimates were informed by a combination of vendor information, NS Power-provided cost information, IBM estimates, analogous utility projects, industry benchmarks, financial modelling, planning-level implementation assumptions, and professional judgment. Where specific pricing information was not available, planning-level estimates and benchmarking were used to support the development of the Class 3 estimate.

IBM considers the resulting estimate sufficiently developed to support decision-making regarding the implementation of the Control Centre. As implementation progresses, estimates will be refined through detailed design, procurement, and execution planning, moving toward Class 2 and ultimately Class 1 precision for both costs and timeline.

3.2.5 Project Economics

While the Project is required to implement IESO Nova Scotia's MAEA mandate, IBM was engaged to conduct an options analysis incorporating expected costs and benefits as part of identifying the recommended solution. IBM developed the cost information and economic analysis. Benefits informing IBM's economic analysis was developed by FTI Consulting.

The FTI benefits report can be found in Appendix 7. FTI used their experience of working across the globe to identify the typical benefits categories one would expect to see in the transition from a vertically integrated utility model to an independent energy system operator model and then developed estimated ranges specifically for Nova Scotia. The work was initially done in line with scope of Scenario 5 and scaled to each of the IBM scenarios based on the capabilities included within that scenario and the associated benefits.

The work identified eight areas of benefits and dis-benefits that moved four buckets of spend that ultimately get passed through to customers: 1) generation capital costs 2) transmission capital costs 3) production costs and 4) carbon costs.

For Scenario 5, the total 25-year anticipated benefit discounted back to 2025 dollars was $1,010 million with a range of $279 to $1,742 million. For Scenario 4, Steady State 1 the 25-year benefit was $300 million, which equates to an annual benefit of approximately $21 million. For Scenario 4, Steady State 2 the 25-year benefit increased to $586 million, which equates to an annual benefit of approximately $41 million (an annual increase of $20 million from Steady State 1).

At IESO Nova Scotia's request, IBM used the data from FTI Consulting's analysis along with its own capital and incremental IESO Nova Scotia operating cost data to conduct an NPV analysis on the recommended program to assess the economic merit of the proposed Project across a range of cost and benefit scenarios.

The key findings are:

- the proposed Phase 2 Project was found to have a positive business case;
- the expected benefits materially exceed the incremental costs;
- the analysis produced an estimated NPV of $219 million over a 17-year assessment horizon; and
- the cost estimates tested included the Class 3 estimate range of -15% to +20%, as well up to 50% increase in anticipated costs at the same time as a 50% decrease in anticipated benefits.

The economic analysis indicates that the full Project (Steady States 1 and 2) has a positive long-term financial outcome, as illustrated by the NPV and positive Internal Rate of Return (IRR) outcomes noted in **Figure 8** below.

Figure 8: NPV Sensitivity Analysis – Full Project

Net Present Value (NPV) Scenarios - Full Project	NPV	IRR
Base Case Scenario	**+$219M**	**37%**
High Case (-15% Capex, +30% benefits)	+$328M	54%
Low Case (+20% Capex, -40% benefits)	+$73M	16%
Capex +50%	+$188M	26%
Benefits -50%	+$52M	15%
Capital costs +50% & Benefits -50%	+$21M	8%
Benefits Delayed 2 Years	+$155M	22%
Base Case Scenario - carbon removed	+$182M	33%

Phase 2A is expected to deliver benefits of approximately $21M/year once the Control Centre is in-service in March 2028.[11] When the full projected costs of Phases 2A and 2B are taken into account, Steady State 1 also delivers a positive long-term financial outcome, even under many possible variations in assumptions and outcomes, as illustrated by the NPV and positive IRR outcomes noted in **Figure 9** below.

[11] Phase 2B is not expected to provide any additional economic benefits after Phase 2A functionality is operational.

Figure 9: NPV Sensitivity Analysis – Steady State 1

Net Present Value (NPV) Scenarios – Phases 2A and 2B	NPV	IRR
Base Case Scenario	+$110M	30%
High Case (-15% Capex, +30% benefits)	+$173M	46%
Low Case (+20% Capex, -40% benefits)	+$26M	11%
Capex +50%	+$88M	20%
Benefits -50%	+$16M	10%
Capital costs +50% & Benefits -50%	-$6M	4%
Benefits Delayed 2 Years	+$75M	18%
Base Case Scenario - carbon removed	+$96M	27%

Please refer to the IBM Report (Appendix 6) and FTI Consulting Report (Appendix 7) for further details, as well as IBM's corresponding economic analysis model (Appendix 8).

3.2.6 Project Schedule

Phase 2A is expected to be completed towards the end of 2027/28, Phase 2B in 2029/30, and Phase 2C in 2031/32. Required workstreams to be completed in support of Phase 2A are shown in **Figure 10** below.

Figure 10: PMO Workstreams

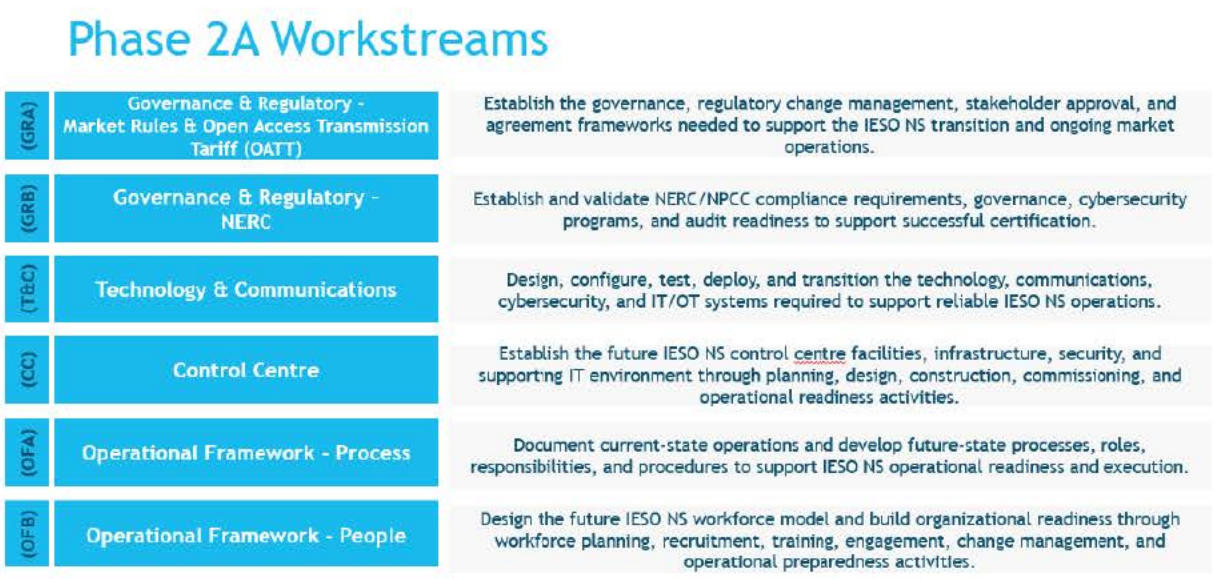
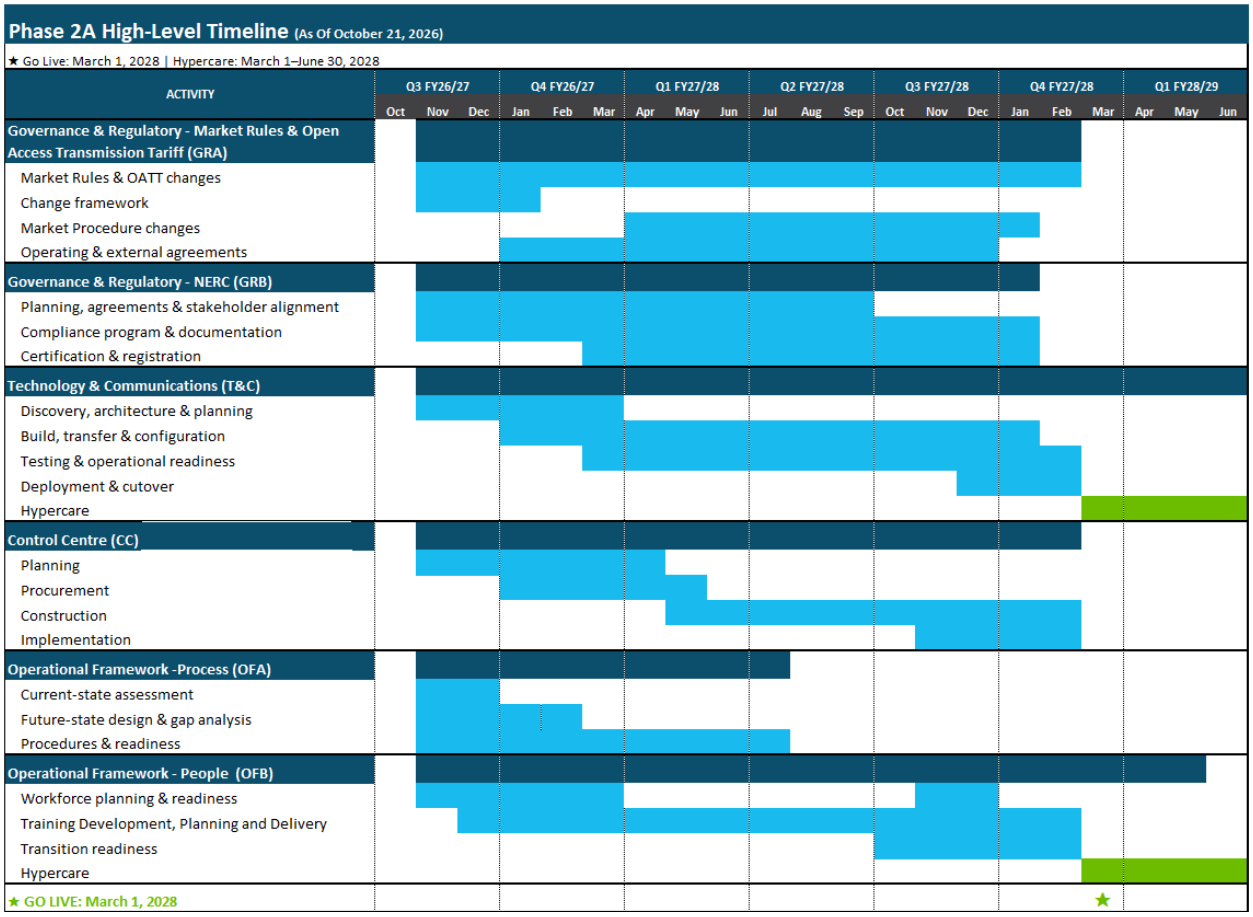


Figure 11 below provides a Project schedule for Phase 2A in Gantt chart format.

Figure 11 – Phase 2A Project Schedule



Phase 2B Sequencing

Although Phase 2B is scheduled for completion after Phase 2A, work on Phase 2B will begin before Phase 2A is complete. This is necessary because Phases 2A and 2B together comprise Steady State 1 and are designed to function as an integrated operating model.

Phase 2A establishes IESO Nova Scotia's ability to independently operate and dispatch the electricity system. Phase 2B builds on that foundation by establishing the settlement, reporting, participant administration, and market interface capabilities required to administer those operations. Accordingly, planning and implementation activities for Phase 2B are expected to commence during the fiscal years covered by this Application to ensure the timely completion of Steady State 1.

This sequencing reflects the fact that the independence contemplated by the MAEA extends beyond operational control. In addition to making operational decisions, IESO Nova Scotia must also establish the systems and processes required to administer settlements, participant information, reporting, and related market functions. Advancing Phase 2B in parallel with the later stages of Phase 2A ensures these capabilities can be implemented without delay and allows IESO Nova Scotia to efficiently achieve the full operational and administrative capabilities contemplated by Steady State 1.

3.2.7 Project Governance and Risk Management

Given the importance of this Project for IESO Nova Scotia's system dispatch and operation function under the MAEA, the organization has established a strong governance framework, including a Transition Committee established under the IESO Nova Scotia Board of Directors to oversee and provide guidance on all Phases of the transition of system operator functions from NS Power, a Project Decision Board established by IESO Nova Scotia leadership to approve key decisions required for Project progress, and a Project Management Office to manage both the overarching Phase 2 Project scope, budget and schedule, and the targeted workstreams. IESO Nova Scotia recognizes that a Project of this scope and complexity requires thoughtful risk identification and mitigation, and has assessed the potential Project risks and developed corresponding mitigation strategies, as described below.

1. **Costs and Timeline**

Risk: As with any major project, there is a risk of cost increases. The Project is complex, so there is the potential for cost and/or timeline increases from actual circumstances differing from assumptions, interdependencies, delays, needing to change plans, poor initial estimates, market price increases, or necessary changes in scope.

Mitigation: An initial AACE Class 3 estimate developed by IBM includes a 15% contingency to address known uncertainties. Due to potential unknowns not yet identified as part of a Class 3 estimate the AACE methodology has an expected range of accuracy of +20% and –15% of the total cost including contingency with an 80% confidence interval. IESO Nova Scotia will make best efforts to keep the project costs within the costs requested in this Application, but recognizes that there is a risk they could reasonably fall outside of that. If at any point unexpected costs or material changes in projected costs appear likely, IESO Nova Scotia, will share this information as part of its quarterly reporting. IESO Nova Scotia will seek to lock in pricing where appropriate through procurement and contracting processes. The governance

structure noted above will provide ongoing oversight of Project scope, schedule, and expenditures. The phased implementation approach, together with annual budgeting and capital planning processes required under the MAEA, allows future phases to be informed by actual Project experience, updated cost information, and refined implementation requirements.

2. Reliability Through Transition

Risk: Material reliability incident occurring during transition, cutover, or early operations, particularly under challenging operating conditions.

Mitigation: The mitigation measures for this risk are multifaceted:

- actively collaborate with NS Power throughout the program
- ensure clarity of roles when separating processes, tools and documentation
- ensure clear protocols for communication – to eliminate gaps and overlaps
- execute parallel operations and extensive testing, deliver appropriate internal and external training
- perform a controlled, staged cutover approach, including assessing up-coming weather as part of the go/no-go decisions.

3. IESO Capacity and Resourcing

Risk: Critical path delays or cost increases due to capacity and resource constraints.

Mitigation: IESO Nova Scotia has developed a project implementation plan that includes work breakdowns and iterative assessments of resourcing requirements (duration, loading and skillsets required). IESO Nova Scotia will then use that information to drive resource acquisition approaches to ensure appropriate resourcing throughout the Project. A robust governance approach is being utilized to support implementation oversight, project delivery, and timely resolution of project issues.

4. NS Power Dependency

Risk: This Project has significant impacts on NS Power, and this is one of its many priorities. Delays or cost increases due to the transition leading to unexpected requirements for NS Power to reconfigure systems, update processes and documentation, support the transfer of capabilities to IESO Nova Scotia, and continue day-to-day operations.

Mitigation: Continued collaboration between IESO Nova Scotia and NS Power is a key component of the implementation approach. IESO Nova Scotia Phase 2 Project Management Office purview has been increased to include IESO Nova Scotia/NS Power shared scope to ensure alignment of program activities (and reduce program management cost). The Joint Transition Committee has been continued from Phase 1 operations to ensure effective communication between IESO Nova Scotia and NS Power leadership. Clear roles, responsibilities, and transfer requirements will be established throughout the transition process. Cost estimates and transfer assumptions have been developed in consultation with NS Power. The phased implementation approach also allows implementation risks and transfer requirements to be reassessed as the Project progresses.

5. Cybersecurity

Risk: Cybersecurity risk associated with shared systems, transitional access arrangements, and interim technology solutions implemented during the phased transition to IESO Nova Scotia operations.

Mitigation: While certain systems will remain shared during the transition, cybersecurity controls including network segmentation, identity and access management controls, and clearly defined access boundaries will be implemented to protect operational systems and information. This was included as part of the roadmap work and associated investment recommendations provided by IBM which included the necessary tools and processes to manage risks. And, in order to obtain certification from NERC and NPCC, all the required Critical Infrastructure Protection (CIP) standards will be met including the provision of the required evidence. As additional capabilities are transferred to IESO Nova Scotia through the phased implementation approach, reliance on shared NS Power systems will be reduced and cybersecurity separation will increase over time. IESO Nova Scotia has already started to establish its own internal Cybersecurity experts and will continue to grow that team and capability throughout program implementation. External subject matter experts will also augment the team throughout implementation. Collaboration with NS Power's cybersecurity team has begun with a detailed cybersecurity risk assessment and development of focus areas to reduce overall and joint cybersecurity risk.

6. Funding

Risk: IESO Nova Scotia has to raise significant funds to support implementation. As a new not-for-profit entity, with limited credit history, no approved enduring fee recovery mechanism, and no current approval for the Project, there is a risk IESO Nova Scotia is not able to secure the necessary funding to complete the Project, impacting Project delivery, timeline, and overall cost.

Mitigation: IESO Nova Scotia has secured an extended line of credit from the Province by $10 million to support initial work. IESO Nova Scotia through this Application is highlighting the importance of timely approval from the NSEB of its fee recovery mechanism and this application and specifically the Project to facilitate securing funding with commercial lenders before the end of the 2026/27 fiscal year. The phased implementation is also supportive as the spend is phased over a longer period of time reducing immediate cash needs. Should IESO Nova Scotia be unable to secure the necessary commercial funding, then it will need to assess other options including potentially applying to the NSEB for pre-funding of costs for capital related projects.

3.2.8 Conclusion and Proposed Expenditures Updates

As noted at the outset of Section 1.7, IESO Nova Scotia is requesting NSEB approval of Project Phases 2A and 2B, regarding operational dispatch and market settlement functions respectively, in the total estimated amount of $48.99 million in proposed capital work in progress expenditures. As demonstrated in the foregoing, Phases 2A and 2B under Scenario 4 provide IESO Nova Scotia with the independent operating model required of it under the MAEA, and significant benefits as identified by FTI's value framework and IBM's strategic scenario and economic analysis.

These phases of the Project and their corresponding proposed expenditures span fiscal years 2026/2027, 2027/2028, 2028/2029, and 2029/2030 as noted in **Figure 7** above.

With respect to proposed expenditures expected to occur in the remainder of fiscal year 2026/2027, these costs are required in order to immediately execute Phase 2A of the Project and reach a timely in-service date for Phase 2A functionality in March 2028. These proposed expenditures were not previously noted in IESO Nova Scotia's 2026/2027 Revenue Requirement application (M12412) as the scope and cost of the Project were not established until well after its filing.

With respect to proposed expenditures associated with Phase 2B that are expected to occur in fiscal year 2028/2029 and 2029/2030, IESO Nova Scotia seeks approval of that portion of the Project and the related future fiscal year costs because some incremental Phase 2B expenditures will nevertheless occur in fiscal year 2027/2028, the market settlement functions covered in Phase 2B are mandatory requirements of IESO Nova Scotia under the MAEA, and timely NSEB approval will facilitate IESO Nova Scotia securing necessary external financing to complete the Project.

Looking ahead, as it is required under s.29 of the MAEA to present proposed expenditures for approval in each s.29 application, updated costs associated with the Project will be provided in each applicable forthcoming annual s.29 application. In this way, the NSEB and stakeholders will be kept apprised of Project costs as the Project matures. Any material variances regarding Project costs and their effect may be considered in future applications, and any new or unexpected costs, or material changes to costs, will be reported in IESO Nova Scotia's quarterly reporting. Furthermore, associated amortization and corresponding recovery via fees will be sought for approval in future s.29 applications with expected or actual final capital expenditures once the underlying asset is in-service.

Finally, as operational experience is gained under Steady State 1, IESO Nova Scotia will further evaluate both the costs and benefits related to a future Phase 2C project. Should Phase 2C continue to have merit from a costs, benefits, and operational perspective, IESO Nova Scotia would make further application for proposed expenditures at a future date.

3.3 Amortization

This Application is the first to include amortization related to IESO Nova Scotia capital assets. Amortization is related to the allocation of costs over the useful life of tangible and intangible assets. As a System Operator, IESO Nova Scotia, is not expected to have regular large capital expenditures like a Transmission, Distribution or Generation owner; however, it will necessarily incur some capital costs from time to time such as those associated with its Phase 2 Control Centre project and various IT related assets. The treatment of capital assets, including various amortization rates, is established in IESO Nova Scotia's accounting policy – Property, Plant and Equipment and Intangible Assets (please refer to Appendix 1). The amortization for each of these categories is described in the sub-sections that follow.

3.3.1 Phase 2 Control Centre

As described above in section 3.2 regarding the Phase 2 Control Centre project, Phase 2A regarding system operational dispatch functionality, and the corresponding control centre assets, are expected to be in-service in March 2028. The control centre assets are anticipated to include building, computer hardware, software and other tools required for dispatch functionality. Accordingly, one month of associated amortization expense is included in revenue requirement in this Application. These investments are consistent with IESO Nova Scotia's strategic priority "Complete the Successful Transition of System Operations" referenced in section 2.3.1. and section 3.2 above. **Figure 12** below enumerates the Control Centre amortization budget.

Figure 12: Control Centre Amortization Budget

		Amortization Budget (M$)	
Cost Category	**Estimated Capital Cost**	**Amortization Period (years)**	**2027/2028F**
Building	$15.95	20	$0.06
Computer Hardware	$5.41	5	$0.09
Software	$10.03	5	$0.15
Regulatory Compliance	$9.52	10	$0.08
Total	**$40.91**		**$0.38**

Further details regarding the costs budgeted as part of this cost category are as follows:

Building: This involves the design, construction, renovation, fit-out, and commissioning of IESO Nova Scotia's independent Control Centre. This includes the dedicated control room, adjacent office space for support staff, supporting facilities, and an effective operating workforce environment required for IESO Nova Scotia to independently conduct real-time operation of Nova Scotia's bulk electricity system and assume BA and TOP responsibilities.

- **Basis of Estimate**: Please refer to the IBM Report provided in Appendix 6 as well as section 3.2 above. Depreciation of the building asset is estimated to be twenty years in accordance with the IESO Nova Scotia accounting policies (Appendix 1).

Computer Hardware: This involves the implementation of IT and OT compute and networking infrastructure to enable and support the system operations functions that IESO Nova Scotia will perform as part of the Phase 2 project.

- **Basis of Estimate**: Please refer to the IBM Report provided in Appendix 6 as well as section 3.2 above. Depreciation of computer hardware assets is estimated to be five years in accordance with the IESO Nova Scotia accounting policies (Appendix 1).

Software: This cost category includes the software solutions that will be used within the Control Centre as well as software tools and systems to enable market activities and supporting functions of IESO Nova Scotia. The software licenses will include subscription licenses for vendor hosted and managed solutions as well as licenses for systems that will be hosted and managed within IESO Nova Scotia premises.

- **Basis of Estimate**: Please refer to the IBM Report provided in Appendix 6 as well as section 3.2 above. Depreciation of software assets is estimated to be five years in accordance with the IESO Nova Scotia accounting policies (Appendix 1).

Regulatory Compliance: In order to perform the required system operations functions of Balancing Authority and Transmission Operator, IESO Nova Scotia will need to implement certain technology and processes to be compliant with NERC standards. This includes a validation and certification process to ensure that system security and reliability is maintained throughout the transition from NS Power to IESO Nova Scotia.

- **Basis of Estimate**: Please refer to the IBM Report provided in Appendix 6 as well as section 3.2 above. Amortization of intangible assets related to NERC and other licenses to perform the system operations functions of Balancing Authority and Transmission Operator are estimated to be ten years in accordance with the IESO Nova Scotia accounting policies (Appendix 1).

3.3.2 Information Technology

Separate from the assets deployed in the Control Centre, IESO Nova Scotia will also need to implement software and hardware assets to enable additional existing business functions. As more employees are onboarded, computers, peripherals and mobile devices will be required to be purchased. IT spend in fiscal year 2027/2028 also includes a software solution to manage the transmission interconnection activities. These represent foundational investments necessary for IESO Nova Scotia's to carry-out all of its strategic priorities referenced in section 2.3 above. **Figure 13** below enumerates the IT amortization budget.

Figure 13: IT Amortization Budget

		Amortization Budget ($)	
Cost Category	**Estimated Capital Cost**	**Amortization Period (years)**	**2027/2028F**
Computers	$0.06	5	$0.01
Software	$0.43	5	$0.04
Total	**$0.50**		**$0.05**

Further details regarding the costs budgeted as part of this cost category are as follows:

Computers: Personal computers and associated peripheral IT and audio-visual equipment to support the planned headcounts.

- **Basis of Estimate**: Computer hardware cost estimates are based on market rates established by recent purchases extrapolated against estimated quantities. Depreciation of computer hardware assets is estimated to be five years in accordance with the IESO Nova Scotia accounting policies (Appendix 1). The amortization budget amount in the year of acquisition is assumed to be 50% of the full year rate to account for timing of mid-year purchases.

Software: Includes the development of a technology solution to enhance the transmission interconnection processes of IESO Nova Scotia. This solution is intended to provide enhanced and interactive reporting and data exchange with interconnection customers via an

interconnection portal. A detailed scope of work has not yet been developed for this solution and it is envisioned that it would be developed during the 2027-28 budget year with stakeholder input. Potential functionality could be similar to portals in place at other system operators such as New York ISO and the UK's NESO; these provide functionality including interconnection request and documentation submission, status reporting and updates, and enhanced interconnection queue visibility.

- **Basis of Estimate**: A high level cost estimate was developed based on high level past experience of similar solution development initiatives. This included estimates for requirements development and stakeholder engagement, data model development, GIS integration, model development, testing, cybersecurity, and program management. Depreciation of software assets is estimated to be five years in accordance with the IESO Nova Scotia accounting policies (Appendix 1). The amortization budget amount in the year of acquisition is assumed to be 50% of the full year rate to account for timing of mid-year acquisition.

3.4 Operating, Maintenance and Administration

In this application, IESO Nova Scotia seeks review and approval of its OM&A revenue requirement for the 2027/28 fiscal year of $14.76M, a slight reduction from IESO Nova Scotia's OM&A revenue requirement request in its 2026/27 Revenue Requirement application (M12663) of $14.85M. IESO Nova Scotia developed its OM&A budget for 2027/2028 using a multi-faceted approach:

- Where available, IESO Nova Scotia relied on historical actual spending information and focused this knowledge base to reflect the areas that IESO Nova Scotia would be developing in the 2027/2028 fiscal year.

- IESO Nova Scotia also relied on supporting evidence for significant costs categories and budget assumptions, including contracts, quotes, market information, and estimation correspondence – where available, the cost category sections that follow reference supporting documentation for corresponding budget estimates.

- Finally, the OM&A budget was determined utilizing the experience and knowledge of IESO Nova Scotia staff. IESO Nova Scotia staff reviewed prior costs category spend, studied available supporting evidence, and determined reasonable assumptions

regarding the work ahead in fiscal year 2027/2028 to establish the budgetary estimates provided herein.

It should be noted that IESO Nova Scotia remains a relatively new organization with less than a full year of fully staffed operational experience, and has limited historical financial and operational information. As such, there may be circumstances that are not readily foreseeable affecting actual spend. As noted in the introduction, as the organization matures, future revenue requirement applications will benefit from additional operating experience, more refined budgeting processes, and the maturation of processes and supporting methodologies. IESO Nova Scotia has adopted a forward-looking approach, focused on continuous improvement of its Revenue Requirement, Proposed Expenditures, and Fees applications over time.

IESO Nova Scotia's OM&A costs are organized into various cost categories representing the different functions of IESO Nova Scotia during the fiscal year. IESO Nova Scotia's OM&A Costs include the costs required for IESO Nova Scotia to carry out its statutory mandate, including the salaries and costs for internal and external resources to perform executive and administrative functions, as well as to carry out those operational functions that have historically been performed by NS Power that have transitioned to IESO Nova Scotia, including system planning, interconnection process management, and energy resource procurement. For part of fiscal year 2027/2028, IESO Nova Scotia is also expecting to begin to incur operational costs related to dispatch of the bulk electricity system – IESO Nova Scotia's new Control Centre is projected to be in-service and operational in March 2028.

IESO Nova Scotia's OM&A budget forecast for the period ending March 31, 2028, is comprised of the cost categories noted in **Figure 14** below.

Figure 14: Summary of OM&A Costs

	2027/28 OM&A Cost Forecast ($) (Millions)
System Planning & Procurement	$4.17
System Operations	$0.74
Information Technology	$2.10
Communications and Stakeholder	$0.94
Legal and Regulatory	$3.05
Finance	$1.03
Human Resources	$0.59
Facilities	$0.61
Corporate Services	$1.53
Total OM&A Expenses	**$14.76**

As noted in the Introduction, the OM&A cost categories in this Application are different from the 2025/2026 and 2026/2027 revenue requirement applications; the OM&A cost categories herein are structured in a manner that is more closely aligned to IESO Nova Scotia functions performed.

Notably, the 2026/2027 cost category "Employees - Administration" has been redistributed across applicable functional categories found in this Application. Each functional category therefore now has a sub-category for the compensation of staff for that function. Category adjustments include: the former "Procurement" and "Operations (System Planning)" categories are now grouped with "System Planning and Procurement"; the former "Governance" category is now grouped with "Legal and Regulatory"; the former "Facilities and Technology" has been split into two new categories, "Information Technology" and "Facilities"; and the former "Corporate Administrative" category has been renamed "Corporate Services" and includes costs from the former "Transition and Operational Planning" category. New categories have been

added to the 2027/2028 application for "System Operations", "Communications and Stakeholder", "Human Resources" and "Facilities". **Figure 15** below provides a visual map of the 2026/2027 cost categories to the 2027/2028 cost categories.

Figure 15 - Cost Category Map

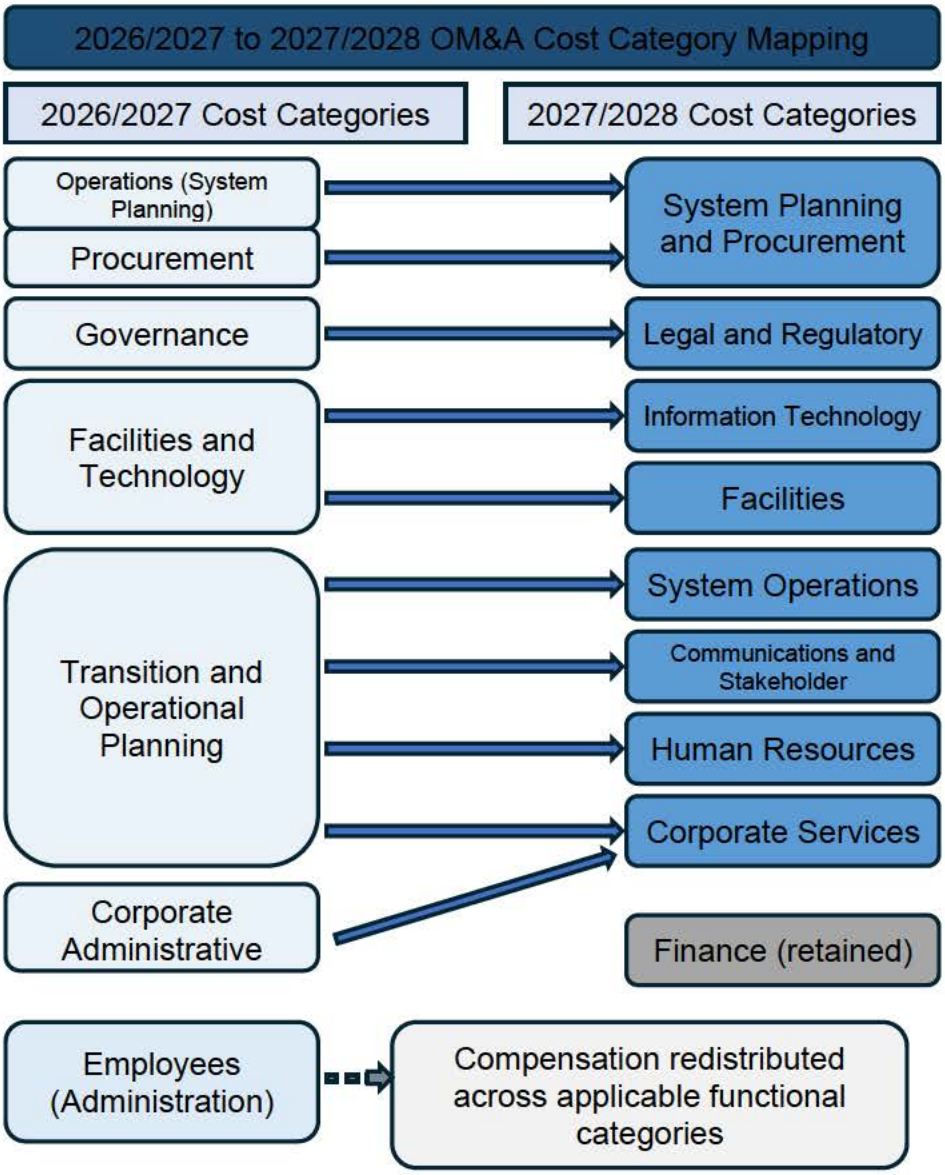


Figure 16 below demonstrations the redistribution of compensation from the 2026/2027 application into the functional categories of this 2027/2028 Application.

1 **Figure 16: Reconciliation to New Cost Categories**

OM&A Cost Category	2026/27 as Filed	2026/27 wages Reclassified	2026/27 category adjustment	2026/27 restated
2026/2027 Cost Categories Redistributed or Eliminated in 2027/2028				
Employees (Administration)[12]	4.44	(4.44)	-	-
Governance[13]	0.49	-	(0.49)	-
Procurement[14]	0.89	0.21	(1.10)	-
Facilities and Technology[15]	1.56	-	(1.56)	-
Transition and Operational Planning[16]	1.77	-	(1.77)	-
Operations (System Planning)[17]	3.64	(3.64)		
2026/2027 Cost Categories Restated as 2027/2028 Cost Categories				
System Planning and Procurement	3.64	0.36	1.10	5.10
System Operations	-	0.56	0.50	1.06
Information Technology	-	0.96	1.18	2.14
Communications and Stakeholder	-	0.28	0.17	0.45
Legal and Regulatory	1.15	0.73	0.49	2.37

[12] Compensation for "Employees Administration" redistributed to applicable functional costs categories in 27/28.

[13] Merged with "Legal and Regulatory" in 27/28.

[14] Merged with "System Planning and Procurement" in 27/28.

[15] Split into two new categories: "Information Technology" and "Facilities" in 27/28.

[16] Also referenced as "Phase II Transitional Costs" in the 26/27 application – these costs were redistributed to "System Operations", "Communications and Stakeholder", "Human Resources", and "Corporate Services".

[17] Merged with "System Planning and Procurement" in 27/28.

Finance	0.65	0.31	-	0.96
Human Resources	-	0.37	0.05	0.42
Facilities	-	-	0.38	0.38
Corporate Services[18]	0.26	0.66	1.05	1.97
Total OM&A Expenses	**14.85**	**-**	**-**	**14.85**

The cost category sections that follow contain information on the differences in revenue requirements sought by IESO Nova Scotia in the 2026/2027 revenue requirement application (as realigned to the 2027/28 revenue application categories as set out in Figure 16) compared to this 2027/2028 revenue requirement application.

Staffing and Compensation

Consistent with IESO Nova Scotia's prior revenue requirement applications (M12412 and M12663), compensation continues to be the single largest category of cost across all functional areas of the organization, comprising approximately $6.9M in fiscal year 2027/2028, representing nearly half of all OM&A costs.

As noted in IESO Nova Scotia's 2026/27 Revenue Requirement proceeding (M12663) IESO Nova Scotia's staffing plan reflects the staged development of a new independent system operator and the progressive assumption of responsibilities assigned under the *MAEA*. IESO Nova Scotia's 2026/27 Revenue Requirement application (M12663) identified 44 positions, comprising approximately 21 transferred system-planning and interconnection employees and 23 functional management and administrative positions that were budgeted for the full year. As of May 2026, 31 employees were in place, with 13 vacancies then being recruited and expected to be substantially filled during 2026/27. As of the time of this filing, IESO Nova Scotia has 39 working employees, it has 2 accepted but the future employee has not yet started, it is in the process of making 1 offer following interviews, and it has 2 roles where interviews are on-going.

Staffing plans for fiscal year 2027/28 reflect the growth of the organization as it takes on its legislative mandate with the largest driver being preparations and readiness for the transfer of

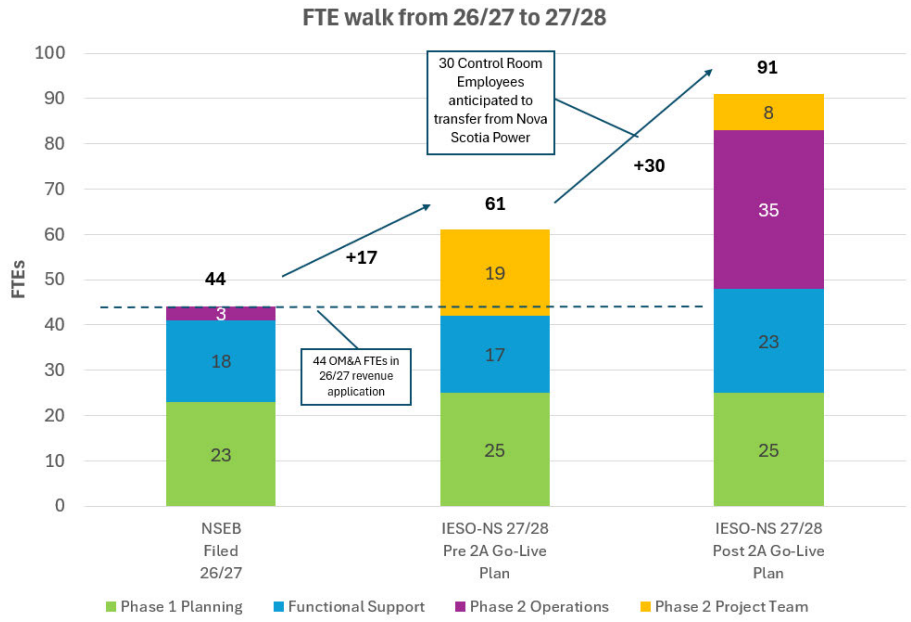
[18] Previously "Corporate Administrative" category in 26/27.

bulk system control operations from NS Power. Areas of growth include control-room and real-time operations, operational engineering, outage and reliability coordination, operational technology, cybersecurity, compliance, data and market services, and program or transition management. Built on the lessons from fiscal year fiscal year 2026/2027, IESO Nova Scotia has phased the budget for its anticipated resourcing needs from 55 FTE in April 2027 through to 91 in March of 2028, as seen in **Figure 17** below. The largest jump in resourcing is in March 2028 with the assumption that 30 Control Centre related employees are transferring from NS Power to IESO Nova Scotia.

Figure 17 also shows how in fiscal year 2027/2028 IESO Nova Scotia intends to have a number of FTEs assigned to supporting the Phase 2 project. As Phase 2A is completed, a number of those roles will move into operational roles with those remaining in the Project focusing on Phase 2B. Eventually all these roles are expected to transfer to necessary operational roles; by resourcing some of the Project with internal FTEs, it reduces costs of the project compared to using outside resources, provides subject matter expertise to the Project, while also building FTE knowledge and expertise that will remain with IESO Nova Scotia after the Project is completed.

IESO Nova Scotia continues to gain experience and understanding of its role and the minimum resourcing that it needs to diligently and prudently deliver on its mandate. It is expected that as detailed design work is completed, there could be changes to FTE requirements, but the best available view at the time of filing is that the total FTE headcount at the end of March 2028 will be 91. Due to the time it takes to get through the hiring process, the importance of the roles and the tight timelines involved with the control center transition, IESO Nova Scotia intends to make progress in fiscal 2026/2027 in building its headcount towards having 55 FTE hired by April 2027. Each of the incremental roles are described in the relevant budget sections below.

Figure 17 – FTE Projected Increases from 2026/2027 to 2027/2028



Anticipated Phasing (by month)

Month	FTEs
Apr-27	55
May-27	55
Jun-27	56
Jul-27	57
Aug-27	57
Sep-27	60
Oct-27	60
Nov-27	60
Dec-27	60
Jan-28	61
Feb-28	61
Mar-28	91

Consistent with IESO Nova Scotia's prior revenue requirement applications (M12412 and M12663), compensation continues to be single largest category of cost across all functional areas of the organization, comprising approximately $6.9M in fiscal year 2027/2028. In support of IESO Nova Scotia's staffing and compensation particulars, Marsh (formally Mercer), a compensation and salary benchmarking consultancy firm, was engaged to examine IESO Nova Scotia's compensation, and to recommended a compensation framework approach that could be adopted going forwards that would align with the organization's market median pay philosophy. The result is a compensation benchmarking report from Marsh (please refer to **Appendix 9**) which reached the following conclusions:

- IESO Nova Scotia's compensation for roles is reasonable and on average was slightly below the market median benchmarked data.

- IESO Nova Scotia would benefit from having a scalable compensation framework with benchmarked pay bands to support compensations decisions for both hiring and employee progression. Marsh provided a recommended approach that IESO Nova Scotia intends to adopt.

- As IESO Nova Scotia's existing employee job descriptions were mapped to the new framework, there were no employees that that exceeded the top ends of the benchmarked bands for their role.

Following review of the Marsh report, IESO Nova Scotia did not make any changes to its OM&A budget for fiscal year 2027/2028. IESO Nova Scotia has adopted the proposed framework and benchmarked salary bands. Going forward, this will support appropriate alignment of new roles to benchmarked salary bands that align to a market median philosophy and progression for existing employees as they develop their skills and capabilities.

3.4.1 System Planning and Procurement

IESO Nova Scotia system planning and procurement budget primarily consists of costs incurred to fulfill its statutory object of carrying out Resource Planning and Transmission Planning as well as competitive energy resource procurements. This Application includes the costs of managing multiple energy resource procurement processes prior to execution of contracts. These procurements have been identified as a need in the most recent IRP conducted by NS Power and the Province of Nova Scotia's Clean Power Plan. As noted by IESO Nova Scotia in M12663, costs associated with the administration of energy resource procurement processes and contracts up to the point of execution of the contract fall under s.29 revenue requirement applications. This work is consistent with IESO Nova Scotia's strategic priority "Advance System Reliability, Building on the Integrated Resource Plan" and "Strengthen System-User Engagement, Transparency and Access" referenced in sections 2.3.2. and 2.3.3., respectively, above. **Figure 18** below provides a summary of System Planning and Procurement costs and its sub-categories, and compares where applicable to the restated 2026/2027 forecast.

Figure 18: OM&A Costs for the System Planning and Procurement Cost Category

	Ongoing OM&A Budget ($)	
Cost Category	2026/2027F Restated	2027/2028F
Total System Planning & Procurement	5.10	4.17
Compensation	4.08	3.52
Procurement	1.10	0.74
System Planning	1.00	0.62
Other	-	0.16
Third Party Recoveries	(1.08)	(0.87)

Further details regarding the costs budgeted as part of this cost category are as follows:

Compensation: IESO Nova Scotia has included 26 roles in the System Planning and Procurement function for 2027/2028, including continuity of the 23 roles budgeted in 2026/2027. For 2027/2028 this category includes the VP Planning and Procurement, Manager Resource Planning, Sr. Technical Advisor Transmission Planning, and Director Energy Resource Procurement, as well as 19 existing engineering and analyst roles. New in 2027/2028 are the additions of a Director of System Planning to support the ongoing leadership of the department, an additional Engineering role to provide capacity for the department to support current workload including the Phase 2 project, and an Energy Resource Procurement Analyst to support the expanding scope of procurement and contract management activities as IESO Nova Scotia continues to procure new energy resources.

- **Basis of Estimate**: Compensation is based on actual rates currently in place for staff plus a four percent cost of living adjustment and includes employer payroll costs such as CPP, EI, WCB as well as the employer cost of benefit plans covering pension and

extended health benefits. Compensation rates have been benchmarked against market rates in the Marsh Report provided as Appendix 9.

Procurement: This cost category primarily consists of costs incurred to fulfill IESO Nova Scotia's statutory object of carrying out competitive energy resource procurements, including for developing and implementing procurement initiatives. This includes costs for consultant support of procurement activities. This revenue application includes the costs of managing multiple competitive procurement processes for energy resources. One of these is a request for proposal (RFP) is for 300-600MW of fast acting generation which was formally launched in July 2026 and is anticipated to be awarded by May 2027. IESO Nova Scotia also anticipates additional procurement process(es) will be underway in 2027/2028 based on the results of the 2026 IRP and the submissions received in response to its Technology Neutral Capacity Request for Qualifications, which is currently anticipated to close in January of 2027. IESO Nova Scotia is developing an Energy Resource Procurement Cost Allocation Guideline, which will establish costs included in revenue requirement applications are distinct from costs related to costs for energy resource supply contracts, and any costs incurred by the IESO for the administration of those contracts, respecting settlements or payments under contracts for energy resources obtained through procurement activities or through reassignments of existing energy supply agreements from NS Power, and that any such costs will be recovered under future proceedings under Section 30 of the More Access to Energy Act.

- **Basis of Estimate**: Costs associated with procurement consulting support are based on existing contract rates for supporting resources and IESO Nova Scotia's experience in 2026/2027 for level of effort associated with similar activities. There are two major procurement initiatives captured for this fiscal year. The fast-acting generation RFP includes costs associated with Legal Support, Contract Monitoring, Site Visits and Meetings, Stakeholder Engagement, and Engineering Support. The capacity procurements processes anticipated to follow from the Technology Neutral Capacity RFQ include Procurement Process Support, Legal Support, Stakeholder Engagement, and Engineering Support costs. Please refer to Appendix 10 for copies of historical consultant contracts which were used as a basis for estimating associated costs in fiscal year 2027/2028.

System Planning: This cost category includes consulting fees related to consultant support for resource and transmission planning activities in 2027/2028. This will include support for IRP

Action Plan items which are determined as appropriate to undertake in the 2027/2028 fiscal year based on the outcomes of the 2026 Integrated Resource Plan.

- **Basis of Estimate:** Consulting costs are estimated based on potential studies and support required in the 2027/2028 year; scope and prioritization will be refined as we approach the year, including in consultation with stakeholders as part of developing the Action Plan resulting from the 2026 IRP.

Third Party Recoveries: Third party recoveries refers to the recovery of labour and consulting costs associated with IESO Nova Scotia technical employees completing interconnection studies. These costs are recovered as allowed under the NSEB-approved Generation Interconnection Procedures, and reflect the actual costs incurred to perform Interconnection Studies on behalf of interconnection customers.

- **Basis of Estimate:** Similar to the approach taken in 2026/2027, Interconnection Revenues are budgeted based on an anticipated number of Interconnection Studies for the fiscal year with revenue assumed to align to the deposit amounts for each study type in the NSEB-approved Generation Interconnection Procedure.

Other: Other costs are primarily travel and conference fees for technical staff which are required to maintain current knowledge of emerging technologies, industry best practices, market trends and regulatory developments and provide employee growth and development opportunities to maintain the team's technical capabilities. Technical group memberships and subscription costs are also included in this category.

- **Basis of Estimate:** Budget is developed by forecasting requirements to stay current with technical and regulatory based on known industry events and trends with costs based on historic experience. Travel costs are estimated based on estimated attendance across the team in NERC/NPCC working groups and task forces, training and employee development activities.

Comparison to 2026/2027 Budget

The costs in this category have reduced from 2025/2026 as the New Brunswick capacity contract moves to the project execution stage and the fast acting generation RFP gets closer to being awarded, but offset with additional procurement process for additional capacity and/or storage

in 2027/2028. For the 2027/2028 budget, the procurement costs include technical experts, legal, communications support, and a procurement consultant. The 2027/2028 budget for compensation decreases whereas the 2026/2027 budget included costs related to training, travel and office expenses which are broken out separately in this Application. Additionally, forecast compensation was based on projection of salary ranges whereas compensation in this application is based actual compensation plus an allowance for up to 4% increase relative to 2026/2027 compensation. It is anticipated that this team will support elements of the Phase 2 transition and accordingly, a portion of labour from this team representing 1 FTE has been allocated to that project budget.

3.4.2 System Operations

This is a new cost category in IESO Nova Scotia's Revenue Requirement Application and has been added in preparation for the transition to assume Phase 2 system operation responsibilities. Costs in this category include staff and consulting transferred from the 2026/2027 revenue requirement application categories of "Employees (Administration)", including the Director Operational Policy & Market Operations and two roles under them, Phase II Transitional Costs", as well as one month of OM&A costs reflecting the projected in-service of the Phase 2 Control Centre of March 1, 2028 and corresponding transfer of staff. As part of the Phase 2 planning engagement, IBM identified operating costs that IESO Nova Scotia will incur as a result of assuming systems operations responsibilities and the costs in this section are based on IBM estimates. A large portion of these costs are incurred for functions transferred from NS Power, however there will be some incremental costs covering necessary activities to support the transition where the FTEs that provide those services are not transferring across to IESO Nova Scotia, as they also are accountable for other work that is not transferring to IESO Nova Scotia. The budgeted numbers are IESO Nova Scotia's best view at the time of filing, but the exact number of employees transferring from NS Power, and necessary supporting roles, will be confirmed prior to implementation. This work is consistent with IESO Nova Scotia's strategic priority "Complete the Successful Transition of System Operation" referenced in sections 2.3.1. above. **Figure 19** below provides a summary of System Operations costs and its sub-categories, and compares where applicable to the restated 2026/2027 forecast.

Figure 19: OM&A Costs for the System Operations Cost Category

	Ongoing OM&A Budget ($)	
Cost Category	2026/2027F Restated	2027/2028F
Total System Operations	1.06	0.74
Compensation	0.56	0.45
System Operation Solutions	0.50	0.29

Further details regarding the expenses budgeted as part of this cost category are as follows:

Compensation: IESO Nova Scotia has budgeted for 37 roles in the System Operations function for 2027/28, including continuity of the 3 roles budgeted in 2026/2027. For 2027/2028 this category includes the Director Operational Policy & Market Operations, Market Rules & Services Specialist, and Market Reporting Specialist. New in the 2027/2028 budget is the VP System Operations to lead the system operations function (this role has transitioned from NS Power in 2026 to lead the Phase 2 project activities), a Settlements Manager and a Settlement Specialist to support the development of the work for Phase 2 and in due course take on the settlement activities related to the operations of the electricity system, and a RTO/NERC Specialist to lead and co-ordinate engagement with NPCC, NERC and other RTOs. There are also 30 positions anticipated to transfer from NS Power to IESO Nova Scotia in March 2028 - this is a budgeting assumption for the purpose of the Application, refinement and discussions with NS Power regarding the specific number and positions will be undertaken as the Project progresses.

- **Basis of Estimate**: Compensation is based on actual rates currently in place for staff plus a four percent cost of living adjustment and includes employer payroll costs such as CPP, EI, WCB as well as the employer cost of benefit plans covering pension and extended health benefits. Compensation rates have been benchmarked against market

rates in the Marsh Report provided as Appendix 9. For transitioning roles please refer to Appendix 6 – IBM report.

System Operations Solutions: This category includes costs for systems, tools and 3rd party provided services to enable system operators to perform their role as BA and TOP.

- **Basis of Estimate:** Please refer to Appendix 6 – IBM Report.

Comparison to 2026/2027 Budget

Although System Operations is a new cost category for fiscal year 2027/2028, there were related costs included in the IESO Nova Scotia's 2026/2027 revenue application that pertain to this category. In the reconciliation of the 2026/2027 OM&A budget to the new cost categories of 2027/2028, three positions originally included in Employees (Administration) as well as consulting costs originally included in "Phase II Transitional Costs" have been allocated to System Operations for the sake of comparison. The reduction in costs in fiscal 2027/2028 is a result of capitalizing a portion of Compensation and System Operation Solutions that were otherwise OM&A in fiscal year 2026/2027 and the non-recurring nature of the Phase II Transitional Costs included in the 2026/2027 application.

3.4.3 Information Technology

IESO Nova Scotia is budgeting $2.1M in expenses as part of the Information Technology cost category. This cost category consists of costs incurred for internal staff, Managed IT Services, IT Application Software, and other IT Services to meet IESO Nova Scotia's various technology needs. The services provided enable each functional area of IESO Nova Scotia to meet its current and future business mandate. The technology strategy and the associated costs are heavily influenced by the effective use of cloud services and managed services to meet the needs of the business. These costs are necessary for IESO Nova Scotia's to carry-out all of its strategic priorities referenced in section 2.3 above. **Figure 20** below provides a summary of IT costs and its sub-categories, and compares where applicable to the restated 2026/2027 forecast.

Figure 20: OM&A Costs for the Information Technology Cost Category

	Ongoing OM&A Budget ($)	
Cost Category	2026/2027F Restated	2027/2028F
Total Technology	2.14	2.10
Compensation	0.96	0.66
IT Application Software	0.89	0.81
Managed IT Services	0.21	0.30
Other IT Costs	0.08	0.33

Further details regarding the expenses budgeted as part of this cost category are as follows:

Compensation: IESO Nova Scotia has budgeted for 11 roles in the Information Technology function for 2027/2028, including continuity of the 6 roles budgeted in 2026/2027. For 2027/2028 this category includes the Director of Technology & Security, Manager of Cybersecurity, Manager of Operational Technology Services, Manager of Enterprise Architecture, Manager of Infrastructure & Applications, and IT Support Desk Specialist. New in the 2027/2028 budget is a Project Manager, Cybersecurity Support Specialist, OT Support Specialist, Data & BIA Specialist, and NERC-CIP Compliance Specialist. These roles will be directly contributing to the delivery of the Phase 2 Control Centre project and will remain after go-live to sustain ongoing responsibilities. There will be a significant amount of technology (IT & OT) involved with the establishment of an independent grid operator and it will require this team to manage the technology and the associated cybersecurity risks. Approximately half of the employees will be spending the majority of their time working on the Phase 2

implementation project and therefore a portion of the IT salary costs will be allocated to the Project.

- **Basis of Estimate:** Compensation is based on actual rates currently in place for staff plus a four percent cost of living adjustment and includes employer payroll costs such as CPP, EI, WCB as well as the employer cost of benefit plans covering pension and extended health benefits. Compensation rates have been benchmarked against market rates in the Marsh Report provided as Appendix 9.

IT Application Software: These costs include the purchase of licenses for the required software for IESO Nova Scotia to successfully perform its functions that began in Phase 1. These costs are for software licenses used in the utilities industry for system planning functions such as integrated resource planning, transmission planning, and reliability studies. This category also includes collaboration and office productivity software subscriptions as well as software subscriptions that enable corporate business functions (HR, Finance, Legal, etc.). The major software and services included in this category include the following:

- *PLEXOS*: facilitates complex resource modeling scenarios to enable Integrated Resource Planning and other resource planning studies. This capacity expansion and production cost simulation tool is used to assess various combinations of system assumptions and constraints to inform decision-making for long-term system resource planning.

- *PSSE*: enables transmission planning and analysis that optimizes power supply and risk mitigation by performing large-scale grid modelling with power flow analysis, contingency and fault analysis, voltage reliability and substation/breaker modelling.

- *PSCAD*: performs grid modeling simulations of Electromagnetic Transient (EMT) factors that are increasingly present with the growing presence of Wind and other Inverter-Based Resources (IBR).

- *Aspen OneLiner*: a computer-based tool used by system protection engineers for short circuit analysis and relay coordination functions.

- *Microsoft Office 365*: general office productivity and collaboration software for corporate email, file storage, file sharing, Teams online meetings, MS Word, PowerPoint, Excel as well as a full suite of Cybersecurity solutions (Defender Suite).

- *AVEVA Connect Data Service*: a cloud-based data historian hub to collect and present visualizations of grid operational information. This solution was implemented in 2026/2027 and will continue to evolve in 2027/2028.

- *Various Other Software*: this cost category includes smaller software solutions such as SaaS solutions for Payroll, Finance, Legal and HR. It also includes the initial operating costs for a foundational data platform for Business Intelligence & Analytics (Fabric).

- **Basis of Estimate:** For the software used for resource planning and transmission system studies, the costs are comprised of annual subscription licenses and software maintenance and support. The agreements for this area were executed in 2025 to enable Phase 1 operations and are continuing into this fiscal year. Please refer to Appendix 11 for copies of these software services agreements.

  For collaboration and office productivity software (e.g. Microsoft Office 365), the subscription licensing costs are based on the anticipated number of users (employees and contractors) applied against Microsoft's standard pricing structure listed on their website. The software subscription costs for Payroll, HR, Finance and Legal systems implemented in the current fiscal year that extend into fiscal year 2027/2028 are also included in this category.

Managed IT Services: The Managed IT Services subcategory includes costs related to having a third-party company provide IT and Cybersecurity managed services. These services not only provide employee technical support and ensure the performance and availability of the technology services deployed but also ensure that cybersecurity risks are managed to an appropriate level. These services commenced in January 2026 under a 3-year agreement and will continue into fiscal year 2027/2028.

- **Basis of Estimate:** The costs for managed services have both fixed and variable components. The estimate in this submission is based on the contract with anticipated growth in IT infrastructure as well as number of users (employees and contractors).

Other IT Costs: Other IT Costs include the costs for communication services, cloud services, website hosting, cybersecurity initiatives and miscellaneous travel costs.

- **Basis of Estimate:** The costs for mobile phone services (under communication services) are estimated based on the number of employees against current contractual arrangements. It also includes cost for Internet access at the main office as well as similar redundant services at the Control Centre. The cloud services costs (Microsoft Azure) are based on estimated growth against our existing costs. Other costs estimates are based on some smaller initiatives to maintain and improve the overall technology area.

Comparison to 2026/2027 Budget

The overall estimated costs associated for Technology are similar to the forecasted amount in fiscal year 2026/2027. As can be seen in **Figure 20** above, some areas are increasing and some are decreasing. Compensation costs show a decrease because many of the employees will be working on the Phase 2 Control Centre project, resulting a portion of the salary costs being charged to the Project. Managed IT Services subcategory increases due to the increasing number of users.

3.4.4 Communications & Stakeholder Engagement

IESO Nova Scotia is budgeting $0.94M in ongoing expenses as part of the Communications and Stakeholder Engagement cost category. This cost category consists of costs incurred in respect of IESO Nova Scotia's public communications and stakeholder engagement activities. This work is necessary for IESO Nova Scotia's to carry-out its strategic priority "Build External Trust and Shape Energy Policy to Benefit Nova Scotians" referenced in section 2.3.4. above. **Figure 21** below provides a summary of Communications & Stakeholder Engagement costs and its sub-categories and compares where applicable to the restated 2026/2027 forecast.

Figure 21: OM&A Costs for the Communications & Stakeholder Engagement Cost Category

	Ongoing OM&A Budget ($)	
Cost Category	**2026/2027F Restated**	**2027/2028**
Total Communications & Stakeholder Engagement	**0.45**	**0.94**
Compensation	0.28	0.25
Consulting	0.14	0.30
Public Education	0.03	0.35
Other	-	0.04

Compensation: IESO Nova Scotia has budgeted for 3 roles in the Communications and Stakeholder Engagement function for 2027/2028, including continuity of the 2 roles budgeted in 2026/2027. For 2027/2028 this category includes the Director, Communications & Engagement, and Engagement Specialist that has been retitled Communications Advisor. New in the 2027/2028 budget there is the addition of a Senior Communications Advisor to support the increased workload of the growing scope of the organization including working with media and Mi'kmaw communities and organizations.

Basis of Estimate: Compensation is based on actual rates currently in place for staff plus a four percent cost of living adjustment and includes employer payroll costs such as CPP, EI, WCB as well as the employer cost of benefit plans covering pension and extended health benefits. Compensation rates have been benchmarked against market rates in the Marsh Report provided as Appendix 9.

Consulting: These costs are associated with managed external resources to support IESO Nova Scotia's internal team with:

- Co-development, with specialized experts, of an Indigenous Relations Framework to support IESO Nova Scotia's relationship-building and long-term engagement with Mi'kmaw communities and organizations.

- Extensive engagement of stakeholders across the province — including Mi'kmaw communities and organizations; municipal, provincial, and federal government officials and staff; business and industry representatives; sectoral partners; advocacy groups; and Nova Scotia residents with an interest in the energy system — on matters such as competitive resource procurement initiatives, long-term system planning, and the ongoing evolution of the province's electricity sector.

- Critical communication initiatives to provide Nova Scotians with timely, informative, and accessible updates on competitive procurement processes, long-term planning, and other information about the province's electricity system, including the development of public communications materials, reports and data, IESO Nova Scotia's website, and other external products.

- **Basis of Estimate:** The costs for this category are based on historical pricing of services delivered to date for required external communications, website development, and stakeholder engagement support for the 2026-27 fiscal year. The Indigenous Relations Framework estimated pricing is provided by the Mi'kmaw consulting firm engaged in its co-development.

Public Education: These costs are associated with engaging external expertise to support the development and delivery of public education initiatives that increase Nova Scotians' understanding of the electricity system, the roles and responsibilities of electricity sector organizations, the factors influencing system planning and operation, and the impacts of energy-related decisions on reliability, affordability, and sustainability. Enhanced public understanding supports more informed and constructive public discourse, enables more effective stakeholder engagement, and contributes to better outcomes for stakeholders, communities, and the electricity system as a whole by addressing information gaps, reducing misunderstanding and misinformation, improving energy literacy, and facilitating informed participation in matters of public interest. These initiatives also support IESO Nova Scotia's commitment to transparency and accountability as the province's independent system and market operator.

- **Basis of Estimate:** The costs for this category are based on quotes, with indicative pricing, provided by communications firms located in Nova Scotia.

Other: These costs include travel and materials required for public and stakeholder engagement activities, industry conferences, and subscriptions costs for media monitoring.

- **Basis of Estimate:** Travel and conference costs are based on historical costs and expected inflationary increases. Media monitoring costs are based on historical costs.

Comparison to 2026/2027 Budget

This cost category increased from IESO Nova Scotia's 2026/2027 Revenue Requirement Application due to:

- Inclusion of Indigenous Relations Framework scope of work.
- Inclusion of Public Education scope of work.

These were somewhat offset by a small reduction in compensation costs with some of the teams' time spent supporting communications and change management for the Phase 2 Project.

3.4.5 Legal & Regulatory

IESO Nova Scotia is budgeting $3.05M in ongoing costs as part of the Legal and Regulatory OM&A cost category. This cost category primarily consists of the following subcategories and associated costs: employee compensation, Board of Directors governance, regulatory proceedings before the NSEB, internal regulatory fees for support for regulatory proceedings, external legal advice to support the General Counsel and Corporate Secretary, and NERC/NPCC compliance. This work is necessary for IESO Nova Scotia to carry-out all strategic priorities requiring legal support as well as "Progress Important Regulatory Outcomes" with respect to Regulatory functions referenced in section 2.3.5. above. **Figure 22** below provides a summary of Legal & Regulatory costs and its sub-categories, and compares where applicable to the restated 2026/2027 forecast.

Figure 22: OM&A Costs for the Legal and Regulatory Cost Category

	Ongoing OM&A Budget ($)	
Cost Category	**2026/2027F Restated**	**2027/2028F**
Legal and Regulatory	**2.37**	**3.05**
Compensation	0.73	0.76
Governance	0.49	0.41
Regulatory Proceedings	0.55	0.86
Internal Regulatory Fees[19]	-	0.31
Legal, Enterprise Risk Management, and Compliance	0.60	0.61
NERC / NPCC Compliance Fees	-	0.1

Further details regarding the expenses budgeted as part of this cost category are as follows:

Compensation: IESO Nova Scotia has budgeted for 5 roles in the Legal and Regulatory function for 2027/2028, including continuity of the 4 roles budgeted in 2026/2027. For 2027/2028 this category includes the General Counsel & Regulatory Affairs, Director Regulatory Affairs, Legal Assistant, and Risk & Compliance Specialist. New in the 2027/2028 budget is the Regulatory Specialist that has been created to support the large Regulatory workload of IESO Nova Scotia and to incrementally reduce external support. This role has been filled in 2026/2027.

[19] Internal Regulatory Fees is new cost category segregated from Regulatory Proceedings and Assessment from the 2026/2027 application for greater transparency.

- **Basis of Estimate:** Compensation is based on actual rates currently in place for staff plus a four percent cost of living adjustment and includes employer payroll costs such as CPP, EI, WCB as well as the employer cost of benefit plans covering pension and extended health benefits. Compensation rates have been benchmarked against market rates in the Marsh Report provided as Appendix 9.

Governance: As with any organization, good governance is the foundation for its success. This cost category includes costs incurred in respect of IESO Nova Scotia's corporate governance, including ordinary course enterprise and board governance activities, board-related support, travel and expense for meetings, and meeting per diems.

- **Basis of Estimate**: With respect to IESO Nova Scotia Board of Director's remuneration, IESO Nova Scotia had undertaken a market driven analysis regarding remuneration. As noted during IESO Nova Scotia's 2026/2027 Revenue Requirement Application proceeding (M12663), IESO Nova Scotia had engaged Huggessen Consulting Inc. to independently complete this market analysis, which formed the basis for IESO Nova Scotia's determination of ongoing remuneration of its directors. For this Application budget, IESO Nova Scotia used this information, together with a projection of the number of meetings, to determine the budgeted amount. A copy of the Huggessen report was provided in the 2026/2027 Revenue Requirement Application proceeding (M12663).

Regulatory Proceedings and Assessments: These costs include an estimate of the costs to be covered by IESO Nova Scotia for the NSEB and legislative regulatory stakeholders, the Consumer Advocate and Small Business Advocate, and their consultants. The budget includes the costs associated with a NSEB assessment as the Act permits the Board to assess expenses against IESO Nova Scotia, and deems those expenses to be recoverable through its rates, tolls and charges.[20]

- **Basis of Estimate:** The estimated budget is based on the number of regulatory proceedings anticipated initiated by the NSEB in fiscal year 2027/2028, the assumed timeframe of the associated proceeding, and whether regulatory stakeholders will intervene.

[20] *More Access to Energy Act*, SNS 2024, c. 2, Sch. B, Section 85.

Regulatory proceedings assumed to occur include the revenue requirement, proposed expenditures, and fees applications falling within the fiscal year, as well as various other reporting and potential as needed one-off applications for NSEB review and approval.

For each filing with an anticipated Board proceeding attached to it, costs were assigned based on 1) the estimated timeframe for the proceeding and 2) available actual historical costs sourced through CA and SBA annual reporting and NSEB invoicing.

For example, revenue requirement, proposed expenditures, and fees applications proceedings falling in 2027/2028 are assumed to cover three quarters based on the NSEB proceeding timeline for the 2026/2027 revenue requirement and fees application, NSEB invoices for Board fees, external consulting, and external legal for one quarter regarding an application are then multiplied by three (for three quarters) to reach an estimated NSEB cost for that proceeding. A similar methodology is used to calculate the CA and SBA fees for the same proceeding, but based on the CA and SBA's most recent annual reports submitted to the NSEB.

Please refer to Appendix 12 for the CA and SBA annual reports.

Internal Regulatory Fees: These costs include IESO Nova Scotia's external legal and consultant support to prepare and to participate in regulatory proceedings before the NSEB during the fiscal year.

- **Basis of Estimate:** The estimated budget is based on the number of regulatory proceedings anticipated initiated by the NSEB in fiscal year 2027/2028, the assumed effort related to the application and proceeding, including whether external consulting or project management will be required. The budget also includes a plug for assumed legal support for regulatory matters.

  Regulatory proceedings assumed to occur include the revenue requirement, proposed expenditures, and fees applications falling within the fiscal year, as well as various other reporting and potential as needed one-off applications for NSEB review and approval.

  For each filing with an anticipated Board proceeding attached to it, costs were assigned based on 1) the estimated effort to support the application and proceeding, and 2) available actual historical costs sourced through external consultant invoicing.

For example, revenue requirement, proposed expenditures, and fees applications proceedings falling in 2027/2028 are assumed to require external consulting and project management support given the high level of complexity and effort associated with the filing and corresponding NSEB proceeding. Expert consulting in support of certain significant assumptions and project management related to the Information Request process are assumed. IESO Nova Scotia's consultant bid for the compensation benchmarking exercise was used as a baseline precedent. A similar process is used for other assumed regulatory filing/application proceedings, with percentage modifier applied based on the assumed level of effort for each proceeding.

Please refer to Appendix 13 for the Marsh compensation benchmarking proposal as well as Barrington consulting quote for project management services.

Legal, Enterprise Risk Management and Compliance: These costs are for the reasonably foreseeable external legal advisory needs of IESO Nova Scotia during the 2027/2028 fiscal year that fall outside of regulatory proceedings, together with the costs of establishing and maintaining an enterprise risk management (ERM) function and meeting IESO Nova Scotia's corporate and reliability compliance obligations. As IESO Nova Scotia moves into its second full year of operations and prepares to assume real-time system operations from Nova Scotia Power under Phase 2, the volume and complexity of contractual, corporate, employment, procurement, privacy, and regulatory-compliance matters increases materially. These costs are reasonable because it (a) advances IESO Nova Scotia's statutory mandate under the Act, (b) reflects work that is necessary to manage the legal, financial and reliability risks of the Phase 2 transition rather than discretionary spend, and (c) is constrained to external support that supplements, rather than duplicates, in-house legal and regulatory capacity.

- **Basis of Estimate:** The budget for this subcategory was built using a bottom-up approach informed by IESO Nova Scotia's actual legal and advisory spend to date and its forecast requirements for 2027/2028. In preparing for this Application, IESO Nova Scotia undertook a comprehensive review of its expected legal services needs in the 2027/2028 fiscal year and sought the advice of three full service firms in Atlantic Canada regarding the estimated scope and quantum of the same. External legal costs were estimated on the basis of anticipated matters, expected hours and negotiated or market hourly rates for expected matters, and reflect the increased advisory demand associated with the growing organization undertaking material changes in its business. Wherever possible,

IESO Nova Scotia relied on historical actuals and engagements; where historical information was limited given its early stage of development, it applied conservative assumptions and the experience of internal staff.

NERC / NPCC Compliance Fees: This is a new cost category that represents one month of the estimated annual NERC and NPCC fees for annual assessments, which is required once IESO Nova Scotia takes on the BA and TOP functions in March 2028.

- **Basis of Estimate:** Historical invoices from NERC and NPCC issued to NS Power for similar services.

Comparison to 2026/2027 Budget

This cost category increased from IESO Nova Scotia's 2026/2027 Revenue Requirement Application due to:

- Regulatory Proceedings and Assessments and Internal Regulatory Fees have been estimated on an anticipated increase in the number of regulatory proceedings and a more precise estimation of regulatory stakeholder, NSEB, and IESO Nova Scotia external consulting and legal fees.
- The Legal, enterprise risk management and compliance subcategory reflects the anticipated increased external legal workload as IESO Nova Scotia prepares for the Phase 2 transition, together with the incremental cost of establishing an enterprise risk management function and meeting expanding corporate and reliability compliance obligations. The estimate also includes a previously unforeseen provision for external legal counsel to defend the procurement decisions and processes that IESO Nova Scotia is obligated to undertake under the Act as a result of the Integrated Resource Plan, including anticipated judicial review applications and other legal challenges by affected proponents and stakeholders. These procurement-related legal costs were not contemplated in the 2026/2027 Revenue Requirement Application and are a direct and necessary consequence of IESO Nova Scotia carrying out its statutory procurement mandate.

3.4.6 Finance

IESO Nova Scotia is budgeting $1.03M in ongoing costs as part of the Finance cost category. This cost category primarily consists of costs incurred in respect of financial services other than insurance, which are covered within the Corporation Administration cost category. This work is a foundational necessity for IESO Nova Scotia to carry-out all strategic priorities. **Figure 23** below provides a summary of Finance costs and its sub-categories, and compares where applicable to the restated 2026/2027 forecast.

Figure 23: OM&A Costs for the Finance Cost Category

	Ongoing OM&A Budget ($)	
Cost Category	2026/2027F Restated	2027/2028
Finance	**0.96**	**1.03**
Compensation	0.30	0.42
Interest Income	-	(0.03)
Financing Costs	0.59	0.49
External Financial Audit	0.04	0.07
Consulting and Other	0.03	0.08

Further details regarding the costs budgeted as part of this cost category are as follows:

Compensation: IESO Nova Scotia has budgeted for 4 roles in the **Finance** function for 2027/2028, including continuity of the 2 roles budgeted in 2026/2027. For 2027/2028 this category includes the Director Finance and the Accounting Specialist. New in the 2027/2028

budget is a Project Accountant to focus on supporting the Phase 2 Project team and a Controller position focused on monthly and annual financial reporting requirements. The 2027/2028 budget assumes that one finance position will work directly on the Project team with costs allocated to the Project.

- **Basis of Estimate**: Compensation is based on actual rates currently in place for staff plus a four percent cost of living adjustment and includes employer payroll costs such as CPP, EI, WCB as well as the employer cost of benefit plans covering pension and extended health benefits. Compensation rates have been benchmarked against market rates in the Marsh Report provided as Appendix 9.

Interest Income: This category is related to funds IESO Nova Scotia is forecasting to hold in its banking account, and the corresponding amount of interest earned. The interest earned is a result of a positive cash balance in IESO Nova Scotia's operating banking account from which to fund operations.

- **Basis of Estimate**: Interest earned on IESO Nova Scotia's operating banking account is based on a rate tied to the bank prime rate and fluctuates with the prime rate and the average cash balance.

Financing Costs: These costs are for interest expenses associated with financing required to provide cash for operations as well as financing related to the system operations for the month of March 2028 when the Control Centre becomes operational. IESO Nova Scotia may require financing to sustain operations in the absence of sufficient cash flow from Fees received from market participants. Accordingly, IESO Nova Scotia has secured an Operating Line of Credit granted by the Province of Nova Scotia. This financing by the Province allows IESO Nova Scotia to move forward with certain of its initiatives at the lowest cost. Additionally, the budget assumes that IESO Nova Scotia will obtain commercial financing to fund a portion of the Phase 2 Control Centre project.

- **Basis of Estimate:** IESO Nova Scotia projects that it will have drawn $10M on its operating line of credit and this outstanding balance will remaining outstanding for the duration of fiscal year 2027/2028. The estimated associated interest expense is 3.60%. The rate is estimated as the Provincial government cost of financing plus a margin using bank forecasts of Government of Canada T-Bill rates and adding risk premium adjustments. With respect to the March 2028 interest expense related to system

operations, the associated financing is included and based on the Provincial Line of Credit, and projected commercial financing at an interest rate of 5.08%. Please refer to Appendix 14 for a copy of the LoC agreement.

External Financial Audit: These costs are for services of an external financial auditor to perform a financial statement audit in accordance with the MAEA.

- **Basis of Estimate:** A contract for an external auditor was awarded for 2025/2026 fiscal year. The costs in fiscal year 2027/2028 were estimated based on an updated proposal from the auditor.

Consulting and Other: These costs are for support associated with implementation of an enhanced financial reporting system as a result of the growth of the organization and increased complexity regarding its operations. Also includes miscellaneous financial related subscriptions and travel.

- **Basis of Estimate:** A scope of requirements is developed where outside resource is required. From this an estimate of hours of work and average industry rates allows for an estimated cost.

Comparison to 2026/2027 Budget

The increase in the Finance cost category between the 2026/2027 budget and the 2027/2028 budget is related to increased compensation and financing costs. Increased compensation is a result of the additional roles for 2027/2028. The increase in financing costs is a result of a higher level of debt due to IESO Nova Scotia requiring debt financing to cover its operations while IESO Nova Scotia operates under the interim fees paid by NS Power and carrying that debt through 2027/2028, and financing of the Phase 2 Control Centre build-out.

3.4.7 Human Resources

IESO Nova Scotia is budgeting $0.59M in ongoing costs as part of the Human Resources OM&A cost category. This cost category primarily consists of compensation for professional staff, recruitment fees, consulting and an allocation for training and professional development for the organization's workforce. This work is necessary for IESO Nova Scotia to carry-out all strategic priorities given staffing requirements, and in particular "Build a Strong Organization Where People Want to Work and Grow" referenced in section 2.3.6. above. **Figure 24** below

provides a summary of Human Resource costs and its sub-categories, and compares where applicable to the restated 2026/2027 forecast.

Figure 24: OM&A Costs for the Human Resources Cost Category

	Ongoing OM&A Budget ($)	
Cost Category	**2026/2027F Restated**	**2027/2028**
Human Resources	**0.42**	**0.59**
Compensation	[redacted]	[redacted]
Consulting	[redacted]	[redacted]
Recruitment	0.10	0.17
Training and Professional Development	-	0.12
Other	-	0.05

Further details regarding the costs budgeted as part of this cost category are as follows:

Compensation: IESO Nova Scotia has budgeted for 2 roles in the Human Resources function for fiscal year 2027/28 as it did in fiscal year 2026/27: Director Human Resources and Human Resources Coordinator.

- **Basis of Estimate**: Compensation is based on actual rates currently in place for staff plus a four percent cost of living adjustment and includes employer payroll costs such as CPP, EI, WCB as well as the employer cost of benefit plans covering pension and extended health benefits. Compensation rates have been benchmarked against market rates in the Marsh Report provided as Appendix 9.

Consulting: Costs associated with external professional and advisory services used to support specialized Human Resources initiatives, programs and organizational requirements where additional expertise or capacity is required.

- **Basis of Estimate**: The consulting expense estimate is based on anticipated requirements for specialized external HR expertise and is consistent with recent experience. Consulting expenditures in the prior year were approximately $60K. Going forward, the budget provides $50K annually for specialized support where expertise or capacity is not available internally, including advisory services related to ongoing HR program administration.

Recruitment: Costs associated with attracting, sourcing and hiring employees, including external recruitment and search firm fees, job advertising, candidate sourcing and other recruitment-related expenses.

- **Basis of Estimate**: The recruiting expense estimate is based on anticipated hiring requirements associated with planned organizational growth and normal workforce turnover. The forecast reflects approximately the average number of employees during the year and assumes annual employee turnover of 5%. This assumption is consistent with IESO Nova Scotia's experience to date.

  Since December 1, 2025, the organization has experienced one voluntary resignation from the approximately 20 employees that transferred from NS Power, equivalent to an annualized voluntary turnover rate of approximately 5%. A separate departure due to retirement has not been included in voluntary resignation. The 5% forecast assumption therefore provides a reasonable allowance above observed turnover for normal employee movement as the organization grows.

  The estimate assumes a blended recruitment approach, utilizing external search firms for select new and replacement hires where specialized market expertise and candidate outreach are required, with remaining recruitment activity supported through internal recruitment capabilities and standard sourcing channels. Based on an average cost of $28K per executive search engagement and an estimated six search assignments during the budget period, total recruiting expense is estimated at $170K.

Training and Professional Development: Costs associated with employee training, professional development and skills development, including courses, certifications, conferences and other learning opportunities that support current and future organizational capability requirements. The budget recognizes the specialized nature of IESO Nova Scotia's workforce and the ongoing need to build internal capability as the organization grows.

- **Basis of Estimate**: The estimate represents a modest annual provision per employee for these activities, and based on anticipated requirements for training courses and development programs needed to maintain and build the professional, technical and leadership capabilities of the organization.

  The forecast represents a centralized organizational training budget that will be allocated on the average number of employees, based on identified organizational, role and employee development requirements.

Other: The Other cost category includes costs associated with general Human Resources programs, tools and activities that are not captured within the other HR cost categories. This includes employee engagement and recognition activities, HR tools and resources, professional memberships, and other incidental costs associated with delivering HR programs and supporting the employee experience.

- **Basis of Estimate**: The estimate represents a modest annual provision for these activities, with actual expenditures expected to vary based on organizational requirements.

Comparison to 2026/2027 Budget

This cost category increased from IESO Nova Scotia's 2026/2027 Revenue Requirement Application due to:

- Increased Training and Professional Development costs associated with workforce growth and the centralization and expansion of formal training and development activities to build internal organizational capability.
- Continued recruitment activity required to support planned organizational growth and preparations for the Control Centre transition.

- Increased HR program and administrative costs associated with supporting a larger workforce and the continued implementation and administration of HR programs, tools and employee initiatives.

3.4.8 Facilities

IESO Nova Scotia is budgeting $0.61M in costs as part of the Facilities OM&A cost category. This cost category consists of the annual costs associated with IESO Nova Scotia's office space as well as one month of operating costs for the Phase 2 Control Centre. This work is necessary for IESO Nova Scotia to carry-out all strategic priorities given facilities requirements, and in particular "Complete the Successful Transition of System Operations" referenced in section 2.3.1. above. **Figure 25** below provides a summary of Facilities costs and its sub-categories, and compares where applicable to the restated 2026/2027 forecast.

Figure 25: OM&A Costs for the Facilities Cost Category

	Ongoing OM&A Budget ($)	
Cost Category	2026/2027F Restated	2027/2028
Facilities	0.38	0.61
Compensation	-	[redacted]
Office Lease	0.38	0.35
Office Costs	-	0.01
Building Operating Costs	-	[redacted]

Further details regarding the costs budgeted as part of this cost category are as follows:

Compensation: IESO Nova Scotia has budgeted for one role in the Facilities function for 2027/28. The role is for a Facility Manager for the Control Centre and includes salary costs for several months prior to the go live of Systems Operations.

- **Basis of Estimate**: Compensation is based on actual rates currently in place for staff plus a four percent cost of living adjustment and includes employer payroll costs such as CPP, EI, WCB as well as the employer cost of benefit plans covering pension and extended health benefits. Compensation rates have been benchmarked against market rates in the Marsh Report provided as Appendix 9.

Office Lease: These costs are to lease approximately 8,900 square feet of office space at Suite 1010, TD Tower, 1791 Barrington Street, Halifax, Nova Scotia. IESO Nova Scotia has entered into a 10-year lease for these premises which commences on January 1, 2026.

- **Basis of Estimate:** Please refer to Appendix 15 for a copy of IESO Nova Scotia's lease.

Office Costs: These costs cover various minor repairs and maintenance associated with IESO Nova Scotia facilities.

- **Basis of Estimate:** Commensurate with the 2026/2027 fiscal year budget.

Building Operating Costs: Transfer of ownership of NS Power's Atlantic Data Centre to IESO Nova Scotia is expected in fiscal year 2026/2027 for the Phase 2 Control Centre Project. Operating costs include utilities, heating, security, cleaning, snow removal and general repairs and maintenance.

- **Basis of Estimate**: Building operating costs based on estimates incorporated in the IBM report for Phase 2 Control Centre Project costs and for one month of costs for March 2028 in alignment with the projected in-service date of the Control Centre.

Comparison to 2026/2027 Budget

This cost category increased from IESO Nova Scotia's 2026/2027 Revenue Requirement Application due to the OM&A cost category restructuring. It is a new cost category which includes Compensation and Building Operating Costs cost sub-categories for one month related to Phase 2 Control Centre projected in-service of March 2028.

3.4.9 Corporate Services

IESO Nova Scotia is budgeting $1.53M in costs as part of the Corporate Services OM&A cost category. This cost category primarily consists of various types of corporate expenses, including executive compensation, consulting, travel and conference fees, insurance, as well as fees related to various memberships, subscriptions and employee education. This work is necessary for IESO Nova Scotia to carry-out all strategic priorities referenced in section 2.3. above. **Figure 26** below provides a summary of Communications & Stakeholder Engagement costs and its sub-categories, and compares where applicable to the restated 2026/2027 forecast.

Figure 26: OM&A Costs for the Corporate Services Cost Category

	Ongoing OM&A Budget ($)	
Cost Category	**2026/2027F Restated**	**2027/2028**
Corporate Services	**1.97**	**1.53**
Compensation	[redacted]	[redacted]
Consulting	[redacted]	[redacted]
Insurance	0.03	0.04
Membership, Subs, Education	-	0.13
Other	0.16	0.11

Further details regarding the costs budgeted as part of this cost category are as follows:

Compensation: IESO Nova Scotia has budgeted for 2 roles in the Corporate Services function for fiscal year 2027/28 as it did in fiscal year 2026/27: President and CEO and Executive Assistant. The President and CEO performance linked variable pay is included in this cost category.

- **Basis of Estimate:** Compensation is based on actual rates currently in place for staff plus a four percent cost of living adjustment and includes employer payroll costs such as CPP, EI, WCB as well as the employer cost of benefit plans covering pension and extended health benefits. Compensation rates have been benchmarked against market rates in the Marsh Report provided as Appendix 9.

Consulting: Consulting cost category is for external consulting support for various initiatives such as process improvement and automation, transparency enhancements such as public dashboards and data-sets, selected market development studies, and leadership development.

- **Basis of Estimate:** Projects that relate to improvements in IESO Nova Scotia delivering on its mandate have been identified and with high level scope of requirements where outside resource is required. From this an estimate of hours of work and average industry rates allows for an estimated cost.

Insurance: IESO Nova Scotia has secured regular and customary insurance to cover commercial risks affecting the enterprise, and the services of an insurance broker, arising from IESO Nova Scotia's scope of operations.

- **Basis of Estimate:** Insurance costs based on current rates with providers and expected inflationary increases.

Membership, Subscriptions, Education: IESO Nova Scotia staff and operations require various memberships, subscriptions and education as part of their professional designations and development. This cost category budgets costs for corresponding fees.

- **Basis of Estimate:** Memberships, subscriptions and education budget are based on historical and current rates for each.

Other: Other expenses consist of travel, conference as well as office expenses and supplies. Travel and conference expenses are required to maintain current knowledge of emerging technologies, regulatory developments and industry best practices. Office and supply costs are associated with various common office materials such as office stationary and kitchen products.

- **Basis of Estimate:** Travel and conference costs are based on historical costs of and expected inflationary increases. Office expenses and supplies budget is based on historical costs and increased based on projected increase in staff.

Comparison to 2026/2027 Budget

This cost category decreased from IESO Nova Scotia's 2026/2027 Revenue Requirement Application due to a decrease in consulting costs as a result of the prior year budget including work for the planning of the Phase 2 transition. For fiscal year 2027/2028, Phase 2 transition work is being moved from OM&A to proposed expenditures as capital work in progress. This was partially offset by various incremental increases in the other cost sub-categories.

3.5 2027 – 2030F Outlook

Pursuant to the NSEB's direction in M12412, this section provides IESO Nova Scotia's three years of projected financial results. Figure 27 below provides 2027/2028F, 2028/2029F, and 2029/2030F for proposed expenditures, amortization, and OM&A total costs. As noted at the outset of this Application, IESO Nova Scotia is newly established not-for-profit with less than a year of operational experience. As such, the accuracy of outer year forecasts will be commensurately subject to change without the benefit of historical operational experience. While IESO Nova Scotia believes the forecasts noted in Figure 28 below directionally correct, they should be understood in this context.

Figure 27: 2027-2030F Outlook

Category	2027/2028F Total Budget	2028/2029F Total Budget	2029/2030F Total Budget
Proposed Expenditures	$27.5	$6.7	$4.8
Revenue Requirement	$15.23	$34.7	$37.6
Amortization	$0.43	$4.7	$5.8
OM&A	$14.8	$30.0	$31.8

The most significant variances across the 2027 – 2030 fiscal year outlook are driven by the transition of IESO Nova Scotia to full operational responsibility for electricity system functions and the commencement of a full year of operations following the in-service of the Control Centre. As a result, total OM&A expenses are forecast to increase from approximately $14.8 million in 2027/2028 to $30.0 million in 2028/2029 and $31.8 million in 2029/2030. A substantial portion of this increase reflects costs that are only incurred for only a month, or are capitalized during project implementation, in 2027/2028 but become full-year operating expenses in the subsequent years.

The largest increases are associated with 2028/2029 representing the first full year of operating the control centre and balancing authority functions, including system operations personnel, operational support, and settlement capabilities. Likewise, the control centre incurs a full year of building operating costs, including utilities, security, property taxes, maintenance, and related services.

The increase from 2028/2029 to 2029/2030 includes increased amortization costs with the on-going deployment of the Phase 2 Project; beyond this work, the increases are largely attributable to normal inflationary adjustments. The forecast assumes no material expansion of organizational responsibilities beyond those contemplated in the 2027/2028 Application.

4 Fees

4.1 Fee Recovery Mechanism

On July 31, 2026, IESO Nova Scotia filed an application with the NSEB (M13007) seeking approval of a Fee Recovery Mechanism pursuant to section 29 of the More Access to Energy Act. The proposed mechanism is intended to replace the interim fee arrangement currently in place with NS Power as approved by the Board and establish a transparent and predictable approach for recovering IESO Nova Scotia's Board-approved revenue requirement from Load Serving Entities ("LSEs") in Nova Scotia.

Under the proposed mechanism, IESO Nova Scotia's approved revenue requirement would be recovered through fixed monthly charges to LSEs, allocated based on each LSE's proportionate share of forecast annual load served in Nova Scotia. The mechanism also includes annual true-

up provisions to reconcile forecast and actual revenue requirements as well as annual adjustments to reflect actual load allocations among LSEs.

At the time of filing this application, the Fee Recovery Mechanism remains before the NSEB and has not yet been approved. Accordingly, the information provided herein reflects the mechanism as proposed and should not be interpreted as prejudging the outcome of the Board's proceeding.

Consistent with the approach proposed in the Fee Recovery Mechanism application, IESO Nova Scotia has calculated fees for approval effective April 1, 2027 on the assumption that:

- The NSEB ultimately approves the proposed Fee Recovery Mechanism;
- The 2026/27 revenue requirement is approved substantially as applied for; and
- The full 2026/27 revenue requirement is recovered in full by March 31, 2027.

As part of the Fee Recovery Mechanism application, IESO Nova Scotia proposed two approaches for incorporating revenue requirement true-ups:

- **True-Up Option 1** - This option incorporates prior-year revenue requirement variances as part of a future revenue requirement proceeding. Under this approach, variances from a given fiscal year are determined through the Deferral and Variance Mechanism ("DVM") and included in a subsequent revenue requirement application, resulting in an approximate two-year regulatory lag between the year in which the variance arises and the year in which it is recovered from or credited to market participants.

- **True-Up Option 2** - This option accelerates recovery or refund of prior-year variances. Under this approach, once audited financial information becomes available and following approval of the subsequent revenue requirement application, IESO Nova Scotia would file a compliance filing to adjust current-year fees for any over- or under-recovery from the prior fiscal year. This approach shortens the recovery period, reduces carrying costs associated with under-recovery, and provides earlier crediting to market participants in the event of over-recovery. IESO Nova Scotia has identified this as its preferred true-up methodology in the Fee Recovery Mechanism application.

As the proposed mechanism has not yet received NSEB approval, this application presents fees calculated under both True-Up Option 1 and True-Up Option 2 to demonstrate the fees of under each and to facilitate review by the Board. Should the NSEB's decision under M13007 direct revisions to the methodology proposed in that proceeding, adjustments may be necessary

4.2 OM&A and Amortization

Consistent with section 29 of the MAEA, IESO Nova Scotia's revenue requirement represents the costs necessary to carry out its statutory mandate and forms the basis for recovery through the proposed Fee Recovery Mechanism.

The revenue requirement proposed in this application is comprised of OM&A and amortization expense associated with capital assets that have been placed into service. Collectively, these amounts represent the costs eligible for recovery through fees charged to market participants under the proposed Fee Recovery Mechanism.

The OM&A component of the revenue requirement is described in section 3.4 and reflects the ongoing costs of operating IESO Nova Scotia and delivering its legislated responsibilities over the twelve month period of this application.

Amortization expense included in the revenue requirement is described in section 3.3 and reflects the recovery of capital investments that support IESO Nova Scotia's operations. For purposes of this application, the amortization component includes one month of amortization expense associated with the Control Centre assets that are expected to be placed into service during the last month of fiscal year 2027/28, as well as various miscellaneous IT assets.

Amortization expense associated with the Control Centre has been calculated based on estimated project costs which have been assigned to asset classes as shown in **Figure 28** below.

Figure 28 - Control Centre Amortization

Control Centre Costs	Cost	Amortization Rate (Years)	Annual Amortization	2027-2028 Amortization (1 month)
Building	$15.08M	20	$0.75M	$0.06M
Computers and Software	$14.60M	5	$2.92M	$0.24M
Licenses	$9.00M	10	$0.90M	$0.08M
Total Control Centre Costs	$38.68M		$4.57M	$0.38M

Total amortization for the 2027-2028 fiscal year, inclusive of other IT assets, is estimated as shown in **Figure 29** below.

Figure 29 - Total Amortization for all Capital

Capital Additions	Cost	Amortization Rate (Years)	Annual Amortization	2027-2028 Amortization
Computer Hardware	$0.06M	3-5	$0.01M	$0.01M
Perpetual Software	$0.43M	5-7	$0.09M	$0.04M
Control Centre	$38.68M	Average 12 (see Figure 28 above)	$4.57M	$0.38M
Total	$39.18M		$4.67M	$0.43M

Depreciation for computer hardware and perpetual software that is planned to be acquired in 2027/2028 is estimated at 50% of the annual rate to reflect that the assets will be acquired during the year and depreciation based on when the assets are available for use. The depreciation for the control centre is estimated as one month for 2027-2028.

4.3 Net Revenue Requirement Deferral and Variance Account

IESO Nova Scotia seeks approval of its 2025/2026 fiscal year variance by way of the net Revenue Requirement Deferral and Variance Mechanism (DVM). Notwithstanding the fact NSEB approval of the DVM is pending under M12663, the variance calculation is the same in either the DVM or the OM&A Deferral and Variance Account, as the 2025/2026 fiscal year application (M12412) only included OM&A costs for NSEB approval. The NSEB provided the following in its Decision under M12412:

> The Board also approves the Net OM&A Deferral and Variance Account. However, specific guidelines and accounting policies must be developed and approved before there is a recovery of Net Ongoing OM&A amounts from the Deferral and Variance Account. IESO Nova Scotia is directed to include these specific guidelines and accounting policies no later than its application for the 2027/2028 revenue requirement.[21]

The guidelines and accounting policies have been provided in this Application for NSEB review as Appendices 3 and 1 respectively. Given the DVM is currently before the NSEB for approval and fundamentally similar to the OM&A Deferral and Variance Account, IESO Nova Scotia drafted the guidelines on the basis of the DVM. The Account Policies of IESO Nova Scotia are the same irrespective of the deferral and variance methodology.

The DVM provides the framework through which differences between forecast and actual revenue requirement amounts are tracked, reviewed, and ultimately recovered from or credited to market participants through future fee adjustments.

Revenue requirements are established using forecasts prepared in advance of a fiscal year, while actual expenditures and revenues are only known after the fiscal year has concluded. Accordingly, variances between forecast and actual results are recorded within the DVM and subsequently incorporated into fee calculations through the applicable true-up methodology.

The purpose of the DVM is to ensure that IESO Nova Scotia market participants ultimately pay amounts that reflect actual costs incurred in carrying out IESO Nova Scotia's mandate.

[21] NSEB Decision, IESO NS 2025/26 Revenue Requirement Application, M12412, February 25, 2026, p.34 para 88.

The DVM tracks variances across the principal components of the revenue requirement, including OM&A and amortization expense, and any other categories that may be approved by the NSEB for inclusion within the mechanism.

4.3.1 2025/2026 Forecast to Actual Variance

For fiscal year 2025/2026, IESO Nova Scotia has recorded via the DVM an underspend of $342,927 as compared to the NSEB approved 2025/2026 budget (M12412). **Figure 30** below provides details regarding the recorded variance based on 2025/2026 actual spend as it pertains to the cost categories presented in the 2025/2026 revenue requirement application (M12412) and IESO Nova Scotia's audited financial statements for the period ended March 31, 2026.

Figure 30 - 2025-2026 Forecast to Actual Cost Variance

	2025-26 Revenue Application	Actual 2025-26	Actual Over/(Under) Revenue Application $	Actual Over/(Under) Revenue Application %
Administration Salaries and Wages	$1,572,751	$1,047,767	($524,984)	(33.4%)
NS Power Employee Transfers and IRP Consulting	$1,613,427	$808,696	($804,731)	(49.9%)
Facilities and Technology	$1,005,532	$861,157	($124,375)	(12.4%)
Corporate Administration	$287,000	$358,986	$71,896	25.1%
Procurement	$985,844	$1,044,647	$58,803	6.0%
Legal and Regulatory	$813,121	$919,778	$106,657	13.1%
Governance	$520,200	$571,909	$51,709	9.9%
Finance	$160,943	$175,899	$14,956	9.3%
Transition and Operational Planning	$1,022,505	$1,783,259	$760,754	74.4%
Amortization Expense	-	$151,916	$151,916	-
Total	**$7,981,323**	**$7,744,013**	**($237,310)**	**(3.0%)**
Add back: Interconnection fees recorded as revenue in IFRS	-	$421,072		
Add back: Interest income recorded as revenue in IFRS	-	$51,628		

Total expenses per audited financial statement	-	**$8,216,713**		
Less: Government Grant	($2,675,000)	($2,675,000)		
Less: Interconnection revenue shown net in revenue application	-	($421,072)		
Less: Interest revenue shown net in revenue application	-	($51,628)		
Less: Amortization expenses not included in revenue application	-	($151,916)		
Less: IFRS finance charge for lease accounting	-	($41,297)		
Add: Cash lease expense	-	$87,595		
Net Revenue Requirement versus actual expense	**$5,306,323**	**$4,963,395**	**($342,927)**	**(6.5%)**

Explanations for cost category actual expense variances greater than 10% from the approved 2025/2026 revenue requirement application values are below. It is important to remember that the original 2025/2026 revenue requirement application was developed and filed with the NSEB before IESO Nova Scotia had any employees and with no operational experience.

- **Administration Salaries and Wages** – 33.4% below revenue application due to actual phasing of filling staffing positions versus budgeted assumptions.

- **NS Power Employee Transfers and IRP Consulting** – 49.9% below revenue application with employee costs lower due to timing variances compared to budget assumptions along with lower IRP consulting costs offset by reduced interconnection revenue.

- **Facilities and Technology** – 12.4% below revenue application as IFRS accounting treatment recorded office lease costs through amortization and finance costs. Certain technology costs were recorded as capital assets and costs covered by government grant. Offset by higher software subscription costs.

- **Corporate Administration** – 25.1% over the revenue application due to increased external costs in advance of hiring internal employees, and various actual costs incurred for travel, memberships and subscriptions, and office supplies that were not considered in the original budget, offset by savings on web hosting and insurance.

- **Legal and Regulatory** – 13.1% over the revenue application with higher costs for regulatory activity as well as higher costs related to first year set-up activity.

- **Transition and Operational Planning** – 74.4% over the revenue application with higher consulting costs required to cover gaps created with the lower administrative salaries

In assessing prudency of its 2025/2026 actual expenditures, IESO Nova Scotia has considered whether those expenditures were:

- Incurred for a legitimate business purpose consistent with its legislated mandate;

- Reasonably foreseeable based on information available at the time decisions were made;

- Managed in a cost-conscious manner;

- Supported by appropriate governance, procurement, and management oversight processes; and

- Consistent with the objective of delivering reliable and efficient services to Nova Scotia electricity customers.

Based on the foregoing, IESO Nova Scotia submits that the overall actual expenditures in fiscal year 2025/2026 are reasonable and that the associated costs were prudently incurred in carrying out its responsibilities under the MAEA.

4.4 Fee Calculation for Fiscal Year 2027/2028

IESO Nova Scotia's fees for fiscal year 2027/2028 have been calculated based on the revenue requirements described above in this Application. Namely, the OM&A and amortization expense of $14.76M and $0.43M, respectively, totaling $15.19M form the basis of these fees.

Power Advisory, building off its work in the Fee Recovery Mechanism application and proceeding (M13007), has calculated the fiscal year 2027/2028 fees to Load Serving Entities – the corresponding calculation model can be found in Appendix 16.

Whereas an NSEB Decision has yet to be received regarding the Fee Recovery Mechanism application (M13007) at the time of the submission of this Application, IESO Nova Scotia has

provided fee calculations based on True-Up Options 1 and 2 as noted in M13007. Accordingly, the fee calculation model established IESO Nova Scotia's 2027/2028 fees for each applicable LSE as noted in **Figures 31 and 32** below for True-Up Options 1 and 2, respectively.

Figure 31: True-Up Option 1 – 2025/2026 Variances Accounted for in 2027/2028 Fees

		2027/28 Fees		2027/28 Fees with 2025/26 Adjustments	
		Total Fee	Monthly Fee	2027/28 Annual Fee with 2025/26 Adjustments	2027/28 Monthly Fee with 2025/26 Adjustments
Option 1	NSPI	$14,959,137	$1,246,595	$14,617,341	$1,218,112
	Berwick Electric Commission	$60,402	$5,034	$60,290	$5,024
	Riverport Electric Light Commission	$14,050	$1,171	$14,050	$1,171
	Town of Mahone Bay	$23,892	$1,991	$24,408	$2,034
	Town of Antigonish	$132,422	$11,035	$130,885	$10,907
	Total	**$15,189,903**	**$1,265,825**	**$14,846,975**	**$1,237,248**

In True-Up Option 1, the 2025/2026 variance is credited to LSE's in this Application via fiscal year 2027/2028 fees.

Figure 32: True-Up Option 2 – 2025/2026 Variances Accounted for in 2026/2027 Fees

		2027/28 Fees		2027/28 Fees with 2026/27 Adjustments	
		Total Fee	Monthly Fee	2027/28 Annual Fee with 2026/27 Adjustments	2027/28 Monthly Fee with 2026/27 Adjustments
Option 2	NSPI	$14,959,137	$1,246,595	$14,959,137	$1,246,595
	Berwick Electric Commission	$60,402	$5,034	$60,402	$5,034
	Riverport Electric Light Commission	$14,050	$1,171	$14,050	$1,171
	Town of Mahone Bay	$23,892	$1,991	$23,892	$1,991
	Town of Antigonish	$132,422	$11,035	$132,422	$11,035
	Total	**$15,189,903**	**$1,265,825**	**$15,189,903**	**$1,265,825**

In True-Up Option 2, the 2025/2026 variance is credited to LSE's in the 2026/2027 fees via the Fee Recovery Mechanism application, and in that scenario has already been credited to customers before fiscal year 2027/2028 fees take affect on April 1, 2027.

In the event the NSEB approves True-Up Option 1 in M13007, then IESO Nova Scotia seeks approval of 2027/2028 fees noted in **Figure 31** above. In the event the NSEB approves True-Up Option 2 in M13007, then IESO Nova Scotia seeks approval of 2027/2028 fees noted in **Figure 32** above.

Should the NSEB's forthcoming Decision under M13007 direct revisions to the underlying Fee Recovery Mechanism, the calculation of Fees may need to be adjusted and resubmitted for Board approval at a future date.

4.5 MAEA s.29(3) Request for Continuation of Fees

In its Fee Recovery Mechanism application (M13007), IESO Nova Scotia requested the NSEB approve fees effective April 1, 2027, based on a continuation of what fees would have been in fiscal year 2026/2027 based on the 2026/2027 fiscal year revenue requirement, in the event that approval of the 2027/2028 fiscal year fees were approved by the Board by March 31, 2027. This would be consistent with the intent of s.29(3) of the MAEA. The M13007 application provided as follows:

> Section 29(3) of the MAEA notes that "Until the Energy Board approves the proposed expenditure and revenue requirements for the fiscal year and the fees the IESO proposes to charge during the fiscal year, the fees approved for the previous fiscal year remain in effect unless the Energy Board orders otherwise." In the event the NSEB does not approve new fees for fiscal year 2027/28 based on IESO Nova Scotia's forthcoming 2027/28 Revenue Requirement and Fees application by March 31, 2027, IESO Nova Scotia believes that the reasonable approach is a continuation of fees in accordance with Section 29(3) based on IESO Nova Scotia's proposed 2026/27 revenue requirement of $14,850,121, and what those fees would be over a 12 month period allocated to the LSEs. The Model calculates those fees as shows in Figure 16 below:

Figure 16 – Continuation of Fees to LSEs Post March 31, 2027

	Total Monthly Fee Calculation		
Market Participant	Proposed Annual Fee 2026/27	# Months of Revenue Collection	Monthly Fees
NSPI	$ 14,635,202	12	$ 1,219,600
Berwick Electric Commission	$ 55,504	12	$ 4,625
Riverport Electric Light Commission	$ 13,245	12	$ 1,104
Town of Mahone Bay	$ 20,336	12	$ 1,695
Town of Antigonish	$ 125,834	12	$ 10,486
Total	**$ 14,850,121**	**12**	**$ 1,237,510**

The Model also calculates those fees based on the 2025/26 variance true-up under the compliance filing true-up methodology as shown in Figure 17 below.

Figure 17 - Continuation of Fees to LSEs Post March 31, 2027 with 2025/26 True-Up

Market Participant	Total Monthly Fee Calculation				
	Proposed Annual Fee 2026/27 Before True-Up	2025/26 True-Up	Proposed Annual Fee 2026/27 with True-Up	# Months of Revenue Collection	Monthly Fees
NSPI	$ 14,635,202	-$ 309,345	$ 14,325,857	12	$ 1,193,821
Berwick Electric Commission	$ 55,504	-$ 1,161	$ 54,343	12	$ 4,529
Riverport Electric Light Commission	$ 13,245	-$ 277	$ 12,968	12	$ 1,081
Town of Mahone Bay	$ 20,336	-$ 425	$ 19,910	12	$ 1,659
Town of Antigonish	$ 125,834	-$ 2,632	$ 123,202	12	$ 10,267
Total	**$ 14,850,121**	**-$ 313,841**	**$ 14,536,280**	**12**	**$ 1,211,357**

[22]

IESO Nova Scotia maintains that this request for the continuation of fees as proposed in M13007 is reasonable and reasserts this request in this Application. Subject to the particulars of the NSEB's hearing order timeline for this Application, in the event the NSEB determines it is unable to render a Decision on this Application or IESO Nova Scotia's Fee Recovery Mechanism application (M13007) by March 31, 2027, IESO Nova Scotia respectfully requests that it render a Decision regarding the continuation of fees by December 31, 2026, so that IESO Nova Scotia is provided a commensurately reasonable amount of time to plan for the funding of its 2027/2028 fiscal year expenses.

5 Conclusion

In the last 15 months, IESO Nova Scotia has progressed from an organization without employees or officers to a functioning and maturing independent system operator. In that short period, it has completed the Phase 1 transition of system planning, generation interconnection and energy resource procurement functions from NS Power; advanced Nova Scotia's inaugural Integrated Resource Plan; launched significant generation and energy storage procurement initiatives; completed its first external financial audit; filed its first Annual Report, quarterly reports and 10-Year System Outlook; advanced updated interconnection processes; established a fee recovery mechanism for NSEB approval; and established regular engagement with regulatory stakeholders. These accomplishments have been delivered by a small organization

[22] IESO Nova Scotia Fee Recovery Mechanism Application (M13007), July 31, 2026, p.42-43.

while simultaneously building the governance, financial, technological, regulatory and human-resource capabilities required to carry out its expanding statutory mandate.

This Application reflects the next stage of that development. It incorporates a more functionally aligned presentation of expenditures, historical actuals and multi-year forecasts, improved supporting evidence, and the accounting policies, financial controls, business planning and DVM Guidelines directed by the Board. These improvements demonstrate an organization that is learning from its early operating and regulatory experience, strengthening its internal disciplines, and providing greater transparency into how customer expenditures will be managed. IESO Nova Scotia recognizes that its systems and processes will continue to mature, but submits that the evidence in this Application demonstrates meaningful progress and a continuing commitment to prudent management, accountability and year-over-year improvement.

Significant work remains. During the 2027/2028 fiscal year, IESO Nova Scotia must continue its existing planning, procurement, interconnection, stakeholder-engagement and corporate responsibilities while preparing to assume real-time system operations. Central to that work is the implementation of Phases 2A and 2B of the Control Centre project. Together, these phases will establish the operational, settlement, participant-administration, reporting and information-management capabilities necessary for IESO Nova Scotia to perform its mandate independently. The proposed phased approach balances operational independence, reliability, implementation risk and cost, while allowing estimates and future requirements to be refined as the organization gains experience. Independent expert analysis indicates that the broader Phase 2 project has the potential to deliver a positive long-term economic case, with expected benefits materially exceeding its incremental costs.

IESO Nova Scotia therefore respectfully requests that the Board approve Phases 2A and 2B of the Control Centre project and the associated capital work in progress expenditures of $48.99 million; approve the 2027/2028 OM&A and amortization revenue requirement of $15.19 million; approve the DVM Guidelines and Accounting Policies as it relates to approval of variances under the DVM; approve the positive 2025/2026 actual expenditure variance of approximately $342,927 underspend through the applicable deferral and variance mechanism; and approve the proposed fees for 2027/2028.

Given IESO Nova Scotia's not-for-profit status, NSEB approval of its proposed expenditures, revenue requirements, and fees on a timely basis is of critical importance for the organization

to continue to carry-out its important legislatively mandated work. IESO Nova Scotia's ability to do so assumes fees sought via its Fee Recovery Mechanism application (M13007) are received in full by March 31, 2027 as requested, and commercial funding is received to complete Phase 2 Project work facilitated through NSEB approval of those proposed expenditures in this Application. These approvals will provide the financial and regulatory foundation required for IESO Nova Scotia to continue maturing as an organization, maintain reliability through the transition, and deliver the independent, transparent and cost-effective system operation contemplated by the legislation. As such, IESO Nova Scotia respectfully requests NSEB approval for all of the above by March 31, 2027, in alignment with IESO Nova Scotia's fiscal year as established by the MAEA.

In the case fees proposed herein for fiscal year 2027/2028 are not approved by March 31, 2027, IESO Nova Scotia requests approval of the fees as described in our Fee Recovery Mechanism application (M13007) (see section 4.5) to take effect on April 1, 2027 in accordance with subsection 29(3) of the MAEA, and that the Board's Decision is received well in advance of March 31, 2027, by December 31, 2026.

6 Relief Sought

IESO Nova Scotia seeks the following approvals from the Board by March 31, 2027:

1. Approval of Phase 2 Control Centre project Phases 2A and 2B and capital work in progress proposed expenditures in the total amount of $48.99 million (please refer to Section 3.2);
2. Approval of the revenue requirements for the 2027/28 fiscal year in the amount of $15.19 million (please refer to Sections 3.3 and 3.4);
3. Approval of IESO Nova Scotia's DVM Guidelines and Accounting Policies as it relates to approval of variances under the DVM (please refer to Appendices 3 and 1).
4. Approval of a positive overall variance of $343k via Net Revenue Requirement Deferral and Variance Mechanism with respect to the 2025/2026 fiscal year (please refer to Section 4.3); and
5. Approval of fees[23] for fiscal year 2027/2028 (please refer to Section 4) in the amounts of:

[23] Fees are subject to applicable HST.

- True-Up Option 1:
    - NS Power - $1,218,112
    - Berwick Electric Commission - $5,024
    - Riverport Electric Light Commission - $1,171
    - Town of Mahone Bay - $2,034
    - Town of Antigonish - $10,907
- Or True-Up Option 2:
    - NS Power - $1,246,595
    - Berwick Electric Commission - $5,034
    - Riverport Electric Light Commission - $1,171
    - Town of Mahone Bay - $1,991
    - Town of Antigonish - $11,035

6. In the event Fees for fiscal year 2027/2028 cannot be approved by the NSEB by March 31, 2027, approval by December 31, 2026 of fees beginning on April 1, 2027 under s.29(3) of the MAEA as requested in M13007 (please refer to Section 4.5).

Nova Scotia Independent Energy System Operator

2027/2028 Proposed Expenditures, Revenue Requirement, and Fees Application

Appendix 1 – Accounting Policies

NON-CONFIDENTIAL



Accounting Policies

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TRADE AND OTHER PAYABLES AND ACCRUED LIABILITIES

Purpose

The purpose of this policy is to establish the accounting principles for the recognition, measurement, presentation, derecognition, and disclosure of accounts payable and accrued liabilities in accordance with International Financial Reporting Standards (IFRS). This policy ensures consistent treatment of obligations arising from the receipt of goods and services and supports accurate reporting of the entity's liabilities.

Scope

This policy applies to all trade and other payables and accrued liabilities arising in the ordinary course of business, including obligations for goods and services received but not yet settled or invoiced at the reporting date. It applies to liabilities denominated in both functional and foreign currencies and includes consideration of significant financing components, offsetting, and supplier finance arrangements where applicable.

Definition

Trade and other payables and accrued liabilities represent obligations to pay for goods and services that have been received in the ordinary course of business.

Recognition

Trade payables are recognised when IESO Nova Scotia becomes obliged to make payment, typically upon receipt of goods or services and acceptance of the related invoice, or in accordance with the terms of the underlying contract.

Accrued liabilities are recognised for goods and services that have been received (or for which an obligation has been incurred) but have not been invoiced at the reporting date. Accrued liabilities are measured based on the best estimate of the consideration required to settle the obligation and are recognised in the same expense category as the related goods or services.

Accrued liabilities that do not represent contractual financial liabilities are accounted for in accordance with IAS 37 – Provisions, Contingent Liabilities and Contingent Assets.

Initial measurement

Trade and other payables and accrued liabilities that meet the definition of a financial liability are initially recognised at fair value. Where subsequently measured at amortised cost, directly attributable transaction costs are added to the initial carrying amount. Trade payables and accrued liabilities that do not contain a significant financing component are generally initially measured at the invoiced amount (or estimated amount for accruals), which approximates fair value.

Subsequent measurement

Trade and other payables and accrued liabilities are subsequently measured at amortised cost using the effective interest method. Due to their short-term nature, the carrying amounts generally approximate amortised cost and fair value.

Significant financing component (where applicable)

Where payment terms extend beyond normal credit terms and the arrangement contains a significant financing component, the liability is measured at the present value of future payments, with the unwind of the discount recognised as finance costs over the term of the liability.

Derecognition

Trade and other payables and accrued liabilities are derecognised when the obligation is discharged, cancelled, or expires. Any difference between the carrying amount and the consideration paid is recognised in profit or loss.

Classification

Trade and other payables and accrued liabilities are classified as current liabilities when they are expected to be settled in the normal operating cycle or within twelve months after the reporting date, or when IESO Nova Scotia does not have an unconditional right to defer settlement for at least twelve months. Amounts due beyond twelve months are classified as non-current when IESO Nova Scotia has an unconditional right to defer settlement for at least twelve months.

Offsetting

Financial assets and financial liabilities are offset and the net amount presented in the statement of financial position only when IESO Nova Scotia has a legally enforceable right to set off the recognised amounts and intends either to settle on a net basis or to realise the asset and settle the liability simultaneously.

Foreign currency

Payables and accruals denominated in foreign currencies are translated into the Group's functional currency at the closing exchange rate at the reporting date. Foreign exchange gains and losses arising on translation are recognised in profit or loss.

Relevant Accounting Standards

- International Financial Reporting Standard 9 (IFRS 9) Financial Instruments
- International Accounting Standard 1 (IAS 1) Presentation of Financial Statements

ACCOUNTS RECEIVABLE

Purpose

The purpose of this policy is to establish the accounting principles for the recognition, measurement, impairment, derecognition, presentation, and disclosure of accounts receivable, in accordance with International Financial Reporting Standards (IFRS). This policy promotes consistent application and ensures that receivables are measured and reported in a manner that reflects their recoverability and economic substance.

Scope

This policy applies to all trade and other receivables arising from contracts with customers or other transactions in the ordinary course of business. It includes receivables denominated in both functional and foreign currencies and addresses the recognition of expected credit losses.

Definition

Accounts receivable represents amounts due from customers for goods sold or services performed in the ordinary course of business. Accounts receivables are recognised when IESO Nova Scotia has an unconditional right to consideration, typically when goods or services have been transferred to the customer in accordance with the relevant contract.

Initial Recognition and Measurement

Accounts receivables are initially recognised at fair value. Trade receivables that do not contain a significant financing component, as defined in IFRS 15 – Revenue from Contracts with Customers, are measured at the transaction price. Other receivables are measured at fair value plus directly attributable transaction costs.

Subsequent Measurement

Accounts receivables are subsequently measured at amortised cost using the effective interest method, less any allowance for expected credit losses. Due to their short-term nature, the carrying amount of trade receivables generally approximates their fair value.

Impairment of Accounts Receivable

IESO Nova Scotia recognises a loss allowance for expected credit losses (“ECLs”) on accounts receivable in accordance with IFRS 9 – Financial Instruments. The simplified approach is applied to trade receivables, whereby lifetime expected credit losses are recognised from initial recognition.

The ECL assessment is based on historical credit loss experience, adjusted for forward-looking information, including current and forecast economic conditions. Receivables are written off when there is no reasonable expectation of recovery.

Derecognition

Accounts receivables are derecognised when the contractual rights to the cash flows expire or are transferred, and the transfer qualifies for derecognition in accordance with IFRS 9.

Presentation and Disclosure

Accounts receivables are presented in the statement of financial position as current assets unless settlement is expected beyond twelve months after the reporting date. Allowances for expected credit losses are presented as a deduction from the gross carrying amount of receivables. Relevant qualitative and quantitative disclosures are provided in the notes to the financial statements.

Relevant Accounting Standards

- International Financial Reporting Standard 15 (IFRS 15) Revenue from Contracts with Customers
- International Financial Reporting Standard 9 (IFRS 9) Financial Instruments
- International Accounting Standard 1 (IAS 1) Presentation of Financial Statements

PROPERTY, PLANT AND EQUIPMENT AND INTANGIBLE ASSETS

Purpose

The purpose of this policy is to establish consistent criteria for the capitalization, depreciation, and disposal of Property, Plant and Equipment (PP&E) and Intangible Assets in accordance with the IESO Nova Scotia accounting framework.

Definition of PP&E

Property, Plant and Equipment are tangible assets that are held by IESO Nova Scotia for use in its operations, or for administrative purposes. Property, plant and equipment are recognized when it is probable that future economic benefits associated with the asset will flow to the entity and the cost of the asset can be measured reliably. These assets are not intended for resale in the ordinary course of business; and are expected to have a useful life greater than one fiscal year. Examples of PP&E held by IESO Nova Scotia include leasehold improvements, computer hardware, furniture and fixtures and construction in progress. Additional future categories of PP&E at IESO Nova Scotia may include land, buildings and computer software.

Capitalization Threshold

To be capitalized, an item must have a useful life greater than one year and a cost that exceeds $3,000 per unit. Individual items below the threshold shall be expensed as incurred. Group purchases of assets that individually are below the threshold may be capitalized.

Measurement and Useful Life

Property, plant and equipment are recorded at cost less accumulated depreciation. Cost includes the purchase price, plus any additional costs directly attributable to the construction of the asset and preparing the asset for its intended use. Such costs may include materials, payroll, consulting resources, borrowing costs incurred during construction for qualifying assets and asset retirement costs. Assets being constructed are categorized as Construction in Progress until the asset is complete and in use and then transferred to the appropriate asset category.

Maintenance and repair costs which do not enhance or extend the useful life of the asset are expensed as incurred.

Depreciation is calculated on a straight-line basis over the estimated useful lives of the assets. No depreciation is provided for land and assets classified as construction in progress. The expected useful lives, depreciation method and residual values of the assets are reviewed annually, with any changes accounted for on a prospective basis.

Depreciation periods for property, plant and equipment are shown in the following table.

Computer and Audio-Visual Hardware	Straight line 3-5 years
Furniture and Fixtures	Straight line 10 years
Leasehold Improvements	Straight line 10 years
Construction in Progress	No depreciation
Land	No depreciation
Computer Software	Straight line 3-10 years
Buildings	Straight line 20 – 40 years[1]

Property, plant and equipment assets are retired when they are fully depreciated and derecognized when disposed of or when there is no future benefits are expected to arise from their use. Any gain or loss on derecognition is recognized in Statement of Income.

Definition of Intangible Assets

Intangible assets are identifiable non-monetary assets without physical substance. These assets are separable and arise from contractual or other legal rights. Intangible assets are recognized when it is probable that future economic benefits associated with the asset will flow to the entity and the cost of the asset can be measured reliably.

Measurement and Useful Life

Intangible assets are recorded at cost less accumulated amortization. Cost includes the purchase price, plus any additional costs directly attributable to the development of the asset and preparing the asset for its intended use. Such costs include payroll, consulting resources and borrowing costs incurred during the development of qualifying assets.

Maintenance and repair costs that do not enhance or extend the useful life of the asset are expensed as incurred.

Costs related to cloud computing software or software as a service, generally do not give rise to legal rights and probable future economic benefits and are expensed as incurred.

Amortization is calculated on a straight-line basis over the estimated useful lives of the assets. No amortization is recorded for an intangible asset with an indefinite life. No

[1] Depreciation period for buildings to be determined based on individual building condition at time of acquisition.

amortization is provided on intangible assets under development. The expected useful lives, amortization method and residual values of the assets are reviewed annually, with any changes accounted for on a prospective basis. Amortization periods for intangible assets are shown in the following table.

Perpetual software licenses	5 years

Intangible assets are retired when they are fully amortized and derecognized when no future benefits are expected to arise from their use. Any gain or loss on derecognition is recognized in the Statement of Income.

Impairment and Obsolescence Review

Property, plant and equipment and intangible assets are reviewed at each reporting date to assess whether there is any indication that an asset may be impaired or has become obsolete. If such indicators exist, the asset's recoverable amount is estimated.

The recoverable amount is the higher of an asset's fair value less costs of disposal and its value in use. An impairment loss is recognized in the Statement of Income when the carrying amount of the asset exceeds its recoverable amount.

Intangible assets with indefinite useful lives and assets not yet available for use are tested for impairment annually, and whenever there is an indication of impairment.

Where circumstances that gave rise to an impairment loss no longer exist, the carrying amount of the asset is reassessed and any reversal of impairment is recognized in the Statement of Income, to the extent that the revised carrying amount does not exceed the asset's carrying amount had no impairment been recognized.

Relevant Accounting Standards

- International Accounting Standard 16 (IAS 16) Property Plant and Equipment
- International Accounting Standard 38 (IAS 38) Intangible Assets
- International Accounting Standard 36 (IAS 36) Impairment of Assets

CASH AND CASH EQUIVALENTS

Purpose

The purpose of this policy is to establish the accounting principles for the recognition, measurement, presentation, and disclosure of cash and cash equivalents in the financial statements, in accordance with International Financial Reporting Standards (IFRS). This policy ensures consistent treatment of cash balances and supports transparent financial reporting.

Scope

This policy applies to all cash balances, bank balances, deposits, and cash-equivalent investments held by IESO Nova Scotia, including restricted cash and foreign-currency cash balances. It also applies to the classification of cash and cash equivalents for purposes of the statement of financial position and the statement of cash flows.

Definition

Cash and cash equivalents comprise cash on hand, demand deposits, and short-term, highly liquid investments that are readily convertible to known amounts of cash and that are subject to an insignificant risk of changes in value. Such investments generally have original maturities of three months or less from the date of acquisition.

Measurement

Cash and cash equivalents are carried in the statement of financial position at amortised cost, which approximates their fair value due to their short-term nature.

Presentation

Restricted cash, being cash balances that are not available for immediate use by the entity due to contractual, legal, or regulatory restrictions, is excluded from cash and cash equivalents and presented separately in the statement of financial position, where material. The nature and extent of such restrictions are disclosed in the notes to the financial statements.

For the purposes of the statement of cash flows, cash and cash equivalents include bank balances and cash in transit. Bank overdrafts that are repayable on demand and form an integral part of the IESO Nova Scotia's cash management are included as a component of cash and cash equivalents; other overdrafts are classified as borrowings.

Cash balances denominated in a foreign currency are translated into the entity's functional currency at the spot exchange rate at the reporting date. Foreign exchange gains or losses arising from such translation are recognised in profit or loss.

Relevant Accounting Standards

- International Accounting Standard 1 (IAS 1) Presentation of Financial Statements
  International Accounting Standard 7 (IAS 7) Statement of Cash Flows
- International Accounting Standard 21 (IAS 21) The Effects of Changes in Foreign Exchange Rates

EMPLOYEE BENEFITS

Purpose

The purpose of this policy is to establish the accounting principles for the recognition, measurement, presentation, and disclosure of employee benefits in accordance with International Financial Reporting Standards (IFRS), specifically IAS 19 – Employee Benefits. This policy ensures consistent and appropriate accounting for obligations arising from services rendered by employees.

Scope

This policy applies to all employee benefits provided by IESO Nova Scotia, including:

- Short-term employee benefits such as paid annual leave and paid sick leave; and
- Post-employment benefits in the form of a registered defined contribution pension plan.

IESO Nova Scotia does not directly provide defined benefit pension plans or other long-term or termination benefits beyond those described in this policy.

General Principles

Employee benefits are recognized as an expense when the employee has rendered service in exchange for those benefits. A corresponding liability is recognized for amounts expected to be paid because of employee service, net of any amounts already paid.

Short-Term Employee Benefits Paid Annual Leave

Paid annual leave is classified as a short-term employee benefit.

- The cost of paid annual leave is recognized as an expense as employees render service that increases their entitlement to future leave.
- A liability is recognized for the expected cost of unused annual leave entitlement accumulated by employees at the reporting date.
- The liability is measured at the undiscounted amount expected to be paid when the entitlement is settled.

Paid Sick Leave

Paid sick leave is classified as a short-term employee benefit.

- Sick leave benefits are recognized as an expense in the period in which the employee's absence occurs.

- To the extent that sick leave benefits accumulate and unused entitlements may be carried forward, a liability is recognized for the expected cost of accumulated unused sick leave at the reporting date.
- If sick leave does not accumulate or is not expected to be taken in future periods, no liability is recognized for unused entitlements.

The liability for accumulated sick leave, where applicable, is measured at the undiscounted amount expected to be paid.

Post-Employment Benefits Defined Contribution Pension Plan

- IESO Nova Scotia sponsors a registered defined contribution pension plan, which is classified as a post-employment benefit under IAS 19.
- IESO Nova Scotia's obligation is limited to making fixed contributions to the plan in accordance with the plan terms.
- Pension expense is recognized in profit or loss in the period during which employees render the corresponding service.
- Contributions payable at the reporting date but not yet paid are recognized as a liability.

Prepaid contributions, if any, are recognized as an asset to the extent that a cash refund or a reduction in future payments is available.

IESO Nova Scotia has no further legal or constructive obligation beyond the payment of specified contributions once those contributions have been made.

Presentation and Disclosure

Employee benefit expenses are presented within operating expenses in the statement of profit or loss. Liabilities for accrued employee benefits are classified as current liabilities unless settlement is not expected wholly within twelve months after the reporting date. Disclosures are provided in accordance with IAS 19 and IAS 1 – Presentation of Financial Statements, sufficient to enable users of the financial statements to understand the nature of employee benefits and their financial effect.

Relevant IFRS Standards

- IAS 19 – Employee Benefits
- IAS 1 – Presentation of Financial Statements
- IAS 8 – Accounting Policies, Changes in Accounting Estimates and Errors

FINANCIAL INSTRUMENTS

Purpose

The purpose of this policy is to establish the accounting principles for the recognition, classification, measurement, impairment, derecognition, presentation, and disclosure of financial instruments in accordance with IFRS 9 – Financial Instruments and related IFRS standards. This policy ensures consistent and transparent accounting for financial assets and financial liabilities held by IESO Nova Scotia.

Scope

This policy applies to all financial instruments recognized by the IESO Nova Scotia which

may include:

- Cash and cash equivalents
- Trade accounts receivable
- Trade accounts payable and accrued liabilities
- Revolving line of credit
- Letters of credit

IESO Nova Scotia does not hold complex financial instruments such as derivatives, equity investments, structured products, or embedded derivatives, currently, and does not apply hedge accounting. The policy will be reassessed annually and updated for complex instruments if required.

Definition of a Financial Instrument

A financial instrument is any contract that gives rise to:

- A financial asset of one entity; and
- A financial liability or equity instrument of another entity.

Financial Assets - Recognition

Financial assets are recognized when IESO Nova Scotia becomes a party to the contractual provisions of the instrument.

Classification and Measurement

IESO Nova Scotia’s financial assets consist of cash and trade accounts receivable. These assets meet the criteria for measurement at amortized cost, as they are held within a business model whose objective is to collect contractual cash flows, and the contractual terms give rise to cash flows that are solely payments of principal and interest.

- Cash and cash equivalents are measured at amortized cost, which approximates
- fair value due to their short-term nature.
- Trade accounts receivable that does not contain a significant financing component are initially recognized at the transaction price in accordance with IFRS 15 – Revenue from Contracts with Customers and subsequently measured at amortized cost.

Impairment of Financial Assets

IESO Nova Scotia recognizes a loss allowance for expected credit losses (ECLs) on trade accounts receivable in accordance with IFRS 9.

- The simplified approach is applied, whereby lifetime expected credit losses are recognized from initial recognition.
- Expected credit losses are estimated based on historical credit loss experience,
- adjusted for forward-looking information where relevant.

Accounts receivables are written off when there is no reasonable expectation of recovery.

Derecognition of Financial Assets

Financial assets are derecognized when the contractual rights to the cash flows expire or when the financial asset is transferred and the transfer qualifies for derecognition under IFRS 9.

Financial Liabilities - Recognition

Financial liabilities are recognized when IESO Nova Scotia becomes a party to the contractual provisions of the instrument.

Classification and Measurement

IESO Nova Scotia's financial liabilities include accounts payable, accrued liabilities, and a line of credit.

- Financial liabilities are initially recognized at fair value, net of directly attributable
- transaction costs.
- Subsequently, they are measured at amortized cost using the effective interest
- method.

Due to their short-term nature, trade payables and accrued liabilities generally approximate their fair value.

Line of Credit

Amounts drawn under IESO Nova Scotia's line of credit facility are classified as financial liabilities and measured at amortized cost. Interest expense is recognized in the Statement of Income using the effective interest method.

Derecognition of Financial Liabilities

Financial liabilities are derecognized when the obligation is discharged, cancelled, or expires. Any difference between the carrying amount and the consideration paid is recognized in the Statement of Income.

Letter of Credit

IESO Nova Scotia has issued a letter of credit in the ordinary course of business.

- The letter of credit represents a financial guarantee contract under IFRS 9 only if it requires IESO Nova Scotia to make specified payments to reimburse the holder for a loss it incurs due to a failure to meet contractual obligations.
- Where the likelihood of payment is remote and no liability is expected to arise, the letter of credit is not recognized on the statement of financial position but is disclosed in the notes as a commitment.
- If it becomes probable that payments will be required under the letter of credit, a liability is recognized at the best estimate of the expected obligation.

Offsetting

Financial assets and financial liabilities are offset and presented on a net basis in the statement of financial position only when the IESO Nova Scotia has a legally enforceable right to offset the recognized amounts and intends either to settle on a net basis or to realize the asset and settle the liability simultaneously.

Foreign Currency Financial Instruments

Financial assets and financial liabilities denominated in foreign currencies are translated into the IESO Nova Scotia's functional currency of Canadian dollars at the closing exchange rate at the reporting date. Foreign exchange gains and losses are recognized in the Statement of Income.

Presentation and Disclosure

Financial instruments are presented in the statement of financial position according to their nature and classified as current or non-current in accordance with IAS 1 –

Presentation of Financial Statements. Disclosures are provided in the notes to the financial statements to enable users to evaluate the significance of financial instruments to IESO Nova Scotia's financial position and the nature and extent of related risks.

Relevant Accounting Standards

- International Financial Reporting Standard 9 (IFRS 9) Financial Instruments
- International Financial Reporting Standard 15 (IFRS 15) Revenue from Contracts with Customers
- International Accounting Standard 1 (IAS 1) Presentation of Financial Statements
  International Accounting Standard 7 (IAS 7) Statement of Cash Flows

PREPAID EXPENSES

Purpose

The purpose of this policy is to establish the accounting principles for the recognition, measurement, amortisation, classification, impairment, derecognition, presentation, and disclosure of prepaid expenses in accordance with International Financial Reporting Standards (IFRS). This policy ensures consistent treatment of advance payments and appropriate matching of costs with the periods in which related goods or services are consumed.

Scope

This policy applies to all prepaid expenses arising from payments made in advance for goods or services to be received in future reporting periods. It applies to both current and non-current prepaid expenses and covers all operating activities of the entity.

Definition

Prepaid expenses represent payments made in advance for goods or services to be received in future reporting periods. Prepaid expenses are recognised as assets when the entity has paid consideration and expects to receive future economic benefits from the related goods or services.

Recognition and Initial Measurement

Prepaid expenses are initially recognised at cost, which represents the amount of cash paid or payable at the time of recognition.

Subsequent Measurement and Amortization

Prepaid expenses are subsequently measured at cost less amounts expensed to profit or loss as the related goods or services are consumed. The prepaid balance is amortised on a systematic basis over the period to which the goods or services relate, consistent with the pattern in which the economic benefits are expected to be consumed.

Amortisation of prepaid expenses is recognised within the appropriate expense category in profit or loss (e.g., administrative expenses, cost of sales).

Current and Non-Current Classification

Prepaid expenses are classified as current assets when the related goods or services are expected to be consumed within twelve months after the reporting date. Prepaid expenses relating to periods extending beyond twelve months are classified as non-current assets. The classification is reassessed at each reporting date.

Impairment

Prepaid expenses are reviewed at each reporting date to assess whether there is any indication that the carrying amount may not be recoverable. Where indicators of impairment exist, the prepaid asset is written down to its recoverable amount, with any impairment loss recognised in profit or loss in accordance with IAS 36 – Impairment of Assets.

Derecognition

Prepaid expenses are derecognised when the related goods or services are received and expensed, or when it is no longer probable that future economic benefits associated with the prepaid asset will be received.

Relevant Accounting Standards

- International Accounting Standard 1 (IAS 1) Presentation of Financial Statements
- International Accounting Standard 8 (IAS 8) Changes in Accounting Estimates and Errors
  International Accounting Standard 36 (IAS 36) Impairment of Assets

REVENUE RECOGNITION

Purpose and Policy Statement

The purpose of this policy is to establish a consistent framework for recognizing revenue earned by IESO Nova Scotia in accordance with International Financial Reporting Standards (IFRS). This policy addresses revenue arising from government grants, fees received as an annual revenue requirement as regulated by the Nova Scotia Energy Board, and services performed for customers as described in the Standard Generator Interconnection Procedures (GIP). This policy represents material accounting policy information necessary to understand the nature, timing, and uncertainty of the entity's revenue and funding.

Scope and Applicable Standards

This policy applies to all sources of operating revenue earned by IESO Nova Scotia and is based primarily on International Financial Reporting Standard 15 (IFRS 15) Revenue from Contracts with Customers and International Accounting Standard 20 (IAS 20) Accounting for Government Grants and Disclosure of Government Assistance. Where judgment is required, revenue recognition reflects economic substance rather than legal form.

Government Grants

Government grant revenue is assistance provided by the government in return for compliance with specified conditions relating to operating activities, public interest mandates, or the delivery of system operator functions. This type of funding meets the definition of government grants under IAS 20. Such funding is not consideration from customers and therefore does not fall within the scope of IFRS 15.

IESO Nova Scotia recognizes government grants as revenue on a gross basis, rather than netted against related expenditures, to present transparently the extent of government support and the full cost of operations. Grant revenue is recognized in income on a systematic basis over the periods in which IESO Nova Scotia recognizes the related costs that the grants are intended to compensate. Where grant conditions require specific activities or the incurrence of eligible costs, revenue is recognized as those conditions are satisfied.

Government grant revenue is deferred and recorded as a liability where cash is received in advance of the satisfaction of grant conditions. Revenue is not recognized until there is reasonable assurance that IESO Nova Scotia will comply with the conditions attached to the grant and that the funding will be received. Any unspent or refundable portions of government grants are recognized as a liability until such time as the repayment obligation is extinguished.

Annual Revenue Requirement

The More Access to Energy Act establishes IESO Nova Scotia as a not-for-profit body corporate independent energy system operator. The costs to operate IESO Nova Scotia are to be recovered from market participants through fees received as an annual revenue requirement regulated by the Nova Scotia Energy Board (NSEB). The regulated annual revenue requirement is included within the scope of IFRS 15 Revenue from Contracts with Customers.

IESO Nova Scotia evaluates revenue from the annual revenue requirement against the five-step recognition model in IFRS 15. IESO Nova Scotia's "customers" in respect of the annual revenue requirement are the market participants that receive system operator services and pay the fees approved by the NSEB. The NSEB does not receive goods or services and is therefore not considered a customer. The transaction price reflects the approved annual revenue requirement, including any approved adjustments or true-ups arising from the regulatory process. Deferral account mechanisms will be evaluated for recognition following this policy. Revenue is constrained to amounts for which IESO Nova Scotia expects to be entitled.

Revenue is recognized when a NSEB approved annual revenue requirement establishes an enforceable contract with rights and obligations, identifiable performance obligations and transaction price. The revenue is allocated to the performance obligations and recognized over the course of the fiscal year with the continuous operation of IESO Nova Scotia.

Standard Generator Interconnection Procedures

IESO Nova Scotia performs services for interconnection customers as described in the Standard Generator Interconnection Procedures (SGIP). As described in the SGIP, IESO Nova Scotia provides separable, contracted services, including Interconnection Feasibility Studies, Interconnection System Impact Studies, Interconnection Facilities Studies and Optional Interconnection Studies ("Interconnection Study(ies)"). Revenue is recognized based on the extent to which the performance obligation has been satisfied and is recognized over time using costs incurred relative to total estimated study costs. Amounts billed in advance of work performed are recorded as contract liabilities and recognized as revenue as services are delivered.

Presentation and Disclosure

Revenue is presented in the statement of operations by source, distinguishing between government grants and revenues earned from contracts with customers. Contract assets and contract liabilities arising under IFRS 15 are presented separately in the statement of financial position.

RIGHT OF USE ASSETS AND LEASE LIABILITIES

Purpose

The purpose of this policy is to establish the accounting principles for the recognition, measurement, presentation, and disclosure of right-of-use ("ROU") assets and lease liabilities arising from lease arrangements entered into by IESO Nova Scotia, in accordance with International Financial Reporting Standards (IFRS). This policy ensures consistent application and transparent reporting of lease transactions.

Scope

This policy applies to all lease arrangements in which IESO Nova Scotia is a lessee, including leases of property, equipment, and other assets, except where recognition exemptions for short-term leases or leases of low-value assets are applied. The policy also applies to lease modifications and foreign-currency-denominated leases, where applicable.

Right-of-Use Assets and Lease Liabilities

IESO Nova Scotia recognizes a right-of-use ("ROU") asset and a lease liability at the lease commencement date for most lease arrangements. The lease liability represents the present value of lease payments to be made over the lease term, and the ROU asset represents IESO Nova Scotia's right to use the underlying asset during the lease term.

Identification of a Lease

A contract is, or contains, a lease when it conveys the right to control the use of an identified asset for a period in exchange for consideration. In assessing whether a contract contains a lease, IESO Nova Scotia evaluates whether it has both:

- The right to obtain substantially all the economic benefits from use of the asset;
- and
- The right to direct the use of the asset.

Lease Term

The lease term is the non-cancellable period of a lease, together with periods covered by an option to extend the lease if IESO Nova Scotia is reasonably certain to exercise that option, and periods covered by an option to terminate the lease if IESO Nova Scotia is reasonably certain not to exercise that option.

IESO Nova Scotia reassesses the lease term upon the occurrence of a significant event or a significant change in circumstances that is within its control and affects whether it is reasonably certain to exercise (or not exercise) an option.

Initial Measurement of Lease Liabilities

At commencement, the lease liability is measured at the present value of lease payments that are not paid at that date. Lease payments include:

- Fixed payments (including in-substance fixed payments), less any lease incentives receivable;
- Variable lease payments that depend on an index or a rate, initially measured using
- the index or rate at the commencement date;
- Amounts expected to be payable under residual value guarantees;
- The exercise price of a purchase option if IESO Nova Scotia is reasonably certain to
- exercise that option; and
- Payments of penalties for terminating the lease, if the lease term reflects IESO Nova
- Scotia exercising an option to terminate.

Lease payments are discounted using the interest rate implicit in the lease when that rate can be readily determined. If the rate implicit in the lease cannot be readily determined, IESO Nova Scotia uses its incremental borrowing rate (IBR) at commencement.

Initial Measurement of Right-of-Use Assets

The ROU asset is initially measured at cost, which comprises:

- The initial amount of the lease liability;
- Any lease payments made at or before the commencement date, less any lease
- incentives received;
- Any initial direct costs incurred by IESO Nova Scotia; and
- An estimate of costs to be incurred in dismantling and removing the underlying asset, restoring the site on which it is located, or restoring the underlying asset to the condition required by the lease terms, where applicable.

Subsequent Measurement of Lease Liabilities

The lease liability is subsequently measured by:

- Increasing the carrying amount to reflect interest on the lease liability, recognized in finance costs; and
- Reducing the carrying amount to reflect lease payments made.

The lease liability is remeasured when there is:

- A change in future lease payments resulting from a change in an index or rate;
- A change in the assessment of a purchase option;
- A change in the lease term; or
- A change in the amount expected to be payable under a residual value guarantee.

Remeasurements are discounted using a revised discount rate when required by IFRS 16.

Subsequent Measurement of Right-of-Use Assets

ROU assets are subsequently measured at cost less accumulated depreciation and accumulated impairment losses and adjusted for any remeasurement of the related lease liability.

ROU assets are depreciated on a straight-line basis from the commencement date to the earlier of the end of the useful life of the underlying asset or the end of the lease term.

Where IESO Nova Scotia is reasonably certain to exercise a purchase option, the ROU asset is depreciated over the useful life of the underlying asset.

Impairment

ROU assets are assessed for impairment in accordance with IAS 36 – Impairment of Assets. Impairment losses and reversals, where applicable, are recognized in profit or loss.

Short-Term Leases and Leases of Low-Value Assets

IESO Nova Scotia applies the recognition exemptions to:

- Short-term leases (lease term of 12 months or less at commencement and without
- a purchase option); and
- Leases of low-value assets.

Payments associated with these leases are recognized as an expense on a straight-line basis over the lease term or another systematic basis if more representative of the pattern of benefit.

Variable Lease Payments

Variable lease payments that do not depend on an index or a rate are recognized in profit or loss in the period in which the event or condition that triggers those payments occurs.

Lease Modifications

A lease modification is accounted for as a separate lease when it increases the scope of the lease and the consideration increase by an amount commensurate with the stand-alone price for the increase in scope. Otherwise, lease modifications are accounted for by remeasuring the lease liability using a revised discount rate and making a corresponding adjustment to the ROU asset.

Presentation and Cash Flows

ROU assets are presented within property, plant and equipment or as a separate line item in the statement of financial position. Lease liabilities are presented separately from other liabilities or disclosed in the notes to the financial statements.

In the statement of cash flows:

- Principal repayments of lease liabilities are classified as financing activities;
- Interest paid is classified in accordance with IESO Nova Scotia's accounting policy
- under IAS 7; and
- Payments for short-term and low-value leases are classified as operating activities.

Relevant Accounting Standards

- International Financial Reporting Standard 16 (IFRS 16) Leases
- International Accounting Standard 1 (IAS 36) Impairment of Assets
- International Accounting Standard 1 (IAS 7) Presentation of Cash Flows
- International Accounting Standard 1 (IAS 1) Presentation of Financial Statements

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2027/2028 Proposed Expenditures, Revenue Requirement, and Fees Application

Appendix 2 – Financial Controls

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Financial Controls

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INTERNAL FINANCIAL CONTROLS OVERVIEW

The approach to internal controls at IESO Nova Scotia is guided by a framework from The Committee of Sponsoring Organizations of the Treadway Commission (COSO). The COSO framework describes an effective system of internal control that consists of five integrated components:

- Control Environment
- Risk Assessment
- Control Activities
- Information and Communication
- Monitoring Activities

CONTROL ENVIRONMENT

The control environment refers to the set of standards, processes, and structures that provide the basis for carrying out internal control across IESO Nova Scotia. As a new organization, this environment was established initially by the appointment of a competent and experienced Board of Directors. The tone from the top of the organization is evidenced by policies initially adopted such as a Board Code of Conduct, an early Procurement Policy and a focus on governance best practices. The Board immediately established an Audit and Risk Committee with accountabilities that include the internal control framework at IESO Nova Scotia and risk management. The Board prioritized retaining a capable, competent and experienced management team to continue with the focus on internal control as the organization continues to ramp up.

RISK ASSESSMENT

The Audit and Risk Committee of the Board of Directors established an Enterprise Risk Management program with regular reviews of the top risks of the organization. The ERM function at IESO NS is continuing to evolve from an early-stage, consultant supported program toward a more mature governance function aligned with International Organization for Standardization 31000, Risk Management – Guidelines (“ISO 31000”). Throughout 2025/26, foundational work was undertaken, including development of an initial ERM framework, risk log, and reporting cadence to the Committee.

CONTROL ACTIVITIES

Control activities are the business processes and procedures that are commonly referred to as an organization’s internal controls. They may be preventative or detective in nature and may encompass a range of manual and automated activities. IESO Nova Scotia has several operational policies that document the control activities in place.

IESO Nova Scotia operational policies and procedures that contain embedded control activities include:

Procurement Policy

The procurement policy establishes a framework for the acquisition of goods, services, including consulting and technology spend by defining procurement principles, approval authorities, budget requirements, and decision-making processes. Embedded control activities:

Preventive controls

- Board approved budget requirement. All procurement must be included in the Board-approved annual budget or supported by an approved budget amendment. This control prevents unauthorized and unfunded spending ensuring alignment between procurement decisions and approved financial plans.
- Defined approval authorities and authorization limits. Clearly specified dollar thresholds for approval by role prevents individuals from approving for spending beyond their authority. Reduces the risk of inappropriate spending and strengthens financial accountability within the organization.
- Purchase order (PO) requirement above a defined threshold prevents unauthorized or informal purchasing. Use of POs for contracts and on-going commitments captures long-term financial obligations at inception.
- Segregation of duties is present in the policy through defined role separation
- which reduces fraud risk.
- Procurement method thresholds and competitive processes encourage market competition and value for money.
- Corporate credit card restrictions on issuance, limits on use and administration to ensuring spending is subject to controls.
- Employee expense reports requirements with segregation on approvals to prevent unauthorized or inappropriate spending.

Detective controls

- Finance department monitors compliance with the policy to detect any inappropriate approvals, non-competitive purchases or budget overruns to enable corrective actions before issues escalate.
- AP aging review – Finance department standard procedure
- Spend vs. budget analysis – Monthly financial reporting process

Payroll Procedures

Payroll procedures are in place to ensure accuracy and segregation of duties to prevent unauthorized spending. Control activities include:

Preventive Controls

- HR and CEO authorization for payroll changes such as new hires, terminations and pay changes.
- Payroll system access is restricted by role to prevent unauthorized changes or processing.
- Segregation between HR data reviews and approvals and the payroll processing and processing reviews and approvals.
- Detective Controls
- Payroll variance analysis versus approved budgets and planned spending to ensure no unauthorized spending or errors.
- Review of system produced exception reports to ensure no errors or unauthorized changes.

Cash & Treasury Procedures

Procedures for bank payments to ensure accuracy and safeguard IESO assets. Preventive controls

- Dual authorization for bank payments as mandated by Board resolution and system enforced. Prevents a single employee from moving IESO funds.
- System access restricted through IT controls to prevent unauthorized transactions and safeguard assets.
- Detective controls
- Monthly bank reconciliations are independently reviewed within the Finance department as part of segregation of duties.
- Cash flow monitoring and variance analysis review as a method to detect reporting errors or unauthorized transactions.

Financial Close & Reporting Procedures

Procedures in place to standardize the financial reporting structures and allow for the organized record keeping required for effective oversight.

Preventive controls

- Standardized monthly close checklist and timetable to ensure financial
- records are prepared in a complete and timely manner.

- Documented accounting policies such as a prescribed accounting framework based on IFRS. Following prescribed standards provides consistency, comparability and reliability to the financial reporting.
- Restricted journal entry access through IT controls prevents unauthorized access improving reliability.

Detective Controls

- Account reconciliations with independent review – Finance procedure
- Analytical review of financial statements versus budgets, planned activities and actual circumstances helps detect where financial reporting is incomplete or contains errors.
- Period-over-period variance explanations help detect anomalies.
- External audit ensures a rigorous examination of the financial reporting and
- helps detect any variances from prescribed accounting standards.

IT General Controls (ITGCs)

These are system-based controls in place at IESO Nova Scotia which help ensure

data is accessed only by authorized staff and kept secure. Preventative controls

- User access provisioning and termination
- Role-based access and privileged access controls
- Change management (testing and approvals)
- Data backups and recovery procedures

INFORMATION AND COMMUNICATION

The information and communication component of an effective system of internal control acknowledges that consistent and timely information distribution and communications to relevant stakeholders is required. IESO Nova Scotia has established regular reporting mechanisms to the Board and its committees, regulators and stakeholders.

MONITORING ACTIVITIES

Monitoring, measuring and reporting on the company's internal controls to determine if it is operating properly is a key part of an effective system of internal control. IESO Nova Scotia has included monitoring activities when creating its internal control environment.

Examples of monitoring activities at IESO Nova Scotia include:

- Ongoing management review of control performance – Finance procedure
- Periodic independent reviews – external financial audit
- Annual reassessment of financial risks – Audit and Risk Committee

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Appendix 3 – Deferral and Variance Mechanism Guidelines

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Net Revenue Requirement Deferral and Variance Mechanism

Guidelines

October 2026

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1.0 DESCRIPTION

This guideline provides details on the administration of the Independent Energy System Operator of Nova Scotia's (IESO Nova Scotia) Net Revenue Requirement Deferral and Variance Mechanism (DVM, Mechanism). IESO Nova Scotia received approval of its predecessor, the Net Operation, Maintenance and Administration Variance and Deferral Account, in the Nova Scotia Energy Board's (NSEB, Board) Decision regarding IESO Nova Scotia's 2025/2026 Revenue Requirement Application (M12412). The DVM is a revised version of the Board approved OM&A Account applied for approval in IESO Nova Scotia's 2026/2027 Revenue Requirement and Fees Application (M12663). Where Board direction was received regarding the approval of the OM&A Account, they are assumed to be applicable for the Mechanism and described herein.

The DVM is for the purpose of calculating and deferring any variance from IESO Nova Scotia's approved revenue requirement for future recovery. In service of this, the Mechanism enables, broadly, the following: Recording and calculating any variances from NSEB approved budget to actual in each revenue requirement application.

Variances (over-expenditures or under-expenditures) will inevitably occur where actual costs incurred are higher or lower than the NSEB approved budget for the applicable fiscal year.

The total net variance for each fiscal year will be recorded and deferred for appropriate treatment in a future fiscal year revenue requirement application. The variance will be incorporated into and passed through a Board-approved fee and cost recovery mechanism.[1] The fee and cost recovery mechanism will calculate fees to be charged to

[1] IESO Nova Scotia's Fee Recovery Mechanism Application was submitted to the NSEB on July 31, 2026. The NSEB has established a written hearing proceeding for its review (M13007).

applicable market participants. For clarity, this guideline pertains only to the administration of the DVM.

Stakeholders shall have the opportunity to review the variances and their treatment through the fee recovery mechanism as part of IESO Nova Scotia's annual More Access to Energy Act s.29 revenue requirement, proposed expenditures, and fees applications.

2.0 REVENUE REQUIREMENT

Variances will be based on prior revenue requirement budgets and in turn treatment through the fee recovery mechanism. IESO Nova Scotia is required under the *More Access to Energy Act* to submit an annual revenue requirement, proposed expenditure, and fee application by December 31st each year for the next fiscal year from April 1 to March 31. The final revenue requirement amount for the upcoming fiscal year approved by the NSEB will be the budget recorded in the Mechanism to track actuals to budget and ultimately determine the variance and fiscal year-end.

3.0 CALCULATION OF THE VARIANCE

The DVM will calculate variances as follows.

Costs	Description
1. Budgeted Revenue Requirement	The NSEB approved budgeted revenue requirement for the fiscal year beginning April 1, 20XX and ending March 31, 20XX+1. This amount is presented as the total Revenue Requirement in each Revenue Requirement and Fees application.
2. Actual Costs incurred.	The actual costs incurred in the fiscal year from April 1, 20XX to March 31, 20XX+1.
3. Variance.	The variance is calculated as the difference between the Actual Costs Incurred (item 2) and the Budgeted Revenue Requirement (item 1). A positive number indicates a variance where IESO Nova Scotia's actual total costs were greater than the approved budget. A negative variance indicates that IESO Nova Scotia's actual total costs were less than the approved budget. The variance is then accounted for in the next Revenue Requirement and Fees application, or by compliance filing pursuant to IESO Nova Scotia's True-Up Option 2 in its Fee Recovery Mechanism application (M13007).

The following examples illustrate how the Net Revenue Requirement Deferral and Variance Mechanism will function. In each scenario, the Board approved total fiscal year Revenue Requirement budget is assumed to be $100 (item 1).

- Scenario 1 – Over-Recovery: during the fiscal year April 1 to March 31, IESO Nova Scotia incurs actual costs of $90 (item 2), lower than the NSEB approved budget (item 1). The Net Revenue Requirement Deferral and Variance Mechanism balance is therefore ($10) (negative ten) (i.e., $90 – 100) (item 3). The ($10) is effectively an over-recovery by IESO Nova Scotia, and will then be incorporated into future associated fees, reducing what the fees might otherwise be for the next fiscal year.

- Scenario 2 – Under-Recovery: during the fiscal year April 1 to March 31, IESO Nova Scotia incurs actual costs of $110 (item 2), more than the NSEB approved budget (item 1). The Net Revenue Requirement Deferral and Variance Mechanism balance is therefore $10 (positive ten) (i.e.$110 - 100) (item 3). The $10 is effectively an under-recovery by IESO Nova Scotia, and will then be incorporated into future associated fees, increasing what the fees might otherwise be for the next fiscal year.

IESO Nova Scotia will track variances at the main cost category level as noted in its revenue requirement, proposed expenditures, and fees applications. The overall variance for revenue requirement is the applicable figure to be used to credit or recover via fees in accordance with the fee recovery mechanism.

4.0 COST TIMING

The cost timing for recording and variance tracking purposes will be IESO Nova Scotia's fiscal year: April 1, 20XX to March 31, 20XX+1.

Tracking actual costs against the NSEB approved amount will begin as at April 1 each year. At the close of a financial year, IESO Nova Scotia will complete a final accounting of costs for that period in comparison to the corresponding approved amount for that fiscal year. The difference is the variance that is recorded in the deferral account as described above.

When there is a balance in the DVM it will be included as an item in the next revenue requirement application submitted by IESO Nova Scotia, or in a compliance filing in the manner proposed in IESO Nova Scotia's Fee Recovery Mechanism application via Revenue Requirement True-Up Option 2 (M13007).

Timing will follow a pattern such as the following (using hypothetical dates):

i. Revenue requirement, proposed expenditures, and fees application submitted by December 31 in fiscal year 1 for fiscal year 2 ahead. An approved amount related to fiscal year 2 is set by the NSEB in Q1 or Q2 of fiscal year 2.

ii. Fiscal year 1 variances are finalized via the DVM in Q1 or Q2 of fiscal year 2. Given this timing.

iii. a. At December 31 fiscal year 2, a revenue requirement application is submitted for fiscal year 3. The fiscal year 1 variances are included in the application via the DVM to credit or recover. (True-up Option 1 in M13007)

Or:

b. In Q2 of fiscal year 2, a compliance filing is submitted adjusting fiscal year 2 fees. The fiscal year 1 variances are included in the compliance filing via the DVM to credit or recover. (True-up Option 2 in M13007)

5.0 RECOVERY/CREDITING OF VARIANCES

Pursuant to IESO Nova Scotia's Fee Recovery Mechanism application (M13007) submitted to the NSEB on July 31, 2026, the final over or under expenditure calculated by the DVM and approved by the NSEB will be passed through the fee recovery mechanism to adjust corresponding fees to applicable market participants. This will be accomplished through annual true-ups.

As described in the Fee Recovery Mechanism application, there are two options presented regarding the revenue requirement true-up:

- Option 1: The delta between IESO Nova Scotia's Board-approved forecast revenue requirement and actual expenditures from FY1 are calculated by the DVM, to determine the true-up amount in FY3.
- Option 2: The delta between IESO Nova Scotia's Board-approved forecast revenue requirement and actual expenditures from FY1 are calculated by the DVM, to determine the true-up amount in FY2 via compliance filing.

Irrespective of the revenue requirement true-up option approved by the NSEB as part of M13007, the DVM variance will be passed through the fee recovery mechanism methodology ultimately approved by the Board in that proceeding.

Variances will be recorded and accounted for pursuant to the methodology described in these guidelines. Each fiscal year will rely on figures from the financial statements, and subject to external audit, for the calculation of budget to actual variance for any financial year. The variance will be recorded in IESO Nova Scotia's accounting records with settlement recognized through the receipt of annual revenue requirement. Accounting controls such as revenue recognition policies and bank account reconciliations will ensure there is no duplication. The fee recovery mechanism calculation model will reconcile revenue requirements for every fiscal year with past

fiscal year variance true-ups and actual load allocations. These processes will ensure appropriate vetting of financials year-over-year, eliminating any potential double counting variances or misalignment with future true-ups.

6.0 VARIANCE THRESHOLDS

The NSEB provided the following direction in its Decision regarding IESO Nova Scotia's 2025/2026 Revenue Requirement Application (M12412) on February 25, 2026:

> The Board agrees with the IESO that it would be efficient to conduct any prudence reviews during the IESO's annual revenue requirement and fees applications. Therefore, IESO Nova Scotia must, in its applications, provide an explanation for cost category variances exceeding +/-10%. For cost overruns, the burden will be on the IESO to demonstrate that the expenditures were prudent.[2]

IESO Nova Scotia's interpretation of the Board's direction in M12412 is that an automatic review is triggered in circumstances in which a main cost category incurs a variance which exceeds +/- 10% of the Board approved revenue requirement. In that circumstance, the variance is subject to a further reasonableness review by the NSEB and subject to Board approval. Costs within that threshold are presumed recoverable or creditable without further prudency review. Nevertheless cost over or under expenditures at the main cost category levels referred to in section 2.2.1 and 2.2.2 will be described in the revenue requirement, proposed expenditures, and fees applications.

[2]

7.0 MATERIAL VARIANCES AND NEW OR UNEXPECTED COSTS

Throughout the course of the fiscal year, cost variances from forecast to actual will be tracked and addressed in the manner described within these guidelines. As part of the tracking of variances throughout the fiscal year, significant variances may emerge or are expected to occur, or circumstances may arise where new and unexpected costs emerge or are expected to occur.

IESO Nova Scotia is required by NSEB direction to provide updates on "material changes" and "new or unexpected costs" in its quarterly reporting. Accordingly, IESO Nova Scotia will provide corresponding updates related to material variances from NSEB approved revenue requirement forecasts, as well as new or unexpected costs, in its quarterly reporting to the NSEB.

IESO Nova Scotia may also provide ad hoc outside-the-quarter reporting on the same, and requests for interim adjustment to fees, if circumstances warrant such reporting and adjustments to fees. Otherwise, the annual review of variances via IESO Nova Scotia's revenue requirement, proposed expenditures, and fees applications will likely provide sufficient frequency to prevent the accumulation of significant variances.

8.0 ANNUAL SUBMISSIONS

IESO Nova Scotia is required under MAEA section 29 to submit to the NSEB its revenue requirements for the next fiscal year by December 31st annually. The DVM and any corresponding variances will be included in each annual IESO Nova Scotia revenue requirement application for consideration and approval for recovery by the NSEB, as well as variance treatment via the fee recovery mechanism. Alternatively, the DVM and corresponding variances may be included in a compliance filing in the manner proposed in IESO Nova Scotia's Fee Recovery Mechanism application via Revenue Requirement True-Up Option 2, as well as variance treatment via the fee recovery mechanism.

9.0 AUDIT AND OVERSIGHT

The More Access to Energy Act provides the following with respect to audit:

> **Auditor**
> **31** The Board of Directors shall appoint a qualified auditor to audit annually the accounts and transactions of the IESO.
> **Annual report**
> **32 (1)** Within six months after the end of every fiscal year, the IESO shall submit an annual report to the Energy Board on its affairs during that fiscal year and shall provide a copy of the report to the Minister.
> **(2)** The audited financial statements of the IESO must be included in the annual report and the annual report must contain any further particulars the Governor in Council may prescribe by the regulations.

Accordingly, the annual financial statements of IESO Nova Scotia are prepared in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board (IASB) and subject to audit by a qualified external audit firm. The resulting audited financial statements will be included in IESO Nova Scotia's annual report and submitted to the NSEB by September 30th each year. The variance amount calculated under the DVM will be included in the audited accounts. Broader regulatory oversight will occur via the MAEA s.31 submission to the NSEB and IESO Nova Scotia's MAEA s.29 applications.

10.0 STAKEHOLDER REVIEW AND DISCOVERY

Annual review will occur via More Access to Energy Act (MAEA) s.29 Revenue Requirement, Proposed Expenditures, and Fees applications. DVM information is expected to be non-confidential and publicly available. The Board's secure document site will be utilized to access the s.29 application and corresponding information. If information is confidential, a Confidentiality Agreement or undertaking will be required to access confidential information. Intervenors with approved Confidentiality Agreements under a corresponding NSEB proceeding will have access through the NSEB's confidential website. All information will be available via electronic PDF or Excel format. In each NSEB s.29 application, stakeholders shall have the opportunity (and access to information) to challenge IESO Nova Scotia's variances calculations and incorporation into fees. Stakeholders shall not be precluded from reviewing prior years' actual results versus prior forecasts in addressing the propriety of the succeeding year's forecast.

Nova Scotia Independent Energy System Operator

Proposed Expenditures, Revenue Requirement, and Fees Application

Appendix 4 – Annual Business and Work Plan

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Project Work Plan and Schedule
Fiscal Year 2026/2027 Results to Date

Project	Key Activities (Updated)	Estimated or Actual Completion	MAEA Objects
Permanent Fee and Cost Recovery Mechanism	- Consultant engagement - Stakeholder engagement - Submission in Q1 2026/27 - Application submitted to NSEB July 31, 2026. - NSEB written hearing proceeding initiated.	NSEB Hearing Schedule into December	MAEA s.9(a),(r),29,30
Integrated Resource Plan	-Stakeholder engagement throughout 2026 -Complete pre-studies (ELCC, Hybrid Heating) and process design work -Complete draft and final modeling -Complete development of IRP Action Plan and final report -Ongoing. ELCC study completed. Assumption Sets 1 and 2 completed. ELCC and assumption sets reviewed by stakeholders and feedback addressed. -Assumption Set 3 completed. Details on commodity forecast, DSM potential study and expanded wind-storage ELCC analysis all included in Assumption Set 3. -IRP timeline updated with the NSEB. -Submission Q4 2026/27, please refer to letter filed with the NSEB on Oct 27, 2026 for further details on updated timeline.	Q4 2026/27	MAEA s.9(b),(h),(j),(o),(p),(q),(r),10,11
Procurement: Fast Acting Generation	-Develop RFP, Tolling Agreement, and supporting documentation -Fast Acting Generation RFP launched on July 10, 2026. -Continue site development activities until handoff to awarded proponents	Q1 2027/28	MAEA s.9 (c),(e),(l),(m),(o),(p),(r)
Procurement: New Brunswick Capacity Purchase	-IESO Nova Scotia entered into agreement with New Brunswick Power for capacity from its RIGS project On April 15, 2026. On May 28, 2026, (NBEUB) approved the RIGS project, including the expansion capacity related to IESO Nova Scotia's agreement with NB Power. (Matter EL-002-2025). -Ongoing agreement oversight continues	Q1 2026/27 (Definitive Agreement)	MAEA s.9(c),(e),(h),(l),(m),(o),(p)
Procurement: Additional Capacity	-RFQ Developed and draft documents released for stakeholder feedback October 19, 2026 -RFQ is expected to launch in Q3 2026/27 with submissions anticipated in Q4 2026/27. Submissions will inform subsequent procurement process(es).	RFQ submissions anticipated Q4 2026/27 Procurement Process ongoing into 2027/28	MAEA s.9(c),(e),(l),(m),(o),(p),10
2027/2028 Revenue Requirement and Fee Application	- Develop initial plan and budget Q1/Q2 2026/27 - Stakeholder engagement Q2 2026/27 - Submission in Q2/Q3 2026/27	Q3 2026/27 NSEB Schedule TBD	MAEA s.9(a),29
FY 25/26 Year End Audit	- Retained qualified accounting firm to conduct audit through competitive bidding - Selected accounting framework that best meets IESO reporting needs - Completed year end audit working papers with supporting documentation - Drafted year end financial statements with complete disclosures - Reviewed audit plan and support audit fieldwork as needed - The year end audit noted no issues with IESO NS's accounting policies and financial controls. - Board review and sign-off of audited financial statements before deadline. - Submitted to NSEB with Annual report	Q2 2026/27	MAEA s.9(a),(r),(s),31
Phase II Planning and Implementation	- Determined best option for establishing IESO Control Center to perform IESO operating functions (Q4 2025/26) - Develoedp implementation plan including key activities, implementation budget & timeline) (Q4 2025/26 - Q1 2026/27) - Selected IBM to help IESO with the implementation of the option selected in the planning phase (Q1/Q2 2026/27) - Implemented the plan - starting Q2 2026/27 Additional work related to: -Project Management Office -Phase II Market Readiness & Transition Planning -Compliance Readiness & Preparedness Assurance -Details are found in this application under the Proposed Expenditures section.	Q4 2027/28	MAEA s.9(a),(b),(c),(d),(e),(f),(i),(l), (m),(n),(p),(q),(r)
SGIP Administration Process	- Submission in Q1 2026/27 -Agreement with NSPI submitted to NSEB on August 18, 2026	Q2 2026/27	MAEA s.9(a),(d),(g),(k),(r)
SGIP Revisions and FERC Order 2023 Recommendations (M12524)	- Stakeholder engagement throughout 2026 - Submission by Q3 2026/27 -TSIP draft completed in August 2026. - IESO NS and NSPI completed review engagement in September 2026. - Stakeholder engagement process on the TSIP is underway.	Q3 2026/27 NSEB Schedule TBD	MAEA s.9(a),(d),(g),(k)
Interconnection Processes Annual Reporting (M12174)	- Submission by March 31 annually - Letter regarding interconnection process annual reporting provided February 12, 2026.	NSEB Schedule TBD	MAEA s.9(a),(d),(g),(k)
Generation Interconnection Processes	-Complete Feasibility and System Impact Studies in alignment with the Generation Interconnection Procedures -Support for comissioning activities for wind farms in development -IESO-NS continuing to complete Feasibility and System Impact Studies as required, including System Impact Studies for Green Choice 1 wind farms. -Feasibility Studies for Green Choice 2 procurement ongoing through Q3 2026/27	Ongoing	MAEA s.9(e),(g),(j),(o),(r)

NERC & NPCC Compliance Activities	-Completion of compliance activities associated with Transmission Planner, Resource Planner, and Planning Coordinator functions -Support NPCC Task Forces and Working Groups for which IESO-NS is a member -Complete Comprehensive Review of Transmission Adequacy under NPCC Directory 1 for the Nova Scotia portion of the Maritimes Area -Complete Interim Review of Resource Adequacy under NPCC Directory 1 for the Nova Scotia portion of the Maritimes Area -Compliance functions are ongoing. -IESO-NS has active membership on the task forces and working groups which are relevant to its NERC functions. -Transmission Adequacy and Resource Adequacy assessments are underway targeting end of Q3 2026/27 for completion.	Ongoing	MAEA s.9(e),(i),(r)
NERC Reliability Standards	- Comments submitted on Quarterly basis -Assisted NSPI in provision of contact information for IBRs to NSEB regarding NERC registration by letter on August 7, 2026.	Ongoing	MAEA s.9(d),(i)
Quarterly IESO Reports	- Beginning May 15, 2026 per NSEB Direction M12412 - First quarterly report submitted to NSEB on May 15, 2026. - Second quarterly report submitted to NSEB on August 21, 2026.	Ongoing	NSEB Direction
Annual IESO Report	- Due September 31, 2026 per the *More Access to Energy Act* section 32 - Submitted to the NSEB on September 31, 2026.	Ongoing	MAEA s.9(a),(r),32

Project Work Plan and Schedule
Fiscal Year 2027/2028

Priority 1 - Complete the Successful Transition of Independent Grid Operations

Key Activity/ Project	Description	Estimated Completion	MAEA Linkage
Independent Grid Operations Planning and Implementation	Please refer to Proposed Expenditures section of the Application for details. Additional work related to: -Project Management Office -Market Readiness & Transition Planning -Compliance Readiness & Preparedness Assurance	Q4 2027-28 for Independent Grid Operations	MAEA s.9(a), (b), (c), (d), (e), (f), (i), (l),
Independent Control Centre	Transfer an existing facility to IESO Nova Scotia, perform retrofit design, implement retrofit, and install technology and equipment to establish an effective and independent control centre.	Q4 2027-28	
NERC Certification	Develop processes, procedures, and documentation to obtain required NERC certification as a new entity responsible for performing Balancing Authority and Transmission Operator functions. Includes validation activities after go-live.	Q4 2027-28	
Updated Market Rules and Tariffs	Establish updated Market Rules and Market Procedures that reflect a new independent entity responsible for creating a new competitive market environment in Nova Scotia. This includes updates to the Open Access Transmission Tariff .	Q3 2027-28	
Operational Processes and People	Adjust existing operational processes to reflect the transition of functions from Nova Scotia Power to IESO Nova Scotia. This includes a detailed people transition plan and associated organizational change management.	Q4 2027-28	
Technology Enablement	Implement the necessary technology solutions and support models to successfully enable IESO Nova Scotia, including cybersecurity, Information Technology infrastructure, Operation Technology systems, and applications that are created new or transferred from Nova Scotia Power.	Q4 2027-28	
Phase 2A Go-Live	Execute all testing and go-live preparations to successfully transfer Balancing Authority and Transmission Operator functions operating from a new independent control centre.	Q4 2027-28	
Settlement Capability	Building on the updated Market Rules and tariffs, plan and implement a new Settlement System capability that sustains a new competitive electricity market, including an information sharing portal for new market participants.	Q3 2028-29	

Activities extending beyond 2027-28:
As discussed in the Phase 2 Control Centre section, while operational cutover of system operations to IESO Nova Scotia's dedicated control centre is targeted for the end of 2027-28, the full transition of is part of multi-year program that anticipates activities around stabilization, settlements, and optimization to continue through to 2028-32.

Priority 2 - Advance System Reliability Building on the IRP

Key Activity/ Project	Description	Estimated Completion	MAEA Linkage
Integrated Resource Plan: IRP Action Plan	Implement IESO Nova Scotia-owned initiatives identified in the 2026 IRP Action Plan. These action items will be identified and reviewed with stakeholders as part of the IRP process. Where necessary, tasks will be prioritized to manage cost and workload.	Multi-Year Action Plan - To be provided at conclusion of IRP process - Ongoing	MAEA s.9 (a), (j), (o), (p), (q), (r), 10, 11
Procurement: Fast Acting Generation	Continue site development activities until handoff to awarded proponents. The procurement schedule currently contemplates proposal submission in January 2027, with project award decision by May 2027. IESO Nova Scotia will continue to have project oversight once award(s) have been made.	Ongoing	MAEA s.9 (a), (e), (l), (m), (o), 10
Procurement: New Brunswick Capacity Purchase	IESO Nova Scotia will continue to have agreement oversight as this facility is developed.	Ongoing	
Procurement: Technology Neutral Capacity RFQ and subsequent procurement steps	The procurement schedule currently contemplates RFQ response submission in late January 2027, with evaluation to follow. IESO Nova Scotia anticipates launching one or more follow-up procurement steps based on the results of the RFQ, combined with the results of the 2026 IRP. Once confirmed, these will launch in 2027-28, with detailed schedules to be determined at that time.	Ongoing	

Activities extending beyond 2027-28:
The System Planning team will continue to implement the 2026 IRP Action Plan beyond 2027-28. In addition, preparations and pre-IRP studies will be undertaken to prepare for the next IRP, currently anticipated to occur in 2029. The Procurement team will continue execution of procurement activities in alignment with the 2026 IRP Procurement Plan. In addition, the team will continue monitoring contracted projects through to commercial operations. An application to the NSEB for the recovery of energy resource costs under Section 30 of the More Access to Energy Act is anticipated in 2028/29.

Priority 3 - Strengthen System-User Engagement, Transparency, and Access

Key Activity/ Project	Description	Estimated Completion	MAEA Linkage
Standard Generation Interconnection Procedures Revisions and Federal Energy Regulatory Commission Order 2023 Recommendations (M12524)	Key activities dependent on NSEB hearing timeline. IESO Nova Scotia initiated stakeholder consultation on updates to the Standard Generation Interconnection Procedures (now the Transmission System Interconnection Procedures) in fall 2026, expects submission to the NSEB by end of calendar year 2026, and anticipates that the regulatory process to approve proposed changes will continue into 2027-28.	NSEB Schedule TBD	MAEA s.9(a), (d), (g), (k)
Interconnection Processes Annual Reporting (M12174)	IESO Nova Scotia submits this reporting by March 31 annually.	NSEB Schedule TBD	MAEA s.9(a), (d), (g), (k)
Generation Interconnection Processes	Interconnection Studies will be completed in alignment with the Generation Interconnection Procedures. IESO Nova Scotia will also provide support for commissioning activities for new transmission-connected facilities in development.	Studies and Commissioning Activities are ongoing.	MAEA s.9 (a), (d), (e), (g), 10(d)
Interconnection Process Improvements	IESO Nova Scotia anticipates that in 2027-28, it will implement a program to enhance the existing interconnection process. A target for this process will be implementation of functionality enhancements by the end of Q4 2027-28.	Q4 2027-28	MAEA s.9(g), 10(d)
Market Engagement	IESO Nova Scotia will establish an updated market participant framework that encourages new entrants to the province's electricity market (updated Open Access Transmission Tariff and Market Rules). A structured approach for collaboration with market participants (e.g. Market Advisory Committee, Market Change Panel, Participant Information Portal) will also be created.	Q3 2027-28	MAEA s.9(a), (k), 10(c), 60-62

Activities extending beyond 2027-28:
Interconnection Studies and commissioning support will continue beyond 2027-28 as part of ongoing work to facilitate new generation, storage, and load connections to the Nova Scotia transmission system.
Depending on the determined scope of Interconnection Process Improvements, including the potential for any software implementations, this work may extend beyond 2027-28 for full implementation.

Priority 4 - Build External Trust and Shape Energy Policy to Benefit Nova Scotians

Key Activity/ Project	Description	Estimated Completion	MAEA Linkage
NERC & NPCC Compliance Activities	-Completion of compliance activities associated with Transmission Planner, Resource Planner, and Planning Coordinator functions -Support NPCC Task Forces and Working Groups for which IESO-NS is a member -Complete Review of Transmission Adequacy under NPCC Directory 1 for the Nova Scotia portion of the Maritimes Area -Complete Review of Resource Adequacy under NPCC Directory 1 for the Nova Scotia portion of the Maritimes Area	Ongoing	MAEA s.9(a),(d),(e), (i), (r)
NERC Reliability Standards	- Comments submitted on Quarterly basis	Ongoing	MAEA s.9(a),(d),(e), (i)
Quarterly Reports	IESO Nova Scotia will continue to issue quarterly reports on its website and to the Nova Scotia Energy Board on a quarterly basis.	Ongoing	NSEB Direction
Annual Report	IESO Nova Scotia will continue to issue its annual report, as required by the *More Access to Energy Act* , by September 31 of each year.	Ongoing	MAEA s.9(a), 32
Indigenous Relations Framework	IESO Nova Scotia will continue to co-develop, with Mi'kmaw consultants, a framework that will support ongoing relationship-building, engagement, and collaboration with Nova Scotia's Mi'kmaw communities and organizations.	Q4 2027-28	Supports all aspects of IESO NS Work MAEA s.9(a),(s)

Public Education	IESO Nova Scotia will continue to build on its role to grow energy literacy in the province by developing and deploying a public education initiative to help Nova Scotians understand how the electricity system works, the various roles and responsibilities in powering and running the grid, the challenges and opportunities in Nova Scotia's energy system, and how decisions are made.	Q4 2027-28	Supports all aspects of IESO NS Work MAEA s.9(a),(s)

Activities extending beyond 2027-28:
Annual reporting will continue beyond the 2027-28 fiscal year. It is anticipated that public engagement activities, including the development and deployment of a public education initiative and the implementation of an Indigenous Relations Framework, may be required to continue beyond the end of 2027-28. This will be informed by ongoing needs assessment through the fiscal year.

Priority 5 - Progress Important Regulatory Outcomes

Key Activity/ Project	Description	Estimated Completion	MAEA Linkage
2027/2028 Revenue Requirement, Proposed Expenditures, and Fees Application	Application submitted in Q3 2026/2027.	Q1 2027/2028 NSEB Decision expected. Pending NSEB establishing hearing timeline.	MAEA s.9(a), 29
2028/2029 Revenue Requirement, Proposed Expenditures, and Fees Application	- Development begins Q2 2027/28 - Intervenor engagement begins Q2 2027/28 - Submission by December 31, 2027	Submission by Q3 2027-28	MAEA s.9(a), 29
Transmission Generation Interconnection Procedures	- Nova Scotia Power Inc. and IESO Nova Scotia entered into an agreement with respect to the interim administration of the existing Standard Generation Interconnection Procedures on August 18, 2026. - IESO Nova Scotia engaged with NS Power regarding the development and material changes of proposed Transmission Generation Interconnection Procedures. Broader stakeholder engagement on the TSIP began in October 2026 and is expected to continue through November 2026. Submission to NSEB expected by December 31, 2026	Dependent on NSEB establishing hearing timeline.	MAEA s.9(a), (d), (g), (k), 10(d)

Activities extending beyond 2027-28: Dependent on NSEB hearing timelines for any related matters.

Priority 6 - Build a Strong Organization Where People Want to Work and Grow

Key Activity/ Project	Description	Estimated Completion	MAEA Linkage
Build Employee and Leadership Capability	-Implement development plans for employees and leaders based on organizational and role-specific capability needs. - Deliver targeted learning and development opportunities to support employee growth and readiness for IESO-NS's expanding mandate.	Q4 2027/2028	Supports all aspects of IESO NS Work MAEA s.9(a),(s)
Strengthen Succession and Knowledge Transfer	- Identify critical roles and organizational knowledge at risk. - Establish succession and knowledge-transfer plans to build internal capability and preserve institutional knowledge as the organization grows.	Q4 2027/2028	Supports all aspects of IESO NS Work MAEA s.9(a),(s)

Activities extending beyond 2027-28: The processes to support Key Activities under Priority 6 are expected to tbe completed in Q4 2027/2028 as noted. However, actual activities under these Key Priorities are expected to be ongoing as the organization matures.

Project Work Plan and Schedule

Object	Summary
9(a)	exercise and perform the powers, duties and functions assigned to the IESO under this Act, the market rules and its licence;
9(b)	enter into agreements with transmitters giving the IESO the authority to direct the operations of their transmission systems;
9(c)	direct the operation of the IESO-controlled grid;
9(d)	establish and enforce criteria and standards relating to the reliability of the integrated electricity system;
9(e)	maintain the adequacy and reliability of the bulk electricity system;
9(f)	procure ancillary services;
9(g)	enter into interconnection agreements with transmitters;
9(h)	work with responsible authorities outside the Province to coordinate the IESO's activities with their activities;
9(i)	participate with any standards authority in the development of standards and criteria relating to the reliability of transmission systems;
9(j)	undertake and coordinate power system planning and development responsibilities to maintain and ensure the adequacy and reliability of the bulk electricity system for present and future needs and for the efficient operation of a competitive market;
9(k)	facilitate the operation of a competitive electricity market;
9(l)	engage in activities related to settlements, payment under a contract entered into under the authority of this Act and payments provided for under this Act, the Electricity Act or the Public Utilities Act;

9(m)	conduct procurements for energy resources, including (i) electricity supply, (ii) electricity capacity, (iii) energy storage, (iv) ancillary services, and (v) hybrid peaking resources;
9(n)	engage in activities to facilitate the diversification of sources of electricity supply by promoting the use of cleaner energy sources and technologies, including alternative energy sources and renewable energy sources;
9(o)	engage in activities in support of system-wide goals for the amount of electricity to be produced from different energy sources;
9(p)	forecast electricity demand and the adequacy and reliability of electricity resources for the Province for the short, medium and long terms;
9(q)	conduct independent planning for energy resources, demandside management and transmission;
9(r)	collect and make public information relating to the short, medium and long term electricity needs of the Province and the adequacy and reliability of the integrated electricity system to meet those needs;
9(s)	perform any other function or engage in any activity the IESO considers necessary or advisable to exercise its powers and carry out its duties, responsibilities and functions under this Act and the regulations; and
9(t)	perform any other duties prescribed by the regulations.

Nova Scotia Independent Energy System Operator

Proposed Expenditures, Revenue Requirement, and Fees Application

Appendix 5 – Letter of Support and Line of Credit Amending Agreement

NON-CONFIDENTIAL – Letter of Support

Letter of Credit Amending Agreement has been removed for confidentiality purposes

NOVA SCOTIA
Energy
Office of the Deputy Minister

1690 Joseph Howe Building, 11th Floor
PO Box 2664
Halifax, Nova Scotia B3J 3P7
Canada

902 424-7109 T

novascotia.ca

November 3, 2026

Johnny Johnston
President & Chief Executive Officer
IESO Nova Scotia

Dear Mr. Johnston,

Re: Government Support for IESO Nova Scotia's Phase 2 Plans

I am writing to confirm the Government of Nova Scotia's support for IESO Nova Scotia's proposed approach for the Phase 2 project and staged implementation timeline, including the planned transfer of operational control of the electricity system from Nova Scotia Power to IESO Nova Scotia in spring 2028.

Government supports the proposed transfer of Nova Scotia Power's data centre for IESO Nova Scotia's use in establishing its independent control centre. Repurposing this existing facility and making effective use of existing infrastructure represents a pragmatic approach to achieving the independence objectives of the *More Access to Energy Act*, while protecting reliability and managing the overall cost to electricity customers.

To support progress on the Phase 2 plans, Government has agreed to increase IESO Nova Scotia's existing line of credit by $10 million. This additional financing has been provided to enable IESO Nova Scotia to advance the planning, procurement and implementation activities necessary to maintain the proposed timeline.

Government also intends, in the coming months, to proclaim the provisions necessary to bring into effect IESO Nova Scotia's remaining objectives under the *More Access to Energy Act* in support of the Phase 2 transition.

We appreciate the work of IESO Nova Scotia's Board and management in developing this proposal and look forward to continued collaboration to deliver independent system operation and long-term value for Nova Scotians.

Yours sincerely,



Stephen MacDonald,
Deputy Minister, Department of Energy

Nova Scotia Independent Energy System Operator

Proposed Expenditures, Revenue Requirement, and Fees Application

Appendix 6 – IBM Control Centre Analysis

NON-CONFIDENTIAL



Phase 2: Control Centre Options Analysis and Recommendation Roadmap

IBM Report

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1. Executive Summary

IBM was engaged by IESO Nova Scotia ("IESO-NS") to assess long-term operating model options for Phase 2 of the transition of Balancing Authority ("BA") and Transmission Operator ("TOP") functions from Nova Scotia Power ("NSP") to IESO-NS, and to recommend the most appropriate implementation pathway. Based on the strategic pathways assessment, IBM recommends that IESO-NS proceed with **Scenario 4 – Enhanced Independence** as the preferred long-term operating model, implemented through a phased **Phase 2A / 2B / 2C** pathway. The recommended end-state and the phased implementation approach are summarized in Figure 1.

The recommendation was supported by a parallel value case assessment undertaken by FTI Consulting, which quantified expected benefits associated with each strategic scenario. The combined strategic assessment and economic evaluation demonstrated that Scenario 4 delivers the strongest overall outcome, achieving the highest long-term NPV while also scoring highest against reliability, legislative alignment, operational independence, and implementation feasibility criteria. The economic analysis identified an estimated NPV of approximately $219 million over the assessment horizon, supporting the conclusion that the recommended pathway delivers positive value for Nova Scotians.

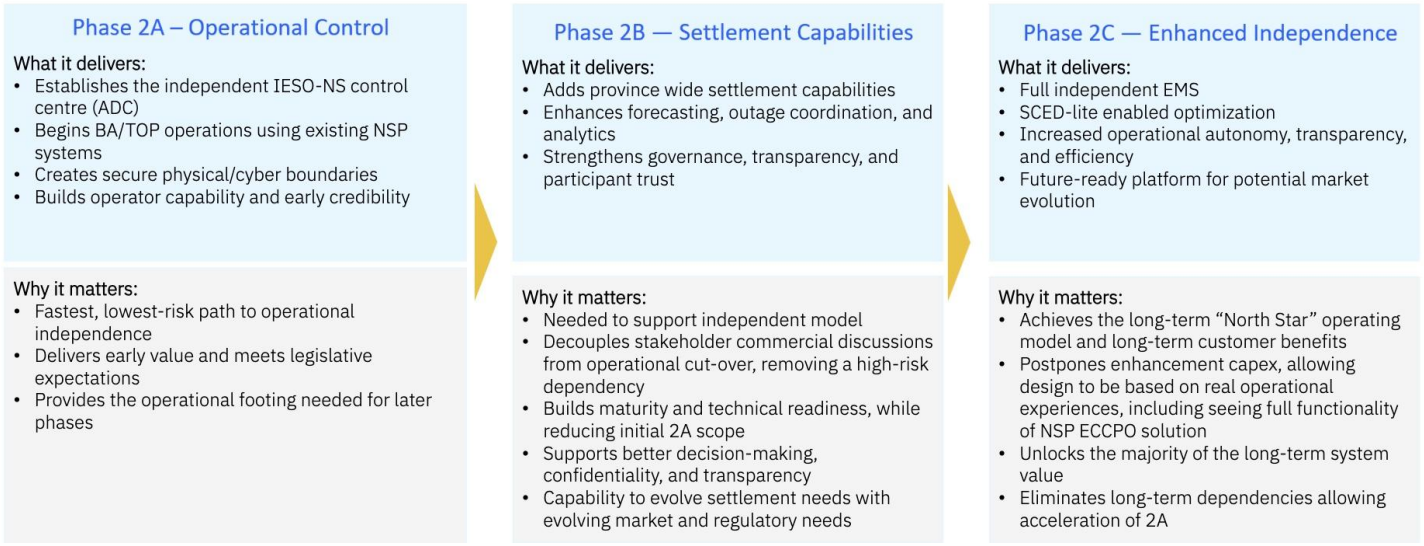


Fig 1: Implementation Phases

This recommendation reflects a structured evaluation of options against criteria including reliability, cost-effectiveness, value for Nova Scotians, regulatory compliance, and alignment with the legislative direction established by the *More Access to Energy Act* ("MAEA"). IBM recommends that IESO-NS proceed with Scenario 4 as the preferred operating model for Phase 2, implemented through a phased pathway for managing implementation risk and preserving reliability.

Phase 2 is the final step in the transfer of operating responsibilities from NSP to IESO-NS, completing the move to independent operational control as required by the MAEA. The work undertaken to date confirms that this transition can be achieved in a manner that protects system reliability, enhances transparency and independence, and delivers positive long-term financial value for Nova Scotians.

The recommended implementation pathway is designed around three phases:

- **Phase 2A** as the first implementation milestone and credible initial operating step for IESO-NS;

- **Phase 2B** to establish commercial arrangements under IESO-NS operation of the electricity system; and
- **Phase 2C** to deliver the full long-term target operating model under Scenario 4 – Enhanced Independence.

The recommended implementation pathway in Fig 2 illustrates how IESO-NS can achieve operational independence through a structured, lower-risk progression from Phase 2A to the full Scenario 4 end-state.

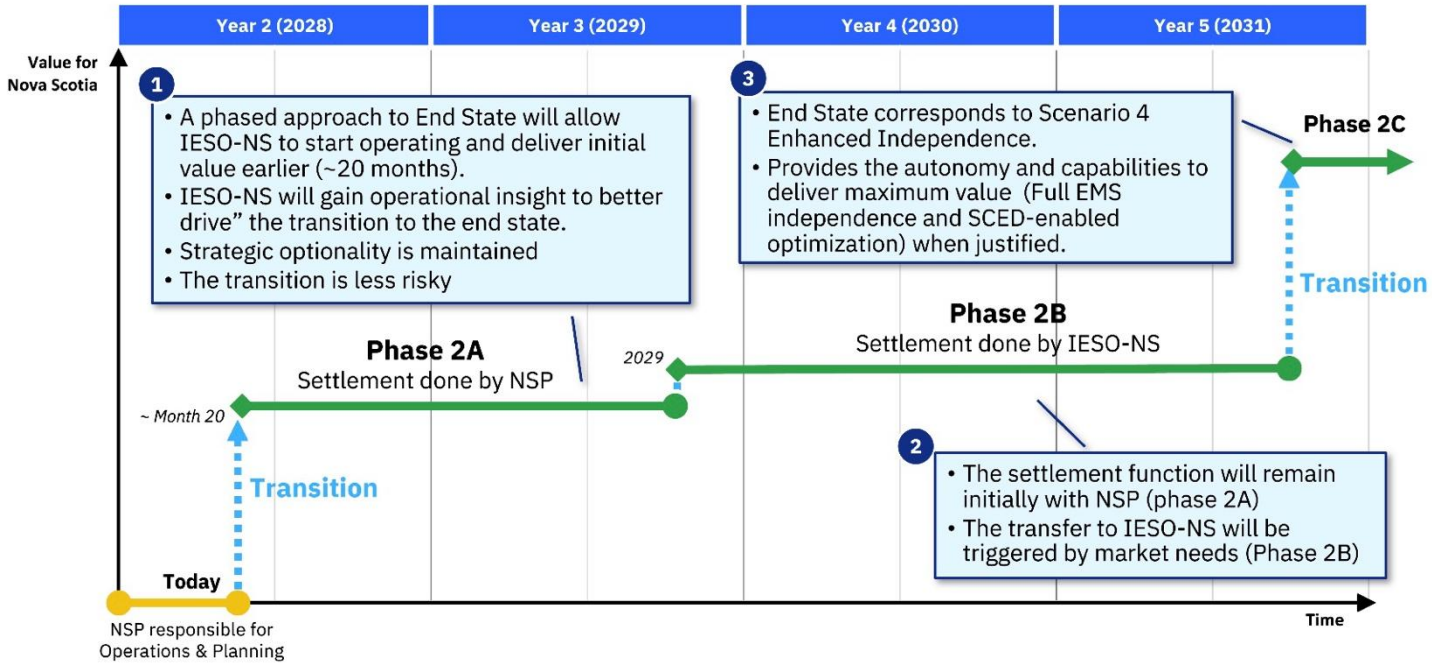


Fig 2: Phase 2 Implementation Pathway

The Phase 2 program is estimated at $75 million in capital over a five-year implementation period, an expected Class 3 estimate accuracy range of -15% to +20%, and approximately $6.3 million per year in incremental operating costs at full implementation. In IBM's opinion, the expected benefits are substantial: the program is associated with an estimated $219 million net present value, with anticipated annual benefits of approximately $21 million per year from 2029/30, following partial realization of approximately $10 million in 2028/29 after Phase 2A implementation.

In IBM's view, Scenario 4 – Enhanced Independence is the most prudent and defensible path for IESO-NS because it best aligns with the MAEA mandate, supports the public interest, enables meaningful operational independence, and delivers the strongest overall balance of value, reliability, and implementation feasibility.

2. Purpose of this Report

This report has been prepared by IBM for IESO-NS to provide a clear recommendation on the preferred strategic approach for Phase 2 of the transition of BA and TOP functions from NSP to IESO-NS.
The report is intended to serve as a stand-alone, public-facing document that IESO-NS may use for multiple purposes, including:

- internal decision support,
- communication with government,
- communication with external stakeholders, and
- support for future regulatory filings and related proceedings.

This is a report from IBM to IESO-NS that explains the recommendation, the basis for that recommendation, the expected benefits, costs, implementation timing, and the management of risks and reliability through the recommended delivery pathway.

IBM's assessment established:

- the preferred long-term BA/TOP operating model for Nova Scotia as **Strategic Scenario 4 – Enhanced Independence**;
- the justification for selecting this model based on evidence and structured evaluation;
- the recommended **2A / 2B / 2C phased pathway** to achieve the preferred end-state; and
- Phase 2A as the recommended first implementation milestone.

3.Legislative and Strategic Context

Phase 2 represents the final step in the transition of operating responsibilities from NSP to IESO-NS, as required under the 2024 *More Access to Energy Act*. Following Phase 1 operations, the focus of Phase 2 is to establish independent operational control in a manner that protects system reliability, optimizes cost and implementation risk, and creates demonstrable value for Nova Scotians.

The MAEA creates both a legislative requirement and a strategic opportunity. IESO-NS must assume independent operational responsibilities. However, the transition can be implemented in a way that improves transparency, supports future system evolution, and generates a positive business case for customers.

IBM's work was undertaken in this context. The objective was not simply to transfer functions mechanically, but to identify the best approach for Nova Scotians to implement the direction of the MAEA. This required balancing legislative compliance with prudence, affordability, operational feasibility, and long-term value.

Phase 2 is therefore more than a compliance exercise. It is a foundational structural change in how Nova Scotia's electricity system will be operated going forward. The recommended model must satisfy the legislative requirement for independence while also supporting reliability, stakeholder confidence, and future readiness.

4. IBM Mandate and Assessment Approach

IBM was engaged to assess long-term operating model options for Phase 2 and recommend the most appropriate model and pathway for implementation. The work was supported by a parallel independent value case analysis prepared by FTI Consulting, which informed the assessment of benefits and long-term value.

The work undertaken in early 2026 involved understanding the operating landscape, mapping out the available options, assessing their costs and benefits, and selecting and developing the best approach for Nova Scotians. The recommendation was the product of a comprehensive strategic assessment and full evaluation of the merits, costs, risks, and benefits of the available options.

To achieve an objective and evidence-based recommendation, IBM developed a structured multi-criteria decision analysis framework that assessed each strategic scenario against technical, operational, financial, regulatory, and strategic criteria. The framework was designed to evaluate not only operational feasibility and reliability, but also the degree to which each scenario supported legislative objectives, implementation practicality, and long-term value for Nova Scotians. The resulting assessment methodology and weighting structure are illustrated in Fig 3 below.

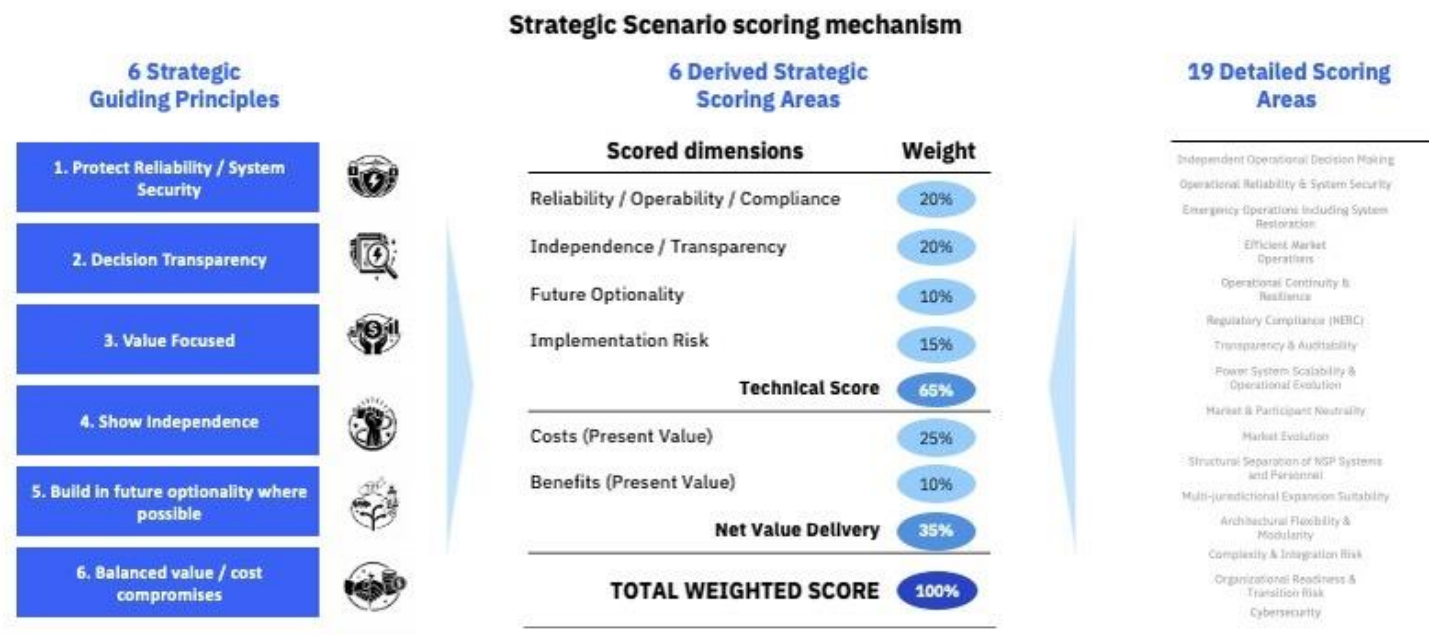


Fig 3: Strategic Scenario Scoring Mechanism

The detailed assessment categories presented in Fig. 3 were grouped into a smaller number of overarching evaluation themes to support comparison of the strategic scenarios. These overarching themes reflect the principal considerations that informed IBM's recommendation and provide a simplified view of the broader assessment framework. The detailed scoring areas shown in Fig. 3 contribute collectively to the evaluation of:

- system reliability,
- cost-effectiveness,
- value for Nova Scotians,
- regulatory compliance, and
- alignment with legislative direction

While Fig. 3 presents the detailed scoring criteria used during the evaluation process, these criteria were ultimately grouped into the five overarching themes used consistently throughout this report: Reliability, Operability and Security criteria informed the assessment of system reliability. Compliance criteria informed the assessment of regulatory compliance. Independence and Transparency criteria informed the assessment of alignment with legislative direction. Future Optionality and Implementation Risk criteria informed the assessment of value for Nova Scotians. Cost and Benefit criteria informed the assessment of cost-effectiveness.

4.1. Strategic Evaluation Methodology

IBM's strategic scenario assessment utilized a structured multi-criteria decision analysis framework to compare the five operating model options on a consistent basis. Assessment criteria were grouped into the five overarching themes defined above: system reliability, cost-effectiveness, value for Nova Scotians, regulatory compliance, and alignment with legislative direction.

Reliability and operational effectiveness were assigned the highest weighting because maintaining secure and reliable operation of Nova Scotia's electricity system represents the primary responsibility of the BA and TOP functions. Economic value and cost considerations were also incorporated to ensure that the preferred option delivered measurable benefits to Nova Scotians while remaining affordable and practical to implement.

Individual criteria were scored using a standardized scoring scale and then weighted to reflect their relative importance. Technical and operational considerations collectively represented 65% of the total assessment, while value delivery considerations represented 35%. The weighting structure was intentionally designed to prioritize operational outcomes over economic outcomes. Reliability, independence, transparency and implementation considerations were collectively assigned 65% of the assessment because failure in these areas could compromise system security, regulatory compliance, or stakeholder confidence regardless of economic benefit. Costs and benefits represented the remaining 35%, reflecting the need to deliver value for Nova Scotians while ensuring that economic drivers did not outweigh fundamental reliability requirements.

The framework enabled direct comparison of the strategic scenarios and provided a transparent and repeatable basis for identifying the preferred operating model.

This approach was intended to demonstrate that the recommended option was not simply technically possible, but also prudent, defensible, and appropriate in the context of Nova Scotia's electricity system and public policy objectives.

Based on this structured assessment methodology, IBM considers the resulting recommendation to be evidence-based, technically sound, and appropriate for IESO-NS's long-term operational requirements.

5. Options Assessed

The assessment considered five operating model options. IBM evaluated these scenarios using a structured assessment framework (described in Section 4) that combined technical and operational criteria with value delivery considerations. Technical score accounted for 65% of total weighting and value delivery accounted for 35%. The resulting strategic scenario scoring showed Scenario 4 – Enhanced Independence achieving the highest total weighted score among the assessed options. This matters because IBM's recommendation is not simply judgment-based; it is grounded in a structured comparative assessment of alternatives and supported by the scenario scoring results.

Scenario 1 - IESO Lite

Scenario 1 represents the lowest-independence model. Under this approach IESO-NS would perform planning, monitoring and advisory functions while NSP retained responsibility for real-time BA and TOP operations. No independent control centre or operational systems would be established. While relatively low cost and simple to implement, this scenario does not satisfy long-term objectives for operational independence, transparency, or direct operational accountability.

Scenario 2 - Shared Operations

Scenario 2 achieves a faster transition by leveraging NSP's existing operational systems and control room infrastructure. IESO-NS personnel would utilize shared systems and facilities, minimizing implementation cost and timeline but retaining substantial operational, cyber and governance dependencies on NSP. While technically feasible, this model limits future flexibility and independence.

Scenario 3 - Minimum Independence

Scenario 3 introduces an independent IESO-NS control room while continuing to utilize NSP-hosted EMS and SCADA environments. This model improves physical separation and organizational independence but continues to rely on key operational and cyber dependencies. As a result, independence objectives are only partially achieved.

Scenario 4 - Enhanced Independence

Scenario 4 introduces an independent EMS environment, enhanced operational optimization capabilities, stronger cyber segregation and greater operational autonomy. It delivers a level of independence sufficient to support the long-term legislative intent of the MAEA while avoiding the implementation complexity associated with a full wholesale market model.

Scenario 5 - Full Market Operations

Scenario 5 builds upon Scenario 4 by introducing a full Market Management System, real-time market operations and day-ahead market functionality. While this option maximizes market capabilities, it also carries significantly greater cost, delivery complexity, organizational change requirements and implementation risk.

At a high level, the options represented different approaches to the degree of operational independence, the scope of independent capabilities, and the pathway by which IESO-NS would assume responsibility for BA and TOP functions. The purpose of the assessment was to identify the model that best balanced statutory compliance, system reliability, implementation feasibility, and long-term value. The five strategic scenarios represented progressively different operating models and capability levels, as summarized in Figure 4.

Strategic Scenarios	1 IESO-Lite Near-term planning role only	2 Shared Operations Shared facilities and systems	3 Minimum Independence Limited tactical investments	4 Enhanced Independence Enhanced Capability	5 Full Market Operations Fit for future market evolution
Control Centre Facility	NSP Operates	Ragged Lake (RAL)	Atlantic Data Centre (ADC)	ADC	Purpose built Control Room
EMS/SCADA	NSP Operates	Current SCADA and EMS shared	Current SCADA & EMS shared	Current SCADA shared EMS owned by IESO	Independent SCADA & EMS - new vendor selection
Dispatch / redispatch	Day ahead – NSP dispatches based on rules set by NS-IESO	Dispatch by IESO based on improved rules in recently deployed NSP optimizer (ECCPO)	Dispatch by IESO based on improved rules in recently deployed NSP optimizer (ECCPO)	Enhance ECCPO (SCED-Lite) to the full extent of its capabilities	Robust SCED implemented combination with other real-time optimization features
Market mechanisms	Generators provides day ahead P x Q pairs	Generators provide P x Q pairs	Generators provide P x Q pairs	Generators provide P x Q pairs	Enabled for wholesale market operation
Other Capabilities	N/A	N/A	Enhance reliability/scalability capabilities to manage more renewables	Further enhance reliability capabilities (potential current vendor limitation)	Further enhance reliability capabilities (no specific vendor limitation)
CAPEX ($) (1)	1.97M (LO) / **2.6M (MID)** / 3.68M (HI)	30.83M (LO) / **41M (MID)** / 57.54M (HI)	33.05M (LO) / **44M (MID)** / 62.7M (HI)	51.22M (LO) / **68M (MID)** / 95M (HI)	125.5M (LO) / **167M (MID)** / 234.4M (HI)
Benefits ($) (2)	24M (LO) / **63M (MID)** / 101M (HI)	84M (LO) / **312M (MID)** / 538M (HI)	84M (LO) / **312M (MID)** / 538M (HI)	171M (LO) / **620M (MID)** / 1068M (HI)	312M (LO) / **1068M (MID)** / 1859M (HI)
Timeline	6-12 Months	12-15 Months	15-18 Months	2-3 Years	3-5 Years

(1) Rough Order of Magnitude (ROM). Low and High represents a -25% to +40% Class 4 estimate. IBM Analysis. AFUDC costs included at a 5% rate
(2) Expected benefits were calculated over a 25-year horizon (2026-2050) and expressed in 2025 present value. For consistent comparison across options, benefits were normalized to a 12-year present value basis for the evaluation

Blue text: new or improved capabilities vs previous scenario

Fig 4: Strategic Scenarios Definitions

Tool/Platform Descriptions

1. **Day-ahead P×Q pairs**: This refers to the day-ahead submission of power (P) and quantity (Q) pairs by generators, indicating their planned generation output and associated costs for the next day. These pairs are used for scheduling and dispatch purposes.
2. **SCADA (Supervisory Control and Data Acquisition)**: SCADA is a system used for real-time monitoring and control of industrial processes, including power generation and transmission. It collects data from sensors and equipment, processes it, and provides operators with the information needed to manage the system.
3. **EMS (Energy Management System)**: EMS is a software platform used by utilities to monitor, control, and optimize the performance of the electrical grid. It includes applications for automatic generation control, network modeling, power flow analysis, and contingency analysis.
4. **NSP optimizer (ECCPO)**: ECCPO stands for Economic Capacity and Constraint Portfolio Optimization. It is a tool used by Nova Scotia Power (NSP) to optimize the dispatch of generation resources based on economic and operational constraints.
5. **SCED (Security Constrained Economic Dispatch)**: SCED is a method used to determine the most cost-effective generation dispatch while ensuring the security and reliability of the power system. It takes into account various constraints such as transmission limits and generation availability.
6. **SCED-lite**: SCED-lite refers to a simplified version of SCED that provides basic optimization capabilities without the full complexity of a complete SCED implementation. It is used for initial optimization and dispatch decisions.

Applying the evaluation framework to each scenario demonstrated that Scenario 4 provided the strongest overall balance of value, reliability, implementation feasibility, and legislative alignment, as illustrated in Fig 5.

Strategic scenario scoring results

Scored dimensions	Weight	1 IESO-Lite	2 Shared Operations	3 Minimum Independence	4 Enhanced Independence	5 Full Market Operations
Reliability / Operability / Compliance	20%	1.5	3.0	3.0	4.1	4.5
Independence / Transparency	20%	1.5	2.3	2.9	3.8	4.5
Future Optionality	10%	1.5	1.9	2.3	3.6	2.9
Implementation Risk	15%	4.5	2.8	2.9	2.3	1.5
Technical Score (Weighted)	65%	1.4	1.7	1.8	2.3	2.3
CAPEX Costs (Present Value)	25%	5.0	4.1	4.0	3.4	1.0
Benefits (Present Value)	10%	1.0	2.0	2.0	3.2	5.0
Net Value Delivery (Weighted)	35%	1.4	1.2	1.2	1.2	0.8
TOTAL WEIGHTED SCORE	100%	2.8	2.9	3.0	3.5	3.1
					Highest Scoring Scenario	

Fig 5: Strategic Scenario Scoring Results

In IBM's opinion, Scenario 4 most effectively balances legislative compliance, operational independence, reliability, implementation risk, and long-term value. Moreover, Scenario 4 achieved the highest overall score because it provides the strongest balance across the assessment framework. Lower-independence scenarios achieved lower scores due to continued reliance on NSP facilities, personnel, or operational technology environments. While Scenario 5 offered additional market functionality and future capabilities, the incremental complexity, implementation risk and cost associated with market development reduced its overall attractiveness relative to the legislative requirements currently facing Nova Scotia. Scenario 4 therefore represented the optimum balance between independence, reliability, implementation feasibility, transparency, and long-term value

The assessment concluded that the preferred long-term model should be achieved through a phased pathway rather than a single-step implementation. IBM's recommendation is not only about the ultimate target state, but also about the way that target state should be reached.

5.1. Basis for Scenario Ranking by Assessment Criteria

Building on the scoring results shown in Fig. 5, this section describes the basis for Scenario 4's ranking against each of the five overarching assessment criteria defined earlier in this report.

System Reliability. Scenarios 1 and 2 maintained significant dependencies on NSP systems, facilities and operating arrangements. While these options offered lower implementation complexity, they provided less long-term assurance of independent operational capability and reduced flexibility for future evolution. Scenario 4 achieved the strongest balance between operational independence and reliable system operation by establishing independent operational capabilities while maintaining a practical and phased implementation pathway.

Regulatory Compliance and Alignment with Legislative Direction. The assessment considered the extent to which each scenario provided clear operational accountability, separation from NSP, auditability of

operational decisions, and the degree to which it supported the objectives of the More Access to Energy Act — including the establishment of a demonstrably independent system operator capable of assuming BA and TOP responsibilities. Scenario 4 performed strongly against these criteria because it establishes independent control centre operations, stronger cyber and operational separation, and enhanced governance transparency, and was assessed as providing the most durable and credible alignment with legislative objectives while maintaining an achievable, risk-managed implementation pathway.

Cost-Effectiveness. Cost-effectiveness was assessed using the Class 4 planning-level cost, benefit and timeline estimates described in the following section. Scenario 4 was found to deliver the strongest overall balance of cost and value among the evaluated pathway options, avoiding both the limited long-term value of lower-independence scenarios and the disproportionate cost and implementation risk of Scenario 5.

Value for Nova Scotians. While lower-independence options generally required lower initial investment, they provided reduced opportunities for operational optimization and future value realization. Scenario 4 offered the strongest balance between affordability, independence and long-term value creation and therefore achieved the highest overall assessment outcome.

5.1.1 Further Considerations

Beyond the named assessment criteria above, the evaluation was also informed by the broader legislative and policy context established by the More Access to Energy Act and the Strategic Guiding Principles set out by IESO-NS. These provided important context for how the criteria above were interpreted and weighted, but were not scored as a separate, independent criterion.

5.2. Basis of Cost, Benefit and Timeline Estimates

The strategic scenarios were supported by high-level Class 4 planning estimates developed to provide a consistent basis for comparing costs, benefits and implementation timelines across the available options. The estimates were not intended to represent detailed project budgets, but rather to provide sufficient accuracy to support strategic decision-making and scenario evaluation.

For each scenario, IBM developed cost estimates using a capability-based assessment approach. Required capabilities were decomposed into major workstreams including control centre facilities, NERC compliance, EMS and SCADA systems, cybersecurity, dispatch optimization, forecasting, outage coordination, telecommunications, market systems, data and analytics, and program integration activities. Capital costs were estimated using a combination of vendor information, NSP-provided cost information, IBM estimates, analogous utility projects and planning-level implementation assumptions. Where specific vendor pricing was not yet available, placeholder or rough-order-of-magnitude estimates were used and identified accordingly.

Examples of cost sources used in the development of the estimates included:

- NSP-provided information for EMS transfers, dispatch optimization tools, telecom assets and operational support arrangements.
- Vendor and product-based estimates for forecasting systems, outage management capabilities and historian platforms.
- IBM effort-based estimates for system integration, cybersecurity implementation, NERC compliance activities, facility design and program delivery services.
- Control centre facility estimates based on identified hardware, workstation, video wall, server, construction and commissioning requirements.

Benefit estimates were developed independently by FTI Consulting and incorporated into IBM's quantitative assessment methodology. The FTI analysis quantified expected system benefits associated with increasing levels of operational independence and optimization capability.

Implementation timelines were developed based on the complexity and sequencing requirements associated with each capability area. Factors considered included facility readiness, procurement lead times, EMS deployment activities, NERC compliance obligations, cybersecurity implementation requirements, operational testing and workforce readiness.

6. IBM Recommendation: Scenario 4 – Enhanced Independence

IBM recommends that IESO-NS adopt **Scenario 4 – Enhanced Independence** as the preferred long-term operating model for Phase 2.

IBM's assessment is that Scenario 4 as the preferred long-term operating model provides IESO-NS with the comprehensive independent capabilities necessary to fulfill its legislative mandate, optimize system outcomes, and deliver sustained value to Nova Scotians.

Scenario 4 is the model under which IESO-NS establishes the operational independence necessary to assume BA and TOP functions in a durable and credible way. It is not a temporary or minimal compliance model. It is a long-term operating model intended to provide:

- genuine operational independence,
- the capability foundation needed for IESO-NS to perform its statutory role,
- improved transparency and accountability in system operations, and
- a platform for long-term value creation.

The recommendation of Scenario 4 is based on the comparative assessment of all five strategic scenarios using the evaluation framework described in Section 4. While multiple scenarios were found to be technically feasible, Scenario 4 consistently achieved the strongest overall balance across reliability, operational independence, legislative alignment, implementation feasibility, and long-term value considerations. Compared with lower-independence scenarios, Scenario 4 provides a more sustainable and credible operating model for IESO-NS. Compared with more extensive independence scenarios, it achieves many of the same strategic objectives while reducing implementation complexity, cost, and delivery risk.

In IBM's view, Scenario 4 is preferred for five principal reasons as follows, as derived from the outcome of its analysis and scoring as described in Section 5 above:

- **Legislative Alignment** - Scenario 4 best supports the legislative intent of the MAEA by establishing a genuinely independent operator rather than a more limited or transitional construct.

- **Reliability and Operational Credibility** - Scenario 4 provides the capability depth required for IESO-NS to perform its operational role credibly and safely over the long term. This is particularly important given that Phase 2 concerns real-time operation and the transfer of core reliability functions.

- **Independence and Transparency** - Scenario 4 improves transparency and independence in system operation. The transition is intended not only to shift responsibilities, but to do so in a way that enhances confidence in how system decisions are made.

- **Long-Term Value** - Scenario 4 is associated with a positive long-term business case. The expected benefits materially exceed the incremental costs, supporting the view that the transition can create net value for Nova Scotians rather than merely impose compliance costs.

- **Feasible Phased Delivery** - Scenario 4 can be implemented prudently through a staged pathway that manages risk and allows lessons learned in early phases to inform later decisions.

7.Recommended Delivery Pathway: Phase 2A / 2B / 2C

IBM recommends that Scenario 4 be implemented through a phased **2A / 2B / 2C** delivery pathway. This phased approach is central to the recommendation. It allows IESO-NS to progress toward the preferred long-term end-state while managing implementation complexity, preserving reliability, and creating decision points before committing to subsequent stages.

The recommended pathway is organized around two operating steady states. Steady State 1 comprises Phase 2A and Phase 2B and represents the first viable independent operating model for IESO-NS, designed to deliver the earliest practical transfer of BA/TOP responsibilities while prudently leveraging selected NSP-hosted or shared systems to accelerate readiness and avoid unnecessary duplication of infrastructure. Steady State 2 corresponds to Phase 2C and represents the completion of the long-term Scenario 4 target model, building on the independent operating capability already established in Steady State 1 to deliver additional technology resilience, cybersecurity segregation, and operational flexibility.

As demonstrated in Fig 6, each phase of the recommended implementation pathway delivers a distinct set of capabilities while progressively reducing implementation risk and increasing operational maturity.



Fig 6: Definition of each phase

Phase 2A – Operational Control is the foundation. It establishes IESO-NS as an independent operator with its own control centre and the core capabilities needed to monitor, dispatch, and operate the Nova Scotia electricity system on a day-to-day basis. At this stage, IESO-NS takes over real-time operational control, while some supporting functions such as settlement temporarily remain with NSP.

Phase 2B – Settlement Capabilities adds the commercial layer. Once IESO-NS is operating the system, Phase 2B establishes independent settlement capabilities, meaning IESO-NS can manage the financial and commercial transactions that flow from system operation. This phase also strengthens forecasting, outage coordination, and participant-facing processes, giving IESO-NS the tools to interact with market participants on a fully independent basis.

Phase 2C – Enhanced Independence builds on the independent operating and settlement capabilities already established in Phases 2A and 2B. It introduces an independent Energy Management System and enhanced dispatch optimization, delivering additional operational flexibility, cybersecurity resilience, and

technical capability. This phase is focused on maximizing long-term value and adaptability to future changes in Nova Scotia's energy system — independence itself is achieved through Phases 2A and 2B, not through Phase 2C.

The overall implementation roadmap in Fig 7 illustrates the sequencing of the three phases and the planned realization of operational capability over time.

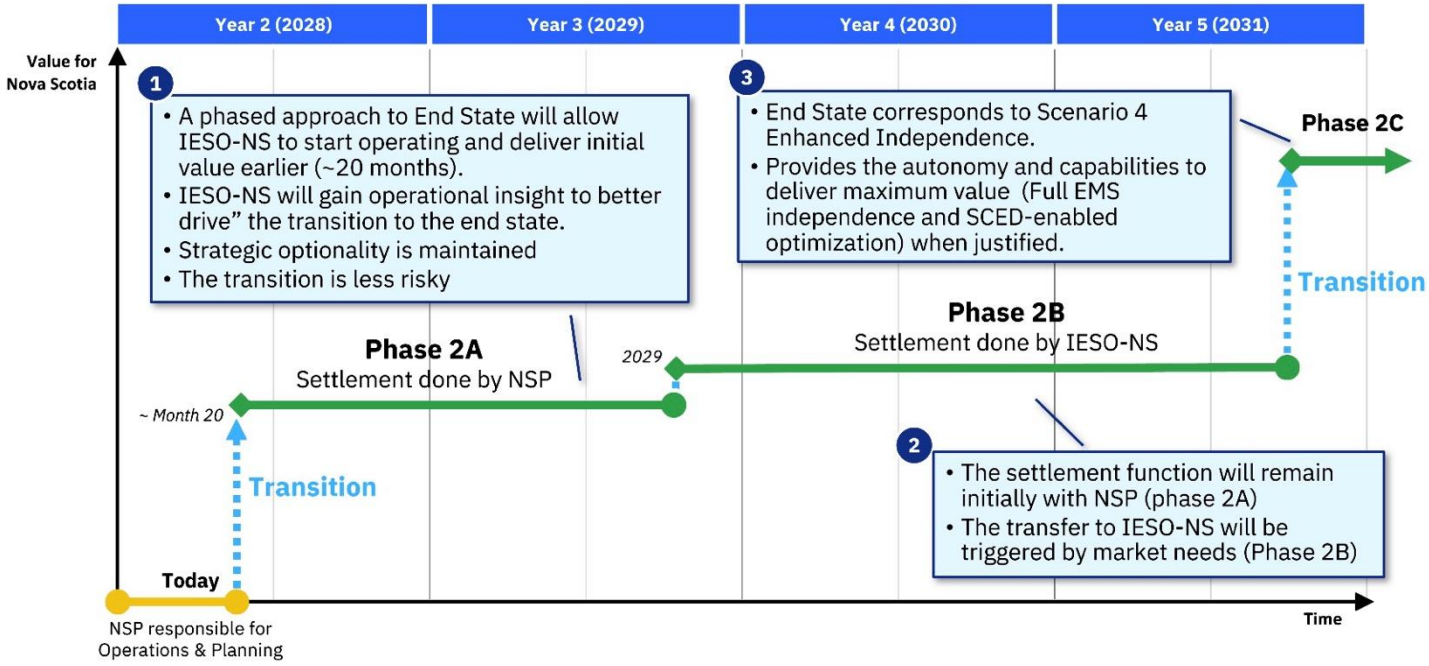


Fig 7: Roadmap Overview

7.1. Phase 2A

Phase 2A is the first phase within Steady State 1, and is the recommended first implementation milestone and a credible initial operating step for IESO-NS. Steady State 1 is intended to establish operational independence while prudently leveraging selected NSP-hosted or shared systems to accelerate readiness and minimize unnecessary duplication of infrastructure. Its objectives are to enable safe and compliant BA/TOP operations in a near-term achievable configuration, establish credible operational independence through an IESO-NS control room and clear decision-making authority, and deliver early value to Nova Scotians by beginning independent operations in alignment with legislation.

In practical terms, Phase 2A establishes IESO-NS' first independent operational capability. It enables IESO-NS personnel to operate and dispatch the provincial electricity system from an IESO-NS control room while leveraging selected NSP-hosted systems during the transition period. This phase delivers the core capabilities required to perform BA and TOP functions safely and reliably, creates a clear separation of operational decision-making authority, and enables the first realization of benefits associated with independent operation.

7.1.1. Rationale for Shared, Transferred and Newly Built Components

The Steady State 1 operating model was intentionally designed to balance operational independence, reliability, cost, and implementation risk. As a result, not all capabilities are treated equally. Components were categorized as shared, transferred, or independently established (newly built) based on asset

ownership, operational requirements, implementation complexity, and the ability to achieve the legislative objectives of the More Access to Energy Act in a practical and cost-effective manner.

7.1.1.1. Shared Components

Shared components are capabilities where NSP continues to provide infrastructure, technical support, or hosting services during the transition period. These arrangements reduce implementation cost and schedule risk while allowing IESO-NS to assume operational authority. For example, SCADA capability is expected to remain shared because NSP continues to own and operate significant transmission infrastructure and associated telemetry systems. Sharing these capabilities avoids unnecessary duplication of assets while preserving operational effectiveness.

7.1.1.2. Transferred Components

Transferred components represent capabilities currently operated by NSP that are required for IESO-NS to exercise independent operational responsibility. These capabilities are transferred where direct operational control is necessary to support the BA and TOP functions and where ownership transfer is more effective than creating entirely new systems.

7.1.1.3. Newly Built Components

Newly built components are new capabilities established directly within IESO-NS to support operational decision-making, governance, compliance, and control room operations. These capabilities form the foundation of IESO-NS' independent operating model.

Fig 8 below illustrates the technology operating model for Steady State 1, with most of the OT components either shared with NSP or transferred from NSP.

Base capabilities	Option selected for this capability	Component
SCADA & Monitoring	Share	The system is built around a core SCADA platform for real-time monitoring, control, and visualization. Supporting subsystems include OPEN SCADA for telemetry acquisition and data processing, OPEN AAR for alarm and event management, OPEN TREND for high-resolution real-time and historical trending, OPEN HIS for short- and medium-term data storage and retrieval, and OPEN CALC for real-time calculated and derived telemetry.
Energy Management System (EMS) including Training & Simulation	Share / Transfer	Key reliability applications include OPEN AGC for automatic generation control and interchange management, OPEN NET for network-model-based operational computations, and the NTP for determining real-time system topology. Power system analysis is supported by the Power Flow engine, the State Estimator for producing the most accurate operating snapshot, and the Contingency Analysis engine for evaluating the impacts of potential outage scenarios. The software platform will be shared (separate partitions, technical support by NSP). Although commercial ownership of the EMS SW asset will remain with NSP, business ownership of the system will be transferred to IESO-NS
ECC Optimization Tool Dispatch / Redispatch	Transfer	ECC Optimization Tools from Hitachi (2Q 2026) + ServiceNow workflows
Market Management	Transfer	Part of the ECC tool + web portal
Operational Forecasting	Transfer	SaaS-based Truepower - UL is used for wind forecasting and comes in as an external data feed ENVERUS – SaaS-based forecasting service providing load, generation, fuel, and market analytics.
Intertie Management	Transfer	OATI Interchange Energy Flow Scheduling (IEFS) is used for interchange energy flow scheduling and e-tagging and is cloud-based.
Outage Coordination	Share	Sun-Net iTOA is used for integrated transmission outage coordination. Specifically iTOA is used for receiving outage requests as well as approvals. The actual systems studies are done using PSSE etc.
Training Systems	Share	Qlarity is used for NERC compliance training and audit support, and is cloud based.
Settlement	Transfer	Spreadsheets with ServiceNow workflow. It will be initially managed by NSP (phase 2B) and then transferred to IESO-NS (phase 2B) when direct participants require independent settlement.
Reporting	Build new (base)	New base reporting capabilities to be created.

Figure 8: Steady State 1- Components Required

The target implementation date for Phase 2A is March 2028. This timing is intended to support orderly cutover planning and the realization of early benefits. Phase 2A was assessed as a credible first milestone because it focuses on establishing the minimum set of people, processes, facilities, governance arrangements, and technology capabilities required for independent operation, while avoiding the need to immediately replace all NSP-supported systems. By leveraging selected existing infrastructure during the transition period, IESO-NS can achieve operational independence earlier, reduce implementation complexity, minimize capital expenditure, and lower cutover risk. The phased approach also allows operational experience and lessons learned during Phase 2A to inform subsequent implementation decisions.

7.2. Phase 2B

Phase 2B remains within Steady State 1. It introduces additional independence and transparency enhancements without changing the core operating model. Phase 2B addresses the establishment of commercial arrangements under IESO-NS operation of Nova Scotia's electricity system. These enhancements include independent settlement capability, participant workflows, market interfaces,

reporting processes, and expanded internal support capabilities. In other words, Phase 2B establishes the business and commercial capabilities needed for IESO-NS to independently administer and support operation of Nova Scotia's electricity system. While Phase 2A focuses on operating and dispatching the system safely, Phase 2B focuses on the processes that support participants interacting with the system, including settlements, reporting, information exchange, and operational administration. These capabilities are necessary to ensure that IESO-NS can independently perform both its operational and commercial responsibilities in a transparent and accountable manner.

Phase 2B increases operational independence by transitioning a number of commercial and market support activities from NSP-operated processes to IESO-NS-operated processes. This includes establishing IESO-NS-controlled settlement capabilities, participant communications, reporting functions, and supporting business processes. These changes improve transparency by allowing market participants, regulators and government stakeholders to interact directly with IESO-NS and providing clearer accountability for system operation and associated commercial activities.. There is more flexibility in the timing of Phase 2B because implementation is dependent on stakeholder consultation and decision-making activities associated with the development of commercial arrangements. These activities may include engagement with market participants, government representatives, regulators, and other affected organizations to define settlement processes, reporting obligations, commercial interfaces, governance arrangements, and implementation requirements.
The current planning information identifies capital of $8 million for Phase 2B. Phase 2B will proceed subject to a formal decision gate review following the successful completion of Phase 2A.

7.3. Phase 2C

Phase 2C corresponds to Steady State 2, which represents the completion of the long-term Scenario 4 target model. Steady State 2 builds on the independent operating model already delivered in Steady State 1, extending it with additional technology resilience, cybersecurity segregation, and operating environment enhancements.

Steady State 1, comprising Phases 2A and 2B, establishes the operational and commercial capabilities required for IESO-NS to assume its BA, TOP, and associated market administration responsibilities. It represents the first sustainable operating model capable of supporting independent operation of Nova Scotia's electricity system.

Steady State 2, delivered through Phase 2C, extends this foundation by introducing additional technology independence, cybersecurity segregation, operational flexibility, and advanced system capabilities. While Steady State 1 enables IESO-NS to meet its core responsibilities, Steady State 2 provides a longer-term target operating model designed to support future system complexity, increased operational maturity, and Nova Scotia's evolving energy transition requirements.

As illustrated in Fig 9 below, Steady State 2 includes deployment of an independent EMS capability, stronger OT/IT separation, expanded data and historian environments, enhanced dispatch optimization tools, and reduced dependency on NSP-hosted infrastructure. It is intended to position IESO-NS for a more complex future grid and to support Nova Scotia’s long-term energy transition.

Strategic Scenario #4 Base capabilities	Option selected for this capability	Component
SCADA & Monitoring	Same as Steady State 1	Same as in Scenario #3. The system is built around a core SCADA platform for real-time monitoring, control, and visualization. Supporting subsystems include OPEN SCADA for telemetry acquisition and data processing, OPEN AAR for alarm and event management, OPEN TREND for high-resolution real-time and historical trending, OPEN HIS for short- and medium-term data storage and retrieval, and OPEN CALC for real-time calculated and derived telemetry.
Energy Management System (EMS) including Training & Simulation	Transferred from NSP and fully operated by IESO-NS	Key reliability applications include OPEN AGC for automatic generation control and interchange management, OPEN NET for network-model-based operational computations, and the NTP for determining real-time system topology. Power system analysis is supported by the Power Flow engine, the State Estimator for producing the most accurate operating snapshot, and the Contingency Analysis engine for evaluating the impacts of potential outage scenarios.
ECC Optimization Tool Dispatch / Redispatch	Enhanced capabilities vs. Steady State 1	ECC Optimization Tools from Hitachi (2Q 2026) + ServiceNow workflows. SCED capabilities will be enhanced to what is possible within the ECCPO tool limitations
Market Management	Enhanced capabilities vs. Steady State 1	Will be enhanced as required by market needs.
Operational Forecasting	Enhanced capabilities vs. Steady State 1	Truepower - UL for wind forecasting; ENVERUS – forecasting service providing load, generation, fuel, and market analytics. Will be enhanced as required to cope with increased volatility.
Intertie Management	Enhanced capabilities vs. Steady State 1	OATI Interchange Energy Flow Scheduling (IEFS) – with integration with SCED
Outage Coordination	Enhanced capabilities vs. Steady State 1	Sun-Net iTOA with no more shared partition
Training Systems	Same as Steady State 1	QTS (Quality Training Systems) is used for NERC compliance training and audit support, and is cloud based.
Settlement	Enhanced capabilities vs. Steady State 1	A new settlement system will be procured and implemented for phase 2B, keeping in line with the market rules
Reporting	Enhanced capabilities vs. Steady State 1	Enhancements around data analysis capabilities.

Figure 9: Steady State 2- Components Required (green indicated key change from Steady State 1)

The current planning information identifies capital of $26 million for Phase 2C, with indicative timeline references to 2030/31. Phase 2C will likewise proceed subject to a formal decision gate review following Phase 2B completion.

7.4. Why the Phased Pathway is Preferred

The phased pathway is recommended because it supports prudency in three ways:

1. It enables IESO-NS to establish an initial credible operating capability before full build-out;
2. It allows early value to begin being realized after Phase 2A; and
3. It creates natural decision gates between phases, allowing cost, performance, risk, and readiness to be reassessed before proceeding further.

This approach is particularly important given that Phase 2 affects real-time operational control and must therefore be implemented with a high degree of care. Steady State 1 enables IESO-NS to assume statutory responsibilities early through a practical and lower-risk operating model, while Steady State 2 provides a clear pathway to the full future-state system operator model when justified by economics and system needs. By adopting this phased approach, IESO-NS can achieve early independence, protect reliability, manage costs responsibly, and preserve the option to build a modern, future-ready system operator over time.

8. Expected Benefits and Value Case

Phase 2 is expected to create meaningful long-term value for Nova Scotians. The expected benefits are approximately $219 million NPV, with an annual run-rate of approximately $21 million for 2A and 2B plus an additional $20 million in 2C, substantially exceeding incremental annual operating costs of approximately $6 million plus amortized capital costs. This NPV calculation is detailed in the IBM NPV calculation model, which is included as Appendix A of this report. The benefits figures are derived from the independent value case analysis prepared by FTI Consulting, which informed the assessment of long-term value and benefits. For further details on the value case, please refer to FTI Consulting's findings report.

Once Phase 2A is in service, IESO-NS expects to realize approximately half of the overall steady-state annual benefits, or about $10 million, during the 2028/29 period, with full annual benefits of $21 million (Phase 2A) anticipated from 2029/30 onward.

Figure 10 brings together the expected implementation timeline, estimated costs, and anticipated benefits across the three phases of the recommended program.

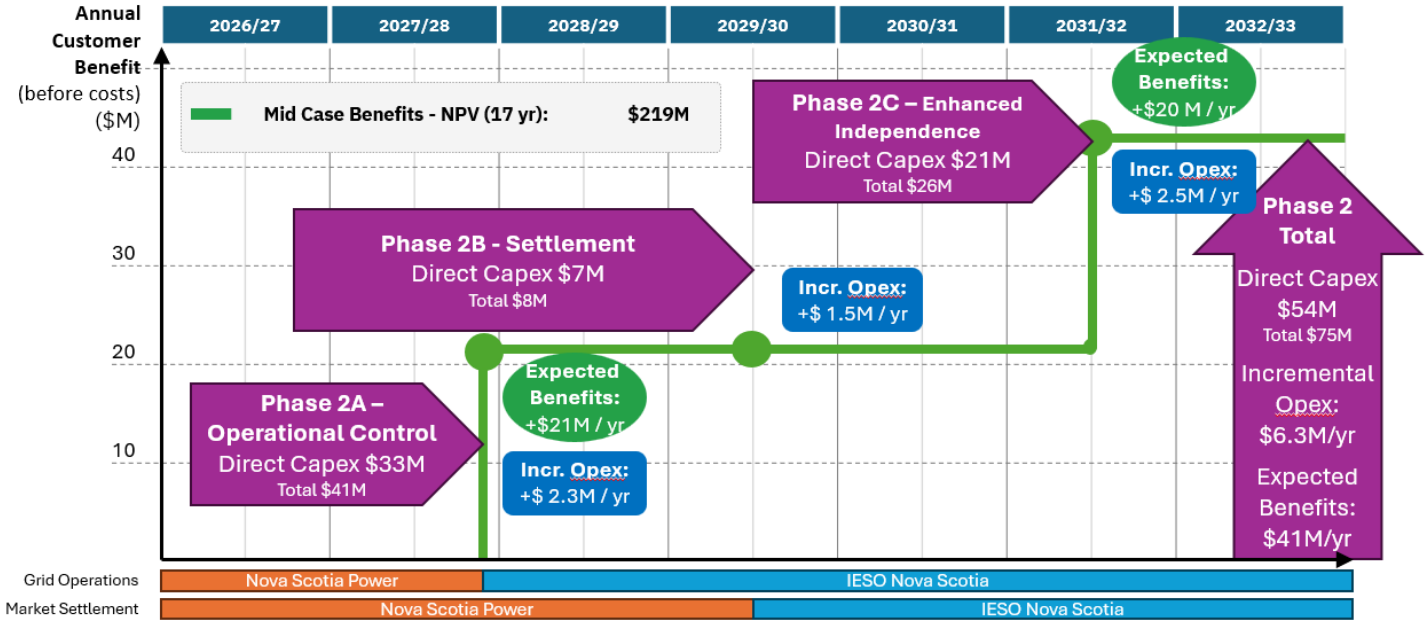


Fig 10: Phase 2 three stage implementation summary including estimated timeline, costs, and expected benefits

By developing both the costs and the potential benefits of Phase 2, it is clear there is an opportunity not only to meet the legislative requirements but to do so with a positive business case demonstrating net anticipated benefit for customers.

For purposes of this report, the most important conclusions from the value case are:

- the expected benefits are material;
- they begin to emerge following Phase 2A;
- they reach a meaningful steady-state annual level from 2029/30; and
- they support a positive long-term economic case for the recommended pathway.

IBM considers the value case to provide strong economic support for the recommended pathway, with expected long-term benefits materially exceeding the incremental costs of implementation.

8.1. Timing of Delivery and the Value of Early Wins

The current plan targets March 2028 for implementation of Phase 2A. This timing matters because Phase 2A is the first credible operational milestone and the point at which benefits are expected to begin to materialize.

The value of early delivery is clear in the planning assumptions:

- approximately $10 million of benefits are expected in 2028/29, reflecting partial-year operation following implementation of Phase 2A during that fiscal period and the assumption that only a portion of annual benefits are realized during the first year of operation; and
- approximately $21 million per year of benefits (Phase 2A) are expected from 2029/30 onward.

A distinction is made between new investment required to deliver Phase 2 and assets or costs that transfer from NSP as part of the transition.

This supports the case for moving forward in a timely but controlled way. Delays to Phase 2A would defer the transition to the recommended operating model and postpone the realization of the associated economic and operational benefits. Depending on the duration and nature of the delay, additional costs could also arise from extended program delivery activities, prolonged transition arrangements, and rescheduling of implementation resources.

At the same time, the phased structure establishes that timing does not come at the expense of prudency. Phase 2A is positioned as the initial milestone because it allows IESO-NS to move forward responsibly while preserving the ability to stage more complex and capital-intensive elements in later phases.

9.Cost Summary

The Phase 2 program is estimated at $75 million over a five-year implementation period.
The cost summary is as follows:

- Total Capital Cost: $75 million
- Incremental Operating Cost: approximately $6.3 million per year

Phase-specific cost amounts are as follows:

- Phase 2A: total phase capital cost of $40.9 million; incremental operating cost of $2.3 million per year
- Phase 2B: total phase capital cost of $8 million; incremental operating cost of approximately $1.5 million per year
- Phase 2C: total phase capital cost of $26 million; with expected additional benefits of approximately $20 million per year upon completion and incremental operating cost of approximately$2.5 million per year

The estimated program costs are summarized in Fig 11 below, illustrating both the total investment and the allocation across each implementation phase.

	(All costs in $M)	Total	Phase 2A	Phase 2B	Phase 2C
CAPEX	IT Costs	$ 20.7	$ 0.8	$ 5.9	$ 13.9
	Program Integration	$ 11.3	$ 9.0	$ 1.0	$ 1.4
	Control Center Build	$ 9.0	$ 9.0	$ -	$ -
	NERC Compliance (process & documentation)	$ 6.4	$ 6.4	$ -	$ -
	Cyber Security	$ 4.6	$ 1.4	$ -	$ 3.2
	NSP Support Costs	$ 5.7	$ 4.2	$ -	$ 1.5
	Other	$ 2.8	$ 2.0	$ -	$ 0.9
	Direct Capex	**$ 60.5**	**$ 32.8**	**$ 6.9**	**$ 20.9**
	Contingency (15%)	$ 9.1	$ 4.9	$ 1.0	$ 3.1
	Capitalized Interest	$ 5.8	$ 3.2	$ 0.2	$ 2.4
	Total Capex – Mid Case	**$ 75.4**	**$ 40.9**	**$ 8.1**	**$ 26.4**
	Total Capex – Low Case (-15%)	$ 64.1	$ 34.8	$ 6.9	$ 22.5
	Total Capex – High Case (+20%)	$ 90.5	$ 49.1	$ 9.7	$ 31.7
OPEX	Incremental Opex	$ 6.3	$ 2.3	$ 1.5	$ 2.5
	NSP Opex Transfer (Not Incremental)	$ 9.9	$ 9.5	$ -	$ 0.4
	Total Opex	**$ 16.2**	**$ 11.8**	**$ 1.5**	**$ 2.9**

Fig 10 – Summary of Phase 2 implementation and on-going Opex costs

The Phase 2 program has been prepared as a Class 3 Budgetary Estimate, with an expected accuracy range of -15% to +20%. This is important and means the figures presented are sufficiently developed to support strategic decision-making but remain subject to the normal variation associated with planning-level estimates of this class.

Back-up for each cost category is provided as follows, explaining how the estimate was determined and what it is based on:

1. IT Costs:

- **Description**: Assumes the configuration of shared platforms (EMS, etc.), transferred platforms, communications, interfaces, and other IT tools. This includes shared or partitioned EMS and SCADA environments, telemetry, and historian systems where continued sharing with NSP delivers the best outcome for Nova Scotian ratepayers, as well as newly built systems required exclusively for IESO-NS.
- **Basis:** The estimate for IT costs is based on vendor quotes, NSP estimates, benchmarks from similar projects, and professional judgment.
- **Data Sources:** Vendor quotes, NSP estimates, industry benchmarks, and past project data.

2. Program Integration:

- **Description:** Includes program management, design authority, process, change and quality assurance, and program administration. This covers the resources and activities required to coordinate design, delivery, and quality assurance across all Phase 2 workstreams, including vendor and system integrator oversight.
- **Basis:** This estimate is derived from a bottom-up approach, considering the detailed design and work packages, and professional judgment.
- **Data Sources:** Internal resource planning, external system integrator inputs, and past project experiences.

3. Control Center Build:

- **Description:** Covers the design, construction, fit-out, physical security systems, and commissioning of the IESO-NS control center. This includes the dedicated primary control centre facility and operating workforce environment required for IESO-NS to conduct real-time operational control independently of NSP.
- **Basis:** The estimate is based on analogous estimates from similar control center projects, and professional judgment.
- **Data Sources:** Benchmarks from similar control center builds, and past project data.

4. NERC Compliance (process & documentation):

- **Description**: Includes compliance program and procedures development, audit readiness, and certification activities. This includes the work required for IESO-NS to be certified by NERC/NPCC to assume Balancing Authority (BA) and Transmission Operator (TOP) functions, including documentation aligned to applicable NERC CIP and reliability standard.
- **Basis:** This estimate is based on professional judgment, benchmarks, and analogous estimates from similar compliance projects.
- **Data Sources:** Industry benchmarks, past project data, and professional judgment.

5. Cyber Security:

- **Description**: Covers security architecture, network controls, monitoring, identity management, and required cyber controls. This includes the cybersecurity architecture and controls needed to support IESO-NS's independent operating environment and to satisfy NERC CIP requirements associated with BA/TOP certification.
- **Basis:** The estimate is derived from vendor quotes, benchmarks, and professional judgment.
- **Data Sources:** Vendor quotes, industry benchmarks, and past project experiences.

6. NSP Support Costs:

- **Description**: Includes internal Nova Scotia Power effort supporting transition, handover, and system readiness. This reflects the effort required from Nova Scotia Power to support the transfer or shared operation of relevant systems and knowledge to IESO-NS during implementation.
- **Basis:** This estimate is based on estimates from NSP.
- **Data Sources:** NSP estimates.

7. Other:

- **Description:** Covers internal IESO-NS effort, software licenses, third-party vendor costs for systems to be transferred/shared, training, and miscellaneous implementation items. This category captures costs that do not fall within the other defined categories but are required to complete the scope of Phase 2 implementation.
- **Basis:** The estimate is derived from a combination of vendor quotes, benchmarks, and professional judgment.
- **Data Sources:** Vendor quotes, industry benchmarks, and past project experiences.

8. Contingency (15%):

- **Description**: A 15% contingency is applied to direct capital to absorb estimate variation within the expected Class 3 range. Contingency is applied to direct capital costs only and does not apply to Opex or Capitalized Interest.
- **Basis:** The contingency estimate is based on standard industry practice for Class 3 estimates.
- **Data Sources:** Standard industry practice and professional judgment.

10. Capitalized Interest:

- **Description:** Reflects financing costs associated with capital deployed during the delivery period. This reflects the estimated interest carrying cost on capital expenditures between the point of investment and the point the associated assets become operational.
- **Basis:** The estimate for capitalized interest is based on financial models and professional judgment.
- **Data Sources:** Financial models and professional judgment.

11. Opex Items:

- **Description**: Includes incremental annual operating costs such as staffing, system operating costs, NERC compliance, training, and telecommunications. This reflects the ongoing annual operating costs required to sustain IESO-NS's independent operations once each phase is complete.
- **Basis:** The estimate for Opex items is based on professional judgment, benchmarks, and analogous estimates from similar operational cost structures.
- **Data Sources:** Industry benchmarks, past project data, and professional judgment.

These estimates were developed during the Phase 2 strategic and implementation planning work and were sufficiently robust to support selection of the preferred scenario. They are planning-level numbers and should be interpreted within the stated Class 3 accuracy range of -15% to +20%. As implementation proceeds, estimates will be refined through detailed design, procurement, and execution planning, moving toward Class 2 and ultimately Class 1 precision.

Accordingly, the total proposed cost of $75 million should be understood as being subject to a reasonable planning range, as follows:

- Low-end estimate: approximately $64 million total program cost (reflecting -15% on direct capital)
- High-end estimate: approximately $90 million total program cost (reflecting +20% on direct capital)

This is not unusual for a program at this stage, particularly one involving operational transition, complex systems, governance development, and staged implementation.

The estimated costs are reasonable for a transformation of this scale and are proportionate to the operational capability, legislative compliance, and long-term value expected from the recommended approach.

9.1. Cost Estimation Method and Assumptions

The cost estimates for the Phase 2 program have been developed as a Class 3 Budgetary Estimate as defined by AACE standards. This indicates an estimate developed at a level appropriate for strategic decision-making and program approval, but not yet at final execution precision.

The Phase 2 work consisted of a detailed assessment of the operating landscape, options, costs, and benefits in order to develop a robust, value-for-money approach. The following can be stated with confidence regarding the basis of the estimates:

1. The estimates were developed during the Phase 2 strategic and implementation planning work and were sufficiently robust to support selection of the preferred scenario.
2. They are planning-level numbers and should be interpreted within the stated Class 3 accuracy range of -15% to +20%.
3. As implementation proceeds, estimates will be refined through detailed design, procurement, and execution planning, moving toward Class 2 and ultimately Class 1 precision.

Key assumptions underpinning the cost estimates include:

- Implementation activities are assumed to commence by August 1, 2026;
- Phase 2A target operational date is March 2028, based on a Spring implementation window that avoids winter peak load periods;
- A 15% contingency has been applied to direct capital, consistent with standard industry practice for Class 3 estimates;
- Incremental annual operating costs of approximately $6.3 million reflect staffing plans, system operating costs, NERC compliance, training, and telecommunications;
- Benefit realization is assumed at 50% in the first year following Phase 2A, ramping to full run-rate in 2029/30; and
- Benchmarking to comparable independent system operator implementations, including the Ontario IESO model, was used to validate staffing, systems, and process development requirements.

IBM considers the Class 3 estimate appropriate for a strategic decision of this nature and consistent with accepted practice for programs at this stage of development.

9.2. Incremental Costs and Transfers from NSP

A clear distinction should be drawn between costs that are incremental — representing new investment required to establish independent operational capability — and costs that represent the transfer of existing

responsibilities and associated cost structures from NSP to IESO-NS as part of the legislatively mandated transition.

The Phase 2 program includes both elements:

- Incremental investment is required to establish the independent control centre, operational technology systems, staffing, training, and governance frameworks that do not currently exist within IESO-NS.
- Transferred costs represent functions currently performed and funded within NSP's cost structure that will move to IESO-NS as operational responsibilities transfer.

10. Net Present Value Analysis and Stress Testing

A comprehensive NPV analysis was prepared to assess the economic merit of the Phase 2 program across a range of cost and benefit scenarios.

The key findings are:

- Phase 2 has a positive business case;
- the expected benefits materially exceed the incremental costs;
- the analysis produced an estimated NPV of $219 million over a 17-year assessment horizon; and
- the cost estimates were tested across the Class 3 estimate range of -15% to +20%.

The economic analysis indicates that the recommended pathway delivers a positive long-term financial outcome, as illustrated by the Net Present Value analysis in Fig 11 below.

Net Present Value (NPV) Scenarios	NPV	IRR
Base Case Scenario	**+$219M**	**37%**
High Case (-15% Capex, +30% benefits)	+$328M	54%
Low Case (+20% Capex, -40% benefits)	+$73M	16%
Capex +50%	+$188M	26%
Benefits -50%	+$52M	15%
Capital costs +50% & Benefits -50%	+$21M	8%
Benefits Delayed 2 Years	+$155M	22%
Base Case Scenario – carbon removed	+$182M	33%

Key Assumptions

Base Year: 2026

Timeline: 17 Years

Discount Rate: 5%

Mid case numbers used unless otherwise stated

Fig 11 – Net Present Value (NPV) Analysis

10.1. Financial Assumptions:

Base Year: 2026

In the context of the NPV analysis, "Base Year: 2026" means that the calculations for the NPV are anchored to the year 2026. This implies that all future cash flows, costs, and benefits are discounted back to their present value as of the year 2026. Essentially, 2026 is the reference point from which the financial analysis begins, and all values are adjusted to reflect their worth in that year.

17-Year Analysis Timeline

The NPV analysis is conducted over a 17-year period. This timeline comprises two distinct phases:

1. **Phase 2A Implementation (2 years)**: The first two years are allocated for the implementation of Phase 2A, during which the foundational operational control capabilities are established.
2. **Depreciation Period (15 years)**: Following the implementation phase, a 15-year depreciation period is assumed. This period reflects the useful life of the assets and the timeframe over which the benefits and costs are amortized.

5% Discount Rate

The discount rate used in the NPV analysis is 5%. This rate is applied to discount future cash flows back to their present value, reflecting the time value of money. The 5% rate is chosen based on the assumed cost

of capital, which represents the opportunity cost of investing resources in the project rather than elsewhere. It is a standard rate used to account for the risk and return expectations of the investment.

NPV Scenarios

1. **Mid (Mid-case) Scenario**: This scenario represents the expected or most likely outcome based on reasonable assumptions and estimates. It uses mid-case numbers for costs and benefits, reflecting a balanced view that is neither overly optimistic nor pessimistic.
2. **High Scenario:** This scenario assumes more favorable conditions, including a 15% reduction in capital expenditure (Capex) and a 30% increase in expected benefits.
3. **Low Scenario**: This scenario assumes less favorable conditions, including a 20% increase in Capex and a 40% reduction in expected benefits.
4. **Additional Stress Scenarios**
    - **Capex +50%**: Assumes a 50% increase in capital costs, resulting in an NPV of +$188M and an IRR of 26%.
    - **Benefits -50%**: Assumes a 50% reduction in benefits, resulting in an NPV of +$52M and an IRR of 15%.
    - **Capital costs +50% & Benefits -50%**: Assumes both a 50% increase in capital costs and a 50% reduction in benefits, resulting in an NPV of +$21M and an IRR of 8%.
    - **Benefits Delayed 2 Years**: Assumes a 2-year delay in benefit realization, resulting in an NPV of +$155M and an IRR of 22%.
    - **Base Case Scenario – Carbon Removed**: Assumes the base case scenario with carbon benefits removed, resulting in an NPV of +$182M and an IRR of 33%.

The NPV analysis was stress-tested by flexing both costs and benefits across high, mid, and low scenarios. The stress testing confirmed that:

- the program retains a positive NPV under a range of cost and benefit assumptions; and
- the principal drivers of value are the expected annual benefits commencing after Phase 2A, the timing of benefit realization, and the capital cost of the program.

The overall conclusion of the NPV analysis is that the program presents a sound economic case for proceeding, and that this conclusion is robust across the assessed range of scenarios. The positive NPV across the assessed scenarios provides strong evidence that the recommended pathway represents a prudent long-term investment.

10.2. Potential Cost Risk Areas

The Phase 2 program was designed to optimize cost and implementation risk while protecting reliability. Notwithstanding the positive overall case, the following cost risk areas are identified as warranting particular attention throughout implementation:

Implementation Timing Risk

Delays to Phase 2A would postpone realization of the anticipated benefits and could require adjustments to program schedules, procurement activities, and implementation plans. Any associated cost implications would depend on the duration and nature of the delay.

Program Integration Risk

The transition of core operational functions involves complex integration between IESO-NS systems, NSP legacy infrastructure, and third-party vendors. The full extent of integration complexity may not be fully known until detailed design is underway.

Commercial Arrangements and Market Implementation Risk

Phase 2B includes the implementation of settlement processes, participant interfaces, reporting mechanisms, and other commercial functions required for IESO-NS to administer electricity market and operational arrangements independently. Implementation of these capabilities may require consultation and alignment with generators, transmission-connected customers, market participants, NSP, regulators, and government stakeholders. The timing and outcome of these engagement and approval activities are not fully within IESO-NS' control and could affect the schedule for Phase 2B implementation

Planning Estimate Uncertainty

As a Class 3 estimate, the program cost appropriately carries a -15% to +20% range. This uncertainty is typical of planning-level estimates and should be considered when evaluating the projected program costs and economic outcomes presented in this report.

Labour Market Risk

Skilled power system operators and engineers are in high demand across the electricity sector. Recruitment timelines and compensation requirements may vary from current assumptions.

Technology Procurement Risk

Vendor pricing and availability for operational technology systems, including EMS components, may vary from planning estimates once competitive procurement is underway.

The key point is that the recommended phased pathway is itself a primary risk mitigation strategy. By staging implementation and creating decision gates between phases, the program preserves the ability to respond to emerging risks before they affect the full program.

IBM considers these risks to be manageable through the recommended phased implementation approach and does not regard them as sufficient to outweigh the overall benefits of the recommended strategy.

11. Managing Risks, Costs, and Reliability Through the 2A / 2B / 2C Approach

A central strength of IBM's recommendation is that it does not propose a single-step transition. Instead, it recommends a phased pathway that manages risk, reliability, and cost over time.

Reliability Management

Phase 2 affects core operating responsibilities for the Nova Scotia electricity system. Accordingly, the recommendation emphasizes Phase 2A as a credible first milestone that allows IESO-NS to establish an initial operating capability before progressing further. Specific reliability safeguards embedded in the implementation approach include:

- a Spring 2028 cutover window that avoids hurricane season and winter peak loads;
- parallel operations during the cutover period to allow real-time validation of IESO-NS systems and dispatch decisions before NSP operations are stood down;
- NERC compliance maintained throughout the transition, with compliance readiness as a gate criterion before operational cutover; and
- operator training and certification completed before IESO-NS assumes live operational responsibilities.

Cost Management

A phased pathway allows capital commitments to be sequenced and enables updated information from earlier phases to inform later decisions. This is especially valuable where costs are planning-level and subject to the normal Class 3 range. Specific cost management mechanisms include:

- 15% contingency on direct capital to absorb estimate variation within the expected Class 3 range;
- decision gate reviews between phases that assess actual costs against estimates before authorizing subsequent expenditures; and
- annual reporting of actual vs. forecast expenditure to support ongoing governance.

Decision Gate Structure

The phased approach creates formal checkpoints between phases. At each decision gate, IESO-NS will assess:

- operational performance and reliability outcomes in the preceding phase;
- actual costs against the approved budget;
- benefit realization to date against forecast;
- updated cost and schedule estimates for the subsequent phase;
- risk profile and any new or emerging risks; and
- stakeholder and regulatory readiness.

Phase 2B and Phase 2C will only proceed once these gate criteria have been assessed and authorization obtained. This is a deliberate design feature of the recommendation, not a contingency.

Early Value with Controlled Progression

Phase 2A allows IESO-NS to begin realizing a portion of the anticipated benefits earlier by establishing independent operational control, decision-making authority and the initial operational capabilities required to support BA/TOP responsibilities. Under the planning assumptions used in the business case, benefit

realization commences following Phase 2A implementation and increases as additional capabilities are introduced through subsequent phases.

Additionally, if IESO-NS was to pause implementation after completion of Phase 2A or 2B, the initiative would still have a positive business case. Some additional NPV and sensitivity analysis was performed to validate this assertation and is included below in Figure 12.

Net Present Value (NPV) Scenarios – Phases 2A and 2B	**NPV**	**IRR**
Base Case Scenario	**+$110M**	**30%**
High Case (-15% Capex, +30% benefits)	+$173M	46%
Low Case (+20% Capex, -40% benefits)	+$26M	11%
Capex +50%	+$88	20%
Benefits -50%	+$16M	10%
Capital costs +50% & Benefits -50%	-$6M	4%
Benefits Delayed 2 Years	+$75M	18%
Base Case Scenario – carbon removed	+$96M	27%

Fig 12 – Alternate Net Present Value (NPV) Analysis

12. Conclusion and IBM Recommendation

IBM recommends that IESO-NS proceed with Scenario 4 – Enhanced Independence as the preferred long-term operating model for Phase 2, implemented through a phased 2A / 2B / 2C pathway.

This recommendation is grounded in a structured assessment of options, supported by cost and value analysis, and aligned with the legislative objectives established by the *More Access to Energy Act*.

In IBM's view, this is the preferred approach because it:

- fulfills the requirement to complete the transition to independent operational control;
- provides a credible and prudent long-term model for IESO-NS;
- protects system reliability by sequencing implementation appropriately;
- enables meaningful transparency and independence in system operation;
- delivers positive economic value, including an estimated $219 million NPV and annual benefits of approximately $21 million from 2029/30 onwards; and
- allows benefits to begin earlier through the implementation of Phase 2A.

The phased pathway is a critical element of that recommendation. It provides the practical means by which IESO-NS can achieve the preferred end-state while managing complexity, preserving reliability, and maintaining prudency through staged delivery.

Accordingly, IBM recommends that IESO-NS:

1. adopt Scenario 4 – Enhanced Independence as the long-term Phase 2 target model;
2. proceed with Phase 2A as the first implementation milestone, targeting operational readiness by March 2028; and
3. continue to Phases 2B and 2C through the recommended staged pathway, subject to formal decision gate reviews.

13. Appendices

To strengthen this report for public and regulatory use, the following appendices should be attached:

- **Appendix A:** IBM Economic Analysis

This report has been prepared by IBM Consulting for IESO Nova Scotia. It is intended as a stand-alone document and may be used by IESO-NS for internal decision-making, stakeholder communication, government engagement, and support for future regulatory proceedings. All cost estimates are Class 3 Budgetary Estimates with an accuracy range of -15% to +20% and should be interpreted accordingly.

Nova Scotia Independent Energy System Operator

2027/2028 Proposed Expenditures, Revenue Requirement, and Fees Application

Appendix 7 – FTI Value Case Report

NON-CONFIDENTIAL

May 29, 2026



The Independent Energy System Operator of Nova Scotia: Value Framework and Business Case

A report from FTI Consulting for IESO Nova Scotia

Disclaimer

This report has been prepared by FTI Consulting LLP ("FTI") for the Nova Scotia Independent Energy System Operator ("IESO-NS") under the terms of Master Service Agreement between IESO-NS and FTI, dated January 16, 2026 (the "Contract").

This report has been prepared solely for the benefit of IESO-NS in connection with their value framework and business case.

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Glossary

AEMC	Australia Energy Market Commission
AEMO	Australian Energy Market Operator
AESO	Alberta Electric System Operator
ACER	EU Agency for the Cooperation of Energy Regulators
ATO	Authorisation to Overspend
AUC	Alberta Utilities Commission
CAISO	California ISO
CapEx	Capital Expenditures
CATO	Competitively Appointed Transmission Owners
CfD	Contract for Difference
CRR	Congestion Revenue Right
CRU	Commission for Regulation of Utilities
DA	Day-Ahead
DER	Distributed Energy Resource
DESNZ	Department for Energy and Net Zero, United Kingdom
EMA	Energy Market Authority, Singapore
EMC	Energy Market Company, Singapore
EPC	Engineering, Procurement, and Construction
EU	European Union
FERC	Federal Energy Regulatory Commission
FTRs	Financial Transmission Rights
FTI	FTI Consulting LLP.
GB	Great Britain
IESO-NS	Nova Scotia Independent Energy System Operator
IESO Ontario	Ontario Independent Electricity System Operator
IPP	Independent Power Producers
IRP	Integrated Resource Plan
ISO	Independent System Operator
ISO-NE	ISO New England
ISP	Integrated System Plan
LCCC	Low Carbon Contracts Company
LMP	Locational Marginal Pricing
LSE	Load-Serving Entity
MISO	Midcontinent ISO
NEM	National Electricity Market, Australia

NERC	North American Electric Reliability Corporation
NESO	National Energy System Operator, United Kingdom
NSEB	Nova Scotia Energy Board
NSP	Nova Scotia Power
NSPSO	Nova Scotia Power System Operator
OATT	Open Access Transmission Tariff
OBPS	Output-Based Pricing System
OEB	Ontario Energy Board
OFTO	Offshore Transmission Owner
Ofgem	Office of Gas and Electricity Markets, United Kingdom
OpEx	Operational Expenditures
OPG	Ontario Power Generation Inc.
PPA	Power Purchase Agreement
RfP	Request for Proposal
ROFR	Right of First Refusal
RT	Real Time
RTO	Regional Transmission Organization
TA	Tolling Agreement
TO	Transmission Owner
Transco	Transmission Company
TSO	Transmission System Operator
VIU	Vertically Integrated Utility
WACC	Weighted Average Cost of Capital

Executive summary

ES.1 FTI Consulting ("FTI" or we) has been retained by the Nova Scotia Independent Energy System Operator ("IESO-NS" or the "IESO") to examine the Business Case and Value Framework of transitioning from an investor-owned vertically integrated utility ("VIU") model to an independent system operator model ("ISO").[1] IESO-NS was established in Nova Scotia Bill No. 404 *An Act to Reform the Law Respecting Energy and Electricity* (Chapter 2, Acts of 2024).

ES.2 Nova Scotia is undergoing its most significant electricity sector transformation in decades, with expected population growth, the electrification of heat and transport, a target of 80% renewable electricity sales by 2030, and the phase-out of coal-fired generation driving change.[2] IESO-NS represents a new institutional model for electricity system governance in the province – one with enhanced transparency that opens electricity sector investment opportunities to more firms.

ES.3 The transition from an investor-owned VIU structure, with most electricity system functions performed by Nova Scotia Power ("NSP"), towards an ISO is expected to deliver strategic benefits across planning, energy resource procurement, and system operations impacting cost, reliability, and environmental performance.

ES.4 This report is divided into four chapters:

1. Transition from the VIU model to IESO-NS: describes the IESO transition and the IESO's current (Phase 1) and planned (Phase 2) roles;

2. A benchmark of the roles, responsibilities and operating costs of an ISO: introduces and discusses a benchmarking group of ISOs in other regions to understand the comparative scope and costs of IESO-NS;

3. Anticipated benefits and costs of an ISO: qualitatively discusses how the transitioning of roles from NSP to the IESO in both phases of the transition are anticipated to result in potential benefits and costs; and

4. Quantification of benefits and costs: provides estimated quantified benefits of the IESO's Phases 1 and 2 over a 25-year period.

[1] We refer to the Nova Scotia Independent Energy System Operator specifically as IESO-NS or the IESO and use ISO to refer to independent system operators in the abstract.

[2] Clean Power Plan, Nova Scotia Power, Accessed 25 March 2026, (link).

ES.5 Our analysis **quantifies benefits between approximately $500 million to $2.4 billion over the 2026-2050 period**, adjusted for the time value of money.[3] This estimation represents a conservative estimate with important qualitative benefits that are discussed in Chapter 3 but difficult to explicitly quantify.

The transition from the VIU model to IESO-NS

ES.6 The newly created IESO-NS is an independent, non-profit organization currently entrusted with responsibility for planning and procurement and eventually reliably operating the province's bulk electricity system. This is planned in two broad phases:

i) **Phase 1** (already established): planning and management responsibilities, including the integrated resource plan ("IRP") processes, energy resource and transmission planning activities, interconnection processes, and energy resource procurement; and
ii) **Phase 2** (initial stage planned for 2027/28): operation of the transmission grid, and other roles with a day-to-day operational focus.

ES.7 From a global perspective, the roles and responsibilities of an ISO are not rigidly defined, and the range of functions an ISO typically executes varies. Moreover, experience in other jurisdictions has shown that roles and responsibilities can evolve over time, and this will likely also be the case for IESO-NS. We describe the high-level roles and responsibilities of IESO-NS as they are today and the phases in which they could evolve in **Chapter 1** of this report.

Benchmarking the roles, responsibilities and operating costs of an ISO

ES.8 In **Chapter 2** of our report, we compare IESO-NS with a benchmarking group of ISOs in other regions. No existing ISO is entirely comparable with IESO-NS in its current form; however, several ISOs share certain characteristics. The benchmarking group is shown in Figure ES-1 below.

[3] All benefit and disbenefit values throughout the report are provided in $2025 CAD, unless specified otherwise. To account for the time value of money, a 4.65% real discount rate is applied, which is based on a 6.65% nominal weighted average cost of capital ("WACC") and 2% assumed inflation rate.

Figure ES-1: Overview of the characteristics of IESO-NS shared by other ISOs



ES.9 We describe the roles and responsibilities of a relevant range of existing ISOs in more detail and contrast them with IESO-NS. We also provide information about the operating costs of those existing ISOs to illustrate a reasonable range of expected costs for IESO-NS once in Phase 2. Our analysis illustrates that for our benchmarking group, we see a general minimum fixed cost to run an ISO of around $70-140 million per year.[4] Two points are key to account for when considering the floor in operating costs:

i) A significant portion of the ISO's operating costs are not incremental for consumers as a result of having an ISO; rather, many of these costs arise from functions that would otherwise need to be performed by a VIU (or Transmission System Operator or "TSO") but are now conducted by the ISO; and

ii) In addition to the overall grid size, the drivers for cost relate to the roles and functions of the ISO, and attempting to scale costs with size can be misleading without accounting for discrete roles and responsibilities performed. For example, many of the benchmarked ISOs operate wholesale energy and capacity markets which is currently not a function envisioned to be introduced in the case of IESO-NS.

[4] Derived from $50-100 million USD. Using the exchange rate of 1.39 CAD = 1.00 USD, as of 30 March 2026. See Bloomberg (link).

Anticipated benefits of an ISO

ES.10 In **Chapter 3,** we describe the anticipated benefits and costs of an ISO in Nova Scotia, in contrast to a VIU model. An investor-owned VIU model, even with regulatory guardrails, inherently creates the potential for perceived or actual conflicts of interest. The clarity of focus on system planning and operation as well as increased independence and level of trust in the independent and not-for-profit IESO create the foundation for most benefits described in this report. This is in addition to the structural changes created by Nova Scotia's Energy Reform (2024) Act, such as the introduction of more competitive procurement for new energy resources, which are better supported under an ISO structure.[5]

ES.11 The IESO's broad benefit categories are unlocked through the following levers, which facilitate the IESO's ability to create benefits for Nova Scotia:

i) **Removal of the potential for (perceived) bias:** The IESO's independence better aligns incentives for efficiency, removing potential material and/or perceived bias that may have occurred under a VIU model;

ii) **Increased competition:** More new generation resources are procured competitively, including via auctions that are conducted by the ISO (rather than NSP), which can lead to lower investment costs, more cost discipline, and open the door overall to a greater pool of competitors (partly incentivized by a more level playing field or the perception of a more level playing field);

iii) **Timeliness:** An increase in trust and more efficient regulatory process, with the regulator focusing on oversight rather than substituting for competition, may result in accelerated energy resource development timelines, with an associated earlier reduction in production costs and carbon emissions resulting from those new resources;

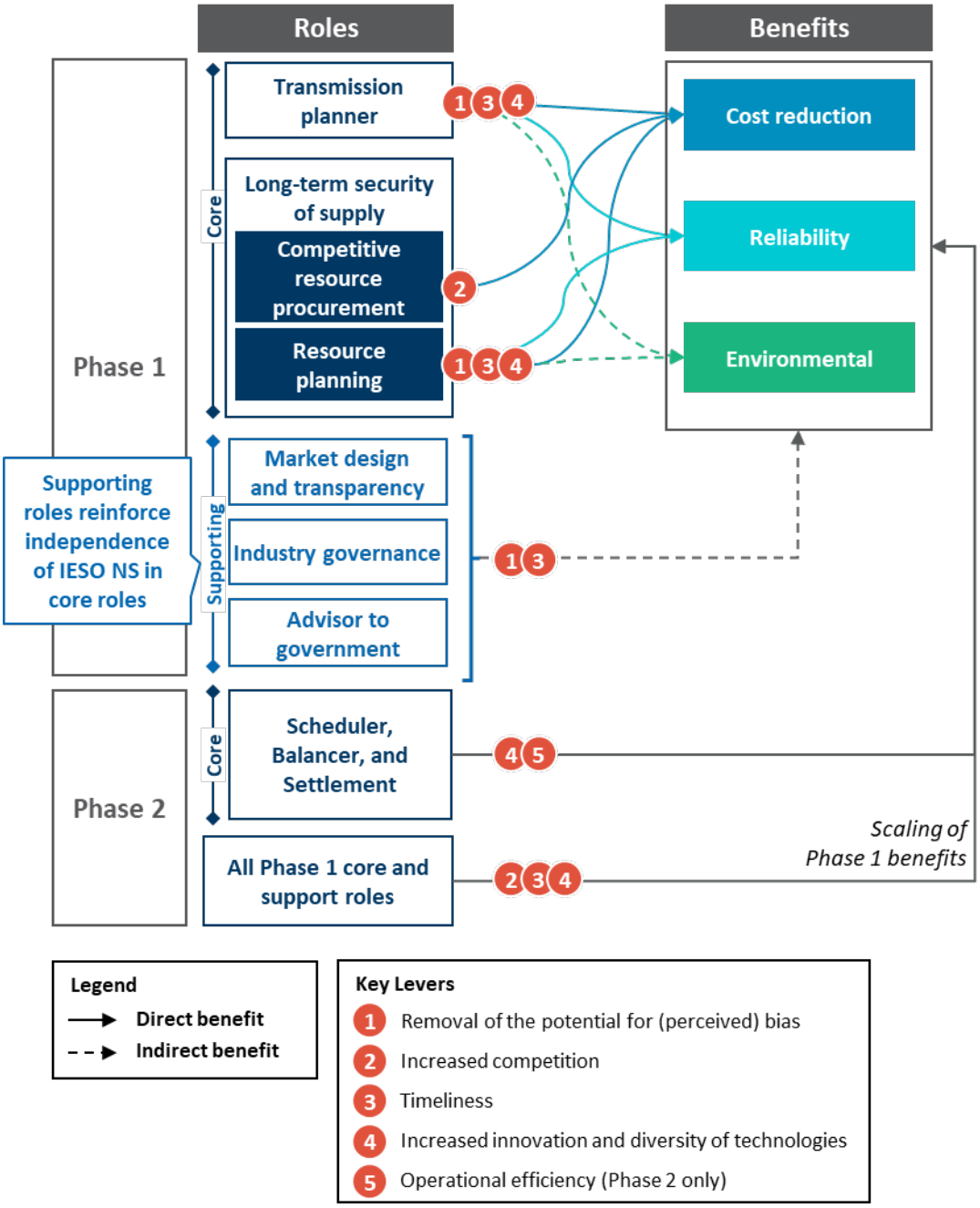
iv) **Increased innovation and diversity of technologies:** The perception of a level playing field and potentially more advanced system planning pathways may result in more clean energy technologies, demand-side management, and less asset-heavy solutions; and

v) **Operational efficiency:** Better incentives to accelerate and make more substantial improvements in the control room may result in improved operational decisions – these improved operations may further advance Phase 1 benefits due to enhanced information quality and availability.

ES.12 In Figure ES-2 below we map how the roles transferred to the IESO from NSP confer cost, reliability and environmental benefits enabled via the abovementioned levers.

[5] Nova Scotia Bill No. 404 *An Act to Reform the Law Respecting Energy and Electricity* (Chapter 2, Acts of 2024).

Figure ES-2: Roles and related benefits of the IESO



Source: FTI Consulting analysis

ES.13 While we identify important benefits from the IESO transition, it must also be acknowledged that certain costs are inherent to a transition of certain tasks from a VIU to an ISO. There is a one-off cost of implementing separation of the IESO from the VIU, such as costs related to setting up a new entity and securing independent facilities. A significant portion of the IESO's costs associated with carrying out the transferred functions — particularly computing and software expenses — is expected to be comparable to those NSP incurred in performing the same functions. However, some operating costs are incremental such as some duplication in corporate functions (e.g., human resources, finance, or legal), the cost of roles dedicated to interfacing between the IESO and other entities, and any duplicate software licenses needed for both planning and real-time operation functions.

ES.14 Finally, in Phase 1 there is likely a loss of synergies due to the separation of system planner and system operator. That loss of synergies is reversed in Phase 2, when the IESO takes over system operation; however, a new loss of synergies emerges, namely between the system operator and the asset owner. These losses of synergies are also quantified in Chapter 4.

Quantification of benefits of Phases 1 and 2 of the IESO

ES.15 In **Chapter 4** we quantify a subset of benefits identified in Chapter 3 that can be organized in four groups leading to 12 benefit (and disbenefit) categories shown in Figure ES-3 below:

i) Phase 1 benefits relating to **increased competition** in resource procurement quantified by benefit categories 1 and 2;

ii) Phase 1 benefits relating to **timeliness** of the deployment of new generation and transmission quantified by benefit categories 3 and 4;

iii) Phase 2 benefits relating to **operational efficiency** improvements by benefit categories 6 and 10; and

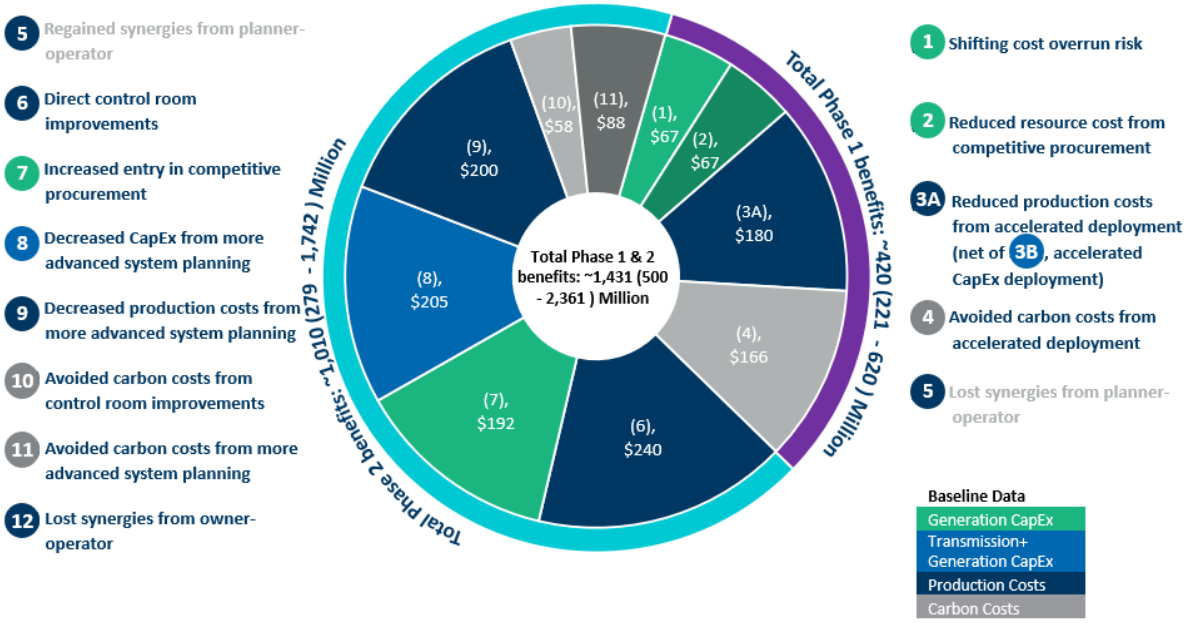
iv) Phase 2 benefits relating to:

(a) operational efficiencies indirectly unlocking more advanced planning pathways leading to **increased innovation and diversity of technologies** by benefit categories 8, 9 and 11.

(b) independent system operation scaling benefits of **increasing competition** in resource procurement by benefit category 7.

ES.16 Further, we also consider the loss of synergies between the system planning and operator introduced in Phase 1 referred to as disbenefit category 5. In Phase 2 that benefit is annulled (as the planning and operational functions revert to being in the same entity) but a loss of synergies between the system operator and asset owner in Phase 2 is introduced which is referred to as disbenefit category 12.

Figure ES-3: Cumulative benefits, midpoint case (2026-2050), $m 2025[6]



Source: FTI Consulting analysis.

ES.17 Quantified benefits total between $500 million and $2.4 billion relative to a baseline without a transition to the IESO. The benefits are spread across 12 distinct benefit categories, as shown in Figure ES-3 above. The benefits are measured as reductions on primary cost categories of the Nova Scotia electricity system: generation capital expenditure ("CapEx") (investment costs), transmission CapEx, energy production costs and the value of carbon emissions. Because this analysis depends on many uncertain parameters over a long time horizon, we calculate a high and a low case for each impact, creating a reasonable range for each benefit.

ES.18 Benefits are expected to be relatively larger in the first 5-10 years of the IESO transition, with $1 billion cumulative benefits estimated to be reached by 2039.[7] This is because Phase 1 benefits in the first few years are driven by fewer delays leading to a pace of system transformation informed by environmental policy goals in line with planning targets, whereas Phase 2 benefits are realised more evenly across the period.

ES.19 Given the transition Nova Scotia is undergoing in the coming decade, a significant amount of CapEx is planned to build new generation and transmission. Hence, even a small percentage saving in CapEx and its subsequent operation is likely to deliver material benefits to consumers.

[6] Disbenefits (5) and (12) are not plotted, but numerically included in the Phase 1 and 2 totals. Disbenefit (3B) is netted against benefit (3A). For sources, see Appendix 3.

[7] Measured in Present Value, applying a 6.65% nominal discount rate.

ES.20 The value of avoided carbon emissions (measured by applicable carbon tax) provides substantial benefits using the current federal price of carbon schedule and provincial Output-Based Pricing system. However, if this benefit category is excluded as a sensitivity, the transition benefits still total between $342 million and $1.9 billion over the 2026-2050 period.

ES.21 We can convert the $500 million to $2.4 billion total benefits to an equivalent annual benefit ("EAB"), a constant annual amount that has the same present value. The EAB is shown in Table ES-1 below.

Table ES-1: Equivalent annual benefit, $m 2025[8]

Equivalent annual benefit, annuity corresponding to PV of benefits	Low	Mid.	High
Phase 1	15	29	43
Phase 2	20	71	122
Total	$35	$100	$165

ES.22 This analysis demonstrates that the annual incremental costs of IESO-NS could be as high as $35 million in the low benefits case for IESO-NS costs to *break even* with benefits. If we believe the incremental costs of IESO-NS are lower than the EAB, then the difference is the net benefit to Nova Scotia consumers of the transition. While we do not calculate incremental costs in this report, if the incremental costs of the transition were, for example, 20% of total operating costs (estimated based on scaling the operating costs of other ISOs to Nova Scotia's size) of $70 million plus a one-off annualised, illustrative cost of $5 million, then in the low benefits case the net benefits are $35 million - $14 million[9] - $5 million = $16 million on an annualised basis, a benefit-to-cost ratio of 1.8. In the mid and high benefits cases with the same illustrative incremental operating costs, this would be a net benefit of $81 million annually and a benefit-to-cost ratio of 5.3, and a net benefit of $146 million annually and a benefit-to-cost ratio of 8.7, respectively.

ES.23 When excluding avoided emissions-related benefits, the EAB is still favourable relative to high-level estimates of the incremental costs of the IESO, as shown in Table ES-2 below.

Table ES-2: Equivalent annual benefit excluding avoided emissions-related benefits, $m 2025[8]

Equivalent annual benefit, annuity corresponding to PV of benefits	Low	Mid.	High
Phase 1	9	18	27
Phase 2	15	61	106
Total	$24	$78	$133

[8] For sources, see Appendix 3.

[9] $70 million * 20% = $14 million.

Conclusion

ES.24 Across both phases, the IESO transition is estimated to:

i) Create a more competitive environment for new energy resource technologies and market participants;

ii) Strengthen planning credibility and accelerate deployment in investment;

iii) Enhance operational efficiency and reduce system costs with accelerated and more substantial improvements to control room processes and tools;

iv) Unlock new planning pathways using innovative technologies with enhanced system knowledge driven by accelerated and more substantial improvements to the control room;

v) Deliver between approximately $0.5 billion and $2.4 billion on a present-value basis in quantifiable benefits in the first 25 years of operation; and

vi) Deliver a net benefit to Nova Scotia consumers when comparing annualised benefits with reasonable annualised incremental costs.

ES.25 The benefits of Phase 2 are approximately twice the size of Phase 1, indicating a strong business case for the continued transition of operational roles to IESO-NS, subject to estimated costs.

ES.26 The annualised values of the range of benefits discounted to today's dollars (EAB) indicates that the business case for Phase 1 and 2 of IESO-NS is favourable if the annual incremental operating costs of the IESO are not higher than $35 million, or $24 million not including the value of avoided carbon. These incremental costs are lower than the IESO's total operating costs, as certain functions are transferred from the VIU to the ISO.

ES.27 The establishment of IESO-NS represents a foundational transformation of Nova Scotia's electricity sector. The shift from a vertically integrated model to an independent, non-profit system operator provides opportunity for increased participation and competition in the electricity sector, creates greater transparency for customers, and aligns incentives in the regulatory process. It positions the province to integrate renewables more efficiently and reduce costs for consumers compared to the alternative VIU case.

1. The transition from the vertically integrated utility model to IESO-NS

1.1 IESO-NS is the most recently founded ISO[10] in North America, having been directed by the Provincial Government in 2024. IESO-NS was formed following a report issued by the Nova Scotia Clean Electricity Solutions Task Force in January 2024. This report recommended the province create an ISO and stand-alone regulator, which the Provincial government later implemented as part of a new Energy Modernization Act.[11] The newly created IESO-NS is an independent, non-profit organization currently entrusted with responsibility for planning and procurement and eventually reliably operating the province's bulk electricity system.

1.2 The specific roles and responsibilities being transferred to IESO-NS from NSP can be divided into two broad phases:

i) **Phase 1**: planning and management responsibilities, including the IRP processes,[12] transmission planning activities, interconnection processes, and energy resource procurement (such as the recent solicitation for new gas resources in Pictou county);[13] and

ii) **Phase 2**: operational planning, balancing system operations, transmission operations and other roles with a day-to-day operational focus, with the initial stage planned for 2027 or 2028.

1.3 This is illustrated in Figure 1-1 below.

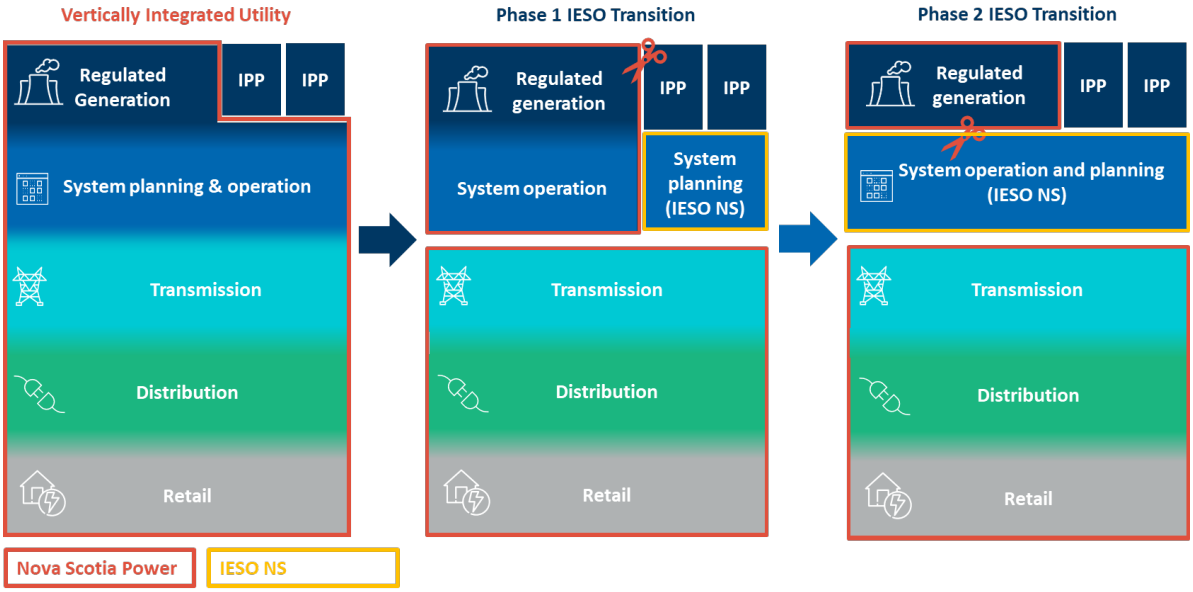
[10] We refer to IESO-NS specifically as IESO-NS or the IESO and use ISO to refer to independent system operators in the abstract.

[11] Statement on Report from Clean Electricity Solutions Task Force, Government of Nova Scotia, 23 February 2024, (link).

[12] Nova Scotians invited to participate in IESO Nova Scotia's first Integrated Resource Plan, IESO Nova Scotia, 15 October 2025, (link).

[13] News release, IESO Nova Scotia, 16 October 2025, (link).

Figure 1-1: Illustrative VIU unbundling of NSP in two phases[14]



Source: FTI Consulting Analysis.

1.4 While differences exist, the typical pathway of market liberalisation is the unbundling of a VIU into separate entities responsible for generation, transmission, distribution, and system operation.[15] An ISO operates the transmission system and, in most instances, serves as the market operator for the wholesale energy market and the ancillary services market.

1.5 In the case of IESO-NS, the focus for now has been on the unbundling of the system operation function from generation, transmission and distribution ownership. At the time of writing, there are no concrete plans to introduce a wholesale energy and ancillary services market or to further unbundle NSP beyond Phase 2.[16]

[14] Although not shown in the retail box of the graphic, the Renewable to Retail ("RtR") program allows licensed retailers to sell locally generated renewable electricity directly to retail customers. Only one retailer has been licensed to date (with a proposed wind project), but it has not yet begun serving customers. See *Nova Scotia Energy Board,* 25 August 2025, (link).

[15] Transmission refers to the high-voltage grid, while distribution refers to the low- and medium-voltage network assets connecting most end-use consumers.

[16] A wholesale energy or 'spot' market refers to a market in which participants bid prices and quantities in contrast to a bilateral market, with prices predetermined by contract. While it would theoretically be possible to create a spot market with a small regional scope in Nova Scotia, this would likely lead to less gains from efficient trade due to less (diverse) market participants, more market power concerns, and a potential need for a market maker obligation.

1.6 The remainder of this report consists of three chapters. In Chapter 2, we first provide a benchmark of existing ISOs and compare their roles, responsibilities and operating costs. After, in Chapter 3 we qualitatively discuss the benefits and drawbacks from the transition to an ISO. We divide the discussion in two according to the two phases in the transition from a VIU to the IESO. Finally, in Chapter 4, we provide estimates of the quantified benefits of the transition to IESO-NS for Nova Scotians.

2. Benchmarking the roles, responsibilities and operating costs of an ISO

2.1 The objective of this chapter is three-fold: (1) benchmarking IESO-NS among its peers globally; (2) understanding from that benchmark what the typical roles and responsibilities of an ISO are; and (3) assessing the typical operating costs of an ISO and the key cost drivers.

2.2 This chapter is organized accordingly. We start by introducing the considered ISOs for the benchmark. At present, there is no other ISO that constitutes a direct comparable benchmark for IESO-NS. However, there are a range of ISOs that share at least certain characteristics with IESO-NS. After, we describe the potential roles and responsibilities of an ISO and compare how those roles and responsibilities have been assigned for the benchmark ISOs. Finally, we map the operating costs of an ISO (i.e., the cost to run the organization) on several key metrics such as population served and installed capacity of the power system they are operating. While some trends are identified, the findings are illustrative rather than conclusive, given the many differences among the range of ISOs across the globe that are not controlled for.

Identification of the ISOs for benchmarking purposes

2.3 IESO-NS has several defining characteristics that influence our benchmarking group selection. We summarise those characteristics and the relevant ISOs in Figure 2-1 below.

Figure 2-1: Overview of the characteristics of IESO-NS shared by other ISOs

CHARACTERISTIC	PEAK LOAD	STRUCTURE	JURISDICTION	AGE	RESOURCE MIX
IESO NOVA SCOTIA	Small Grid	Large Incumbent(s)	Single Province within a Nation	Newly Restructured	High Renewables
	EirGrid GROUP TRANSPOWER ENERGY MARKET AUTHORITY	ENERGY MARKET AUTHORITY ISO new england MISO CAISO ieso Independent Electricity System Operator	aeso ieso Independent Electricity System Operator ENERGY MARKET AUTHORITY CAISO	NESO National Energy System Operator	EirGrid GROUP AEMO CAISO ieso Independent Electricity System Operator TRANSPOWER

Source: FTI Analysis, logos from ISO websites.

2.4 As can be seen from Figure 2-1, we have considered five characteristics of IESO-NS and, for each characteristic, mapped a selection of ISOs that share it:

i) **Peak load:** IESO-NS covers a relatively small power system with, at the time of writing, a peak load of approximately 2.5 GW. Closest comparable ISOs are EirGrid in the Republic of Ireland, Transpower[17] in New Zealand and the Energy Market Authority ("EMA") in Singapore, operating a grid with 6 GW, 7 GW, and 8 GW peak load, respectively;

ii) **Utility structure:** with a power system composed primarily (currently, almost entirely) of a former VIU, we have included several grids with large incumbent structures. In Singapore the regulator and system operator EMA holds the primary authority over the grid operation with a separate wholesale market operator (Energy Market Company or "EMC") and a state-owned generation and network assets owner (SP Group). The California Independent System Operator ("CAISO"), ISO New England ("ISO-NE") and Midcontinent ISO ("MISO") have large, privately-owned vertically integrated utilities that are part of the geographical area they operate.[18, 19] In Ontario, Ontario Power Generation Inc. ("OPG") owns a significant share of the generation fleet in the grid operated by the Independent Electricity System Operator of Ontario ("IESO Ontario"). OPG is fully owned by the province of Ontario and an important share of its current generation assets are legacy assets from the former VIU structure;[20]

[17] Transpower is the state-owned owner-operator of the transmission system in New Zealand, playing a role similar to that of a Transmission System Operator ("TSO") in Europe, but also operating the wholesale electricity market. For ease of comparison, in this report we refer to Transpower as an ISO.

[18] The VIUs (owning generation, transmission, distribution and retail) operate within an ISO and depending on the jurisdiction share transmission and resource planning tasks with the ISO and state public utilities commissions. Several New England states have passed some form of liberalisation laws that required some form of legal or functional separation of asset classes, or divesture of generation assets. Transmission planning remains primarily with the utility.

[19] In this context, privately owned refers to entities that are not government or state-owned; many vertically integrated utilities in the US are ultimately owned by publicly traded corporations.

[20] Most VIUs in Canada are government-owned, e.g., BC Hydro, Manitoba Hydro, SaskPower, New Brunswick Power and Hydro-Quebec.

[21] See *Bonneville opts to join SPP's Markets+ day-ahead market over CAISO alternative,* Utility Dive, 7 March 2025, (link).

iii) **Jurisdictional footprint:** spanning one province, IESO-NS is similar to Alberta Electric System Operator ("AESO") and IESO Ontario, each of which can focus on the policy objectives of one provincial government with minimal federal involvement. In contrast, federal policies and regulations still play a large role in single-state ISOs such as CAISO in the US. Other ISOs span over more than one province or state, each of which may have differing energy policy objectives. The CAISO is an interesting case as it is undergoing a major market expansion process into a larger, multi-state region. Jurisdictional and governance concerns are key issues in the details of this process. [21] Examples of multi-province/state ISOs are the Australian Energy Market Operator ("AEMO") spanning five Australian states, ISO-NE covering six US States, and MISO covering 15 US States and the Canadian province of Manitoba; [22]

iv) **Age:** IESO-NS is very new – most ISOs were established 20+ years ago. However, Great Britain ("GB")'s government-owned National Electric System Operator ("NESO") was only unbundled in 2024 from the National Grid, one of the three privately-owned transmission owners ("TO") in GB, providing a key example for a market that recently underwent an unbundling process. [23] Age of an ISO also ties into degree of independence, with more mature ISOs having more time to establish independence from related sector parties; [24] and

[21] See *Bonneville opts to join SPP's Markets+ day-ahead market over CAISO alternative,* Utility Dive, 7 March 2025, (link).

[22] Multi-state ISOs are in the US often referred to as Regional Transmission Organizations ("RTOs").

[23] FTI worked with National Grid early in its inception when different ISO models were considered, and later on was commissioned by Ofgem, the GB regulator, to assess the potential benefits of an ISO compared to a TSO model. See GB System Operator Review, Report Prepared for Ofgem, 22 January 2021, (link).

[24] Additionally, multi-jurisdictional ISOs have an obligation to impartiality across governing bodies.

v) **Resource Mix:** IESO-NS is in the midst of a planned transition away from coal and to increasing shares of renewables including wind. Ontario and Transpower both have significant shares of hydro resources, with Transpower having a substantial share from geothermal.[25,26] In-state utility-scale solar generation in CAISO is approximately 25% with another approximately 10% from rooftop solar.[27,28] Wind in EirGrid provides approximately one-third of total electricity.[29] AEMO is shifting from historical reliance on coal to a system with over 20% electricity from solar and 15% from wind.[30] CAISO, EirGrid, and AEMO are also now managing systems with significant instantaneous shares of inverter-based resources like wind and solar, which changes the type of grid services required to keep the system within safe operating limits. This is increasingly challenging when the penetration is high across the entire synchronous grid, as in AEMO and EirGrid. Rooftop solar in South Australia regularly exceeds demand in many hours in the small state, which has limited connectivity to the rest of AEMO.

25 Ontario IESO, Accessed 26 March 2026, (link).

26 New Zealand Ministry of Business, Innovation, and Employment, Accessed 26 March 2026, (link).

27 California Energy Commission, Accessed 26 March 2026, (link).

28 California Energy Commission, Accessed 26 March 2026, (link).

29 Eirgrid, 13 February 2026, (link).

30 AEMO, Accessed 26 March 2026, (link).

Table 2-1: Key metrics for benchmarking group[31]

	Unit	CAISO	ISO-NE	MISO	AESO	IESO Ontario	NESO	EirGrid	AEMO	EMA	Trans-power	IESO Nova Scotia
Approximate people served	*millions*	32	15	45	5	15	67	5	23	6	5	1
Transmission	*km*	41,800	14,500	127,100	26,000	30,000	35,900	6,700	40,000	2,600	11,000	5,200
Installed Capacity (GW)	*GW*	89	31	207	23	38	72	15	73	13	11	3
Peak Load	*GW*	48	25	123	12	25	45	6	34	8	7	2.5
Total Energy Consumption	*TWh*	253	117	638	63	139	275	32	190	58	40	11
Approximate Employees		700	600	1,000	500	1,000	2,000	400	1,800	400	1,000[32]	N/A
Ownership structure		Non-profit	Non-profit	Non-profit	Non-profit	Non-profit	State owned company	State owned company	Non-profit	Gov. agency	State owned company	Non-profit
Operating costs	*USD$ million*	**$222**	**$252**	**$440**	**$113**	**$206**	**$476**	**$124**	**$224**	**$65**	**$132**	**N/A**
Installed Capacity	% renewable % coal % other											

Note: Latest available data used, most from 2024 or 2025; Operating costs include the cost to run an ISO organization mostly consisting of salaries, services, administrative, hardware and software costs. Operating costs do not include the costs to run a grid, e.g., ancillary services and balancing costs; Renewables includes solar, wind, storage, biofuel, biomass, hydro, waste energy and geothermal.



[31] Sources provided on prior page.

[32] Transpower employment data also includes the transmission ownership function.

2.5 Table 2-1[33] above also includes **operating costs**. Alongside the size of the power system covered by the ISO, the remit of the roles and responsibilities of the ISO will impact its operating costs. Hence, before discussing the operating costs in more depth at the end of this chapter, we first describe the roles and responsibilities of each.

Roles and responsibilities of the benchmarked ISOs

2.6 Each of the ISOs introduced in the previous section has its own differing set of roles and responsibilities – each having its own associated costs and benefits. To draw additional value from the comparison of operating costs in Table 2-1, we provide a comparison of key roles, functions and responsibilities of the benchmarking group and IESO-NS in Table 2-2. In what follows, we first provide initial takeaways. After, we briefly introduce and discuss the different roles and responsibilities outlined.

2.7 Four initial findings comparing IESO-NS to the benchmarking group are that:

i) Most ISOs operate competitive bid-based wholesale energy markets and all operate in jurisdictions in which there is a competitive wholesale market. Examples where the ISO is not the market operator are Singapore, Great Britain and the Republic of Ireland;

[33] Sources: CAISO 5-year summary (link), Transpower 2025 Annual Report (link), RIIO-2 Regulatory Financial Reporting Pack Guidance (link), IESO 2023 Annual report (link), EMA Annual and Sustainability report 2024/2025 (link), AEMO Annual Report 2025 (link), AESO Annual Report 2024 (link), NESO Annual Report 2025 (link), EirGrid Annual Report 2024 (link), ISO New England Financial report 2024 (link), Capital IQ Data Accessed 10 December 2025, CAISO About (link), ISO-NE Key Stats (link), MISO corporate fact sheet (link), AESO About (link), Export grid status: Market Renewal in Ontario (link), World Bank Group: Access to electricity (%) (link), ONS: Estimates to population for UK (link), AEMO Fact sheet (link), World Bank Group: Population (link), Stats NZ: National population estimates (link), IESO-NS Phase 2 (link), AESO About the grid (link), IESO Introduction (link), NEXT European TSOs list (link), SP Group: Safeguarding the Backbone of Singapore's Grid (link), Transpower: What we do (link), NS Power 2025 10-Year System Outlook (link), CAISO Department of market monitoring update (Nov 23) (link), ISO-NE Energy Load and Demand Report (link), AESO Annual Market Statistics Report (January 2026) (link), IESO Transmission-Connected Generation (link), UK Gov DUKES 2025: Table 5.12 (link), EirGrid All-Island Resource Adequacy Assessment 2025–2034: pp. 141-142 (link), AEMO Generation Information (link), EMA Singapore Energy Statistics: Ch. 2 (link), NZ MBIE Data tables for electricity (link), CAISO 2024 statistics (link), MISO S&P Capital IQ data (accessed 11 December 2025), AESO 2024 Annual Market Statistics (link), 360 Energy: Summer Heat Drives Record Electricity Demand in Ontario and the US Northeast (link), NESO: Britain's Electricity Explained: 2024 Review (link), NEM seasonal peak demand (link), EMA monthly peak system demand (link), Transpower Security of supply review winter 2025 (link), MISO 2024 Load Forecast and Process Enhancements Workshop (link), IESO 2024 Year in Review (link), CSO data (link), NEM Annual electricity consumption (link), EMA SES Chapter 3: Energy Consumption (link), Transpower market indicators (link), CAISO Q3 2025 financial report (link), ISO-NE 2025 and 2026 Preliminary Operating and Capital Budgets (link), MISO Information (link), AESO LinkedIn (link), IESO Information (link), NESO About (link), Transpower NZ Information (link), British Irish Chamber of Commerce: EirGrid (link), EMA Home page (link), CAISO Decision on 2025 budget (link).

ii) Operational planning, system balancing, and congestion management are core real-time functions of all of these ISOs, as this is part of the fundamental functionality of system operation;

iii) Most ISOs are responsible for transmission planning. An important share of ISOs has provisions in place that allow for the competitive procurement of transmission assets. However, in practice most of the transmission is built and owned by an incumbent TO; and

iv) Resource planning, including IRPs and generation procurement, is not generally performed by ISOs in the US or elsewhere. Instead, due to the competitive nature of generation (both in investment and operation) many ISOs perform resource adequacy assessments that inform in many cases the demand in capacity markets or guide competitive procurements for resources that deliver capacity and/or energy. Note that in an important share of jurisdictions, the government provides investment support to certain technologies to achieve policy goals (e.g., renewables and nuclear power in GB). In general, there are very few jurisdictions that rely entirely on incentives provided by the wholesale market to invest and retain generation capacity.

2.8 Table 2-2 is a high-level overview; an exhaustive assessment beyond the scope of this report could include more details. In what follows we describe in some more detail the different ISO roles.

Table 2-2: Electricity sector role benchmarking

Role	Responsibility	MISO	ISO-NE	CAISO	AESO	IESO Ontario	NESO	EirGrid	AEMO	EMA	Transpower	IESO Nova Scotia
Transmission planner	Transmission planning	☑	☑	☑	☑	☑	☑	☑	☑ (excl. Victoria)	☑	☑	☑
	Competitive transmission procurement	Potential (FERC 1000)	Potential (FERC 1000)	Potential (FERC 1000)	Possible but rare	Possible but rare	Potential (OFTOs/ CATOs)	☒	☑ (excl. Victoria)	☒	Possible but rare	☒
	Transmission grid interconnection	☑	☑	☑	☑	☑	☑	☑	☑	Limited to approval role	☑	☑
Long-term security of supply (resource)	Resource planning & procurement	☒	☒	☒	☒	Guides procurement and directly procures	Guides procurement programs	☒	Guides procurement programs	☑	☒	☑
	Capacity market	☑	☑	Bilateral obligations (capacity)	☒	☑	☑ (NESO run, LCCC counterparty)	☑	Bilateral obligations (energy)	☒	☒	☒
	Long-term load forecasting	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑
Industry governance	Reliability standards	☒ (NERC)	☒ (NERC)	☒ (NERC)	☑	☒ (NERC)	☑ (regulator approves)	☑ (regulator approves)	☒	☑	☑	☑
Advisor to government	Influence policy decisions	Stakeholder process	Stakeholder process	☑	☑	☑	☑	☑	☑	☑	☑	☑
Market design	Rules incl. settlement & pricing	ISO + FERC	ISO + FERC	ISO + FERC	ISO + AUC	ISO + OEB	ISO + DESNZ + Ofgem	ISO + CRU + ACER	☒	☒	☒	ISO + NSEB
	Market monitor	Independent party	Independent party	Independent party	Independent party	ISO+ Independent party	Internal + Ofgem	Internal + CRU/ACER	Regulator competency	☑	Regulator competency	Undecided
Market operator	Operate wholesale markets	DA & RT markets	DA & RT markets	DA & RT markets	Implementing RT LMP, considering DA	DA (2025) & RT markets	☒ (Power exchanges)	☒ (SEMO)	RT market (5-min)	☒ (EMC)	RT market (30-min)	Bilateral contracts + OATT

Continued on following page.

Role	Responsibility	MISO	ISO-NE	CAISO	AESO	IESO Ontario	NESO	EirGrid	AEMO	EMA	Transpower	IESO Nova Scotia
Residual energy & system balancer	Balancing/ ancillary services	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	Phase 2 Decision
	Congestion management	LMP & FTRs	LMP & FTRs	LMP & CRRs	Transitioning to LMP	LMP & FTRs (2025)	Single price + Constraint management (curtailment)	Single price + Constraint payments	Zonal price (no constrained-off payments)	LMP	LMP & FTRs	Phase 2 Decision
	Operational planning	☑	☑	☑	☑	☑	☑	☑	☑	☒	☑	Phase 2 Decision
	Controls synchronous area	☒	☒	☒	☒	☒	☑	Shared with SONI	☑	☑	☑	☒
Settlements	Reconcile bid & actual volumes/ payments	☑	☑	☑	☑	☑	☒ (Elexon)	☒ (SEMO)	☑	☒ (EMC)	☑	Phase 2 Decision
Transmission owner	Transmission ownership	☒	☒	☒	☒	☒	☒	Owns offshore assets	☒	☒	☑	☒

Notes: Day-ahead ("DA") and Real-Time ("RT") markets refer specifically to energy markets. Additional abbreviations – OATT: Open Access Transmission Tariff, LMP: Local marginal pricing, CRRs: Congestion revenue rights, FTRs: Financial transmission rights, OFTO: Offshore transmission owner, CATO: Competitively appointed transmission owners, Transco: Transmission Company, LCCC: Low Carbon Contracts Company, NERC: North American Electric Reliability Corporation, FERC: Federal Energy Regulatory Commission, AUC: Alberta Utility Commission, OEB: Ontario Energy Board, Ofgem: Office of Gas and Electricity Markets, CRU: Commission for Regulation of Utilities, ACER: EU Agency for the Cooperation of Energy Regulators, NSEB: Nova Scotia Energy Board, DESNZ: Department for Energy and Net Zero.

2.9 **Transmission planner** roles such as transmission planning[34] and managing transmission grid interconnection requests are generally core functions of ISOs. The ISO's role in competitive transmission procurement is more mixed. In the US, for example, most ISOs perform long-term transmission planning of interregional projects, but incumbent VIUs (where they are in place) and TOs can also build their own local reliability projects subject to the state regulator's approval. However, for certain US ISOs, even when ISOs determine interregional projects for competitive transmission procurement, development is often still predominantly handled by incumbent utilities due to state-level laws for Right of First Refusal ("ROFR"). In AESO and IESO Ontario, the ISO plans transmission and, with few exceptions, large incumbents generally are awarded the ISO-planned projects.

2.10 In Australia, AEMO publishes an Integrated System Plan identifying locations of key lines to be built (as well as resources),[35] while specifically in the state of Victoria, state business corporation VicGrid is responsible for transmission planning.[36, 37] Further, in GB, NESO performs coordinated gas and hydrogen network planning alongside electric grid networks, which is not seen in any other benchmarking group ISOs. In GB, as in Ireland, land-based transmission building and ownership is typically awarded to the incumbent TOs.

[34] Transmission planning generally encompasses planning across the network to provide recommended investment options (including performing long-term forecasts to identify system needs to be met via those options) and performing the detailed planning to deliver transmission investment (e.g. design, routing, permitting, etc.).

[35] Integrated System Plan, AEMO, Accessed 26 March 2026, (link).

[36] About the Electricity Sector, Victoria State Government, 22 January 2025, (link).

[37] Victoria's electricity transmission network planning responsibilities transitioned from AEMO, through its AEMO Victorian Planning division, to VicGrid on November 1, 2025. See AEMO press release "AEMO supports VicGrid's new role in leading Victoria's transmission planning", 31 October 2025, (link).

2.11 To ensure **long-term security of supply**, ISOs typically do not have a formal generation planning and procurement process in place.[38, 39] There are a few exceptions. IESO Ontario has an extensive resource planning and procurement function and is itself the contract counterparty, rather than, e.g., the provincial government. Additionally, EMA issues Requests for Proposals ("RfPs") to build, own, and operate specific types of new generation capacity. AEMO can procure additional electricity capacity in Western Australia (not part of its main purview, the National Electricity Market ("NEM") and within a separate interconnection) via the Supplementary Capacity mechanism if shortfalls are predicted. AEMO's Integrated System Plan also serves as a detailed guide for generation investment that informs centralised government procurement.

2.12 Nearly all other benchmarked ISOs, while not relying on a formal generation planning and procurement process, have procurement mechanisms beyond the wholesale market in place that aim to ensure that there are sufficient resources to meet load, i.e., resource adequacy. These mechanisms require ISOs to model the future outbuild of the power system, and some publish long-term scenarios of resource build-out informed by policy goals, e.g., the Future Energy Scenarios of NESO in GB.[40]

2.13 The most common resource adequacy mechanism is a capacity market, typically a centralised forward auction in which resource capacity is derated based on estimated availability at critical future time intervals. Instead of a centralised market, CAISO's resource adequacy program requires load-serving entities ("LSEs") to enter into bilateral contracts to meet capacity targets. Under Australia's Retailer Reliability Obligation, if triggered by reliability deficits identified by AEMO, electricity retailers and major energy users can be required to enter into sufficient forward contracts in the energy market.[41] All ISOs are responsible for long-term load forecasts. Those forecasts inform network planning and the need and/or specific demand requirements in resource adequacy mechanisms.

[38] Certain VIUs within ISO-NE, MISO and CAISO still do their own generation planning and procurement subject to state-level approval.

[39] Centralised procurement of some specific resource types for policy reasons is done in several jurisdictions outside the scope of the ISO. For instance, Australia's Capacity Investment Scheme offers a revenue collar to new variable renewables and storage, and contracts-for-difference ("CfDs") between the government and suppliers provide revenue stability for renewables in many countries in the European Union ("EU") as well as the UK. Other governments such as the US use production or investment tax credits to subsidise renewables and storage investment.

[40] Future Energy Scenarios, NESO, Accessed 26 March 2026, (link).

[41] 2024 Electricity Statement of Opportunities, AEMO, August 2024, (link).

2.14 **Market design and transparency** for an open access tariff, wholesale markets, market procedures or other business rules is generally drafted by the ISO but often approved by an external body, with some exceptions. AEMO, EMA, and Transpower have separate market design entities, e.g., the Australian Electricity Market Commission ("AEMC"). Market monitoring exists to evaluate the performance of the markets and identify attempts to exercise market power. This responsibility can be an internal ISO or external function (or both). While the first two phases of IESO-NS do not anticipate the introduction of a wholesale market, we might expect declared variable costs from independent power producers ("IPPs") to be required, which would then be used to determine the schedule and eventually dispatch. If so, declared variable costs will likely also require regular auditing.

2.15 **Industry governance**, such as setting reliability standards for the bulk electricity system defined above a voltage threshold, is often at the synchronous grid or higher level, with NERC (along with regional reliability entities such as the Northeast Power Coordinating Council) setting standards in North America. Some ISOs, however, operate in their own synchronous areas or are weakly connected to the rest of the synchronous grid (e.g., Alberta with the Western Interconnection) and set or partially set their own standards.

2.16 The **advisor to government** role is a nuanced category as the interaction between ISOs and their federal and/or provincial government is generally bidirectional. In the US, state commissions are stakeholders in general ISO decision-making processes and can be stakeholders in Federal Energy Regulatory Commission ("FERC") dockets, while the ISO's planning processes may influence policymakers at the state level. Similarly, in the systems managed by the AESO, IESO Ontario, and AEMO, system planning analyses provide guidance to policymakers and can include specific policy consultation briefs. In the UK, the federal government has a formal framework to request analysis, with the legislative framework specifically describing NESO's role as advising the government. [42] For state-owned companies EirGrid and Transpower, similar, formal roles exist in directly shaping future policy alongside federal government, [43] while EMA itself is a government agency.

[42] National Energy System Operator (NESO) framework document, UK Government, Accessed 26 March 2026, (link).

[43] Security of supply, Transpower, Accessed 26 March 2026, (link); Decision-making process for major policy proposals, Accessed 26 March 2026, (link).

2.17 Without having a bid-based wholesale market in place, the ISO or VIU must determine the schedule of its assets (and any IPPs) to meet demand – typically based on audited or declared costs and existing bilateral contracts. In contrast, in all benchmarked ISOs, a wholesale market has been introduced to determine the dispatch schedule. The **wholesale market operator** receives bids from buyers and sellers and determines a least-cost security-constrained economic schedule and clearing price. [44]

2.18 As stated above, the **residual energy and system balancer** role is a core function of all of these ISOs. A defining physical characteristic of electricity networks is that the volume of energy injected onto a network must equate to the volume of energy that users offtake from the network on a second-by-second basis. This requires a high degree of central coordination in real time. Even for grids with wholesale energy markets, a "backstop" balancer is always needed to take a residual role. At a high level, three possible responsibilities under this role, which are core functions of all benchmarked ISOs, are:

i) Balancing services: actions taken by the ISO to keep the system balanced. For example, differences between the schedule for energy suppliers (including generators, importers and energy storage) and actual system demand result in the need for ancillary services including reserves and frequency regulation to keep the grid within engineering operating limits. Some ancillary services may be procured via competitive auctions. In best practice, operating reserve is co-optimised with energy dispatch;

ii) Congestion management: market mechanisms to manage transmission congestion, ideally providing transmission customers with efficient price signals that reflect the value of transmission (i.e., LMPs); and

iii) Operational planning: ISOs forecast approximately a year-ahead out up to day-ahead for load and weather patterns to inform operational and maintenance schedules (particularly relevant for large hydro and nuclear) to ensure that there is sufficient generation and transmission available to serve expected load in real-time. The only ISO not performing operational planning is EMA (the market operator EMC does this).

[44] All US ISOs and the IESO in Ontario have a day-ahead and real-time market which are operated by the ISOs. In the US, ISOs generally were born out of tight power pools or spot markets for trading between various VIUs and IPPs, evolving into the ISOs and RTOs that exist today – the market function predated the full system operation function. AEMO, Transpower and the AESO only have a real-time market that is operated by the ISO. To increase market efficiency (the amount of social welfare achieved by the market outcome), the system operator should consider both the constraints of the market participants and the transmission system, resulting in a nodal price, called the locational marginal price ("LMP"). All North-American ISOs and Transpower have a nodal wholesale market in place except for AESO (transitioning towards a nodal market). As well in Singapore a nodal wholesale market is in place but is not operated by EMA. In GB and Ireland, the day-ahead single-price wholesale market is operated by power exchanges. In real-time no wholesale market is operated in those markets but rather a "balancing mechanism."

2.19 Operating its own synchronous area is not common for ISOs as most are in large, interconnected balancing areas such as the Eastern Interconnection in North America. In the case of multiple ISOs (and/or VIUs) operating one synchronous area, coordination mechanisms need to be established to secure frequency stability (which NESO and AEMO do). The primary goal of NERC reliability standards and regional criteria is to preserve interconnected system reliability where multiple entities (ISOs and/or VIUs) are synchronously connected.

2.20 **Market settlement** is the process by which an ISO calculates payments based on market outcomes and actual system performance. For all but three ISOs (NESO, Eirgrid and EMA) settlement is performed by the ISO. In the case that this role is performed by the ISO, ISO acts as a financial clearinghouse to reconcile bids with actual volumes and payments without taking ownership of the energy traded.

2.21 The **transmission owner** role in the context of asset ownership generally stays separate from the ISO, as most ISOs are designated as non-asset owning. Transmission ownership unbundling, to some extent, is common in most liberalised markets in which ISOs operate. This often includes multiple transmission-only companies (TOs or TransCos) and potentially merchant transmission owners. This differs from Transpower's model in New Zealand where an owner-operator controls the transmission grid. The owner-operator model is common in the EU, where market operation is a separate function. Among important impacts on the incentives of an ISO when planning the grid, an ISO building and owning transmission implies a potential conflict of interest when organizing competitive transmission procurement.

Operating costs

2.22 In this section, we compare and discuss major operating costs of the benchmarking group. These fall generally into the major categories of salaries and benefits; outside services; facility, equipment, various IT and office; depreciation and amortisation; utilities and equipment lease; and generally, administration and maintenance expenses. The scope of responsibilities of each operator, as laid out in the previous section, will influence the operating costs. A case in point is the high operating costs (and high number of employees) of Transpower relative to the size of the New Zealand power system. As shown in Table 2-2, Transpower is the only ISO among the benchmarking group that also owns significant transmission assets (although EirGrid owns and manages offshore wind transmission assets[45]), which likely explains its relatively high operating costs compared to the other ISOs.

2.23 The ISO operating costs overlap in large part with those of the former VIU. Here we estimate the total operating costs, acknowledging that many functions, e.g., control centre equipment and operation, are costs transferred from the utility to the ISO rather than incremental costs. We discuss incremental costs for implementing and operating an ISO beyond that of a VIU in Chapter 3.

[45] EirGrid Offshore Program, EirGrid, December 2025, (link).

2.24 We do not consider the costs for the procurement of system services as operating costs from an ISO (e.g., ancillary services and congestion management costs). While efficient functioning of an ISO and its geographical size will impact those costs, they are to an important extent driven by power system characteristics and conditions (e.g., having large hydro resources might imply low ancillary service costs everything else equal and a high gas price will increase ancillary service costs if gas-fired power plants provide such services).

2.25 Detailed and comparable cost data is not available for all benchmarked ISOs, therefore, Table 2-3 includes only ISOs with comparable line items. In Table 2-3, we exclude regulatory fees, which are jurisdiction-dependent. Regulatory fees tend to include regulator fees such as to FERC, Ofgem, or other regulatory boards. FERC fees are levied based on MWh of transmission usage, resulting in MISO's fee being higher than other US ISOs shown.[46] Additionally, we exclude transition costs because they are not long-term, ongoing costs. These excluded costs listed above are not included in the operating costs total line, but the line items are still included in the table for reference.

[46] Regulatory fees tend to include regulator fees such as to FERC, Ofgem, or other regulatory boards. FERC fees are levied based on MWh of transmission usage, resulting in MISO's fee being higher than other US ISOs shown.

Table 2-3: Operating costs benchmarking, $m USD[47]

	ISO-NE	MISO	AESO	IESO Ontario	NESO	Transpower
Year	2024	2024	2024	2023	FY2025	FY2025
$m USD						
Salaries and related benefits	154	243	70	129	153	68
Outside services	25	81	7	15	79	7
Facility and equipment costs	4	19	4			19
Hardware, software maintenance and licensing						9
Computer maintenance and office supplies	24	40	9			1
Depreciation and amortisation	32	35	18	17	144	
Utilities and equipment leases	5		1			
Administration, maintenance & other	9	22	4	45	100	27
Operating Costs ($m USD)	**$252**	**$440**	**$113**	**$206**	**$476**	**$132**
Operating Costs Scaled to Nova Scotia's Size[48]	**$22-54**	**$8-56**	**$19-29**	**$18-26**	**$9-31**	**$32-55**
OpEx m$/TWh	***2.2***	***0.7***	***1.8***	***1.5***	***1.7***	***3.3***
Note(s)	*Excludes $8m regulatory fees*	*Excludes $76m regulatory fees*	*Excludes $18m regulatory fees*		*Excludes $59m regulatory fees, & $192m transition costs*	*Excludes $9m regulatory fees*
Data aggregated in other lines						

Note: Administration, Maintenance & Other (for ISOs who specify such costs) includes: Operations and maintenance, Administration, Study and interconnection services, Travel and vehicle costs, Insurance, Research and development, and Others. Outside services can include contract labour and consultants, in addition to cloud and other data storage services.

47 Transpower Annual Report, Transpower, 2025, (link), RIIO-2 Regulatory Financial Reporting Pack Guidance, Ofgem, 21 August 2025, (link), Annual report, IESO, 2023, (link), Annual Report, AESO, 2024, (link), Annual Report, NESO, 2025 (link), Financial report , ISO New England, 2024, (link), Cap IQ Data Accessed 10 December 2025.

48 These scaled numbers do not consider a possible floor to minimum annual costs described later in this section. Scaling based on the following metrics, without consideration of IESO's differing roles and responsibilities, or fixed costs as illustrated in Figure 2-2: Approximate people served, transmission length (km), installed capacity (GW), peak load (GW), total energy consumption (GWh), approximate employees. The range represents the minimum and maximum values found based on these scalars.

2.26 As shown in Table 2-3, salaries and benefits tend to be the largest expense category for ISOs, ranging from one-third to two-thirds of overall operating expenses. This reflects that ISOs don't own large infrastructure assets like transmission or generation facilities. Outside services such as consulting or contracted labour can be up to one-fifth of operating expenses. Other expenses such as hardware, software licensing, facility fees and utility bills are generally a smaller share of total expenses.

2.27 Depreciation (of capital or tangible assets) and amortisation (of intangible assets) captures capital expenditures in an annualised methodology. The assets may include land and buildings, office equipment, control room equipment and software. This expense can range from one-tenth to one-third of operating expenses. NESO stands out as having relatively high depreciation expenses; this is attributable to its young age as many recently purchased assets for a wide variety of functions are still being depreciated.

2.28 The decision (within accounting rules) of whether to capitalise (capture on income statement across several years via the depreciation charge) or simply expense (include full cost in an expense line item such as computer hardware) differs by ISO and can drive the differences in share of expenses in depreciation or other line items such as computer hardware.

2.29 Accounting methods and classifications vary by jurisdiction, making the comparison in Table 2-3 approximate and for discussion purposes only. FTI has not performed audit-level analysis of the financial statements, nor have we sought to analyse year-over-year performance and variation; the findings provided in Table 2-3 hence serve as indication of typical orders of magnitudes of cost items.

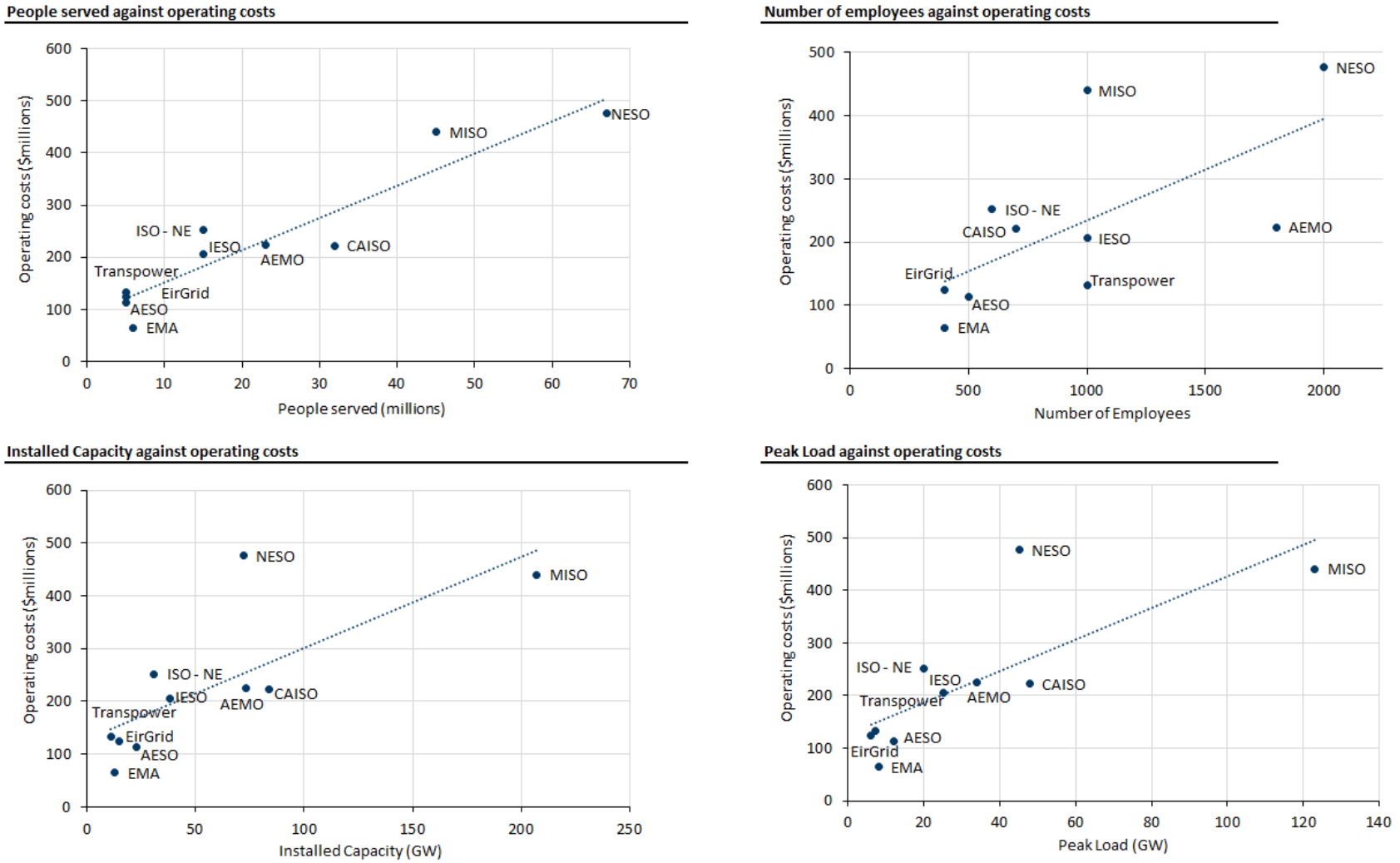
2.30 In addition, Figure 2-2 below graphically displays the association between key metrics for the benchmarking group ISOs and their operating costs. While the plots we provide are not the outcome of rigorous quantitative analysis of ISO cost drivers that controls for a range of variables, the plots in Figure 2-2 illustrate a general minimum annual cost to run an ISO of around 50-100 million USD per year. In CAD, this is approximately $70-140 million per year.[49] Two points are key to repeat when considering the identified floor in operating costs:

i) A significant portion of the ISO's operating costs are not incremental for consumers as a result of having an ISO; rather, many of these costs arise from functions that would otherwise need to be performed by a VIU; and

ii) In addition to the overall grid size, the drivers for cost relate to the roles and functions of the ISO, and attempting to scale costs with size can be misleading without accounting for discrete roles and responsibilities performed.

[49] Derived from $50-100 million USD. Using the exchange rate of 1.39 CAD = 1.00 USD, as of 30 March 2026. See Bloomberg (link).

Figure 2-2: Plots of ISO operating cost to key metrics[50]



[50] Sources same as Table 2-3.

3. Anticipated benefits of an ISO

3.1 In this chapter, we describe the benefits and costs from the establishment of an ISO. The establishment of an ISO is a step in the liberalisation or restructuring of the electricity sector.

3.2 Unbundling a vertically integrated business is expected to lead to reduced potential for (perceived) bias,[51] and increased competition and innovation that may drive down consumer costs. The IESO serving as an independent planner and ensuring fair access to the grid may also lead to increased diversity in technologies and non-wires alternatives that benefit consumers. However, unbundling comes with incremental costs as well, including one-off and ongoing expenses for equipment and staff as well as a potential loss of synergies across certain roles.

3.3 We start this chapter by describing the roles that will gradually be transitioned from NSP to IESO-NS. This is followed by a discussion of potential benefits of the establishment of the IESO in Nova Scotia's current context in which IESO-NS assumes system planning and energy resource procurement functions ("Phase 1"). Next we discuss the incremental benefits of IESO-NS assuming the system operator role ("Phase 2"). For both phases, we also list the cost implications of an ISO over and above the cost of these functions had they stayed with the VIU. Additional detail on the description of more specific qualitative benefits is provided in Appendix 1. This chapter is qualitative and acts as a broad discussion of the benefits case; quantified benefits are estimated in Chapter 4.

IESO role transition

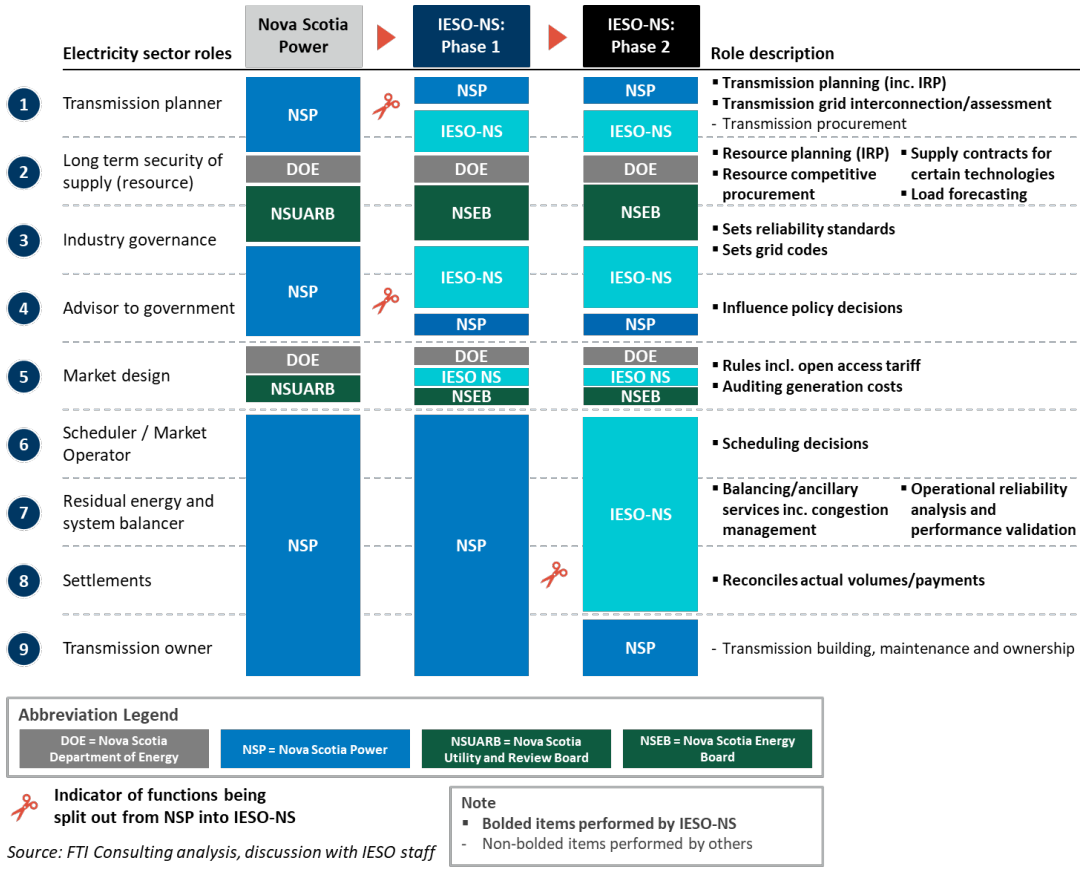
3.4 The rationale for establishing the IESO was to create an independent body with enhanced focus on the system's energy requirements.[52] The IESO transition is planned in two phases (as explained in more detail in the introduction of this report): Phase 1 assuming long-term planning and procurement functions, and Phase 2 assuming real-time operations functions.

[51] When referring to (perceived) bias, we refer to the potential for either actual or perceived bias.

[52] Nova Scotia Clean Electricity Solutions Task Force, 31 January 2024, (link).

3.5 Chapter 2 discussed the common roles and responsibilities of ISOs in our benchmarking group, which highlights the unique set of responsibilities that IESO-NS could take on. These responsibilities are illustrated, at a high level, in Figure 3-1 in order of the roles adopted in Phase 1 followed by Phase 2. The extent to which system operator roles are transferred from NSP to IESO-NS is currently still under discussion. Throughout the transition, ownership of the transmission system, but not its operation, will remain with NSP.

Figure 3-1: Illustrative roles before and after IESO transition[53]



Source: FTI Consulting analysis, discussion with IESO staff

3.6 In the remainder of this chapter we discuss in further detail the primary drivers through which benefits could be realised from the IESO's adoption of each role, in each phase. We subsequently discuss the cost implications of IESO-NS adopting these roles. Table A1-1 in Appendix 1 summarises the mechanisms leading to benefits within each role and transition phase.

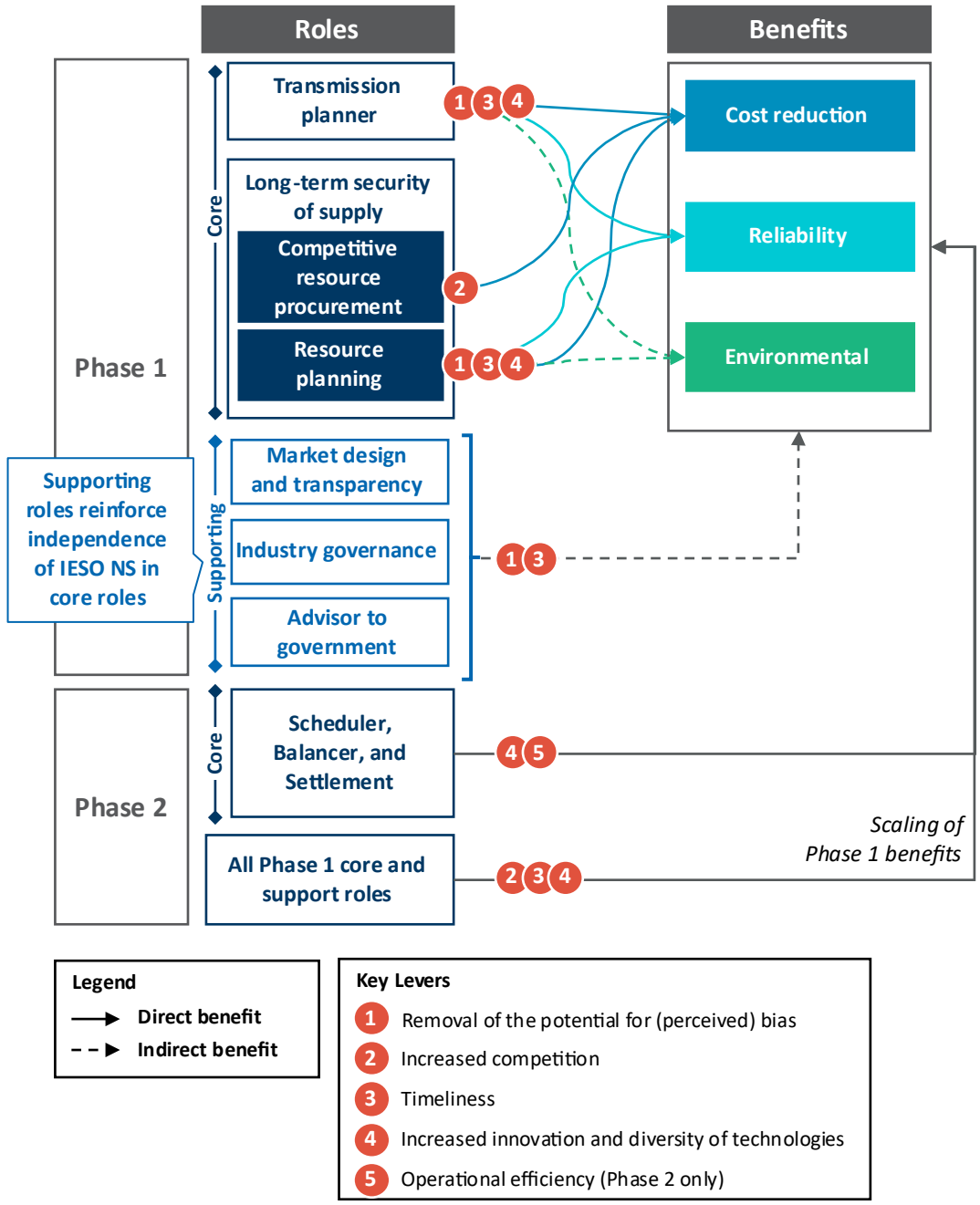
53 Note: In Figure 3-1, we list NSP for responsibility under Nova Scotia Power System Operator ("NSPSO"), for simplicity. NSPSO is a department within NSP responsible for ensuring planning, dispatch and operation within the province and the application of the market rules. See *Nova Scotia Power Inc. Standards of Conduct For the Provision of Wholesale and Renewable to Retail Electric Transmission Service*, 10 June 2016 (as amended), (link).

Benefits overview

3.7 In its two phases, the different roles transitioned from NSP to IESO-NS are expected to lead to benefits in terms of cost reductions, environmental improvements, and enhanced reliability, but setting up a new entity also has incremental costs.

3.8 Figure 3-2 below maps the potential benefits of Phase 1 and 2 IESO-NS roles to key benefit categories of cost reduction, reliability and environmental benefits, alongside key levers which drive benefits for each.

Figure 3-2: Potential benefits of Phases 1 and 2 of the IESO transition



Source: FTI Consulting analysis

3.9 Levers 1-4 are unlocked by Phase 1, whereas lever 5 is incremental to Phase 2.

i) **Removal of the potential for (perceived) bias:** The IESO's independence better aligns incentives for efficiency, removing potential material and perceived bias;

ii) **Increased competition:** More new generation resources are procured competitively, including via auctions operated by IESO-NS, which can lead to lower procurement costs by opening the door overall to a greater pool of competitors and by increasing cost discipline during construction and operation;

iii) **Timeliness:** An increase in trust and more efficient regulatory process, with the regulator focusing on oversight rather than substituting for competition, may result in accelerated energy resource development timelines, with an associated earlier reduction in production costs and carbon emissions resulting from those new resources and potentially improved reliability;

iv) **Increased innovation and diversity of technologies:** The perception of a level playing field and more advanced system planning pathways may result in more clean energy technologies, demand-side management, and less asset-heavy solutions;[54] and

v) **Operational efficiency (Phase 2 only):** Improved incentives to innovate and improved mission focus may result in improved operational decisions.

3.10 As pictured in Figure 3-2 above, each lever maps to several roles being transitioned to IESO-NS. We provide an overview of these, and their benefits for each phase below, before discussing Phase 1 and 2 in further depth.

Phase 1: *Independent planning and competitive resource procurement*

3.11 For the purposes of this section, we divide Phase 1 roles transferred to IESO-NS into core roles and supporting roles. We separately categorise more discrete, individual benefits within core roles in our quantification of benefits (Chapter 4), while supporting roles are generally qualitative in nature.

3.12 The **core roles** under Phase 1 – and their benefits – are:

i) **Long-term security of supply:** Cost savings are expected from the introduction of competitive procurements for selected new energy resources. Competition, rather than rate-regulated, incumbent-built resources, can lead to improved cost discipline. Reduced potential for (perceived) bias and increased trust in the planning entity embodied by IESO-NS may also lead to timelier buildout of resources, including demand-side management that may lead to cost reductions and improve reliability through innovation; and

ii) **Transmission planner**: Due to decreased (perceived) bias and increased trust, the IESO may facilitate more efficient transmission investment decisions and timely construction, including non-wires alternatives, lowering costs for consumers in the long-term and increasing reliability.

3.13 Table 3-1 below summarises the benefits that are explained and quantified in Chapter 4 and how they relate to the roles and levers described above.

[54] The prediction or quantification of exact changes to the future resource mix is out of scope for this report, and are not quantified in Chapter 4; however, the fact that new, innovative technologies potentially could be introduced by the IESO's planning and operation roles is an underlying justification for some benefits quantified in Chapter 4.

Table 3-1: Phase 1 benefits and underlying levers

	Long-term security of supply	Transmission planner
2 **Increased competition**	(1) Shifting cost overruns risk (2) Reduced resource investment cost from competitive resource procurement	
3 **Timeliness**	(3A) Reduced production costs from accelerated deployment (3B) Accelerated *resource* CapEx deployment (financial disbenefit) (4) Avoided carbon costs from accelerated deployment	(3A) Reduced production costs from accelerated deployment (3B) Accelerated *transmission* CapEx deployment (financial disbenefit) (4) Avoided carbon costs from accelerated deployment

3.14 Increased trust in IESO-NS as an independent entity enables the IESO to also take up the following **supporting roles** under Phase 1:

i) **Market design and transparency**: Market rules improving access to the grid and increasing availability of data can provide a more level playing field for new resources to connect and participate in the power system;

ii) **Industry governance:** An impartial non-profit is generally better trusted, even if it is only a matter of perception rather than any material bias, to implement reliability standards, grid codes, and engineering guidance for networked assets; and

iii) **Advisor to government**: The IESO providing impartial advice to government can support and accelerate needed investments without the perception of bias imposed on a VIU. Advisory costs incurred by government seeking independent advice can be reduced, while greater consistency in advisory support can enhance the quality of advice.

3.15 Adopting the supporting roles in Phase 1 has the potential to reduce overall consumer costs to some extent, but the most important benefit is the enhancement of the IESO's independence in the execution of its core responsibilities, thereby increasing trust from stakeholders and policymakers and removing a source of friction in decision making.

3.16 It must be acknowledged that certain **costs** are inherent to a transition of certain tasks from a VIU to the IESO. While many costs are likely to be transferred from one entity to another, e.g., many computing and software costs, some are incremental. Two categories of costs, direct costs and lost synergies, are further explained in 3.21 to 3.24.

***Phase 2**: More efficient operations and further unlocking benefits from independent planning and resource procurement*

3.17 The core roles transferred to IESO-NS under Phase 2 are **Scheduler, Residual Energy System Balancer and Settlement**. Improved incentives to reduce operational costs and innovate are expected due to the organization having a greater clarity of focus and more specific mission to plan and run the system. This is expected to increase the efficiency of energy resource and transmission asset scheduling and dispatch, as well as balancing and operational reliability. This is ultimately reflected in the settlement role, where asymmetry of information no longer has the potential to play a role.[55]

3.18 The core operational roles in Phase 2 can as well unlock further benefits in the core planning and procurement roles in Phase 1. The latter is primarily driven by the following:

i) **Indirect benefits related to the long-term security of supply and transmission planner role:** any improvements in operational efficiency may in the long-run unlock different planning pathways that will improve system planning processes. Increased knowledge of the day-to-day operational reality of power system conditions due to these improvements can improve both planning and procurement functions;[56] and

ii) **Scaling of benefits related to the long-term security of supply procurement role:** the removal of the VIU's perceived potential information advantage as a system operator may increase the magnitude of developers willing to participate in competitive auctions.

3.19 Similarly, as under Phase 1, there are two important cost categories under Phase 2 (direct and synergies), further explained in ¶3.25 to 3.28.

3.20 Table 3-2 below summarises the benefits from Phase 2 that are quantified in Chapter 4 and how they relate to the roles and levers.

[55] Acting as the settlement agent, a VIU has access to greater information (e.g., from IPP contracts) than potential and current market participants, which creates information asymmetry.

[56] For instance, adopting modern tools in the control room to dispatch the system based on a security-constrained economic dispatch ("SCED") may allow for greater incorporation of variable wind onto the system and the need for less thermal units to stay online to keep the grid in safe operating limits, potentially altering the planning and procurement decisions to serve customers at least cost for a given level of reliability.

Table 3-2: Phase 2 benefits and underlying levers

	Direct benefits from Phase 2	Indirect benefits on Phase 1 roles from Phase 2		Scaling of Phase 1 benefits
	Scheduler, residual energy system balancer and settlement	Long-term security of supply	Transmission planner	Long-term security of supply
5 **Operational efficiency**	(6) Decreased production costs from direct control room improvements (10) Avoided carbon costs from control room improvements	(9) Decreased production costs more advanced system planning (11) Avoided carbon costs from more advanced system planning		
4 **Increased innovation and diversity**		(8) Decreased CapEx from more advanced system planning, unlocked by operational efficiencies		
2 **Increased competition**				(7) Increased entry in competitive procurement

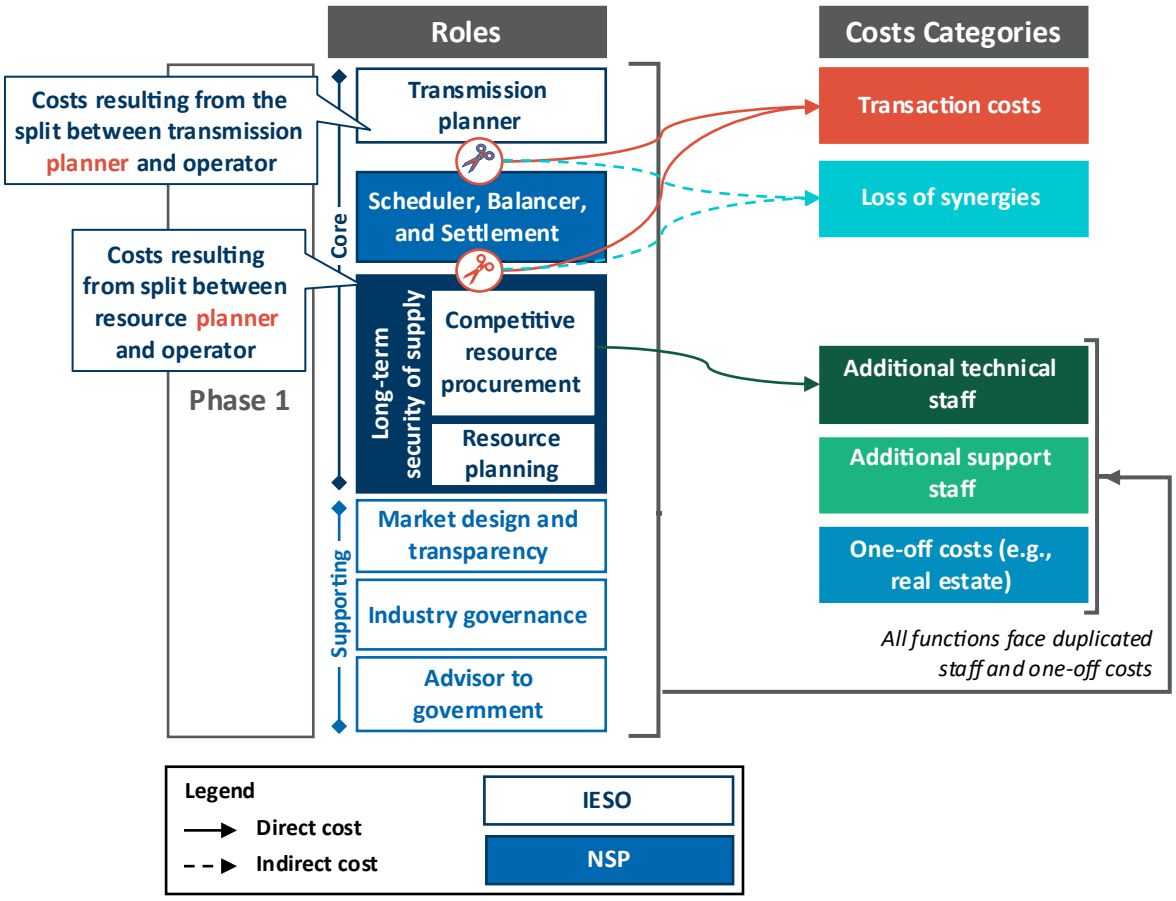
Costs overview

Phase 1 incremental costs

3.21 It must be acknowledged that certain costs are inherent to a transition of certain tasks from a VIU to an ISO. While many costs are likely to be comparable, e.g., many computing and software costs, some are incremental. As illustrated in Figure 3-3 below, the link between costs and IESO roles is less linear than benefits as many fixed costs cut across functions and support costs scale with the number of roles.

3.22 Concretely, the costs of separating the IESO from the VIU could involve one-off upfront costs, such as the purchase of a building to house a control room. This may also include the ongoing costs of additional roles that need to be present across both the IESO and other entities (e.g., NSP), such as corporate functions (e.g., human resources, finance, or legal) or the cost of roles dedicated to interfacing between the IESO and other entities. Particularly for Phase 1, incremental costs include any duplicate software licenses needed for both planning and real-time operation functions.

Figure 3-3: Incremental costs of Phase 1 IESO transition



Source: FTI Consulting analysis

3.23 Furthermore, by only implementing Phase 1 without progressing to Phase 2, loss of synergies may occur due to the separation of the planner and operator roles. We quantify this disbenefit in Chapter 4.

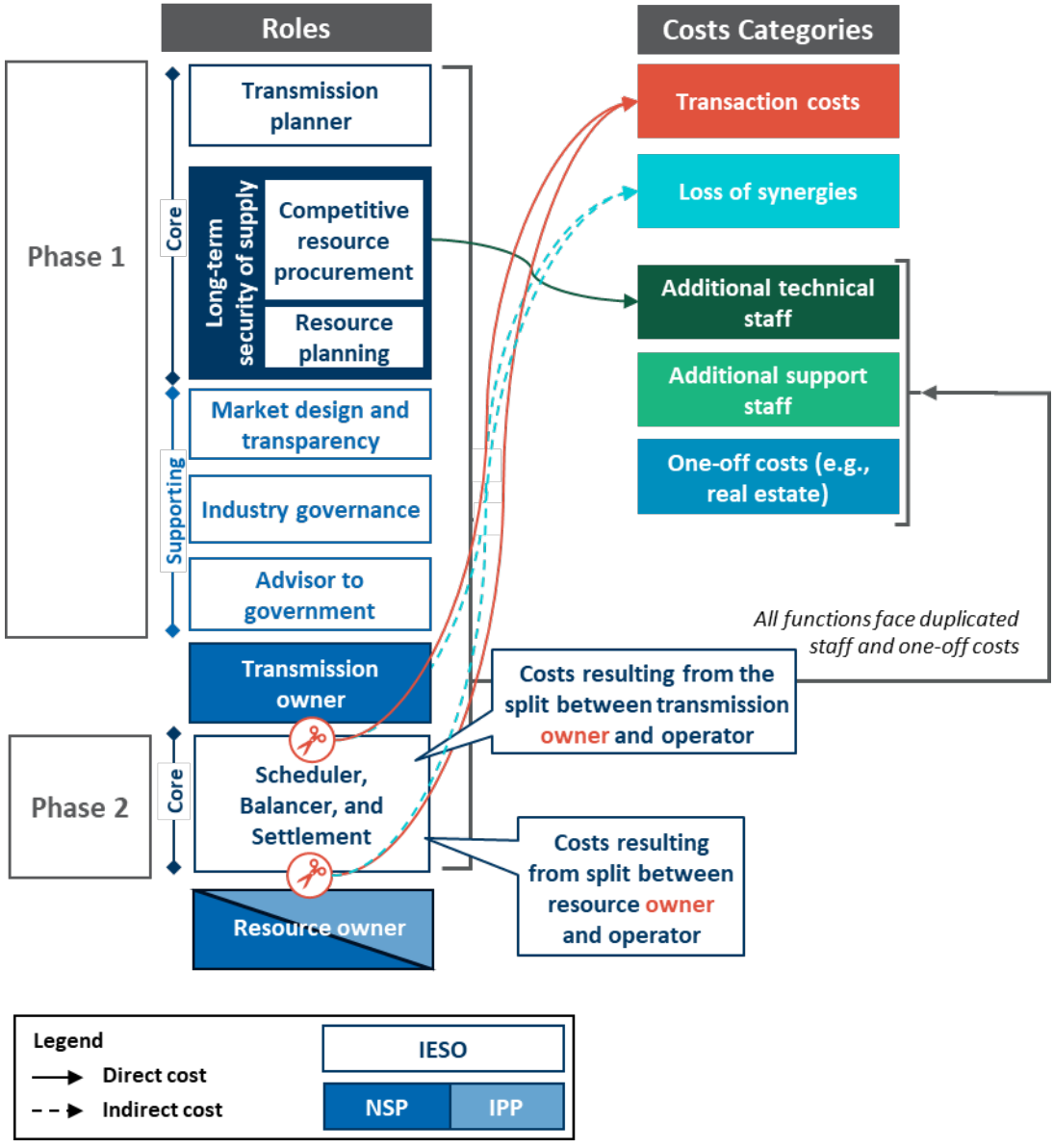
3.24 This disbenefit arises because technical expertise in operations is necessary for efficient planning and procurement decisions. This may additionally reduce decision-making efficiency; for a transmission or resource planner to make efficient investment decisions, it is critical that the planner has a deep understanding of system operations. Efficiency can be improved by communication with the operator, e.g., acquiring detailed operational information needed from NSP, resulting in transaction costs. Specific to the Nova Scotia case is the bulk transfer of NSP employees to various IESO-NS functions, which could naturally smooth communication given the working history among many of the key members of either entity.

Phase 2 incremental costs

3.25 Much of the cost for Phase 2 falls into the same broad categories as Phase 1, but to a larger magnitude for one-off costs associated with the control room and other capital-intensive activities. The implementation costs of Phase 2 heavily depend on the degree of ownership the IESO takes of system operation. With greater changes to current practice would come greater cost, to the extent that the IESO chooses to update and modernize the control room and other core elements of system operation. Increased control room investments (and associated costs) are expected to deliver increased system and consumer benefits (see Chapter 3).

3.26 The synergy between the planning and operator roles is restored with Phase 2, but a loss of synergy may instead result from the separation of the asset owner and operator roles. This is illustrated in Figure 3-4 below.

Figure 3-4: Incremental costs of Phases 1 and 2 of the IESO transition



Source: FTI Consulting Analysis.

3.27 With Phase 2, the lost synergy between the planning and operation functions is restored. However, there may be a loss of operational synergies associated with the integration of network operation and transmission and generation ownership, which might be reduced if they are unbundled. These operational synergies revolve around the IESO's role as the Balancing Authority. This loss of synergy may, for example, result in increased transaction costs due to negotiation costs for efficient asset operation. We quantify this disbenefit as well in Chapter 4.

3.28 An example of increased transaction costs is that network congestion might be cost-effectively resolved by allowing for temporary overloading of lines. Such operational practice can be relatively straightforward to execute in a vertically integrated business as the same entity operating the network owns the assets, but might lead to transaction costs (due to information that is incomplete and/or not received as quickly and the need for negotiated payments) which might at times be prohibitive when such activities are unbundled.[57]

[57] For example, before unbundling in GB, the system operator owned the England and Wales transmission systems but not Scotland's; we are aware, anecdotally, that temporary overloading in Scotland was less common than in England and Wales, likely indicating the transaction costs were high enough to discourage optimal asset management.

4. Quantification of benefits of Phases 1 and 2 of the IESO

Introduction

4.1 This chapter focuses on a subset of direct, quantifiable benefits of both Phases 1 and 2 of the IESO transition, while the full range of benefits and underlying rationale of the IESO transition are described in Chapter 3 and, in more detail, Appendix 1.[58] We organize the benefits into four key categories, based on the underlying benefit driver and provide an overview of the 12 distinct impacts from the IESO transition in Table 4-1 below.[59] The four categories of benefits are the following:

i) **Phase 1 unbundling related benefits (benefits 1, 2 and 5),** which relate to the separation of asset owner and planner, including the introduction of more competition in the energy resource market. A disbenefit from unbundling of the planning function is the loss of potential synergies between the system planner and operator function;

ii) **Phase 1 benefits from accelerated deployment (benefits 3 and 4)**, which relate to an accelerated deployment timeline for the delivery of new energy infrastructure,[60] due to the IESO running competitive procurements and also functioning as an independent entity (and therefore without perceived or actual conflicts of interest, hence accelerating the planning and approval processes) trusted to advise government and policymakers;

iii) **Phase 2 core roles benefits (benefits 5, 6 and 10)**, the direct operational benefits related to the IESO taking over the control room function and the regained synergies between the system planner and operator role; and

iv) **Phase 2 impact on Phase 1 roles:** the IESO taking on Phase 2 will provide benefits to Phase 1 roles.

[58] Benefits as used in the report includes both benefits and disbenefits.

[59] More efficient planning for both transmission and generation may be possible from Phase 1 with the IESO, an independent and impartial planner, if there is material (including implicit) bias in NSP's IRP process. However, for this analysis, we assume the IRP as performed by NSP has been unbiased and assume no related potential benefits. Further, as currently competitive procurement of transmission is not considered in Nova Scotia, we do not consider any related potential benefits.

[60] For this analysis, the accelerated deployment is modelled as an expected reduction in delay relative to the VIU case (of 1 to 2 years) but in line with the IRP.

(1) **Indirect benefits:** refer to new benefits that are not present until Phase 2. More advanced system planning pathways will be unlocked due to control room improvements. The IRP is expected to be more cost effective in the long-run, because the IESO's modernized control room operations and dispatch process will open new pathways to more efficient use of existing resources, and the integration of new, innovative technologies including more distributed energy resources ("DERs"); and

(2) **Scalars of Phase 1 benefits (benefits 7-9 and 11-12)**: refer to Phase 1 benefits that are amplified when the IESO takes on Phase 2 roles. The presence of an independent system operator is expected to increase participation and enhance competition in the procurement process by reducing the potential for perceived bias in the operator's role. The disbenefit from transitioning the system operator role for NSP to the IESO is the loss of synergies between the system operator and asset owner.[61]

4.2 Table 4-1 below shows the real present value ("RPV") of benefits of the IESO transition per phase for the 2026-2050 horizon with and without including the benefits from avoided emissions. To assess the business case for the IESO transition, the RPV of benefits should be compared with the RPV of costs. These costs include both the one-off expenses associated with establishing the IESO and the ongoing operational costs that are incremental compared to the scenario in which the VIU continues to perform planning and system operation functions. Discussion of these benefits and results is provided throughout this chapter.

[61] The relevant assets are transmission and an important share of existing generation that would remain to be owned by NSP.

Table 4-1: Quantification of IESO transition benefits, RPV for 2026-2050 period ($2025)[62]

Benefit (CADm)	Low	Mid.	High
(1) Shifting cost overrun risk	47	67	87
(2) Reduced resource cost from competitive procurement	-	67	135
(3A) Reduced production costs from accelerated deployment	186	274	363
(3B) Accelerated CapEx deployment (financial disbenefit)	(64)	(94)	(125)
(4) Avoided carbon costs from accelerated deployment	92	166	240
(5) Lost synergies from planner-operator (disbenefit)	(40)	(60)	(80)
Phase 1 total	**221**	**420**	**620**
(5) Regained synergies from planner-operator	40	60	80
(6) Control room improvements	80	240	400
(7) Increased entry in competitive procurement	36	192	347
(8) Decreased CapEx from more advanced system planning	41	205	370
(9) Decreased production costs from more advanced system planning	39	200	360
(10) Avoided carbon costs from control room improvements	19	58	96
(11) Avoided carbon costs from more advanced system planning	47	88	130
(12) Lost synergies from owner-operator (disbenefit)	(24)	(32)	(41)
Phase 2 total	**279**	**1,010**	**1,742**
Total Benefits	**$500**	**$1,431**	**$2,361**
Total Benefits (W/O avoided carbon)	**$342**	**$1,119**	**$1,895**

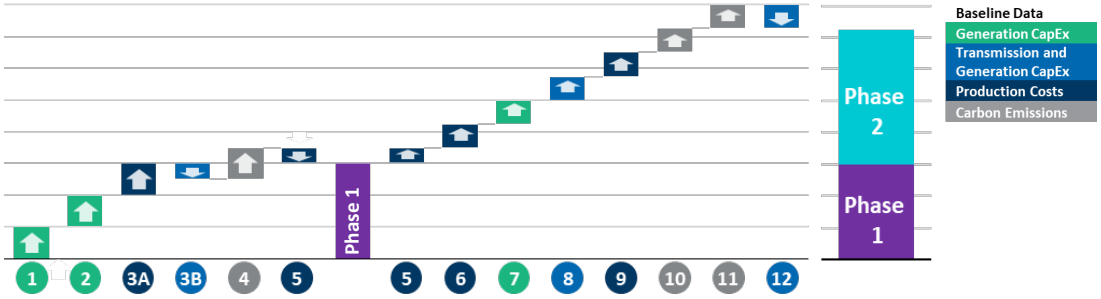
Source (FTI analysis of): Nova Scotia Power 2025 Annual Capital Expenditure Plan, NSUARB, 9 December 2024, (link); NREL Annual Technology Baseline ("ATB") Data, NREL, 2024, (link); EIA Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies, EIA, January 2024, (link); NSP 2022 Evergreen IRP Updated Assumptions, Nova Scotia Power, 26 January 2023, (link); NSP-provided data (confidential); assumptions as discussed throughout this report.

4.3 Benefits above are presented on an RPV basis, which is adjusted for the time value of money. Due to this, a *financial* disbenefit (such as 3B above) is due solely to the time value of money rather than increased cost.

4.4 Figure 4-1 below visualises the additive contribution each individual benefit makes to the overall benefits case.

[62] All cost and benefit values throughout the report are provided in CAD. RPV calculated using a 4.65% real discount rate, based on a 6.65% nominal WACC and 2% assumed inflation rate.

Figure 4-1: Illustrative additive benefits case



Source: FTI Analysis.
Note: The graphic is purely illustrative, final quantification results are further explored in the "Results of quantification" section.

4.5 As Figure 4-1 shows, there are some disbenefits (3B, 5 and 12) from transitioning from a VIU model to an ISO model. However, across the two phases, only one standalone disbenefit is present: lost synergies from owner-operator, which is assumed to be only approximately 3% of total benefits. This is because the other disbenefits are netted against corresponding benefits: the disbenefit from accelerated Capital Expenditure ("CapEx") deployment (3B)[63] is netted against associated production cost reductions arising from faster CapEx delivery in (3A), while lost synergies between planner-operator (5) is incurred in Phase 1 and reversed in Phase 2.

4.6 In the following two sections, we first explain the methodology behind the quantification of the benefits (and disbenefits) of the IESO transition, i.e., we provide the underlying rationale behind each of the identified benefits of the transition and describe the intuition behind the approach to quantify each benefit (and disbenefit). After, we provide results of the quantification, accompanied by a discussion of outcomes.

4.7 Detailed descriptions of the underlying calculations, summary of key assumptions and datasets are provided in Appendices 3 to 5.

[63] An identified benefit of Phase 1 is faster deployment of generation and transmission relative to the VIU base case due to more streamlined regulatory approval processes. A faster deployment of resources identified as required in the IRP will lead to operational benefits when more quickly deployed. However, faster deployment will also lead to capital expenditures (i.e., in the case of IESO-NS, tolling agreements and PPAs) being incurred earlier which leads to a financial disbenefit due to the time value of money. Hence, the net benefit from faster deployment is the difference between those two dynamics (3A and 3B).

Methodology

4.8 In this methodology section, we first discuss the data and general approach used to compute the benefits and disbenefits listed in Table 4-1 above. After, we describe in more detail the underlying rationale behind each of the identified benefits of the transition. A summary of data sources, key assumptions and the methodology, (including the formulas used to calculate the benefits), are found in Appendices 3, 4 and 5, respectively.

General approach and key data

4.9 For each of the identified benefits and disbenefits listed in Table 4-1, we apply a percentage reduction to existing cost categories (or increase in the case of disbenefits), based on assumed gains from the IESO transition.[64] The cost categories and corresponding benefits are shown in Figure 4-2 below.

Figure 4-2: Benefits and cost categories

Cost Category	Category
Generation CapEx	(1) Shifting risk of cost overruns (2) Reduced generation cost from competitive procurement (3B) Accelerated CapEx deployment (financial disbenefit) (7) Increased entry in competitive procurement (8) Decreased CapEx from more advanced system planning
Transmission CapEx	(3B) Accelerated CapEx deployment (financial disbenefit) (8) Decreased CapEx from more advanced system planning
Production costs	(3A) Reduced production costs from accelerated deployment (5) Lost synergy between planner/procurer and operator (disbenefit) (6) Control room improvements (9) Decreased production costs from more advanced system planning (12) Lost synergy between asset owner and operator (disbenefit)
Carbon costs	(4) Avoided carbon costs from accelerated deployment (10) Avoided carbon costs from control room improvements (11) Avoided carbon costs from more advanced system planning

64 With the exception of benefits 3A, 3B and 4, which assume a reduction in delays of 1-2 years in spending relative to the VIU case rather than percentage change in spending.

4.10 Because this analysis depends on many uncertain parameters over a long time horizon, many of the assumptions made about percentage changes to costs or length of delay are inherently subjective. While assumptions are based on empirical data where available, there is often no available data to derive estimates of impacts. We therefore calculate a high and a low case for each impact, creating a reasonable range for each benefit. For simplicity, in the results section we focus mostly on the midpoint case, which is the average of the high and low cases.

4.11 All benefits quantified are presented on a RPV basis which accounts for the time value of money through discounting. This is consistent with the methods used by NSP when performing its IRP.[65]

4.12 The relevant cost categories impacted by the IESO transition include generation CapEx, transmission CapEx, production costs and the value of carbon emissions. Below we provide a brief overview per cost category, for more detail on the derivation of these datasets, see Appendix 3.

4.13 **Generation CapEx** captures the capital cost of new energy resources that are planned to be built in the 2026-2050 period. Because cost recovery for these long-life assets is stretched over a multi-decade period, capital costs are annualised across the estimated useful life of each asset so that only the portion of an asset used in the 2026-2050 period is valued in that period. This is roughly analogous to IESO-NS entering tolling agreements and power purchase agreements ("PPAs") with energy resources, which is a revenue stream that enables the asset owner to recover the asset's capital costs. However, these agreements are financing and risk allocation instruments rather than strictly annualisation mechanisms. This cost category is separated into two subcategories:[66]

i) **Newly competitively procured** (e.g., batteries, gas generation). This includes all CapEx that will be subject to competitive procurement run by the IESO that would have otherwise been the responsibility of NSP to procure. Existing renewable (wind, solar) procurements are excluded, as they would be competitively procured even without the establishment of the IESO.

ii) **Always competitively procured**. This includes all CapEx that has historically been subject to competitive procurement, such as wind generation acquired through Rate Base Procurement or Green Choice Programs.

[65] We use a nominal 6.65% WACC converted into a 4.65% real WACC based on a 2% estimated inflation rate. The 2% inflation rate was sourced from NSP's IRP, while the 6.65% WACC was taken from *NSP's 2024 WACC and AFUDC Rates for 2025 Application* (Matter No. 11990, approved 31 May 2025).

[66] A third category of NSP-built generation is excluded from all analysis. This type of CapEx, including unit fuel conversions selected in the IRP that are owned by NSP, is not expected to change in timing or cost during or after the IESO transition.

4.14 **Transmission CapEx** represents the cost of new transmission planned to be built in the 2026-2050 period.[67] Similar to Generation CapEx above, CapEx is annualised over the expected useful life of the asset class, and increases over the 2026-2050 period.

4.15 **Production costs** represent the short-run, day-to-day variable costs to serve electricity demand in Nova Scotia. These include, e.g., the cost of fuel but not the capital costs. This value sharply decreases with the transition away from coal and then approximately stabilises over the 2026-2050 period.

4.16 **Carbon emissions value** represents the cost of carbon emitted by power plants in Nova Scotia. This is calculated from carbon emissions, the percentage of carbon emissions shielded from the carbon tax via policy exemptions, and the federal carbon price, updated May 2026.[68] System-wide carbon emissions sharply decrease with the transition away from coal and then approximately stabilise over the 2026-2050 period. The underlying carbon emission data assumes a transition away from coal, in line with policy goals, and reaching 80% renewables by 2030.[69]

4.17 The planned start date for each modelled reduction (or increase), and hence each benefit (or disbenefit), depends on the predicted start date the IESO can have impact on the relevant cost category. This means that although the considered horizon for our benefits case is 2026-2050,[70] some benefits start later than 2026 due to the phased nature of the IESO transition – most Phase 2 benefits begin in 2029 to allow for improvements from IESO control of the system to take effect. Additionally, the CapEx benefits that include an acceleration of deployment relative to the VIU case will sum costs through 2051 and 2052 for one- and two-year delays, respectively, to capture spending that would otherwise have occurred in the 2026-2050 period.

[67] As of now, there is no plan for competitive transmission procurement in Nova Scotia.

[68] The existing planning documents and dispatch simulations provided at the time of analysis reflect the federal carbon pricing schedule prior to May 15, 2026. They do not account for any changes in dispatch that would occur due to the different price signal.

[69] Clean Power Plan, Nova Scotia Power, Accessed 25 March 2026, (link).

[70] This horizon was chosen as it matches the period in the 2023 Evergreen IRP.

Phase 1: *Planning and procurement responsibilities*

(1) Shifting cost overrun risk

4.18 Cost overruns are common in large capital projects, and when borne by a utility with cost-based rates, these are typically passed on to ratepayers. Merchant facilities, however, are more likely to bear the risk of cost overruns or bear the risk on forgone potential profits degraded by higher capital costs, since their contracts are negotiated prior to construction. Hence, by introducing more competitive procurement, the IESO transition can create the opportunity for reduced costs to electricity customers with locked-in PPA or tolling agreement rates (instead of cost-based rates), which may reduce both:

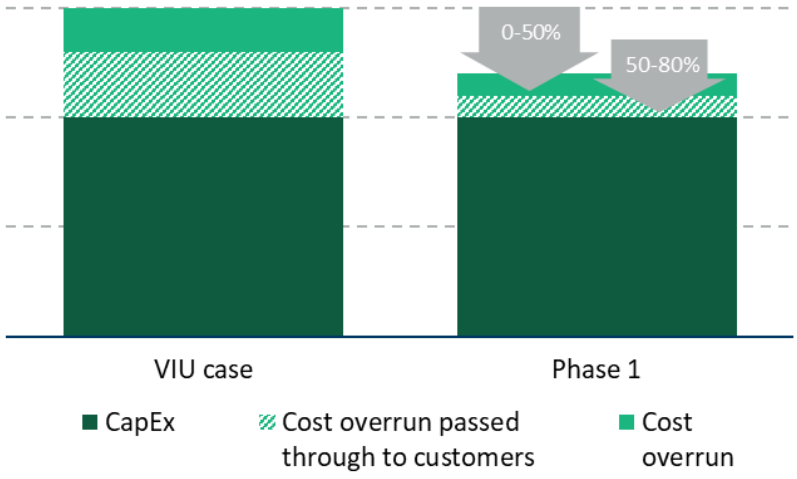
i) % capital cost overrun; and

ii) % of cost overrun passed on to customers.

4.19 Although there have been examples of contracts being re-negotiated due to increased costs, the IESO is more likely to be able to decline those requests, or structure their contract terms to discourage such actions.

4.20 We illustrate the benefit of shifting cost overrun risks in Figure 4-3.

Figure 4-3: Illustrative benefit (1)



4.21 Expected VIU cost overrun is informed by historic NSP spending on major capital projects greater than $1 million, which has averaged **16%**.[71] The extent to which this is passed on to customers is evaluated as **90%**, allowing that some overspend may be disallowed by the NSEB.

[71] See NSP's 2025 Annual Capital Expenditure Plan, Appendix D.

4.22 To capture the range of outcomes, we estimate that the IESO can reduce the cost overrun relative to a VIU model by **0%** in the low benefits scenario (i.e. no change) and **50%** in the high benefits scenario.[72] We estimate that the IESO can reduce the proportion of overspend incurred by customers relative to a VIU model by **50%** given increased independence in the low scenario[73] and by **80%** in the high scenario.[74] To see more detail on this calculation, see Appendix 5. This benefit is expected to go into effect in **2026**, effective immediately with the start of Phase 1, with the first savings realised in 2028 when the first newly procured generation is expected online.

(2) Reduced resource investment cost from competitive resource procurement

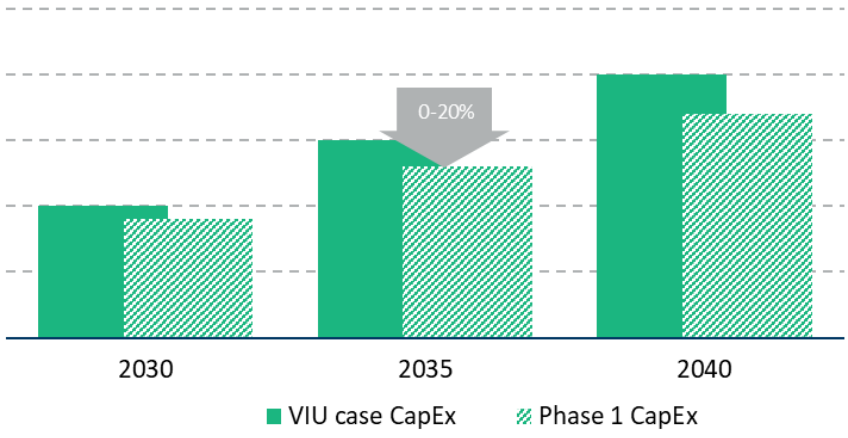
4.23 NSP, as a VIU, has historically built the majority of non-renewable generation assets. The IESO transition will allow for increased competitive procurement of new generation, which can:

i) Encourage other firms to enter the market given the increased perception of a level playing field, that can allow greater competition in building, maintaining and operating certain generation assets which can put downward pressure on the required capital costs; and

ii) Encourage firms that potentially have increased access to lower cost capital to enter the market.

4.24 The overnight cost of building new generation assets is expected to decrease with the increased share of energy resources that are subject to competitive procurement. We therefore apply a percentage savings on newly procured capacity additions, as visualised in Figure 4-4.

Figure 4-4: Illustrative benefit (2)



[72] Concretely, that capital cost overruns exceed original estimates by 16% in the low scenario (the same as NSP) and (1-50%)*16% = 8% in the high scenario.

[73] This implies that (1-50%)*90% = 45% of the cost overrun is passed on to customers.

[74] So that only (1-80%)*(90%) = 18% of the cost overrun is passed on to customers.

4.25 As mentioned in ¶4.13, for each new project the CapEx is annualised and spread across its assumed lifetime. For example, savings in CapEx for a project with an assumed lifetime of 20 years that is competitively procured in 2026 will be entirely accounted for, with the cost spread evenly over the 20 year period ending in 2046.[75] In contrast, only half of the savings in CapEx for a project with an assumed lifetime of 20 years that is expected to be competitively procured in 2040 will be considered because only half of its useful life falls within the 2026-2050 period.

4.26 This benefit is expected to go into effect in **2026**, effective immediately with the start of Phase 1, with the first savings realised in 2028 when the first newly procured generation is expected online, and have an expected savings percentage range of **0-20%**. The savings assumptions are informed by limited empirical examples.[76]

(3A) Reduced production costs from accelerated deployment

4.27 VIUs can often experience delays in the deployment of both generation and transmission projects. We assume that under the IESO such delays will be reduced. The assumed drivers behind the faster deployment of generation and transmission are:

i) Faster development timelines (due to reduced or streamlined regulatory approval) for new energy resources, transmission lines and transmission upgrades are expected with the introduction of the IESO acting as the planner without having a perceived or potential conflict of interest regarding the generation and transmission requirements it projects to be required; and

ii) Competitive procurement by the IESO can perhaps be expected to bring new energy resources online more quickly than in a VIU model due to the IESO's ability to launch Request for Proposals ("RfPs") quickly following completion of the IRP, without the need for regulatory pre-approval for capital spending.

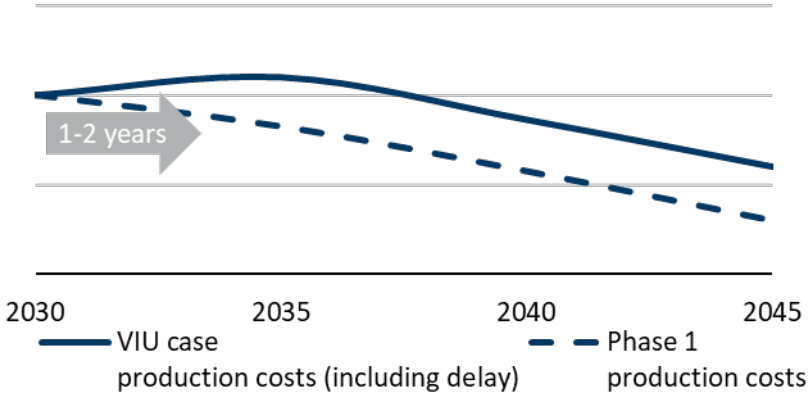
4.28 While running a solicitation and choosing a winning bidder rather than an incumbent requesting to build a new asset adds a new step to the development timeline, a VIU would likely also have to procure a contractor through an Engineering, Procurement, and Construction ("EPC") contract to construct the asset. We believe the greater effect is the removal of the NSEB approval needed for NSP spend greater than $1 million, which adds a potentially lengthy additional step to the development timeline early in the process.

[75] This annualization is not modelled to exactly match the various depreciation methodologies that could apply to different assets.

[76] Newly procured resources are predominantly natural gas plants and batteries. Construction cost data from S&P CapIQ datasets, sourced from FERC Form 1 data yielded inconclusive data for natural gas plants built in a deregulated market or by a VIU. A recent proposal from NSP estimates the cost of building a battery at parity with the estimates in the IRP from EIA and NREL data (see NSEB matter No. M11539). A high-end estimate of *transmission* (rather than generation) cost savings provides an example of competitively procuring a specific technology but is not a perfect comparison (*see Cost Savings Offered by Competition in Electric Transmission*, Brattle, 2019, (link)).

4.29 Relative to the VIU base case, production costs are expected to fall sooner over time as new, lower variable-cost capacity (primarily wind) comes online with sufficient new gas, batteries, and transmission to support it. This benefit is visualised in Figure 4-5.

Figure 4-5: Illustrative benefit (3A)



4.30 This benefit is expected to go into effect in **2026**, effective immediately with the start of Phase 1, with the first savings realised in 2028 when production costs begin to materially decline year over year. Project advancements are estimated as a range of **1-2 years** for our low and high case, respectively.[77]

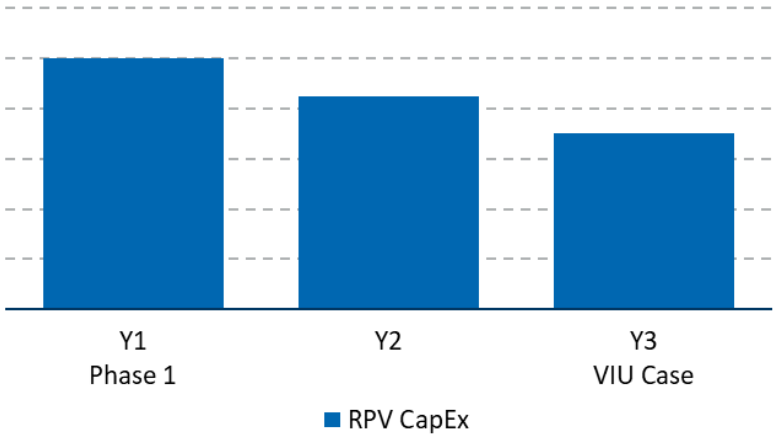
4.31 While there are likely important reliability benefits from accelerated deployments of new energy resources in line with the IRP timeline, we do not quantify these explicitly.

(3B) Accelerated CapEx deployment (financial disbenefit)

4.32 As discussed above, for both generation and transmission, we can expect faster construction timelines and a faster reduction of production costs relative to the counterfactual VIU scenario. However, by deploying capital faster, there is a financial (time value of money) cost arising from the creation of the IESO. This is because if the costs are incurred earlier, the discounted costs of those investments are higher than if there had been a delay. This present value increase under the IESO in CapEx is illustrated in Figure 4-6 below.

[77] Although NSP has a historic average delay of six months for major capital projects over $1 million (See *NSP's 2025 Annual Capital Expenditure Plan*, Appendix D), we would anticipate greater delays for building new, large-scale capital projects (for reference, the last large thermal power plant NSP built was commissioned in 1994) and substantial transmission upgrades that are anticipated to be required over the period to 2050.

Figure 4-6: Illustrative disbenefit (3B)

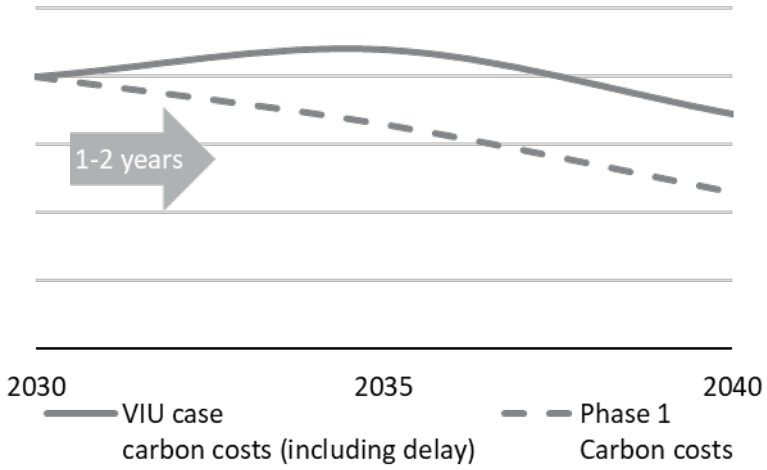


4.33 This disbenefit is expected to go into effect in **2026**, effective immediately with the start of Phase 1, with the first costs realised in 2028 when the first newly procured generation is expected online. Accelerated deployments are in the same **1-2 year** range used in 3A above.

(4) Avoided carbon costs from accelerated deployment

4.34 As with production costs, the changing resource mix will drive a reduction in carbon emissions. Faster deployment results in a reduction in the average carbon intensity of the system, as mostly renewable assets and storage come online earlier in the IESO case relative to the counterfactual. When calculating the value of avoided carbon, we consider both the federal carbon tax and the percentage of emissions shielded from the carbon tax via policy exemptions.

Figure 4-7: Illustrative benefit (4)

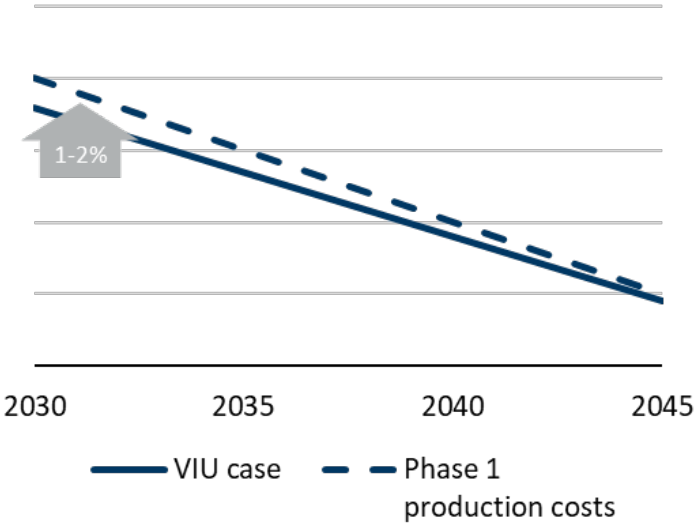


4.35 This benefit is expected to go into effect in **2026** immediately with the start of Phase 1, with the first savings realised in 2028 when carbon emissions begin to materially decline year over year. Accelerated deployments are the same **1-2 year** range used in 3A and 3B above.

(5) Loss of synergies from planner and operator

4.36 Prior to the IESO, the planner and operator functions were combined under NSP. Separating these functions – if Phase 1 only was implemented - can conceivably create additional transaction costs and remove inherent system knowledge valuable in planning, notably increasing barriers for information flows. We anticipate this may lead to increased production costs as the system is operated in a manner different to that expected by the planner without detailed knowledge of real-time operational constraints. This increase in costs is visualised in Figure 4-8 below.

Figure 4-8: Illustrative disbenefit (5)



4.37 This disbenefit is expected to go into effect in **2029**, since the planning process takes several years for impacts to be realised. We estimate an expected increase in production costs ranging from **1-2%**.

***Phase 2:** Independent system operation*

4.38 This analysis assumes an implementation timeline for the initial stage of Phase 2 in 2027 with substantial control room improvements effective in 2029. Because the timeline of Phase 2 is still under development, we also provide a sensitivity analysis using a conservative timeline of 2028 as the initial stage of Phase 2 and 2032 for control room improvements, although initial improvements are expected to be implemented prior to this date.

(5) Regained synergies from planner and operator

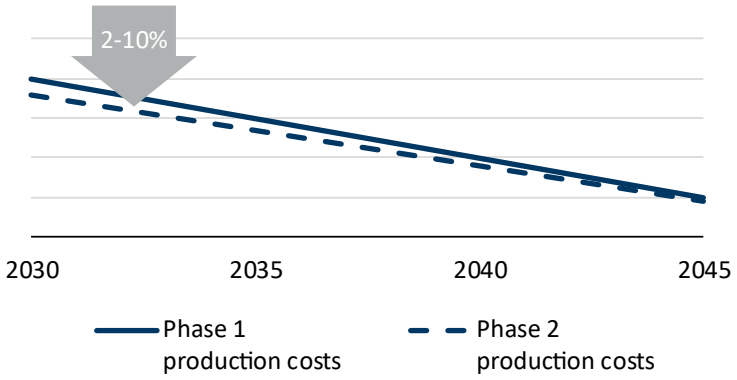
4.39 Re-combining the planner-operator function regains the synergies explained in (5) in Phase 1 above. This simply cancels out the disbenefit above.

(6) Direct control room improvements

4.40 The transfer of system operations from NSP to the IESO is expected to coincide with a significant modernization of the current dispatch process.[78] Updates to operational assets and practices would likely be delayed and more limited under the VIU base case due to greater institutional inertia. Moreover, as system operation is the *core function* of an ISO—rather than one of many responsibilities within a VIU—the increased focus on the system operator function is expected to drive permanent operational improvements. These improvements, in turn, are anticipated to enhance the efficiency of resource utilisation leading to a reduction in overall production costs.

4.41 Modernization and additional investment in control room hardware, software and overall management, is expected to reduce system production costs. This is visualised in Figure 4-9 below. The incremental costs of investment in the control room are over and beyond those incurred by NSP, and are not considered in this analysis. These will have to be compared to the RPV of the benefits from control room improvements as part of future analyses and business case development.

Figure 4-9: Illustrative benefit (6)



4.42 This benefit has cascading effects represented in the following benefits below, as the more sophisticated control room and associated dispatch capabilities will unlock further benefits throughout Phase 2 and Phase 1 roles (see benefits 8-11).

[78] Recently, NSP has begun implementing the NSP Hitachi Energy Control Centre Portfolio Optimization tool. We are unable to find published expected benefits for this project, so we calculate benefits based on a baseline that does not include any benefits from this project. Improvements made by NSP would diminish, but are overall expected to be lesser than, the benefits calculated in (6) attributed to the IESO-led control room improvements.

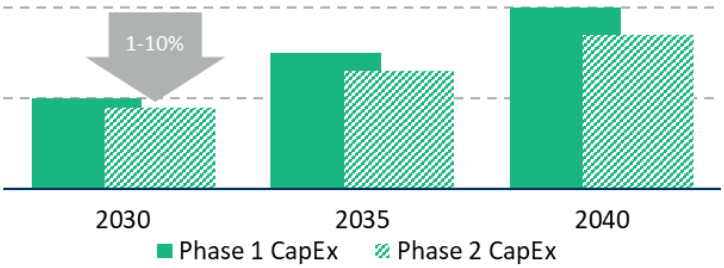
4.43 This benefit is expected to take effect in **2029**, assuming that substantive control room improvements may take an additional two years to implement after the Phase 2 start date in 2027. Expected savings of **2-10%** is informed by estimates in operational efficiency improvements with more sophisticated dispatch processes[79] and a recognition of the range of improvement possible in dispatch processes.

(7) Scaling effect from independent system operation: increased entry in competitive procurement

4.44 In a Phase 1-only IESO, a dispatch run by the incumbent NSP may deter some participation of third-party competitors in IESO-led procurements. The removal of information asymmetries and potential conflicts of interest associated with the VIU acting as the real-time system operator is expected to increase participation and reduce perceived risk in competitive procurements, both for already competitively procured resources such as renewables and newly procured resources under the IESO. This, in turn, is expected to lower capital costs for new generation and storage assets.

4.45 This benefit is visualised in Figure 4-10.

Figure 4-10: Illustrative benefit (7)



4.46 This benefit is expected to take effect in **2027**, starting as soon as Phase 2 begins. Expected savings are estimated at **1-10%**, and will be incremental to (2) above.

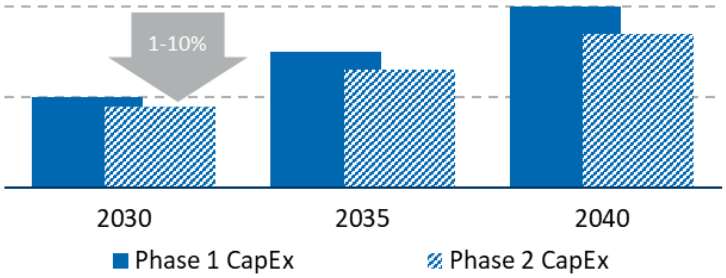
(8) Indirect benefit from control room improvements: decreased CapEx from more advanced system planning

4.47 More advanced planning for both transmission and generation is expected when the IESO can unlock new planning pathways with detailed knowledge of the costs and constraints of the system enabled by improvements in the control room. In addition, the modernization of the control room likely will allow the IESO to access more detailed system information than was previously available, leading to potential further improvements in system planning processes.

4.48 This is visualised in Figure 4-11.

[79] Most studies involve gains observed in jurisdictions that transitioned to wholesale energy spot markets, which often entails an improvement in the centralised dispatch process used by the system operator compared to the former VIU (but also includes market-price incentives). Some of the gains are from operational improvements and some from trade. See for example, *Do markets reduce costs? Assessing the impact of regulatory restructuring on US electric generation efficiency*, Fabrizio et al., 2007, (link); and *Imperfect markets versus imperfect regulation in US electricity generation*, 2022, Cicala, (link).

Figure 4-11: Illustrative benefit (8)

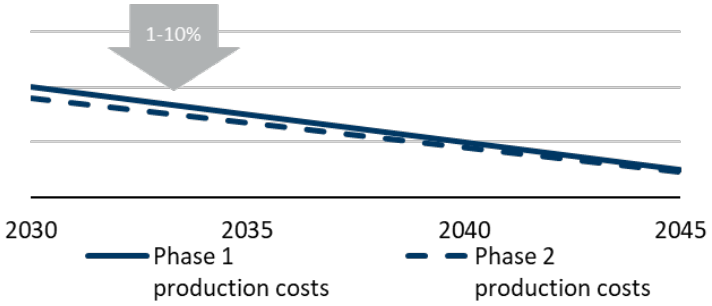


4.49 This benefit is expected to take effect in **2029**, a few years after the first IESO-produced IRP is completed and after the Phase 2 transition occurs. While somewhat subjective, we have assumed that expected savings are **1-10%** of CapEx spend.

(9) Indirect benefit from control room improvements: decreased production costs from more advanced system planning

4.50 The outcome of more advanced planning in benefit (8) above will likely result in reduced production costs. This is visualised in Figure 4-12.

Figure 4-12: Illustrative benefit (9)

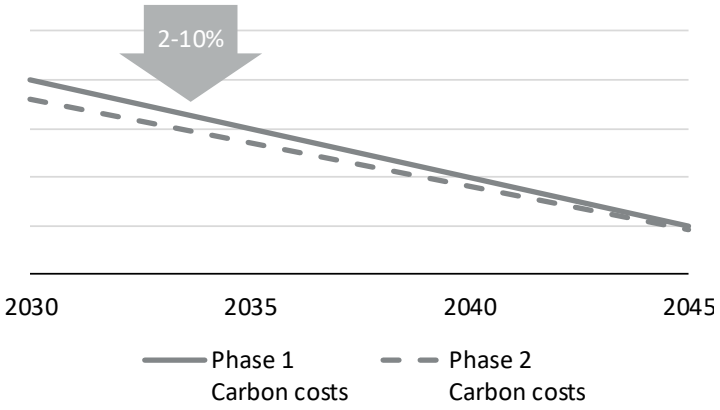


4.51 This benefit is expected to take effect in **2029**, a few years after the first IESO-produced IRP is completed and after the Phase 2 transition occurs. Expected savings are estimated at **1-10%**, and may differ in magnitude from the savings in (8) above depending on specific planning pathways unlocked (i.e., some pathways may have trade-offs between high and low CapEx vs production costs but still result in overall savings).

(10) Scaling effect from control room improvements: avoided carbon costs from control room improvements

4.52 Improvements in the control room as described in (6) could lead to increased diversity in dispatched technologies, particularly less carbon-intensive technologies via lower curtailment of wind or increased demand-side participation. This is represented in Figure 4-13.

Figure 4-13: Illustrative benefit (10)



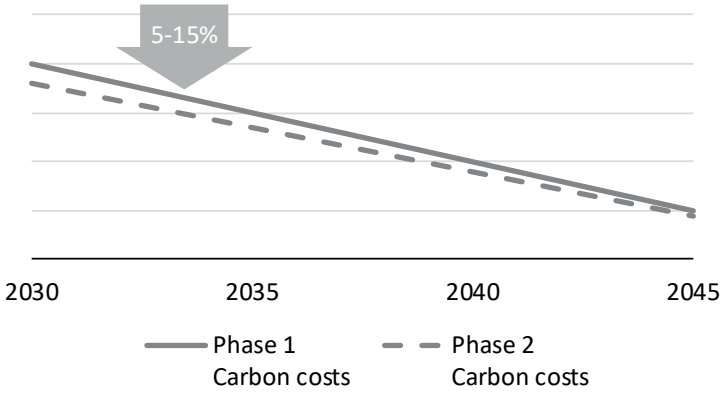
4.53 When calculating the value of avoided carbon, we consider both the federal carbon tax and the percentage of emissions shielded from the carbon tax via policy exemptions.

4.54 This benefit is expected to take effect in **2029**, a few years after the first IESO-produced IRP is completed and after the Phase 2 transition occurs. Expected savings in carbon emissions of **2-10%** are linked to estimates of production cost savings. The carbon savings associated with production costs savings depends on the ratio of marginal to average carbon intensity compared to the ratio of marginal to average production costs. This relationship is conservatively estimated at 1:1 assuming wind displaces generation from a simple-cycle gas turbine.

(11) Indirect benefit from control room improvements: avoided carbon costs from more advanced system planning

4.55 New system planning pathways unlocked by control room improvements, as described under benefit (8), may result in fewer carbon-intensive resources built and operated less often. This is visualised in Figure 4-14.

Figure 4-14: Illustrative benefit (11)



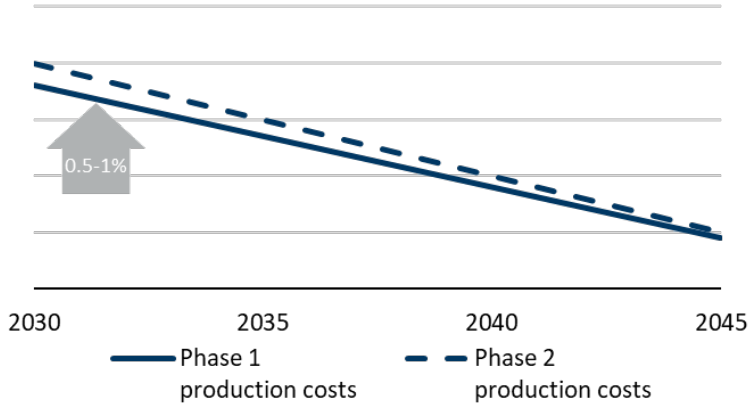
4.56 For the value of avoided carbon, we again consider both the federal carbon tax and the percentage of emissions shielded from the carbon tax via policy exemptions.

4.57 This benefit is expected to take effect in **2029**, a few years after the first IESO-produced IRP is completed. Expected savings in carbon emissions of **5-15%** are likely to be higher than in (10) since they reflect new planning pathways rather than only a change in operation of a given resource mix and transmission system.

(12) Loss of synergies between asset owner and operator (disbenefit)

4.58 The separation of asset ownership and operation creates some lost synergies, as explained in Chapter 3. This is due to the change to a contractual interface (in which negotiations, formalised contracts and payments may be required) rather than only an operational interface, creating friction. This leads to transaction and information sharing costs in operational decisions, resulting in an expectation of a slight increase in production costs. This is visualised in Figure 4-15 below.

Figure 4-15: Illustrative disbenefit (12)



4.59 This disbenefit is expected to take effect in **2027**, once Phase 2 begins. Expected increases in production costs of **0.5-1%** are informed by FTI experience working with a system operator owning transmission in some but not all regions over which it operates the assets.

Results of quantification

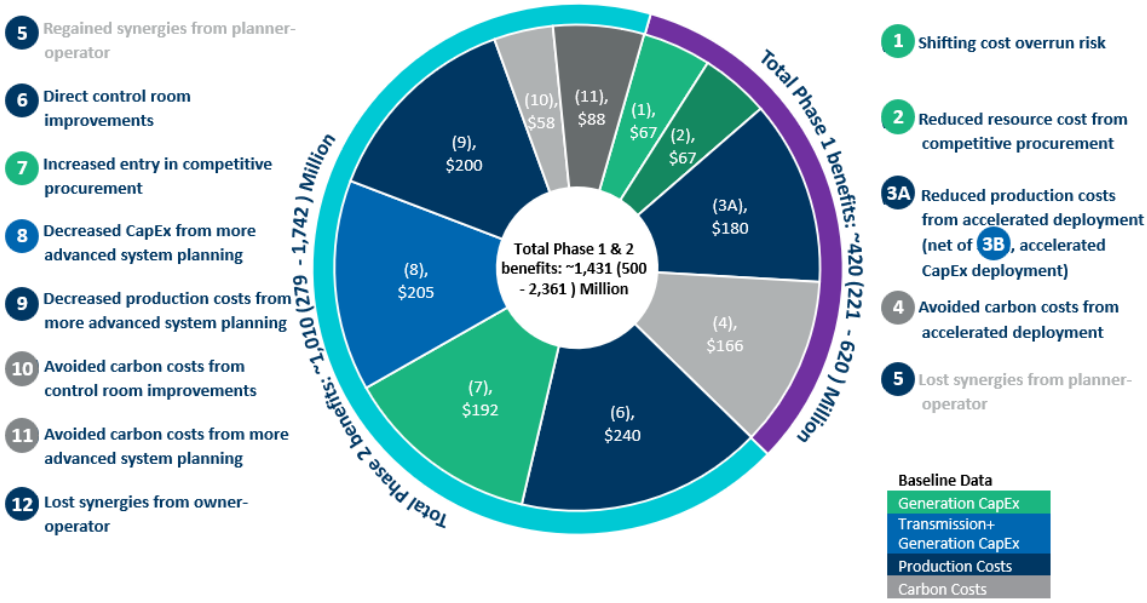
4.60 The results section consists of six parts. First, we introduce the overall results of the quantification of the identified benefits and disbenefits, i.e., the RPV of the IESO transition over the 2026-2050 horizon. Second, we show the yearly benefits in more detail. Third, we describe the results excluding the impact of avoided carbon costs. Fourth, we describe the results with full-priced carbon emissions with no policy shield. Fifth, we assess the magnitude of incremental annualised costs for the IESO that would result in a break-even outcome under the various scenarios. Sixth and finally, we perform a sensitivity analysis using a conservative timeline of 2028 as the initial stage of Phase 2 and 2032 for control room improvements.

Core results

4.61 The results of the quantification described above sum to over $1.4 billion in the midpoint case, within a range of $500 million to $2.4 billion over the 2026-2050 period. The IESO transition has a diverse set of benefits impacting a variety of cost categories (CapEx generation, CapEx transmission, production costs, carbon emissions). All four cost categories have significant benefits across Phase 1 and Phase 2.

4.62 Below in Figure 4-16 we show the cumulative RPV of benefits for the midpoint case.

Figure 4-16: Cumulative benefits, midpoint case (2026-2050), $m 2025[80]



Source: FTI Analysis.

4.63 Figure 4-16 above shows that Phase 2 benefits make up approximately two-thirds of the total benefits in the midpoint case, with approximately 40% of benefits coming from avoided carbon costs in Phase 1 and 14% in Phase 2 (see steep decline of fossil generation with the phase out of coal early in the 2026-2050 period driving large carbon emissions reductions, shown in Figure A3-3 in Appendix 3). Over 75% of benefits are driven by reduced CapEx costs and reduced production costs.

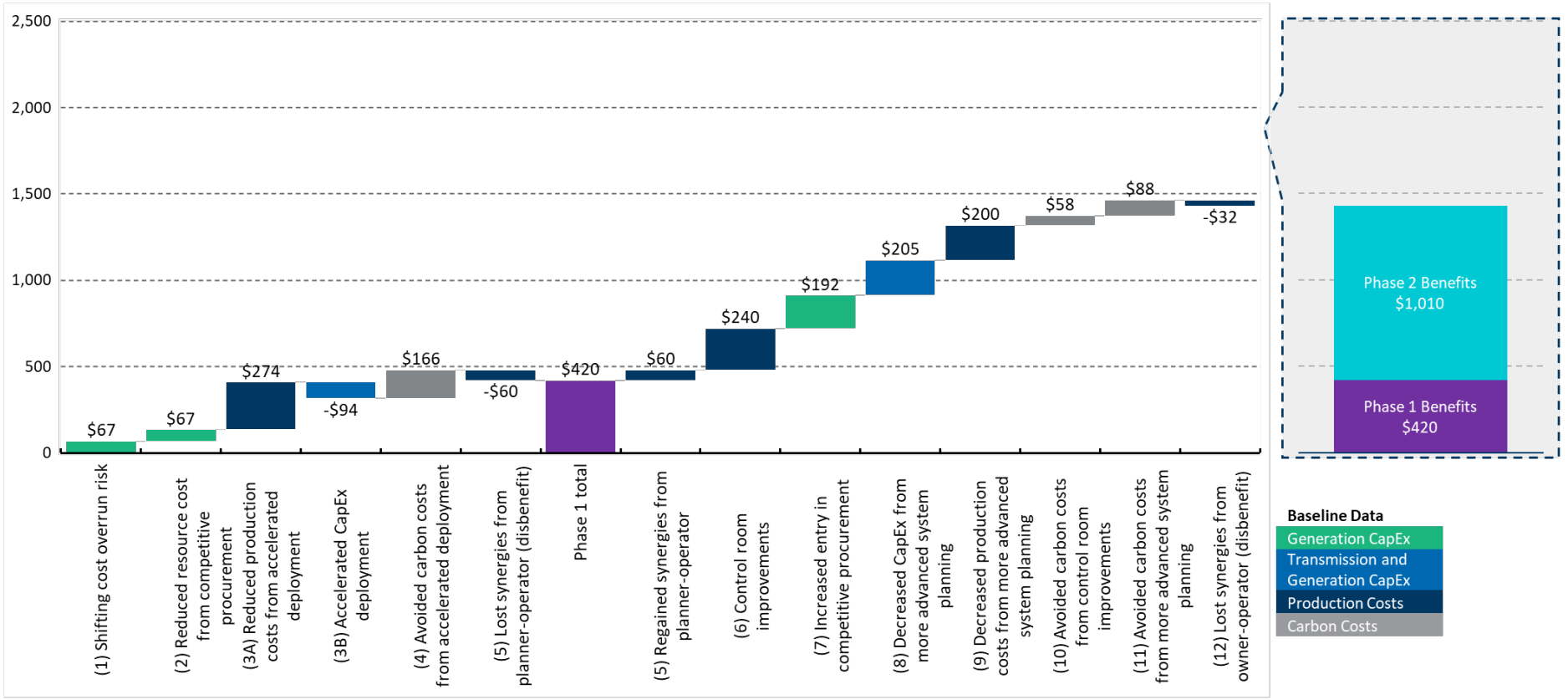
4.64 Benefits from Phases 1 and 2 are shown in Figure 4-17 below, each shown as a step in the IESO transition as the cumulative benefits sum to $1.4 billion. The disbenefits (3B, 5 and 12) are shown as downward steps while each of the positive benefits are upward steps towards the final total.

4.65 Phase 1 benefits largely stem from an accelerated decarbonization trajectory relative to the VIU baseline, while Phase 2 benefits predominantly stem from control room improvements over and above the Phase 1 baseline.

80 Disbenefits (5) and (12) are not plotted, but numerically included in the Phase 1 and 2 totals. Disbenefit (3B) is netted against benefit (3A). For sources, see Appendix 3.

4.66 Benefit (6), control room improvements, has cascading impacts on following Phase 2 benefits (benefits 8-11). Hence the total benefits of control room improvements are estimated to be $791 million when considering the connected benefits. Without control room improvements, Phase 2 also provides benefits in the competitive energy resource procurement process by removing material or perceived bias in control room operation.

Figure 4-17: Phase 1 and 2 cumulative benefits, midpoint case (2026-2050), $m 2025[81]



[81] For sources, see Appendix 3.

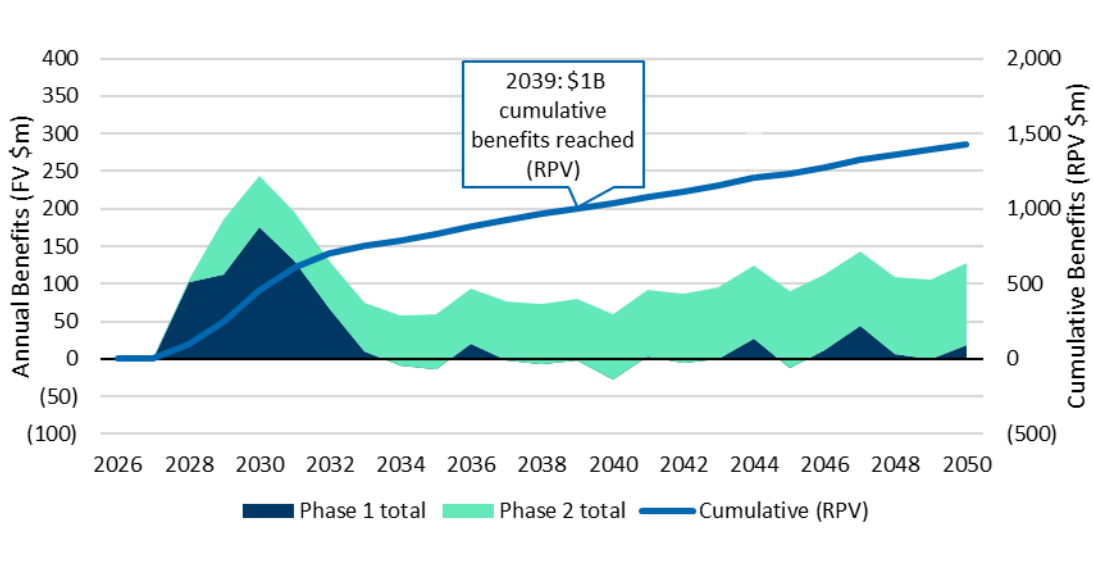
Benefits by year

4.67 The benefits of the IESO transition are frontloaded given (1) the greatest reduction in carbon emissions occurring in the 2027-2030 period, and (2) the steepest decline in production costs occurring in 2027-2032.[82]

4.68 Figure 4-18 below shows annualised benefits on a future value ("FV") basis, to show how benefits would be valued during each future year, while the RPV of cumulative benefits is additionally graphed to provide a future-looking view of the benefits as shown in other graphics in this report. The shaded annualised values show that Phase 2 begins providing benefits in 2028 and provides larger benefits 2035 onwards, while Phase 1 benefits are mostly realised in the first few years of the period. This is because Phase 1 benefits are concentrated in the first few years due to an accelerated decarbonization trajectory with associated cost savings relative to the VIU baseline, whereas Phase 2 benefits are enduring and hence spread out over the long term.

4.69 Changes in the future that trigger additional resource deployment beyond the resource plan in the most recent IRP, including significant electrification acceleration, industrial load growth, or technology policy changes, would result in further savings from the implementation of the IESO model. Due to the accelerated development timelines of the IESO relative to the VIU, the benefits of Phase 1 would increase across the horizon whenever substantial new deployments are planned.

Figure 4-18: Phase 1 and 2 FV annual benefits and RPV of cumulative benefits, midpoint case (2026-2050), $m 2025[83]



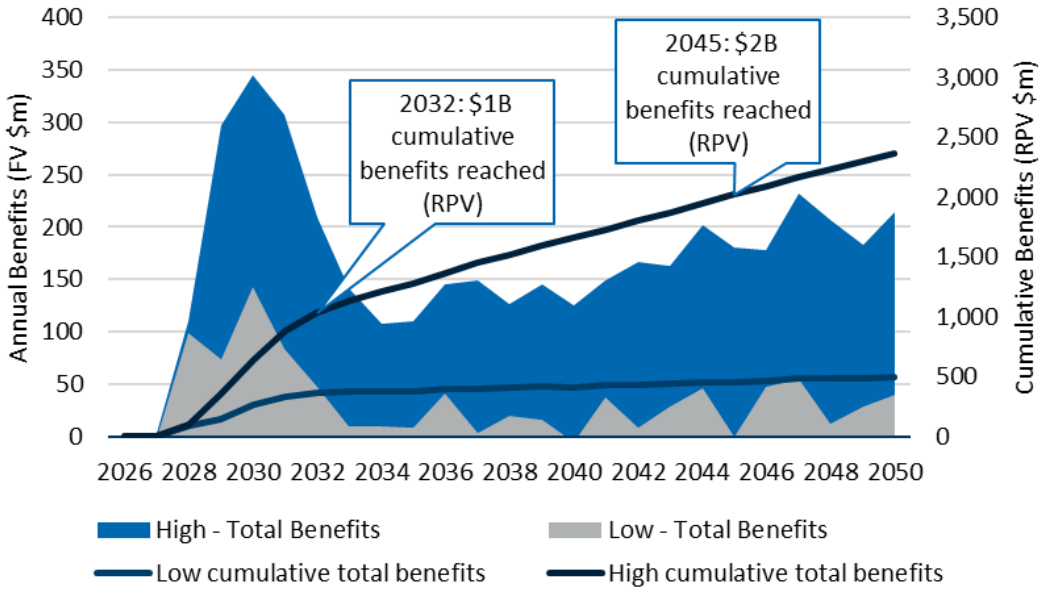
[82] Although a large share of generation CapEx is incurred early in the period, because annualised values are used to allocate CapEx across an asset's useful life (see **Figure A3-1**), CapEx-related benefits steadily increase over time.

[83] For sources, see Appendix 3.

4.70 A major milestone of $1 billion cumulative RPV of benefits is highlighted as expected in 2039. On an RPV basis, over half of benefits are realised within the first eight years of the 2026-2050 period under midpoint assumptions.

4.71 Figure 4-19[84] below shows the high and low cases separately to highlight that the high case realises $1 billion in RPV benefits in 2032 while the low case reaches $0.5 billion in RPV benefits near the end of the period.

Figure 4-19: High and low case FV annual benefits and RPV of cumulative benefits (2026-2050), $m 2025[85]



Benefits excluding avoided carbon costs

4.72 Benefits driven by reductions in carbon emissions range from 32% to 20% of total benefits in the low and high cases, respectively. This benefit category is not as monetarily direct as the other benefit categories, and is a function of the federal price of carbon and both federal and provincial carbon policies.[86]

4.73 As shown in Table 4-2 below, when excluding this benefit category from the analysis, the cumulative benefits across the 2026-2050 period are $1,119 million in the midpoint case.

[84] Unlike Figure 4-19 which shows Phases 1 and 2 as stacked areas (for example, the sum of Phases 1 and 2 in 2029 are approximately $300 million), Figure 4-20 is parallel areas where the high case is graphically behind the low case.

[85] For sources, see Appendix 3.

[86] Further detailed in Appendices 3 and 5.

Table 4-2: Quantification of IESO transition benefits excluding avoided emissions-related benefits, $m 2025[87]

Benefit (CADm)	Low	Mid.	High
(1) Shifting cost overrun risk	47	67	87
(2) Reduced resource cost from competitive procurement	-	67	135
(3A) Reduced production costs from accelerated deployment	186	274	363
(3B) Accelerated CapEx deployment	(64)	(94)	(125)
(5) Lost synergies from planner-operator (disbenefit)	(40)	(60)	(80)
Phase 1 total	**129**	**254**	**380**
(5) Regained synergies from planner-operator	40	60	80
(6) Control room improvements	80	240	400
(7) Increased entry in competitive procurement	36	192	347
(8) Decreased CapEx from more advanced system planning	41	205	370
(9) Decreased production costs from more advanced system planning	39	200	360
(12) Lost synergies from owner-operator (disbenefit)	(24)	(32)	(41)
Phase 2 total	**213**	**864**	**1,516**
Total Benefits	**$342**	**$1,119**	**$1,895**

Benefits with full-priced carbon emissions

4.74 If carbon emissions are not shielded by any policy exemptions and priced at the federal carbon price, updated in May 2026, the value of avoided carbon is over twice as high, with a total midpoint of $684 million compared to $312 million with the policy shield.

Table 4-3: Quantification of different methods for IESO transition benefits related to avoided carbon costs, midpoint and range, $m 2025[88]

Benefit (CADm)	Full-priced carbon	Carbon emissions policy shield
(4) Avoided carbon costs from accelerated deployment	476 (318-635)	166 (92-240)
(10) Avoided carbon costs from control room improvements	82 (27-137)	58 (19-96)
(11) Avoided carbon costs from more advanced system pathways	126 (67-185)	88 (47-130)

Break-even costs

4.75 To determine the net benefit of the establishment of the IESO, we must compare the incremental benefits determined in this report to the incremental costs of having an IESO.

87 For sources, see Appendix 3.

88 For sources, see Appendix 3.

4.76 Since our incremental benefits are already net of incremental costs from lost synergies (which we refer to as disbenefits in this report), we must only compare the incremental benefits to the incremental costs above and beyond the costs a VIU would incur to fulfil the roles now fulfilled by the IESO. The incremental costs include incremental running costs of the IESO, e.g., duplication of some staff, an additional real estate expense for an office building, etc., and the one-off setup costs of an ISO, particularly investments in the control room.

4.77 Note that incremental running costs are a subset of total running costs of the IESO, as many of the costs incurred by the IESO would have otherwise been incurred by NSP, i.e., the costs to customers in Nova Scotia remains, in large part, unchanged. In Chapter 2, we estimated the total annual running costs of a small-scale IESO in today's dollars to be approximately 70-140 million CAD, of which only a small fraction is truly incremental as a result of the creation of the IESO.

4.78 To determine if these annual incremental costs are likely to be beneficial to Nova Scotia consumers, we compare them to the equivalent annual benefit ("EAB") of the incremental benefits. This allows us to compare annualised benefits to annual incremental costs. We convert the present value of benefits into annualised benefits using an annuity factor:

*PV of benefits $ * Annuity factor*
Annuity factor = r / (1 – (1+r)$^{-t}$)

r = discount rate

t = number of years in period

4.79 The EAB, a constant annual amount that has the same present value is shown in Table 4-4 below.

Table 4-4 Equivalent annual benefit, $m 2025[89]

Equivalent annual benefit, annuity corresponding to PV of benefits	Low	Mid.	High
Phase 1	15	29	43
Phase 2	20	71	122
Total	$35	$100	$165

[89] For sources, see Appendix 3.

ES.28 This analysis demonstrates that the annual incremental costs of IESO-NS could be as high as $41 million in the low benefits case for IESO-NS costs to *break even* with benefits. If we believe the incremental costs of IESO-NS are lower than the EAB, then the difference is the net benefit to Nova Scotia consumers of the transition. While we do not calculate incremental costs in this report, if the incremental costs of the transition were, for example, 20% of total operating costs (estimated based on scaling the operating costs of other ISOs to Nova Scotia's size) of $70 million plus a one-off annualised, illustrative cost of $5 million, then in the low benefits case the net benefits are $35 million - $14 million[90] - $5 million = $16 million on an annualised basis, a benefit-to-cost ratio of 1.8. In the mid and high benefits cases with the same illustrative incremental operating costs, this would be a net benefit of $81 million annually and a benefit-to-cost ratio of 5.3, and a net benefit of $146 million annually and a benefit-to-cost ratio of 8.7, respectively.

4.80 When excluding avoided emissions-related benefits, the EAB is still favourable relative to high-level estimates of the incremental costs of the IESO, as shown in Table 4-5 below.

Table 4-5: Equivalent annual benefit excluding avoided emissions-related benefits, $m 2025[91]

Equivalent annual benefit, annuity corresponding to PV of benefits	Low	Mid.	High
Phase 1	9	18	27
Phase 2	15	61	106
Total	$24	$78	$133

Sensitivity analysis

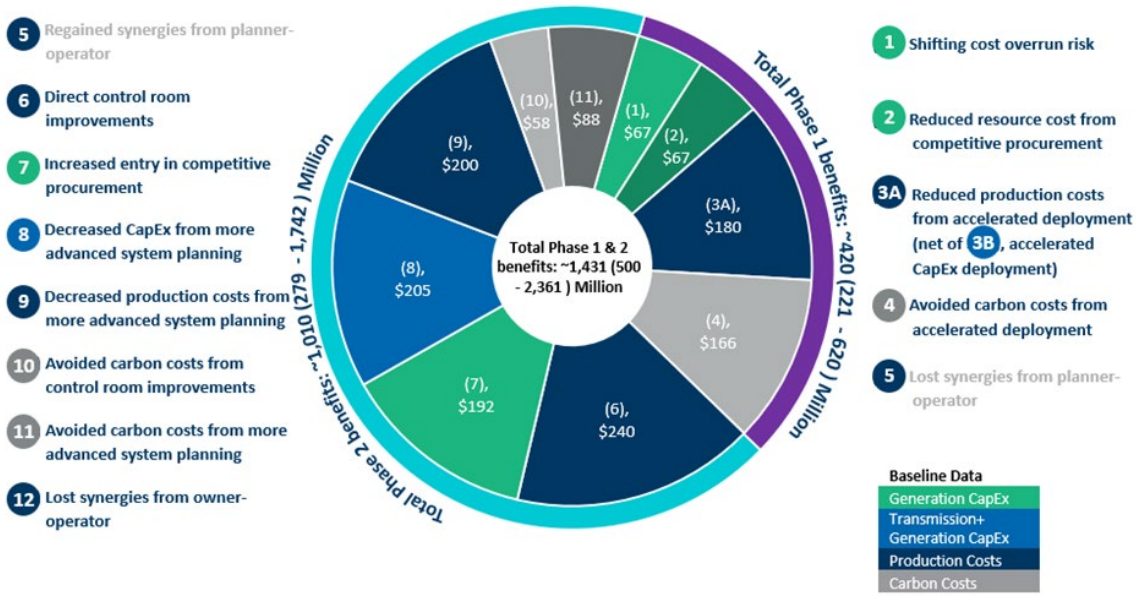
4.81 Because the timeline of Phase 2 is still under development, we also provide a sensitivity analysis using a conservative timeline of 2028 as the initial stage of Phase 2 and 2032 for control room improvements, although improvements are expected to begin prior to this date. This represents a conservative lower bound of benefits in relation to the Phase 2 timeline.

4.82 In this sensitivity analysis, benefits in the midpoint case are $1.287 billion, a 10% decrease compared to the base case scenario, ranging from $460 million – $2.113 billion in the low and high benefits cases. This is shown in Figure 4-20 below. Benefit (6), control room improvements, in the midpoint case is $189 million (down from $240 million in the base case), with cascading benefits from control room improvements (benefits 8-11) totalling $459 million.

[90] $70 million * 20% = $14 million.

[91] For sources, see Appendix 3.

Figure 4-20: Sensitivity analysis cumulative benefits, midpoint case (2026-2050), $m 2025[92]



Source: FTI Analysis.

4.83 The EAB, a constant annual amount that has the same present value of the benefit stream, is shown in Table 4-6 and Table 4-7 below, with and without the value of avoided carbon.

Table 4-6: Sensitivity analysis equivalent annual benefit, $m 2025[93]

Equivalent annual benefit, annuity corresponding to PV of benefits	Low	Mid.	High
Phase 1	15	29	43
Phase 2	17	61	105
Total	$32	$90	$148

Table 4-7: Sensitivity analysis equivalent annual benefit excluding avoided emissions-related benefits, $m 2025[94]

Equivalent annual benefit, annuity corresponding to PV of benefits	Low	Mid.	High
Phase 1	9	18	27
Phase 2	13	52	92
Total Break-even Costs	$22	$70	$118

92 Disbenefits (5) and (12) are not plotted, but numerically included in the Phase 1 and 2 totals. Disbenefit (3B) is netted against benefit (3A). For sources, see Appendix 3.

93 For sources, see Appendix 3.

94 For sources, see Appendix 3.

5. Conclusions

5.1 The establishment of IESO-NS represents a foundational transformation of Nova Scotia's electricity sector. The shift from an investor-owned vertically integrated model to an independent, non-profit system operator provides opportunity for increased participation and competition in the electricity sector, creates greater transparency for customers, and aligns incentives in the regulatory process.

5.2 The transition from a VIU model to an ISO model in Nova Scotia is anticipated to yield benefits between $500 million and $2.4 billion in today's dollars. The reasonable range is created as the benefits depend on many uncertain parameters over a long time horizon. The benefits are spread across 12 distinct benefit categories ranging from increased competition to accelerated deployment timelines for new energy and transmission resources to operational efficiency improvements in the control room. Benefits are expected to be relatively larger in the first 5-13 years of the IESO-NS transition, due both to an accelerated trajectory of decarbonization relative to the VIU and the time value of money, with $1 billion cumulative benefits estimated to be reached by 2039 in the midpoint scenario.[95]

5.3 The benefits of Phase 2 (real-time operations), which are spread more evenly across the horizon, are approximately twice the size of Phase 1 (planning and procurement), indicating a strong business case for the continued transition of operational roles to IESO-NS, subject to estimated costs.

5.4 The annualised values of the range of benefits discounted to today's dollars (EAB) indicates that the business case for Phase 1 and 2 of IESO-NS is favourable if the annual incremental operating costs of the IESO are not higher than $35 million, or $24 million not including the value of avoided carbon. These incremental costs are lower than the IESO's total operating costs, as certain functions are transferred from the VIU to the ISO.

5.5 The establishment of IESO-NS positions the province to integrate renewables more efficiently and reduce costs for consumers compared to the alternative VIU case.

[95] Measured in present value, applying a 6.65% nominal discount rate.

Appendix 1: Benefits and costs of the creation of IESO-NS

Benefits and costs of Phase 1 of the creation of IESO-NS

5.6 In this section, we describe Phase 1 core roles and benefits, supporting roles and benefits, as well as incremental costs of implementation.

Phase 1 core roles: *timelier and efficient transmission and energy resource investment*

Transmission planner and long-term security of supply

A1.1 The creation of an ISO in Nova Scotia has been under consideration for well over a decade.[96] In recent years, public opinion of NSP as a VIU with conflicting incentives has accelerated the push for an ISO.[97] As a VIU, NSP has two competing responsibilities: (1) providing reliable, affordable and safe electricity supply to its customers,[98] and (2) providing a profit to its shareholders.[99] These competing responsibilities give rise to an inherent conflict of interest for a VIU in relation to system planning and investment decisions.

A1.2 Concretely, with cost-based rates that are designed to earn a profit on the company's regulated asset base, a VIU is fundamentally incentivized to focus on capital-intensive activities.[100] Alternately, a VIU may avoid or delay augmenting the transmission system to accommodate more IPPs onto the system that compete with its core generation business,[101] or even avoid spending altogether due to customer rate pressure.

96 See *Transmission & System Operator Options for Nova Scotia*, SNC-Lavalin ATP Inc., December 2009, (link).

97 Nova Scotia Clean Electricity Solutions Task Force, 31 January 2024, (link); and Statement on Report from Clean Electricity Solutions Task Force, Government of Nova Scotia, 23 February 2024, (link).

98 *NSEB Matter No. M12451, IN THE MATTER OF an Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges, and Regulations,* (link); *and Public Utilities Act, Chapter 380 of the Revised Statutes, 1989 (as amended),* (link).

99 NSP is wholly owned by parent company Emera Incorporated, which is traded on the Toronto Stock Exchange under symbol "EMA." See 2024 NSP Annual Financial Reports Attachment 2; and Nova Scotia Clean Electricity Solutions Task Force, 31 January 2024, (link).

100 *Hansard – Bill No. 132 - Electric Utility Capital Accountability and Transmission Competition Act*, Nova Scotia Legislature, 24 September 2025, (link).

101 See also potential delays in the interconnection process described in the Market Design role in ¶A1.20.

A1.3 However, NSP does not necessarily make self-serving decisions and there are important regulations in place to deter this.[102] Additionally, various laws and statutes maintain NSP's accountability and uphold its role as a public utility. New generation and transmission resources were planned through an IRP process which involved significant NSEB and stakeholder input, which was ultimately submitted to the NSEB.[103] In addition, the Electricity Act allows the Minister of Energy to run generation procurement for renewable generation with which NSP is obligated to sign Power Purchase Agreements ("PPAs").[104]

A1.4 Despite NSP's theoretical ability to balance its responsibilities, supported by the checks and balances described above, the inherent conflict of interest creates an underlying lack of trust in the VIU – both in public opinion and policy making. The key contention is whether the current institutional setup gives rise to persistent suspicion toward any decisions made by NSP, regardless of their merit. Broader affordability concerns in the province further exacerbate this issue.

Competitive generation procurement

A1.5 The creation of the IESO established a competitive procurement process for new energy resources identified through the IRP process. This increases access to the Nova Scotia energy market for IPPs, whereas prior to the Energy Reform Act, procurement was run only for renewables.

A1.6 Introducing competition and shifting more risk onto investors and away from ratepayers may have benefits when there are cost overruns. A VIU that has already had its initial expenditure approved can typically get additional costs approved if the project goes overbudget, as the project is already confirmed.[105] Cost overruns for competitively procured resources may either be borne by the developer or present an opportunity for the IESO and regulator to choose to cancel the project. Increased competitive procurement then may reduce risks borne by consumers of cost overruns (**quantified benefit 1**) in the construction of new generation assets.

[102] As defined in the Public Utilities Act, NSP must obtain approval for every capital expenditure it proposes to make over $1 million. See *Regulatory Matters*, NSP, (link).

[103] See *Powering a Green Nova Scotia, Together, 2020 Integrated Resource Plan,* Nova Scotia Power, 27 November 2020, (link).

[104] See Nova Scotia Clean Electricity Solutions Task Force, 31 January 2024, (link); and *Electricity Act, Chapter 12 of the Statutes of Nova Scotia, 2022 (as amended),* (link).

[105] See historic Authorization to Overspend ("ATO") applications filed by NSP with the NSEB.

A1.7 Competitive procurements overall can reduce resource capital costs (**quantified benefit 2**) by:

i) Incentivizing innovation, both in operations and through choice of technology;
ii) Introducing new market participation from firms with greater expertise in both existing and new technologies;
iii) Opening the pool of bidders to include firms in other geographic areas that are specialists in certain technology, e.g., efficient installation and operation of more efficient gas plant configurations, and;
iv) Increased access to capital with the introduction of, e.g., larger multinational firms, which could lower financing costs.

A1.8 Competition for generation resource procurement incentivizes firms to improve efficiency, innovate, and lower prices to win contracts, yielding benefits for consumers. Competition reduces the information asymmetry between the regulator and the incumbent responsible for building all resources, i.e., rather than evaluating costs for prudency, competing firms are incentivized to reveal their costs via the bidding process.

A1.9 IESO-NS's competitive procurement process will reduce barriers to entry for new non-renewable asset owners, create more opportunities for renewable developers, and facilitate competition to fill new system needs as the province heads towards coal retirements.

A1.10 Phase 1 benefits of competition are expected to reduce **resource investment** costs through lower capital investment costs.

Independent transmission and resource planning

A1.11 A potential perception of bias may lead to denials or delays of installations for which the reliability benefits do outweigh the costs.[106, 107] Rather than placing guardrails on potentially biased planning, an impartial recommendation for increased spending on certain assets could be better received when coming from an ISO than a for-profit utility (which by design increases profits in line with asset base under the current regulatory regime). Hence an important potential benefit of an ISO is likely accelerated investment (**quantified benefit 3**) in necessary transmission and generation due to a faster approval process, given the reduced perception of bias in investment decisions. As such, reliability issues are avoided and a less costly system can result due to a more efficient balance of generation and transmission outbuild. Further details of accelerated development timelines are given in the *Phase 1 (Planning) supporting roles* section.

A1.12 Phase 1 benefits of independent planning are expected to reduce **system production costs** due to accelerated deployment of lower cost generation coming online.

A1.13 This report does not assume that NSP's IRP was inherently biased or inefficient, but does assume that enhanced data from a more advanced control room in Phase 2 will improve the IRP process, as explained in the Phase 2 section below.

Phase 1 supporting roles*: the importance of independence*

A1.14 Independence is the fundamental quality of an ISO that underlies most, if not all, benefits. However, many of the direct benefits of independence are less quantifiable. Independence is an outcome of the removal of the inherent conflict of interest under a VIU, leading to increased transparency and public trust. Public trust in IESO-NS as an independent entity enables IESO-NS to better perform supporting roles. Taking up those supporting roles, in turn, can increase the trust of investors supporting developers in the competitive procurement process in the existence of a level playing field between competitors.

A1.15 While difficult to quantify, the increase in independence also may create a culture that attracts high-calibre staff. The establishment of an ISO may unlock a new pool of candidates that wish to work for a mission-driven organization as part of the energy transition.

[106] NSP has repeatedly missed reliability targets in recent years, however outages are more often caused by distribution-level than transmission-level issues. See *Nova Scotia Power fails to meet performance standards for 8th consecutive year*, CBC News, 11 September 2025, (link).

[107] For example, NSP's denial from the NSEB for its $6 million Remote Terminal Unit (RTU) Replacement Program due to concerns over estimated labour costs. See NSEB Matter No. M12012, *IN THE MATTER OF AN APPLICATION by NOVA SCOTIA POWER INCORPORATED for approval of its Annual Capital Expenditure Plan for 2025,* 19 August 2025, (link).

A1.16 However, the degree of the benefit of independence is tied to how little regulatory capture is present. The governance structure of the ISO must not give undue weight to large incumbent utilities in decision-making, which would reduce the independent nature of the ISO's impact on system planning and operation.[108] Additionally, the ISO's role for transmission can only go as far as planning – after the handoff from comprehensive, long-term IRP decisions to granular, near-term Capital Expenditure Plan delivery, a large degree of functional decision-making remains with NSP.

Market design

A1.17 Market design includes rules and mechanisms that govern trading and access. Market access is improved by aligned incentives to find capacity for new connections and timeliness of connection responses. Vertically integrated businesses may limit entry of competitors via both pricing rules and physical grid access.

A1.18 For example, pricing rules that strengthen locational signals to encourage more efficient siting decisions of generators and demand are, everything else equal, likely to be less favoured by network owners as, by design, the measures will reduce the need for network assets. Similarly, suboptimal market design might lead to an inefficient operation of existing generation and storage assets leading to an inflated perceived need of investment in those assets.

A1.19 VIUs owning and operating the transmission grid while being active in the generation business can also deter entry by slowing down or making the connection process more costly for competing generation willing to connect to their grid.[109, 110]

A1.20 There is a potential for perceived conflicts of interest in any step of a competitive process in which NSP participates, or is relied upon – such as performing feasibility, interconnection and operational studies[111] – despite the presence of theoretically competitive processes.

[108] This is seen in many US ISOs where incumbent utilities retain a large voting share in stakeholder committees, which approve certain tariff revisions before they go to the regulator.

[109] See the Board's 2023 review in NSP's interconnection processes: *In the matter of the Public Utilities Act and In the matter of a Review of Nova Scotia Power Incorporated's interconnection processes under s. 2C of the Electricity Act*, Nova Scotia Utility and Review Board, 11 June 2024, (link).

[110] The Nova Scotia Clean Electricity Solutions Task Force concluded "lack of access to the transmission system" was "[o]ne of the biggest impediments to the development of a large-scale wind energy industry in Nova Scotia", see Nova Scotia Clean Electricity Solutions Task Force, 31 January 2024, (link).

[111] See Rate Base Procurement description in Nova Scotia Power 2025 Annual Capital Expenditure Plan, 9 December 2024, (link).

Industry governance: Improved reliability standards and grid codes

A1.21 The ISO may, as an independent and knowledgeable neutral entity, help to implement reliability standards and set grid codes better reflecting the economic trade-off between cost and load served. For instance, a VIU would potentially benefit from a tighter than required reliability standard (as stricter standards typically involve building more assets). Alternately, a VIU under pressure for ratepayer affordability may defer investment, even if favourable from a reliability perspective. Further, the ISO avoids conflicts of interest in which grid codes are administered by an entity that owns generation and transmission assets.

Advisor to government

Independence in advice to government

A1.22 Advice given to Government by NSP may be perceived to be in NSP's self-interest, or to not necessarily be in the best interests of consumers. Such a perception of bias, which could undermine the value of such advice – even in the absence of any actual bias.[112] This may impact the extent to which advice given by IESO-NS is valued by the Provincial Government or NSEB. If policy makers perceive a given suggestion to be biased, they may delay taking actions that would result in benefits to consumers.

A1.23 In the context of the growing decarbonisation challenge, this may be of additional importance as the public trust associated with the technical and operational expertise of the ISO, as a neutral entity becomes increasingly important to assist in decision-making.

Avoided professional services costs

A1.24 Some professional services costs may be avoided with an ISO. For instance, the government can avoid direct hire of consultants if it can rely on ISO expertise, or reduce the amount of auditing and investigation costs needed to police a VIU. Greater consistency in advisory support can as well enhance the quality of advice. Finally, less oversight of the VIU by the regulator may also lead to labour cost savings as part of the overall reduced administrative burden.

Benefits and costs of Phase 2 of the creation of IESO-NS

A1.25 The IESO takes on real-time operations roles in Phase 2. Much of the inherent biases and perceived conflicts of interest in operations would be eliminated with independent system operation.

A1.26 Due to the foundational nature of system operation, Phase 2 reaches all benefit categories. Additionally, as shown in Figure 3-2, many of the benefits in Phase 1 would be amplified if the IESO takes on full system operation.

[112] See the Board's 2023 review in NSP's interconnection processes, where intervenors voiced concerns of bias in the interconnection process but could not give any examples, and the report ultimately found no proof of bias: *In the matter of the Public Utilities Act and In the matter of a Review of Nova Scotia Power Incorporated's interconnection processes under s. 2C of the Electricity Act*, Nova Scotia Utility and Review Board, 11 June 2024, (link).

A1.27 In this section, we describe Phase 2 core roles and benefits, scaling impacts on benefits of Phase 1, as well as incremental costs of implementation.

Phase 2 core roles: *more efficient operations from control room improvements*

Scheduler, residual energy system balancer, and settlement

A1.28 In contrast to the more obvious conflict stemming from the system planner being an investor and retail entity, the concern with the system operator also being the asset owner is more subtle. Operational expenditures ("OpEx") are not direct drivers of net income because utility ratemaking sets a rate of return on assets in rate base, while OpEx is directly added to the revenue requirement – it is designed to be recovered without an additional allowed return. This leads to less of a direct financial upside for NSP to favour its assets in scheduling decisions. However, operational outcomes eventually do impact planning decisions, and hence indirectly, can impact more significantly the returns of a VIU.

A1.29 Restructuring in Nova Scotia created NSPSO, establishing a degree of separation of the system operator function within NSP. Standards of conduct approved by the Utility and Review Board ("UARB")[113] ensure market sensitive information is not shared among other groups within NSP, especially transmission and the marketing and sales groups.[114] IRP and other planning activities, however, were housed outside of these specific functions.[115]

A1.30 Notwithstanding, despite being functionally separated and the likely more limited financial gains from favouring its own assets as an operator, there remains a perception that NSP might influence day-to-day decision-making in its role as a system operator, due to the limited transparency around operational decisions. For example, NSP could be perceived to operate its units at a level of operational prudence above the level applied in dispatching merchant facilities. This may result in a disadvantage to IPPs and resulting advantage to NSP's units.

A1.31 This perceived conflict of interest might be of minor importance as there are currently relatively few IPPs in Nova Scotia, and because these few existing IPPs are non-dispatchable resources with scheduling priority. However, its significance is expected to rise with increasing dispatchable IPPs, such as batteries and fast acting generation, which are expected to connect to the Nova Scotia grid. Furthermore, this perceived conflict of interest may also impact imports from other jurisdictions, which act effectively as dispatchable resources that can offset the VIU's owned generation.

A1.32 Direct benefits from Phase 2 therefore result in **production cost savings**, due to more efficient and fair use of the existing assets in the system.

[113] The NSEB was formerly titled the UARB.

[114] *Nova Scotia Power Inc. Standards of Conduct For the Provision of Wholesale and Renewable to Retail Electric Transmission Service*, Section B.1 Separation of Functions, June 10 2016 (as amended), (link) Nova Scotia Clean Electricity Solutions Task Force, 31 January 2024, (link).

[115] Nova Scotia Power Standards of Conduct SOC-006 Organizational Chart, March 2025, (link).

Optimal use of resources

A1.33 For IESO-NS, the clarity of focus, increased scrutiny, and reputational risk may also incentivize innovation and operational efficiency improvements (**quantified benefit 6**). As discussed above, an ISO does not have the conflicting incentives that an operator that also owns assets has. In addition, an ISO has a smaller purview than a VIU, enabling it to focus more on issues in the control room. This could result in less incremental and more long-term thinking in operational improvements.

A1.34 It is hard to entirely erase the incentive a VIU may have to sub-optimally utilise existing resources and instead maximise the dispatch of the resources it has a stake in.[116] Hence, a transitioning of the system operator role to an ISO with impartial dispatching of resources may reduce system costs and renewables curtailment, improve transmission system utilisation, and enable more efficient demand-side participation (which could be perceived to be in direct competition with the incumbent generation). Depending on the VIU's profile, this could have outcomes that span cost reduction, reliability improvement and environmental benefits.

A1.35 For instance, NSP has used a static merit order of its supply stack day-ahead, with a heuristic-based approach to make changes in system operation close to real-time.[117] In contrast, a more efficient approach would be to integrate the economic merit order with security constraints and transmission constraints to create a feasible optimal dispatch in real-time. This type of improvement could lead to improved transmission system utilisation and reduce renewables curtailments.

Phase 2 scaling impacts on benefits of Phase 1

Competitive generation procurement

A1.36 Transparency of dispatch is key for competitive procurement, which reduces costs by incentivizing innovation to increase efficiency among a larger pool of bidders **(quantified benefit 7)**. The IESO, with a more focused mission, will have greater expertise in system planning and operation (previously functionally separated within NSP), which will give it greater perspective when conducting resource procurement. However, this is only fully realised in Phase 2 when the IESO has full operational control.

[116] For example, in MISO, a 2020 study by the Independent Market Monitor found a net operating revenue loss of $492 million from 2016 to 2019 due to a small share of integrated utilities favouring their own costly coal plants over lower-cost merchant facilities. See *MISO integrated utilities lost $492M from 2016-2019 via uneconomic coal dispatch: market monitor*, Utility Dive, 9 October 2020, (link).

[117] See *Proposal to establish, adopt or amend a standard, code or Market Procedure,* Form MPF-05-03, Nova Scotia Power System Operator, 2007, (link).

A1.37 Without Phase 2, NSP has a potential advantage due to overseeing the dispatch process of its competitors, and there may be concerns (real or perceived) that NSP may dispatch its plants preferentially to IPPs. If IPPs are not fully insulated from operational risk (i.e., if their profitability under contract depends at all on their actual operations), this may lead to greater investment risk. Furthermore, as the dispatcher NSP would have access to highly sensitive cost information of all IPPs; while regulatory guardrails exist, this information could be perceived to give NSP an advantage in the competitive procurement of generation. In that regard, an ISO handling settlement to reconcile actual and scheduled volumes and payments is crucial to increase transparency and trust. Eventually all these factors could lead to less IPP investments or higher cost of capital of the relevant investments to cover the (perceived) risks.

A1.38 The increased participation in competitive procurement expected from the IESO taking over the operator role is expected to **reduce resource investment costs**.

More efficient transmission and resource investment

A1.39 Taking on the operations roles in Phase 2 can further unlock benefits in the core Phase 1 planning roles. Any improvements in operational efficiency may in the long run unlock different planning pathways **(quantified benefits 8-9)**, e.g., more demand-side management allowing for less electricity production at peak times, which leads to benefits for consumers through **reduced resource investment** needs. Improved operation of the grid would in the long run also lead to an improved usage of the existing transmission grid, which could align long-term planning decisions with best available information and avoid the distortion of suboptimal grid use, or investment.

A1.40 The selection of specific types of resource and transmission investments may also be improved with an ISO that has a more advanced system operation process, leading to a more efficient resource and transmission choices (via IRP), and improved balance in resource and transmission planning decisions **(quantified benefits 8-9)**. This is due to an ISO being better positioned to ensure a level playing field when considering options in the IRP and transmission studies, including new technologies that may compete with existing resources,[118] which may increase diversity in solutions which support clean energy goals **(quantified benefits 4, 6-11)** and non-wires alternatives **(quantified benefits 6, 8-11)**.[119] These technologies may include wind, storage, distributed energy resources and demand-side management,[120] all of which may also have environmental benefits (**avoided carbon costs**) in addition to cost-saving benefits (**reduced system production costs**).

A1.41 As explained above, IESO's incentive for innovation in control room improvements can enhance operational knowledge above what a VIU may have been able to access. Deep familiarity with system operations is key for making optimal planning, procurement, and contracting decisions **(quantified benefits 8-9)**. Technology choice may be informed in the IRP. Network planning tools do not necessarily include detailed power flow calculations in the operational timeframe, but access to this information as both planner and operator may better inform decisions. Operations may also influence procurement and contracting decisions. For instance, integrating greater shares of wind without curtailment may not always be physically possible or economically optimal given system limits and existing resource constraints. In short, by taking up the system operator role in Phase 2, an important identified incremental cost (or disbenefit) of Phase 1 can be annulled.

A1.42 While direct Phase 2 benefits were shown in production cost savings, Phase 1 scaling benefits on the planning role are shown in reduced **resource and transmission investment** costs through a more informed IRP process, in addition to **avoided carbon emissions** as a result of that more efficient system usage.

[118] IPPs in Nova Scotia, particularly wind producers, have claimed that NSP favoured its own resources in both procurement and dispatch, see: *Meeting Nova Scotia's 80% renewable electricity target*, Halifax Examiner, 2 September 2025, (link).

[119] Generally, VIUs are disincentivized to choose non-wires alternatives in two ways: (1) a regulated business may favour technologies that create more demand for transmission or choose capital-intensive generation to increase its rate base; and (2) VIUs ultimately receive income through electricity sales, with non-wires solutions generally reducing the VIU's income. For example, DERs are expected to serve load closer to where it is consumed, which may displace the need for transmission or distribution upgrades, and if behind the meter, may also reduce a utility's kWh sales.

[120] See also the creation of EfficiencyOne in Nova Scotia, where demand-side management was separated from NSP due in part to concern over this conflict of interest.

Improved application of reliability standards and grid codes

A1.43 An ISO taking over the operations role also scales the benefits derived from the supporting roles in Phase 1. With the ISO responsible for operations, it can better set grid and reliability standards as part of its Industry Governance role.

Independence in advice to government and avoided professional services costs

A1.44 Deep technical expertise at the operational level is key to providing advice to government, and the removal of the perception of bias can lead to this advice being appropriately trusted. A large component of the Market Design role is creating rules that are followed by the Scheduler/Market Dispatcher and Balancer. This function is likely to become more efficient as the ISO sees operational realities, e.g., in congestion management, which can also provide valuable expertise to the regulator and government.

A1.45 Table A1-1 below summarizes these cost and benefits as they correspond to the IESO's roles and responsibilities.

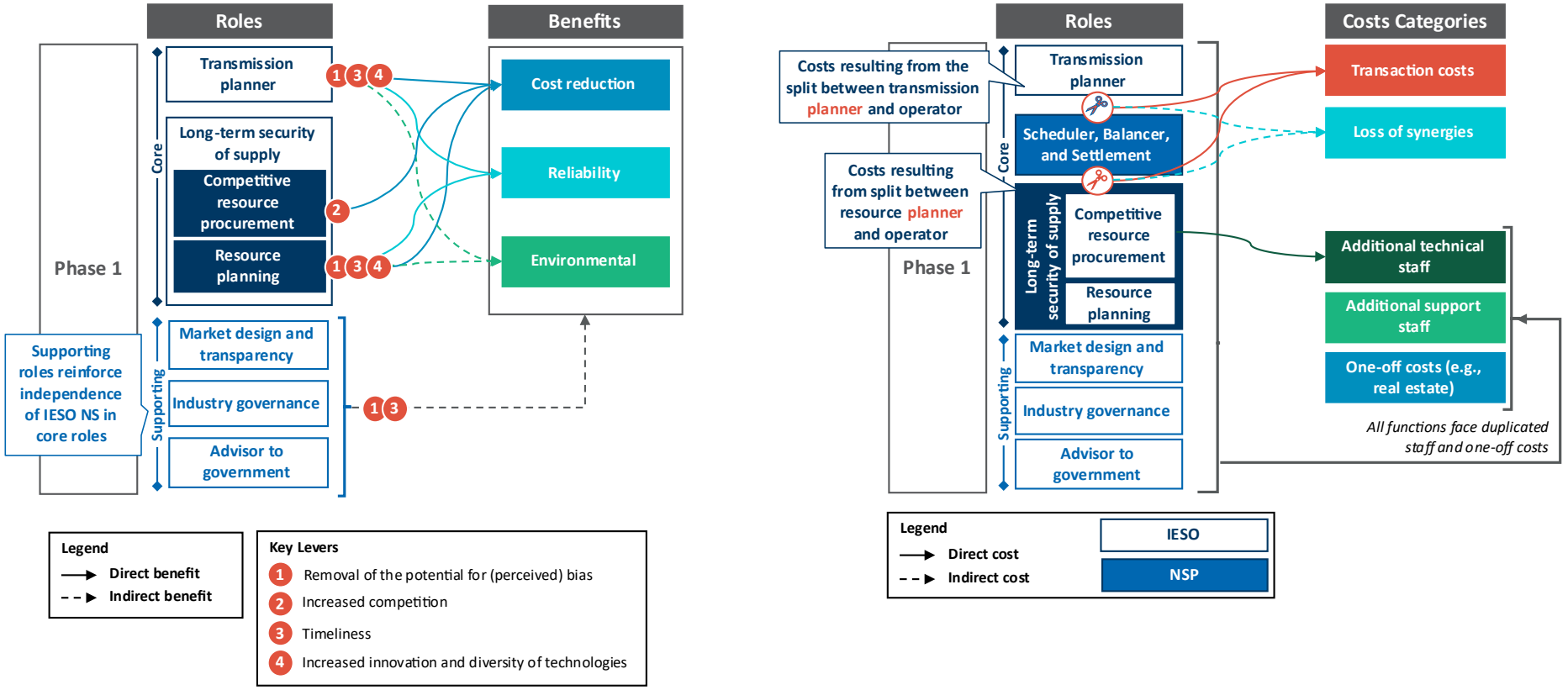
Table A1-1 Benefits and cost categorisation

IESO Nova Scotia Role		Outcome
Benefits (⚙ indicates benefit directly quantified in Chapter 4, and corresponding benefit number)		
Phase 1 (unlocked or scaled up by Phase 2)	**CORE**	
	Transmission planner and long-term security of supply	
	Competitive generation procurement	▪ Reduced risks borne by consumers of cost overruns (⚙)(1) ▪ Potential cost savings from competitive auction for selected new energy resources (by IRP) (⚙)(2) ▪ Further gains from competitive procurement due to lack of (perception of) bias/privileged information in operations (⚙)(7) ▪ **Key Levers: 3 Timeliness, 2 Increased competition and cost discipline, 4 Increased innovation and diversity in technologies**
	More efficient transmission and resource investment	▪ Accelerated investment when historically delayed due to mistrust (⚙)(3A)(3B)(4) ▪ Unlock new planning pathways (⚙)(8)(9) ▪ More optimal investment choices, i.e., balance between generation and transmission (⚙)(8)(9) ▪ Supporting non-wires alternatives (⚙)(6)(8-11) ○ Lower system costs via DERs and demand-side participation over capital intensive solutions ▪ Supporting clean energy goals (⚙)(4)(6-11) ○ Level playing field for renewables and storage ▪ Improved planning decisions from deep technical expertise in operations (⚙)(8)(9) **Key Levers: 3 Timeliness, 1 Removal of (perceived) bias, 4 Increased innovation and diversity in technologies**
	SUPPORTING	
	Industry governance	
	Improved application of reliability standards and grid codes	▪ Neutral entity ▪ Improved system expertise **Key Levers: 3 Timeliness, 1 Removal of (perceived) bias**
	Advisor to government	
	Independence in advice to government	▪ Increased public trust ▪ Increased technical expertise **Key Levers: 1 Removal of (perceived) bias**
	Accelerated development timelines	▪ Accelerated deployment (⚙)(3A)(3B) ▪ No (perception of) bias in recommended capital investments (⚙)(3A)(3B) **Key Levers: 3 Timeliness, 1 Removal of (perceived) bias**

	Avoided professional services costs	▪ Trusted ISO expertise ▪ Expanded ISO expertise in operations **Key Levers: 1 Removal of (perceived) bias**
	Market design	
	Improved market access and design	▪ Finding capacity for new connections ▪ Timeliness of connection responses ▪ Increased insight into network congestion **Key Levers: 3 Timeliness, 1 Removal of (perceived) bias**
Phase 2	**Scheduler, Residual Energy System Balancer, and Settlement**	
	Optimal use of resources	▪ Impartial dispatch (⚙)(6) ▪ Demand-side participation (⚙)(6) ▪ Operational efficiency improvements (⚙)(6) ▪ Improved transmission system utilisation (⚙)(6) ▪ Reduced renewables curtailment (⚙)(6) **Key Levers: 4 Increased diversity in technologies, 5 Operational efficiency**
Costs		
Phases 1 & 2	**Direct (implementation and ongoing) costs**	▪ Costs of implementing separation, additional staff
	Loss of synergies and increased transaction costs	▪ Phase 1: Reduced decision-making efficiency due to planner and operator separation ▪ Phase 2: Costs of negotiations between asset owner and operator for efficient asset operation

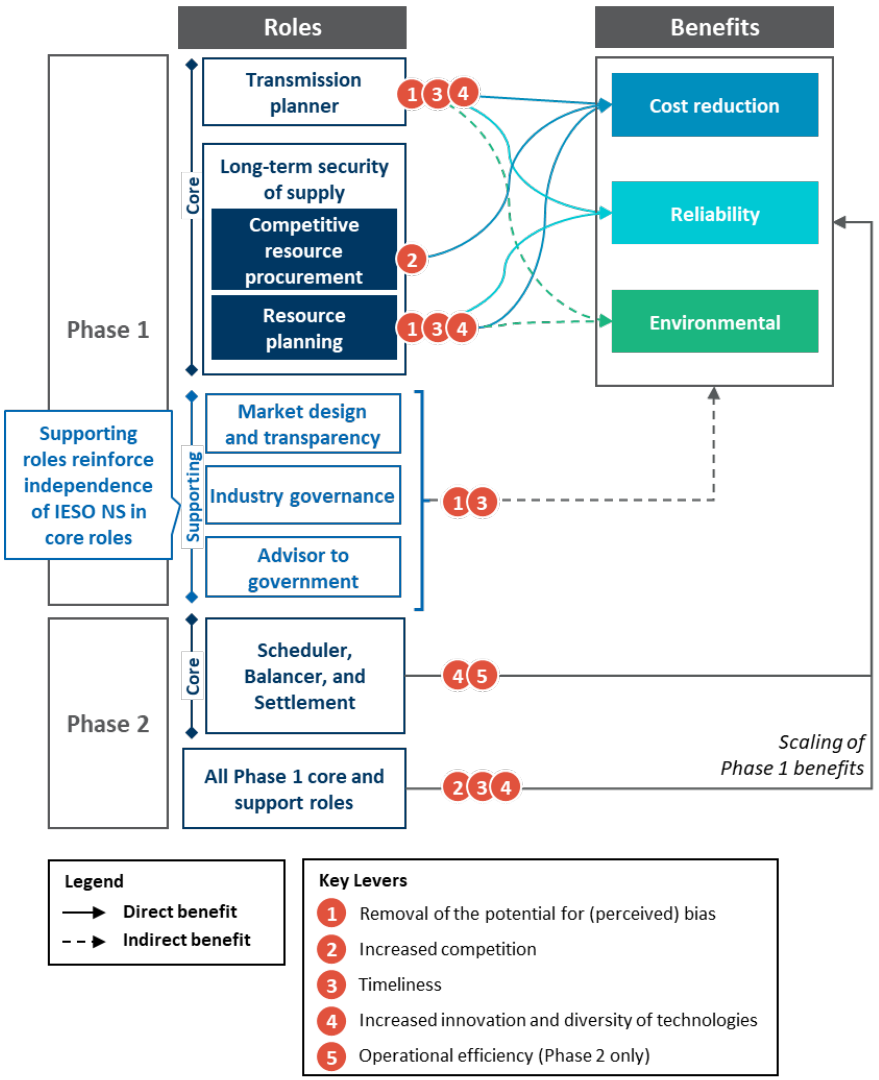
Appendix 2: Combined benefits and costs graphics

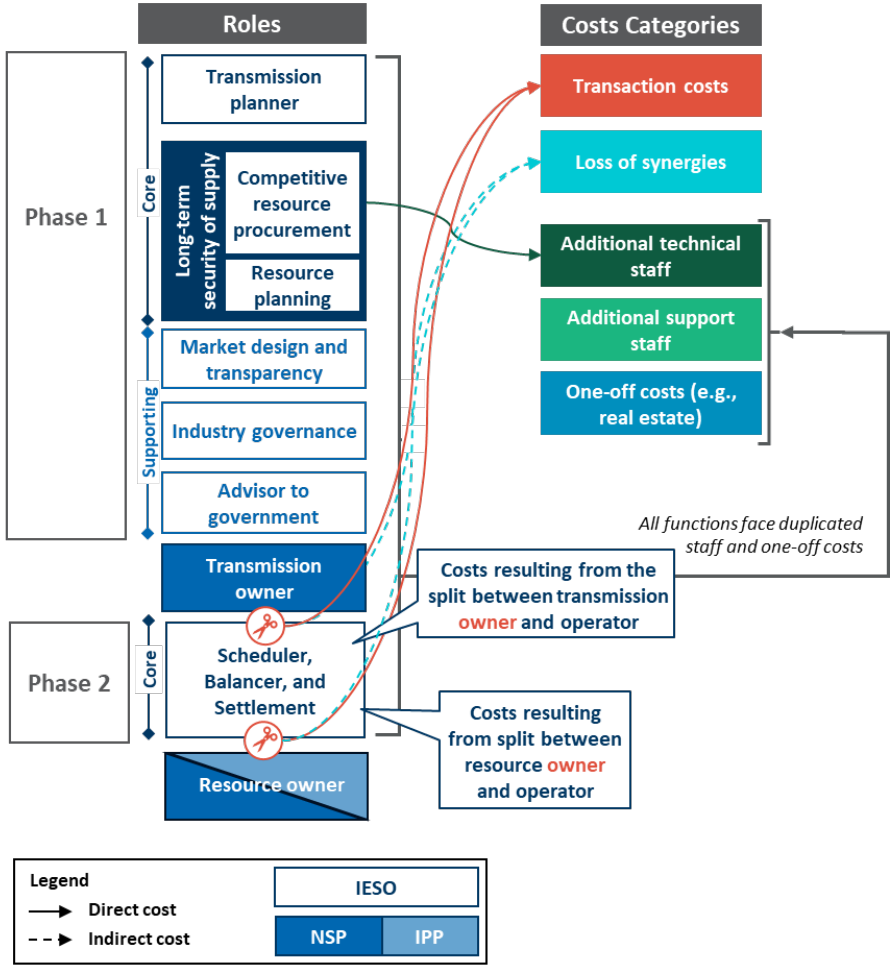
Phase 1 only



Source: FTI Consulting analysis

Phase 1 and Phase 2





Source: FTI Consulting analysis

Appendix 3: Data sources

Generation CapEx

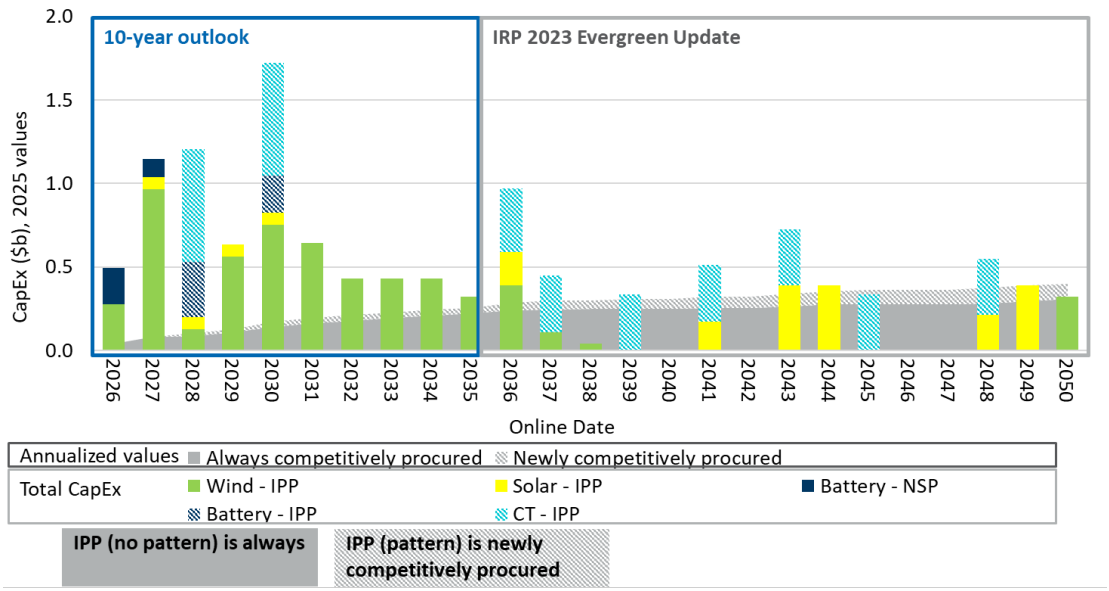
A3.1 Capacity additions (MW) are informed by two primary sources: (1) NSP's 2025 10-Year Outlook for the 2026-2035 period; and (2) the 2023 Evergreen IRP additions from the CE1-E1-R2 scenario for the remaining period up to 2050.[121]

A3.2 The annual additions estimated by the IRP include 150 MW and 300 MW non-emitting, dispatchable resources (e.g. nuclear, natural gas with carbon capture and storage, long duration storage, or green hydrogen-fuelled generation) added in 2049 and 2050, respectively. Due to the uncertain nature of this resource type, we have excluded this CapEx.

A3.3 Expected capital costs per technology are informed from a mixture of updated EIA, NREL and Lazard estimates as used in the 2023 Evergreen IRP. Financing costs have been excluded. We have replicated the relative importance assigned to each estimate in the 2023 Evergreen IRP, with adjustments where data availability differs between years.

A3.4 Annual CapEx is visualised in Figure A3-1, with bars indicating CapEx values for overnight capital costs of all new capacity coming online in each year, and with a shaded region showing the annualised values used in this analysis.

Figure A3-1: Cumulative additions underlying CapEx estimates, $m 2025



[121] Data is used from the 2023 Evergreen IRP data tables (supporting final modelling results). We remove capacity additions which are assumed to already exist based on the *Atlantica Centre for Energy Maps*, Atlantica Centre for Energy, Accessed 19 February 2026, (link). We include an adjustment in 2036, for capacity which had been expected to be built in the 2023 Evergreen IRP but which is not built in the NSP 10-Year Outlook.

Source: 2023 IRP final modelling results, Nova Scotia Power, 2023, (link), Ten year system outlook, 14 July 2025, (link).

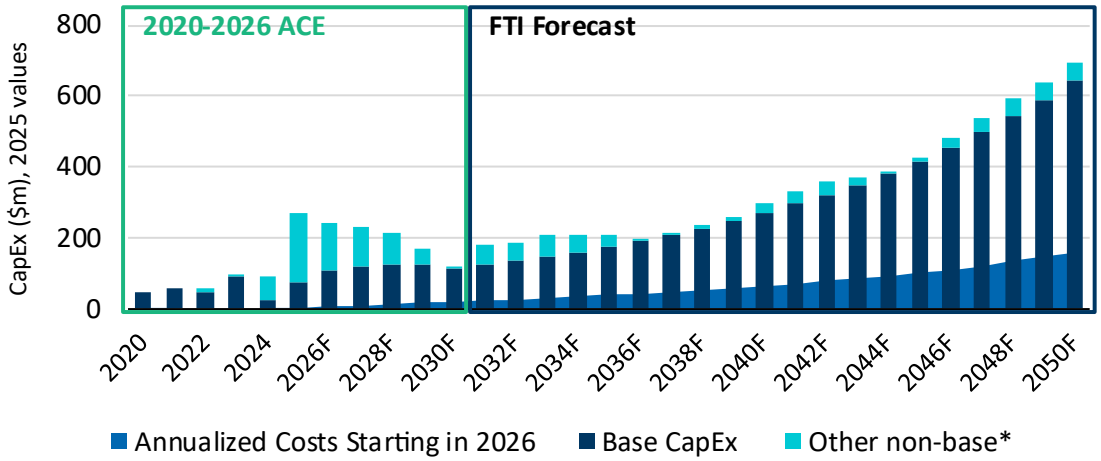
Transmission CapEx

A3.5 Transmission CapEx was informed by NSP's annual Capital Expenditure Plans filed between 2020 and 2026. The most recent plan, filed in 2026,[122] includes forecast spending through 2030. Our forecast applies the historic base spending CAGR from 2020 to 2030 to estimate base spending out until 2050.

A3.6 Other non-base spending[123] is modelled to precede non-thermal resource additions in the same fashion as experienced in the 2020-2030 period covered in ACEs. This has shown that non-base spending occurs 1-2 years prior to new resources coming online.

A3.7 Figure A3-2 visualises the transmission CapEx forecast with bars indicating annual CapEx, and with a shaded region showing the annualised values used in this analysis.

Figure A3-2: Historic and forecast transmission CapEx, $m 2025



Notes: (1) Includes ROW Widening, energy storage, and synchronous condenser.*

Source: Nova Scotia Power 2025 Annual Capital Expenditure Plan, NSUARB, 9 December 2024, (link); see also: Capital Expenditures | Nova Scotia Energy and Regulatory Boards Tribunal.

Production costs

A3.8 Production costs are short-run power production costs informed by primary confidential data sources provided to us by the IESO. Data sources include generation (GWh) for each major technology (coal, solar, wind, etc.) and expected fuel, variable operations and maintenance, and startup and shutdown costs for the 2027-2050 period. The data also includes expected imports and prices. From this, FTI estimated system production costs for the 2026-2050 period.

[122] *Nova Scotia Power 2025 Annual Capital Expenditure Plan*, NSUARB, 9 December 2024, (link); see also: Capital Expenditures | Nova Scotia Energy and Regulatory Boards Tribunal.

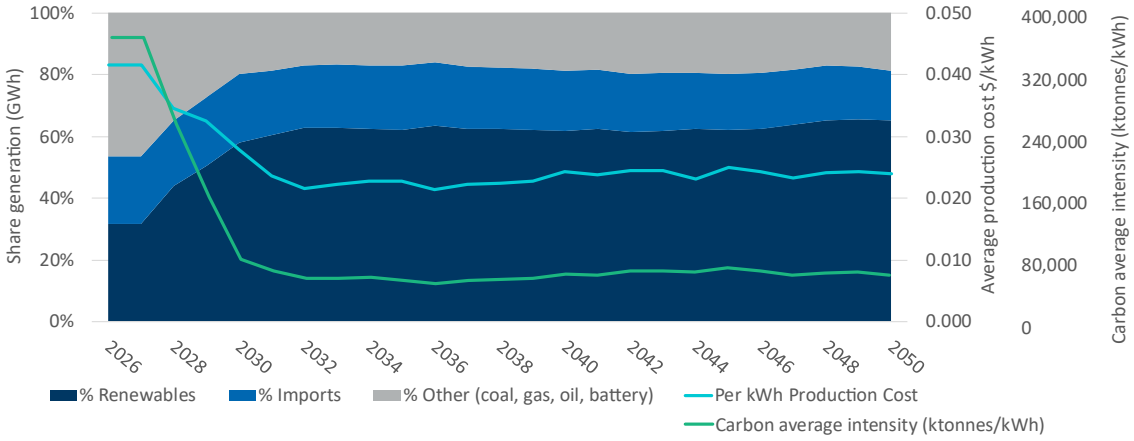
[123] Non-base spending excludes any spending on interties.

A3.1 We assume negligible short-run production costs for wind and solar. PPAs for low variable-cost assets recover fixed costs, and fixed costs are represented by CapEx in our analysis.

A3.9 For calculations involving accelerated deployment, we calculate and shift only the average production cost per unit of electricity and keep the yearly total generation fixed (as a proxy for demand).

A3.10 Figure A3-3 illustrates the assumed average short-run, variable production cost and average carbon intensity, plotted against the evolution of the resource mix.

Figure A3-3: Generation mix (GWh), average production cost ($/kWh), average carbon intensity (ktonnes/kWh)



Source: (FTI analysis of): NSP-provided data (confidential).

Carbon emissions

A3.11 Expected system carbon emissions and generation are sourced from the same primary confidential data source provided to us by the IESO. For calculations involving accelerated deployment, we calculate and shift only the average carbon intensity per unit of electricity and keep the yearly total generation fixed (as a proxy for demand). Avoided carbon is valued at the federal carbon price, updated May 2026, escalating from $95 per tonne CO_2 in 2026 to $130 in 2035, with a 1.5% annual inflation escalator starting in 2036 and ending at $140 in 2040.[124] We assume these values are nominal dollars and convert them to real $2026 using the given annual inflation escalator of 1.5%. We assume the price stabilizes in real dollars at the 2040 level from 2041-2050.

A3.12 The existing planning documents and dispatch simulations provided at the time of analysis reflect the prior federal carbon pricing schedule.[125] They do not account for any changes in dispatch that would occur due to the different price signal.

[124] Industrial carbon pricing in Canada, Government of Canada, 19 May 2026, (link).

[125] Update to the *Pan-Canadian Approach to Carbon Pollution Pricing 2023-2030*, Government of Canada, 5 August 2021, (link).

A3.13 Some emissions are shielded from taxation due to performance standards for different types of electricity generation that change between 2026 and 2030 under the provincial Output-Based Pricing System ("OBPS").[126] We assume the standards in 2030 apply until 2050.

[126] Schedule A, Table 3: Performance standards for electricity generation *in* Output-Based Pricing System Reporting and Compliance Regulations made under Section 112ZJ of the Environment Act. (link)

Appendix 4: Assumptions summary

Phase 1: Planning and procurement responsibilities	Assumptions
(1) Shifting risk of cost overruns	0-50% reduction in cost overruns from 16% historic overspend 50-80% reduction in pass-through to customers from 90% historic
(2) Reduced generation cost from competitive procurement	0-20% reduction
(3A) Reduced production costs from accelerated deployment	Based on assumption that YoY reduction in production costs would have a 1-2 year timeline difference with NSP
(3B) Accelerated Capex deployment (financial disbenefit)	Based on assumption that new Tx and generation assets would have a 1-2 year timeline difference with NSP
(4) Avoided carbon emissions from accelerated deployment	Based on assumption that YoY change in carbon emissions would have a 1-2 year timeline difference with NSP
(5) Lost synergy between planner/procurer and operator (disbenefit)	1-2% increase in production costs
Phase 2: System operation	
(5) Resolved synergy between planner/procurer and operator	1-2% reduction in production costs (netting out Phase 1 disbenefit)
(6) Control room improvements	2-10% reduction in production costs
(7) Increased entry in competitive procurement	1-10% additional reduction beyond (2) in comp. procured CapEx due to more interest from IPPs, including renewables
(8) Decreased CapEx from more advanced system planning	1-10% additional reduction beyond (3),(7) due to better informed planning as improved real-time system operator
(9) Decreased production costs from more advanced system planning	1-10% additional reduction beyond (6) due to better informed planning as improved real-time system operator
(10) Avoided carbon emissions from control room improvements	2-10% additional reduction in carbon emissions due to more efficient dispatch
(11) Avoided carbon emissions from better-informed IRP	5-15% additional reduction in carbon emissions due to better informed planning as system operator
(12) Lost synergy between asset owner and operator (disbenefit)	0.5-1% increase in production costs

Appendix 5: Calculation methodologies

Phase 1: Planning and procurement responsibilities

(1) Shifting cost overrun risk

A5.1 The measurement of cost overruns is calculated in two parts. First, the counterfactual (VIU case) expected cost overrun passed on to consumers is calculated as:

VIU Case expected cost overrun passed on to customers $ =

RPV of expected newly procured resource additions CapEx $ × VIU cost overrun %
× VIU cost overrun passthrough to customers %

A5.2 Expected VIU cost overrun is informed by historic NSP spending on major capital projects greater than $1 million, which has averaged **16%**.[127] The extent to which this is passed on to customers is evaluated as **90%**, in case any ATOs are not approved. When multiplied together, this yields an expected total amount of cost overrun passed on to customers of 90%*16%=14% of original project capital costs.

A5.3 Next, the expected cost overrun with the IESO case is calculated as:

IESO expected cost overrun passed on to customers $ =

RPV of expected newly procured resource additions CapEx with cost savings from competitive procurement (2) $
× (1- reduction in cost overrun relative to VIU %)
× VIU cost overrun %
× (1- reduced cost overrun passed on to consumers relative to VIU %)
× VIU cost overrun passthrough to customers %

A5.4 To capture the range of outcomes, we estimate that the IESO can reduce the cost overrun relative to the VIU by **0%** in the low benefits scenario and **50%** in the high benefits scenario.[128] We estimate that the IESO can reduce the cost overrun passed on to customers relative to the VIU by **50%** in the low scenario[129] and **80%** in the high scenario.[130] This equates to a total amount of cost overrun passed on to customers between 7% in the low benefit scenario and 1% in the high benefit scenario.[131] Note that the benefit in cost overrun under the IESO cannot be disentangled from the benefit of capital cost savings from competitive procurement (see benefit 2, discussed below). This is because we apply these percentage savings to the cost of expected newly procured capacity adjusted for cost savings from competitive procurement.

127 See NSP's 2025 Annual Capital Expenditure Plan, Appendix D.

128 Concretely, that project costs exceed original estimates by 16% in the low scenario (the same as NSP) and (1-50%)*16% = 8% in the high scenario.

129 i.e., (1-50%)*90% = 45% of the cost overrun is passed on to customers.

130 So that only (1-80%)*(90%) = 18% of the cost overrun is passed on to customers.

131 16%*45% = 7% of original project costs in the low scenario and 8%*18%=1% in the high scenario.

A5.5 Finally, the difference between the expected cost overrun passed on to customers under the VIU case and under the IESO is the incremental benefit of the IESO in reducing costs overruns:

VIU expected cost overrun passed on to customers $
- IESO expected cost overrun passed on to customers $

(2) Reduced resource investment cost from competitive resource procurement

A5.6 As explained in ¶4.24, the overnight cost of building new generation assets is expected to decrease with the increase in energy resources that are subject to competitive procurement.

A5.7 Reduced energy resource investment costs are calculated as:

RPV newly procured resource additions CapEx $
× Expected savings from competitive procurement %

A5.8 This benefit has an **associated scalar benefit from Phase 2,** explained under benefit (6). This is due to the removal of the information advantage and potential conflict of interest from having NSP as the system operator (which could deter some competitors to enter and/or price in additional risk).

(3A) Reduced production costs from accelerated deployment

A5.9 This benefit is calculated as:

RPV production costs without delays - RPV production costs with delays

A5.10 Because we assume the total demand on the system is unaffected by delayed investments in generation and transmission, we calculate the average production cost per MWh, delay it, and multiply this by the same system demand trajectory:

Production cost with delays =

Average production costs with delay $/MWh
× Total system demand without delay MWh

A5.11 For example, in our low case with a one-year delay, in 2030 we would calculate production cost with delays as the product of expected 2029 per-MWh production cost, and expected 2030 MWh production. For simplicity, we make the conservative assumption that the average cost per MWh remains the same for a given resource mix serving higher load, while in reality we would expect it to increase with higher capacity factors of peaking units.

A5.12 Because in (3B) we assume only delays on newly competitively procured CapEx and Transmission, we are not explicitly assuming a delay in always competitively procured wind. The shifting of average production costs represents a simplifying assumption that the new wind in its year of installation, absent the required transmission and balancing resources planned to be completed by that year but delayed in the VIU case, would not be able to be incorporated into the system. In reality, some new wind could likely be incorporated even with other asset delays, resulting in lower production costs, but not as low as anticipated in the IRP.

(3B) Accelerated CapEx deployment (financial disbenefit)

A5.13 This disbenefit of accelerated deployment is measured as:

(RPV of new capacity additions with delays – RPV of new capacity additions CapEx without delays $)

+ (RPV of new transmission CapEx with delays – RPV of new transmission CapEx without delays $)

A5.14 However, as shown in Table 4-1, this is a lesser magnitude than the benefit for accelerated deployment of production cost improvements.

(4) Avoided carbon costs from accelerated deployment

A5.15 A delay in the reduction in carbon emissions in the VIU case (while holding annual MWh production constant), will result in overall higher carbon emissions across the 2026-2050 period.

A5.16 We calculate the percent of emissions subject to the carbon tax by estimating the emissions above the OBPS performance standard based on GWh of production for each technology type in each year and estimated carbon-equivalent intensity of generation of each technology type.

A5.17 We calculate a percentage emissions subject to tax for each year for the standard IRP trajectory (no delays), a lagged production trajectory of 1 year starting in 2026, and a lagged production trajectory of 2 years starting in 2026.

A5.18 The value of avoided carbon emissions is calculated as:

RPV carbon emissions with delays – RPV carbon emissions without delays

A5.19 Because we assume the total demand on the system is unaffected by delayed investments in generation and transmission, we calculate the average carbon intensity per MWh, delay it, and multiply this by the same system demand trajectory and the federal carbon price trajectory. For simplicity, we make the conservative assumption that the average carbon intensity per MWh remains the same for a given resource mix serving higher demand, while in reality we would expect it to increase with higher capacity factors of peaking units.

A5.20 RPV carbon emissions with delays, is the discounted sum of each year's estimated carbon emissions, calculated as:

Annual carbon emissions value (with delays) =
Average Carbon intensity with delay tonnes CO_2/MWh
× Total system demand without delay MWh
× Carbon price $/tonne

× Percent emissions subject to tax %

(5) Loss of synergies from planner and operator

A5.21 To quantify this disbenefit, we apply a percentage incremental cost associated with production costs:

RPV production costs
× Expected increased cost from lost synergies

***Phase 2:** Independent system operation*

(5) Regained synergies from planner and operator

A5.22 This cancels out the disbenefit above.

(6) Direct control room improvements

A5.23 Innovation in control room design and management benefits will be calculated as:

RPV production costs × Expected savings from improvements

(7) Scaling effect from independent system operation: increased entry in competitive procurement

A5.24 We apply an incremental percentage saving to those realised in (2), and apply this percentage reduction to both newly and already competitive procured generation CapEx (unlike (2)). This benefit is calculated as:

Expected additional savings from competitive procurement
× (RPV newly procured resource additions CapEx × (1- Expected savings from competitive procurement in (2) [132] *)*
+ RPV always procured resource additions CapEx)

(8) Scaling effect from control room improvements: decreased CapEx from more advanced system planning

A5.25 This is additive to the established CapEx reductions in (2) and (7), therefore the always procured CapEx is subject to the reduction in (7) above, while the newly procured CapEx is already subject to the reductions in (2) and (7) above. This further reduction in required CapEx, unlocked with Phase 2, is calculated as:

(RPV newly procured CapEx $
× (1- Expected savings from competitive procurement in (2) + (7) %)
+ RPV always procured CapEx
× (1-Expected savings from competitive procurement in (7) %)
+ RPV transmission CapEx $)
× Expected savings from more advanced planning %

(9) Scaling effect from control room improvements: decreased production costs from more advanced system planning

A5.26 These further reductions in production costs unlocked by more advanced planning enabled by control room improvements are calculated as incremental benefits beyond the savings from control room improvements as:

(RPV expected production costs $
×(1-Expected savings from (6)) %)
× Expected savings from more advanced planning enabling reduced production costs %

[132] We calculate each distinct benefit within a cost category (CapEx, production costs, carbon emissions) such that the sum of the distinct benefits in a category is the total benefit for that category. However, for some benefits that depend on other benefits, such as this benefit applying reduced CapEx in the IESO case, it is possible that the distinct benefits could differ depending on the order of calculation, while the total benefits remain the same.

(10) Scaling effect from control room improvements: avoided carbon costs from control room improvements

A5.27 We calculate the percent of emissions subject to the carbon tax by estimating the emissions above the OBPS performance standard based on GWh of production for each technology type in each year and estimated carbon-equivalent intensity of generation of each technology type. For simplicity, we assume the average emissions per GWh shielded from the carbon tax remains the same with the change in operations that results in lower carbon emissions.

A5.28 The RPV of avoided carbon emissions is calculated with the following equations:

RPV carbon emissions
× Expected carbon savings

A5.29 Noting that, for each year, the non-discounted value of carbon is calculated as:

Carbon emissions annual value $ =
Annual carbon emissions ktonne CO2
× Carbon price $/ktonne CO2
× Percent emissions subject to tax %

(11) Scaling effect from control room improvements: avoided carbon costs from more advanced system planning

A5.30 We use the same percent of emissions subject to the carbon tax as in (10).

A5.31 Carbon emissions are calculated as:

RPV carbon emissions $
× expected carbon savings %
× (1- expected carbon savings from (10) %)

(12) Loss of synergies between asset owner and operator (disbenefit)

A5.32 The disbenefit of this loss of synergy is calculated as:

((-1) × expected cost %) ×

(RPV production costs pre-control room improvements $
+ (RPV production costs post-control room improvements $
× ((1 - expected savings in (6) %) × (1- expected savings in (9) %))

A5.33 Production costs pre-control room improvements are the production costs in (6) above for the years 2026 and 2027, while production costs post-control room improvements are the reduced costs in 2029 onwards.

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Nova Scotia Independent Energy System Operator

Proposed Expenditures, Revenue Requirement, and Fees Application

Appendix 8 – IBM Economic Analysis

This Appendix has been provided in an electronic spreadsheet format

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Nova Scotia Independent Energy System Operator

Proposed Expenditures, Revenue Requirement, and Fees Application

Appendix 9 – Marsh Report

This Appendix has been removed for confidentiality purposes

Nova Scotia Independent Energy System Operator

Proposed Expenditures, Revenue Requirement, and Fees Application

Appendix 10 – Historical Consultant Contracts

This Appendix has been removed for confidentiality purposes.

Nova Scotia Independent Energy System Operator

Proposed Expenditures, Revenue Requirement, and Fees Application

Appendix 11 – Software Service Agreements

This Appendix has been removed for confidentiality purposes.

Nova Scotia Independent Energy System Operator

2027/2028 Proposed Expenditures, Revenue Requirement, and Fees Application

Appendix 12 – Consumer Advocate and Small Business Advocate Annual Reports

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pink larkin
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VIA WEB PORTAL

March 31, 2026

Crystal Henwood, Clerk of the Board
Nova Scotia Energy Board
1601 Lower Water Street, 3rd Floor
P.O. Box 1692, Unit "M"
Halifax, NS B3J 3S3

Dear Ms. Henwood:

RE: 2025 ANNUAL REPORT OF THE NOVA SCOTIA CONSUMER ADVOCATE

INTRODUCTION

The Consumer Advocate (the "CA") represents residential customers of the various regulated utilities in Nova Scotia, including Nova Scotia Power Inc. ("NSP" or "NS Power"), Nova Scotia Power Maritime Link ("NSPML"), the Nova Scotia Independent Energy System Operator ("IESO NS"), Efficiency One ("E1"), Halifax Regional Water Commission ("Halifax Water" or "HRWC"), and Eastward Energy Inc. ("Eastward" or "EEI"). The CA's work primarily involves participation in hearings before both the Nova Scotia Energy Board (the "NSEB" or the "Energy Board") and the Nova Scotia Regulatory and Appeals Board (the "NSRAB") (together, referred to as the "Board" in this Report), and advocating on behalf of residential customers to ensure that utility services remain reliable and affordable for the residential rate class.

In accordance with the *Public Utilities Act*, the CA is required to file an annual report with the Board covering the CA's activities during the preceding calendar year, which must include various details with respect to each matter or proceeding in which the CA was involved.

In what follows, the CA briefly addresses the annual reporting requirement, and then provides some general comments as well as a more detailed summary of the relevant matters and proceedings that occurred in 2025 and in which the CA participated.

The CA requests that the Board accept this Report as filed, and is prepared to engage in any further process or provide any other such information as the Board may deem necessary.

ROLE OF THE CONSUMER ADVOCATE

Section 91 of the *Public Utilities Act* permits the Nova Scotia Energy Board and the Nova Scotia Regulatory and Appeals Board to appoint an advocate in a hearing to represent the interests of residential customers. Section 22A of the *Gas Distribution Act* provides a similar provision. Once appointed, the Consumer Advocate participates in all aspects of the hearing before the Board and represents the interests of residential consumers as a full intervenor with power to enter into settlement agreements with other parties; and has all the powers and authorities necessary to carry out their duties. Generally speaking, the mandate of the Consumer Advocate includes the following:

- Represent the interests of the residential consumers (e.g., appropriate rates, consumer protection, improved planning, appropriate resource decisions);
- Exercise professional judgement about the nature and extent of involvement. This may include but is not limited to submission of Information Requests (IRs), submission of evidence, attendance at oral hearings, participation in paper proceedings, oral or written summations, oral or written rebuttals, and other filings as required;
- If appropriate, engage and direct experts to provide evidence, be witnesses, assist with data interpretation and development of Information Requests, etc;
- Work with other parties in the matter to ensure an orderly exchange of information;
- Attend at hearings, technical conferences, planning meetings, or similar events related to assigned matters;
- If appropriate, enter into settlement or other agreements;
- Fully comply with orders or other direction issued by the Board in a matter;
- Address with media requests and appropriately communicate with ratepayers who contact them.

The activities described above are all undertaken with the objective of providing a strong voice for residential customers, with the general goal of protecting members of the residential rate class.

In many of the proceedings in which the CA is engaged, the CA relies extensively upon various consultants and subject matter experts who are critical to ensuring the CA fulfills its mandate. Most of these consultants have previously testified before the Board as expert witnesses, or have provided testimony in similar proceedings in other jurisdictions. These consultants not only assist with data interpretation, but are also key to developing Information Requests and advising the CA on potential matters of concern to the residential rate class. In some matters, the consultants may provide evidence and recommendations, where needed. Given the volume and technical nature of many of the proceedings brought before the Board, the work of these consultants is truly indispensable.

ANNUAL REPORTING REQUIREMENT

The *Public Utilities Act* establishes statutory annual reporting obligations for the Consumer Advocate. Specifically, s. 94 requires the CA to file an annual report with the Board covering the CA's activities during the preceding calendar year (the "Report"). This requirement came into effect last year, and the CA's first annual report was accepted as filed.

In accordance with s. 94, the Report must itemize each matter or proceeding in which the CA participated, and provide various details respecting each matter or proceeding. Section 94 of the *Public Utilities Act* is stated as follows:

> 94 (1) A consumer advocate appointed pursuant to subsection 91(1) and a small business advocate appointed pursuant to subsection 92(2) shall each file an annual report with the Board no later than March 31st of each year covering the activities of the advocate during the preceding calendar year.
>
> (2) An annual report filed with the Board pursuant to subsection (1) must itemize each matter or proceeding in which the advocate participated with details respecting each matter or proceeding including
>
> > (a) the activities carried out by the advocate and the hours spent by the advocate on each activity;
> >
> > (b) the name and qualifications of, role of and hours spent on an assigned task by any expert or consultant retained by the advocate;
> >
> > (c) the manner in which an expert or consultant retained by the advocate was compensated, including fixed fee, hourly rate or other compensation structure;
> >
> > (d) a detailed accounting of the fees and costs submitted for recovery by the advocate, including fees and costs of any expert or consultant; and
> >
> > (e) such other information as the Board may request or which the Governor in Council may prescribe by regulation.
>
> (3) Upon receipt of an annual report filed pursuant to subsection (1), the Board may set a process to obtain comments on the report.
>
> (4) The Board shall accept the report as filed or undertake such process on the report as the Board determines appropriate and in the public interest.

In accordance with the above requirements, what follows is a high-level summary of the CA's activities over the past year, followed by a detailed summary of the matters the CA and its consultants were involved in, consistent with the requirements of sub-clauses 94(2)(a) to (e). The CA asks that the Board accept this Report as filed, and is prepared to engage in any further process or provide any other such information as the Board may deem necessary.

2025 ANNUAL REPORT

(a) General Comments

The 2025 regulatory calendar involved the hearing of various significant matters before the Board, and particularly with regards to matters involving NSPI and Halifax Water, which both filed General Rate Applications in 2025. The hearing of these matters occurred at a time of significant and evolving change for the current regulatory landscape following the passage of Bill 404, which, in addition to introducing this reporting requirement for Board-appointed advocates, also created the current Board structure, and established a new independent energy system operator, among other changes. Notably, NSPI was also the subject of a cyberattack in 2025, the fallout from which continues to be felt by NSPI and its customers, and remains under review by the Board in two separate proceedings.

Consistent with its mandate, in 2025 the CA has worked continuously to hold NSPI and other utilities accountable to ensure they continue to provide their services in a reliable and cost-effective manner. In that regard, the CA participated in over 100 different proceedings before the Board (including 31 paper hearings and 6 oral hearings). Of these, 52 proceedings were new matters filed in 2025, and 57 were matters filed in previous years that continued into 2025. In 50 of these matters, the CA provided submissions and/or evidence on behalf of residential ratepayers. The majority of these matters related to applications filed by or relating to NSPI, but the CA was also significantly involved with matters involving other utilities as well.

A sample of matters is provided below:

- *M12451 – NSPI – General Rate Application:* Application filed by NSPI for approval of new rates impacting all customer classes. The Application also sought approval for the adoption of a new Cost of Service methodology.
- *M12600/M12273 – Board Inquiry into NS Cybersecurity Incident/Minister of Energy - Accountability for Nova Scotia Power* – Ongoing inquiries concerning NSPI cybersecurity incident.
- *M11902 – NSPI - 2025 AA/BA Riders Application:* Application for approval of NSPI's 2025 FAM AA/BA Rider to address unrecovered fuel costs.
- *M12012 – NSPI – 2025 Annual Capital Expenditure (ACE) Plan:* Application by NSPI for approval of 2025 capital projects totalling $263.8 million.
- *M11533 – NSPI – Fuel Adjustment Mechanism (FAM) Audit, conducted by Bates White:* Public hearing process following the filing of Bates White's audit report for NSPI's FAM for the years 2022 and 2023 (while various pre-hearing processes occurred throughout 2024, the oral hearing occurred in March 2025).
- *M12185 - NSPI - 2024 Annual Performance Standards Report:* Report filed by NSPI detailing its performance results for 2024.

- *M12004 – PHP - Application Re NSPI's $500 million regulatory asset*: Application filed by PHP seeking a declaration that PHP would not be responsible for any costs associated with the $500 million regulatory asset. PHP subsequently filed for judicial review of the Board's decision with the Nova Scotia Supreme Court, and also filed an appeal pursuant to s. 36 of the Energy and Regulatory Boards Act. The CA continues to participate in both matters.
- *M12394 - NSPML - 2026 Assessment Application* – Application filed by NSPML seeking approval for its 2026 assessment costs.
- *M12249 - EfficiencyOne - 2026 DSM Extension Application* – Application filed by E1 seeking approval to extend its DSM Plan for an additional year beyond the prior plan term.
- *M12282 - EfficiencyOne - New Benefit Cost Analysis Test* – Application filed by E1 seeking approval of a new benefit cost analysis test to be used for assessing cost-effectiveness of E1's programs.
- *M12217 - Wasoqonatl Transmission Incorporated - NS-NB Reliability Tie* – Application filed by WTI seeking approval for the NS-NB reliability interconnection tie, at a cost of $684.7 million.
- *M12412 - NSIESO - Application for Approval of Proposed Expenditure and Revenue Requirements* – Application filed by IESO NS seeking approval for certain expense and revenue requirements for the 2025/2026 fiscal year.
- *M11877/M12261 - Eastward Energy - CRP Recovery Rate Application/RDA Recovery Rate Amendments Application* – Applications filed by Eastward Energy seeking approval (and subsequent amendment) to recover deferrals (initially sought for the CRP, but approved for the RDA).
- *M12257 – Halifax Water – General Rate Application*: Application filed by Halifax Water for approval of new rates in 2025 and 2026.

In addition, the CA also participated in a number of ongoing formal and informal working groups, stakeholder sessions, and technical conferences, including the NSPI FAM Small Working Group and the E1 DSM Advisory Group.

While all of the CA's work is critical, some of the key achievements for the 2025 calendar year included:

- Representing the interests of NSPI's residential customers in respect of the General Rate Application ("GRA") filed by NSPI on September 18, 2025, which was preceded by months of intensive consultations and negotiations between NSPI and its key stakeholders, all of which led to the development of a Settlement Agreement and consensus approach to the GRA. NSPI's GRA also followed an in-depth consultative process concerning NSPI's cost of service methodologies, which were also addressed in the GRA.

- Representing the interests of NSPI's residential customers concerning NSPI's Fuel Adjustment Mechanism (FAM) for 2022-2023 (to ensure that all costs charged to the FAM were reasonably and prudently incurred) and its 2025 and 2026 Annual Capital Expenditure (ACE) Plans (to ensure that all costs incurred for capital projects are reasonable and that NSPI has taken adequate measures to minimize those costs). Notably, the Board disallowed $1.14 million in costs following the results of the 2022-2023 FAM Audit, which was credited to the FAM;

- Advocating for improved performance by NSPI following the filing of its 2024 Performance Standards Report, following which the Board ordered NSPI to pay an administrative penalty of $1 million to promote future compliance with the established performance standards and targets. This penalty was credited to the FAM;

- Working closely with NSPI to continue to monitor and improve its collection processes for customers in arrears, given the impact this can have on low-income customers. The work of this group has evolved into quarterly meetings where the impact of changes to NSPI's collection processes can be assessed constructively with new ideas brought forward for consideration and implementation, as well as an annual report filed with the Board;

- Representing the interests of NSPI's residential customers in relation to two pending matters arising from the cyber incident in 2025;

- Representing the interests of NSPI's residential customers in relation to the programs and services provided by E1, including participation in E1's application for approval of a new Benefit Cost Analysis, as well as E1's application to extend the DSM Plan to 2026;

- Representing the interests of NSPI's residential ratepayers with regard to the establishment of the Nova Scotia Independent System Operator, and this included participation in IESO NS's first application to the Board for approval of its operating expenses and revenue requirement in its first year of operation (2025/2026 fiscal year);

- Representing the interests of Eastward Energy's ratepayers, including with respect to Eastward's applications concerning recovery of deferral accounts (including the CRP and RDA);

- Representing the interests of HRWC's ratepayers in various matters, including M12257 – HRWC – General Rate Application, in which HRWC had applied for significant rate increases. The CA opposed the proposed rate increases, and filed evidence from its consultant addressing various aspects of HRWC's application. The Board ultimately approved the application, subject to various significant disallowances and adjustments.

The CA is pleased with the results it was able to achieve on behalf of its customer class, and looks forward to continued involvement in the coming year.

A more detailed summary of the relevant matters and the CA's participation is provided below.

(b) Detailed Summary of Relevant Matters

As noted above, s. 94 requires the CA to report on the following:

> (a) the activities carried out by the advocate and the hours spent by the advocate on each activity;
>
> (b) the name and qualifications of, role of and hours spent on an assigned task by any expert or consultant retained by the advocate;
>
> (c) the manner in which an expert or consultant retained by the advocate was compensated, including fixed fee, hourly rate or other compensation structure;
>
> (d) a detailed accounting of the fees and costs submitted for recovery by the advocate, including fees and costs of any expert or consultant; and
>
> (e) such other information as the Board may request or which the Governor in Council may prescribe by regulation.

With regards to (c) above, the CA can confirm that in all matters where an expert or consultant was retained, they were compensated by an hourly rate, in accordance with usual practices.

With regards to (a), (b), and (d) above, the CA confirms that it has submitted invoices to the Board on a monthly basis, which includes specific detail concerning its activities and hours spent on each activity for all matters in which the CA was engaged. The table enclosed with this Report as **Appendix A** provides brief summaries of these activities and associated financial details for reference. The table enclosed with this Report as **Appendix B** further sets out the qualifications and hourly rates of each of the CA's consultants.

CONFIDENTIAL TREATMENT

As with the Annual Report filed for 2024, the CA has enclosed a confidential and non-confidential version of the Consumer Advocate's Annual Report (the "Report").

The Consumer Advocate (the "CA") is requesting confidential treatment of certain portions of the Report which have been filed in confidence, particularly with regards to information contained in Appendices A and B to the Report. Attached to this correspondence is a Confidential Undertaking for the Nova Scotia Energy Board's approval.

The CA's rationale in support for seeking confidential treatment is provided below:

- Appendix A contains information concerning the hours worked and rates charged by the CA's consultants with respect to various proceedings, and Appendix B specifies the hourly rates for each of the CA's consultants. The CA respectfully submits that the hourly rates charged by the CA's consultants is commercially sensitive information. Keeping these rates confidential prevents potential competitors from using this information to gain a competitive advantage, and also better ensures that the CA is able to negotiate reasonable rates with its consultants. For these reasons, the CA requests that any information that could be used to determine consultants' hourly rates should receive confidential treatment.

In addition, the CA also notes that Appendix A contains information concerning the hours worked and rates charged by the CA with respect to various proceedings. The CA notes that the hourly rates charged by the CA are determined solely by the Board, and may be considered confidential information of the Board. The CA would therefore defer to the Board as to whether the CA's hourly rates should be afforded confidential treatment.

CONCLUSION

As set out above, 2025 was a busy year for the Consumer Advocate, and included a number of significant proceedings affecting all ratepayers, including residential ratepayers. Through the CA's advocacy, and with the valuable assistance of its expert consultants, the interests of residential ratepayers were brought forward in all of these respective matters, ensuring that these concerns and interests were taken into account by the relevant utilities, as well as the Board. The CA is pleased with the results it was able to achieve on behalf of its customer class, and looks forward to continued involvement in the current calendar year.

The CA asks that the Board accept this Report as filed, and is prepared to engage in any further process or provide any other such information as the Board may deem necessary.

Yours very truly,

PINK LARKIN



David Roberts
Consumer Advocate
Enclosure: Appendix A – Matter Summaries and Financial Details
Appendix B – Qualifications and Hourly Rates of Consultants

Appendix A

Company	Sum of PL Hours	Sum of PL Fees	Sum of PL Costs	Sum of PL Tax	Sum of PL Total	Sum of Consultant Hours	Sum of Consultant Fees (USD)	Sum of Consultant Fees (CAD)	Sum of Consultant Costs (USD)	Sum of Consultant Costs (CAD)	Sum of Consultant Tax (CAD)	Sum of Consultant Total (CAD)	Sum of Consultant Total (USD)	SUM OF GRAND TOTAL
Eastward Energy	9.50	$ 2,527.50	$ 0.25	$ 357.60	$ 2,885.35		$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 2,885.35**
EfficiencyOne	129.70	$ 30,847.50	$ 65.89	$ 4,342.34	$ 35,255.73		$ -	$ 78,758.75	$ -	$ -	$ -	$ 78,758.75	$ -	**$ 114,014.48**
Halifax Regional Water Commission	212.90	$ 55,505.00	$ 684.02	$ 7,909.77	$ 64,098.79		$ -	$ 79,032.50	$ -	$ 2,371.01	$ 11,430.62	$ 92,834.13	$ -	**$ 156,932.92**
IESO Nova Scotia	20.70	$ 5,427.50	$ 5.00	$ 760.55	$ 6,193.05		$ 525.00	$ -	$ -	$ -	$ -	$ -	$ 525.00	**$ 6,718.05**
Miscellaneous	85.20	$ 22,512.50	$ 61.08	$ 3,165.19	$ 25,738.77		$ 5,562.50	$ -	$ -	$ -	$ -	$ -	$ 5,250.00	**$ 30,988.77**
Nova Scotia Power Incorporated	924.90	$ 233,202.50	$ 2,816.24	$ 33,771.44	$ 269,790.18		$ 58,415.00	$ 122,840.00	$ -	$ 3,522.05	$ 17,059.60	$ 143,421.65	$ 58,415.00	**$ 471,626.83**
Nova Scotia Power Martime Link	91.40	$ 23,642.50	$ -	$ 3,311.70	$ 26,954.20		$ 2,100.00	$ -	$ -	$ -	$ -	$ -	$ 2,100.00	**$ 29,054.20**
Grand Total	**1,474.30**	**373,665.00**	**3,632.48**	**53,618.59**	**430,916.07**		**$ 66,602.50**	**$ 280,631.25**	**$ -**	**$ 5,893.06**	**$ 28,490.22**	**$ 315,014.53**	**$ 66,290.00**	**$ 812,220.60**

***This grand total amount does not adjust for USD conversion*

Matter ID	Company	Matter Description (First Line)	Narrative/Description of Activites	PL Hours	PL Fees	PL Costs	PL Tax	PL Total	Grid Strategies Hours	GEEG Hours	InterGroup Hours	Grid Strategies Fees (USD)	GEEG Fees (CAD)	InterGroup Fees (CAD)	GridStrategies Costs (USD)	GEEG Costs (CAD)	InterGroup Costs (CAD)	GEEG Tax (CAD)	InterGroup Tax (CAD)	GEEG Total (CAD)	InterGroup Total (CAD)	Grid Strategies Total (USD)	GRAND
0490-021	Eastward Energy	M10960 - Eastward Energy	Compliance Reporting: Review of all filed reports and related correspondence.	0.70	$ 182.50	$ -	$ 27.38	$ 209.88				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-050	Eastward Energy	Eastward - General	General: Attended to various general matters.	4.20	$ 1,112.50	$ -	$ 155.75	$ 1,268.25				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-171	Eastward Energy	M11877 - Eastward Energy - CRP Recovery Rate Application	Paper Hearing: Review of all evidence and material filed in matter. Correspondence with Board and EE, as required. Prepared and filed submissions with Board.	0.70	$ 187.50	$ -	$ 28.13	$ 215.63				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-228	Eastward Energy	M12261 - Eastward Energy - RDA Recovery Rate Amendment	Review Proceeding: Review of all evidence and material filed in matter. Correspondence with Board and EE, as required. Prepared and filed submissions with Board.	3.90	$ 1,045.00	$ 0.25	$ 146.34	$ 1,191.59				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-103	EfficiencyOne	EfficiencyOne - DSM Advisory Group	Stakeholder Matter: Attendance at workshops and stakeholder sessions. Review of relevant materials and reports. Correspondence with E1, consultants, and other interested parties as required.	23.80	$ 6,212.50	$ -	$ 882.38	$ 7,094.88				$ -	$ 32,027.50	$ -	$ -	$ -	$ -	$ -	$ -	$ 32,027.50	$ -	$ -	$
0490-198	EfficiencyOne	M12030 - EOne - Behavioural Program Update	Review Proceeding: Review of all filed reports and related correspondence.	0.80	$ 205.00	$ -	$ 30.75	$ 235.75				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-217	EfficiencyOne	M12186 - EfficiencyOne - 2024 DSM Annual Progress and Ev	Review Proceeding: Review of all filed reports and related correspondence.	0.60	$ 150.00	$ -	$ 21.00	$ 171.00				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-230	EfficiencyOne	M12249 - EfficiencyOne - 2026 DSM Extension Application	Paper Hearing: Review of all evidence and material filed in matter. Correspondence with Board and E1, as required. Meetings with consultants, E1, and interested parties as required. Prepared and filed submissions.	13.10	$ 3,325.00	$ 4.25	$ 466.10	$ 3,795.35				$ -	$ 24,641.25	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,641.25	$ -	$ -	$
0490-235	EfficiencyOne	M12282 - EfficiencyOne - New Benefit Cost Analysis Test	Oral Hearing: Review of all evidence and material filed in matter. Correspondence with Board and E1, as required. Attendance at various stakeholder sessions. Prepared and filed submissions. Meetings with consultants, E1, and interested parties as required.	90.40	$ 20,697.50	$ 61.64	$ 2,906.06	$ 23,665.20				$ -	$ 22,090.00	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,090.00	$ -	$ -	$
0490-236	EfficiencyOne	M12290 - EfficiencyOne - 2025 Q1 Demand Side Manageme	Review Proceeding: Review of all filed reports and related correspondence.	0.70	$ 175.00	$ -	$ 24.50	$ 199.50				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-265	EfficiencyOne	M12438 - EfficiencyOne- 2025 Q2 Demand Side Manageme	Review Proceeding: Review of all filed reports and related correspondence.	0.30	$ 82.50	$ -	$ 11.55	$ 94.05				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-029	Halifax Regional Water Commission	M10941 - HRWC - Fairview Cove	Compliance Reporting: Review of all filed reports and related correspondence.	0.10	$ 25.00	$ -	$ 3.50	$ 28.50				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-065	Halifax Regional Water Commission	M11158 - HRWC - Water Supply Enhancement Program - Pr	Compliance Reporting: Review of all filed reports and related correspondence.	1.00	$ 250.00	$ -	$ 37.25	$ 287.25				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-087	Halifax Regional Water Commission	M11255 - HRWC - Port Wallace Transmission Main Highway	Compliance Reporting: Review of all filed reports and related correspondence.	0.40	$ 100.00	$ -	$ 14.00	$ 114.00				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-111	Halifax Regional Water Commission	M11418 - HRWC - Burnside Operations Centre - $89,100,00	Compliance Reporting: Review of all filed reports and related correspondence.	0.60	$ 150.00	$ -	$ 22.00	$ 172.00				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-119	Halifax Regional Water Commission	M11537 - HRWC - Sullivan's Pond Storm Sewer System Rep	Compliance Reporting: Review of all filed reports and related correspondence. Prepared and filed IRs.	1.30	$ 325.00	$ -	$ 45.50	$ 370.50				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-133	Halifax Regional Water Commission	M11606 - HRWC - Mill Cove WWTF Expansion & Upgrade - $	Compliance Reporting: Review of all filed reports and related correspondence.	0.80	$ 200.00	$ -	$ 28.50	$ 228.50				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-148	Halifax Regional Water Commission	M11672 - HRWC - Mt. Edward 1 Reservoir Replacement - $2	Compliance Reporting: Review of all filed reports and related correspondence.	0.70	$ 175.00	$ -	$ 25.00	$ 200.00				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-182	Halifax Regional Water Commission	M11909 - HRWC - Annual Filing Regional Development Cha	Paper Hearing: Review of all evidence and material filed in matter. Correspondence with Board, HRWC, and consultants, as required. Meetings with consultants and interested parties as required. Prepared and filed submissions.	15.20	$ 4,007.50	$ -	$ 590.81	$ 4,598.31				$ -	$ -	$ 3,312.50	$ -	$ -	$ 99.38	$ -	$ -	$ 511.78	$ 3,923.66	$ -	$
0490-186	Halifax Regional Water Commission	M11899 - HRWC - 2024 Integrated Resource Plan Update	Review Proceedings: Review of all evidence and material filed in matter. Correspondence with Board and HRWC as required. Meetings with consultants and interested parties as required.	1.00	$ 257.50	$ -	$ 37.63	$ 295.13				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-200	Halifax Regional Water Commission	M11966 - HRWC - Mill Cove WWTF Expansion & Upgrade - $	Paper Hearing: Review of all evidence and material filed in matter. Prepared and filed IRs.	3.30	$ 857.50	$ -	$ 128.63	$ 986.13				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-210	Halifax Regional Water Commission	M12153 - HRWC - Sullivan's Pond Storm Sewer Replacemer	Paper Hearing: Review of all evidence and material filed in matter. Correspondence with Board and HRWC as required. Prepared and filed submissions. Meetings with consultants and interested parties as required.	5.20	$ 1,327.50	$ -	$ 185.85	$ 1,513.35				$ -	$ -	$ -	$ -	$ -	$ 99.38	$ -	$ -	$ 477.66	$ 3,889.54	$ -	$
0490-220	Halifax Regional Water Commission	M12205 - HRWC - Windsor Street Exchange Redevelopment	Paper Hearing: Review of all evidence and material filed in matter. Correspondence with Board and HRWC as required. Prepared and filed IRs. Prepared and filed submissions. Meetings with consultants and interested parties as required.	6.20	$ 1,572.50	$ -	$ 220.15	$ 1,792.65				$ -	$ -	$ -	$ -	$ -	$ 59.93	$ -	$ -	$ 288.05	$ 2,345.48	$ -	$
0490-229	Halifax Regional Water Commission	M12257 - HRWC - 2025 General Rate Application	Oral Hearing: Review of all evidence and material filed in matter. Correspondence with Board and HRWC, as required. Prepared for and attended hearing. Prepared and filed submissions with Board. Meetings with consultants and interested parties as required.	166.60	$ 43,472.50	$ 684.02	$ 6,181.05	$ 50,337.57				$ -	$ -	$ -	$ -	$ -	$ 2,010.39	$ -	$ -	$ 9,663.21	$ 78,686.10	$ -	$
0490-249	Halifax Regional Water Commission	M12384 - Halifax Water Operations Audit	Audit: Review of all information filed in matter. Correspondence with Board and HRWC as required.	2.20	$ 590.00	$ -	$ 82.60	$ 672.60				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-251	Halifax Regional Water Commission	M12348 - HRWC - 2025 Institutional Capacity Report	Paper Hearing: Review of all evidence and material filed in matter. Correspondence with Board and HRWC as required. Prepared and filed submissions. Meetings with consultants and interested parties as required.	8.30	$ 2,195.00	$ -	$ 307.30	$ 2,502.30				$ -	$ -	$ 3,397.50	$ -	$ -	$ 101.93	$ -	$ -	$ 489.92	$ 3,989.35	$ -	$
0490-253	IESO Nova Scotia	M12412 - NSIESO - Application for Approval of Proposed Ex	Paper Hearing: Review of all evidence and material filed in matter. Correspondence with Board and HRWC as required. Prepared and filed IRs. Meetings with consultants and interested parties as required.	20.70	$ 5,427.50	$ 5.00	$ 760.55	$ 6,193.05				$ 525.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 525.00	$
0490-092	Miscellaneous	Working Group on Low to Middle Income Energy Assistance	Stakeholder Matter: Correspondence with interested parties and participants, as required.	0.30	$ 52.50	$ -	$ 7.88	$ 60.38				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-178	Miscellaneous	M11903 - DNRR - Community Solar Power Purchase Agreen	Review Proceeding: Review of Board decision.	0.20	$ 50.00	$ -	$ 7.50	$ 57.50				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-202	Miscellaneous	M11978 - Steve R. Murphy's Auto Services Ltd. & Wayne Pa	Oral hearing: Review of all evidence and material filed in matter. Prepared and filed IRs. Prepared for and attended hearing. Prepared and filed submissions with Board.	47.90	$ 12,940.00	$ 20.83	$ 1,818.37	$ 14,779.20				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-221	Miscellaneous	M12217 - Wasoqonatt Transmission Incorporated - NS-NB P	Paper Hearing: Review of all evidence and material filed in matter. Correspondence with Board and consultants, as required. Prepared and filed IRs and submissions. Meetings with consultants and interested parties as required.	31.60	$ 8,120.00	$ 38.00	$ 1,142.12	$ 9,300.12				$ 4,900.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,900.00	$
0490-239	Miscellaneous	M12311 - Power Advisory - Application for Approval of a Tida	Paper Hearing: Review of all evidence and material filed in matter. Correspondence with Board and consultants, as required. Meetings with consultants and interested parties as required.	0.90	$ 225.00	$ -	$ 31.50	$ 256.50				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-242	Miscellaneous	M12339 - Renewable Energy - Request for Tariffs	Review Proceeding: Review of all evidence and material filed in matter. Correspondence with Board and consultants, as required. Meetings with consultants and interested parties as required.	2.80	$ 712.50	$ 0.75	$ 99.86	$ 813.11				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-243	Miscellaneous	M12306 - Antigonish - Community Solar Garden Capital Wo	Paper Hearing: Review of all evidence and material filed in matter. Correspondence with Board and consultants, as required. Meetings with consultants and interested parties as required.	0.50	$ 137.50	$ -	$ 19.25	$ 156.75				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-244	Miscellaneous	M12307 - Mahone Bay - Community Solar Garden Capital W	Paper Hearing: Review of all evidence and material filed in matter. Correspondence with Board and consultants, as required. Meetings with consultants and interested parties as required.	1.00	$ 275.00	$ 1.50	$ 38.71	$ 315.21				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-203	Miscellaneous	M12014 - ECI - Report on Renewable to Retail Update to Boa	Review Proceeding: Review of all filed reports and related correspondence. Prepared and filed submissions with Board.	6.20	$ 1,562.50	$ -	$ 232.13	$ 1,794.63				$ -	$ -	$ 662.50	$ -	$ -	$ 19.88	$ -	$ -	$ 102.36	$ 784.74	$ -	$
0490-025	Nova Scotia Power Incorporated	M10416 - NSPI - 2020/2021 FAM Audit	Compliance Reporting: Review of all filed reports and related correspondence.	0.20	$ 50.00	$ -	$ 7.50	$ 57.50				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-026	Nova Scotia Power Incorporated	M10905 - NSPI - Interconnections	Review Proceeding: Review of all evidence and material filed in matter.	6.70	$ 1,717.50	$ -	$ 241.20	$ 1,958.70				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-032	Nova Scotia Power Incorporated	M11307 - NSPI - 2023 Evergreen Integrated Resource Plan (	Compliance Reporting: Review of all filed reports and related correspondence. Corrrespondence with consultants, as required.	5.70	$ 1,425.00	$ -	$ 201.50	$ 1,626.50				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-034	Nova Scotia Power Incorporated	M10632 - NSPI - Wreck Cove Tunnel T-2 Remediation Projec	Compliance Reporting: Review of all filed reports and related correspondence.	0.20	$ 50.00	$ -	$ 7.50	$ 57.50				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-035	Nova Scotia Power Incorporated	M11349 - NSPI - Low Income Customers Review Process	Stakeholder Meetings/Review Proceedings: Review of all filed reports and related correspondence. Attended meetings with NSPI and other interested parties, as required. Prepared and filed comments with Board.	14.80	$ 3,545.00	$ -	$ 508.68	$ 4,053.68				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-044	Nova Scotia Power Incorporated	M10197 - NSPI - CI 29807 - HYD - Tusket Main Dam Refurbi	Compliance Reporting: Review of all filed reports and related correspondence.	0.40	$ 100.00	$ -	$ 14.00	$ 114.00				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-053	Nova Scotia Power Incorporated	NSPI - General	General: Attended to various general issues relating to the utility.	22.20	$ 5,915.00	$ 6.75	$ 880.81	$ 6,802.56				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-082	Nova Scotia Power Incorporated	M11220 - NSPI - Decarbonization Deferral Account Stakeho	Compliance Reporting: Review of correspondence.	1.10	$ 275.00	$ -	$ 38.50	$ 313.50				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-090	Nova Scotia Power Incorporated	M11588 - NSPI - Update on ELIADC Tariff Development	Review Proceeding: Review of correspondence.		$ 50.00	$ -	$ 7.50	$ 57.50				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-097	Nova Scotia Power Incorporated	NSPI - FAM SWG	Stakeholder Matter: Attendance at stakeholder sessions. Review of relevant materials and reports. Correspondence with NSP, consultants, and other interested parties as required.	38.20	$ 10,002.50	$ 8.50	$ 1,423.48	$ 11,434.48				$ 10,675.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,675.00	$
0490-107	Nova Scotia Power Incorporated	M11458 - NSPI - 2024 Annual Capital Expenditure (ACE) Pla	Compliance Reporting: Review of correspondence.	0.20	$ 50.00	$ -	$ 7.50	$ 57.50				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-110	Nova Scotia Power Incorporated	M11475 - NSPI - Cost of Service Study Process	Stakeholder Matter: Correspondence and conferences with interested parties and consultants, as required.	7.50	$ 1,990.00	$ -	$ 298.26	$ 2,288.26				$ 1,890.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,890.00	$
0490-114	Nova Scotia Power Incorporated	M11539 - NSPI - CI 00045132 Battery Energy Storage Syster	Compliance Reporting: Review of all filed reports and related correspondence.	0.30	$ 75.00	$ -	$ 10.50	$ 85.50				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-117	Nova Scotia Power Incorporated	M11533 - NSPI - 2022/2023 FAM Audit	Oral Hearing: Review of all evidence and material filed in matter. Correspondence with Board, NSP, consultants, and interested parties, as required. Meetings with consultants and interested parties as required. Attended hearing. Prepared and filed submissions with Board.	160.50	$ 41,492.50	$ 431.36	$ 6,184.05	$ 48,107.91				$ 12,950.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,950.00	$
0490-120	Nova Scotia Power Incorporated	M09579 - NSPI - Gaspereau Dam Safety Remedial Works	Compliance Reporting: Review of all filed reports and related correspondence.	0.40	$ 105.00	$ -	$ 15.25	$ 120.25				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-121	Nova Scotia Power Incorporated	M10013 - NSPI - Annapolis Tidal Generation Station Retirem	Compliance Reporting: Review of all filed reports and related correspondence.	0.20	$ 50.00	$ -	$ 7.00	$ 57.00				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-123	Nova Scotia Power Incorporated	M11556 - NSPI - CI C0050414 HYD Roseway Asset Decomm	Paper Hearing: Review of all evidence and material filed in matter. Correspondence with Board, NSP, and consultants, as required. Prepared and filed IRs and submissions. Meetings with consultants and interested parties as required.	8.70	$ 2,227.50	$ -	$ 321.00	$ 2,548.50				$ 1,575.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,575.00	$
0490-125	Nova Scotia Power Incorporated	NSPI - TVP Stakeholder Session	Stakeholder Matter: Attended all required workshops and stakeholder sessions. Correspondence with interested parties.	12.00	$ 2,422.50	$ -	$ 357.56	$ 2,780.08				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-128	Nova Scotia Power Incorporated	M11588 - NSPI - ELIADC Tariff - 2023 Annual Report	Review Proceedings: Review of all filed reports and related correspondence.	0.20	$ 55.00	$ -	$ 8.25	$ 63.25				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-134	Nova Scotia Power Incorporated	M11621 - NSPI - Smart Grid Nova Scotia Project - Final Repo	Compliance Reporting: Review of all filed reports and related correspondence.	0.20	$ 50.00	$ -	$ 7.50	$ 57.50				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-135	Nova Scotia Power Incorporated	M11656 - NSPI - Michelin Waterville Dynamic Voltage Resto	Compliance Reporting: Review of all filed reports and related correspondence.	0.20	$ 50.00	$ -	$ 7.00	$ 57.00				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-137	Nova Scotia Power Incorporated	M11626 - NSPI - Commercial Net Metering Program - 2023 A	Compliance Reporting: Review of all filed reports and related correspondence.	0.20	$ 50.00	$ -	$ 7.00	$ 57.00				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-151	Nova Scotia Power Incorporated	M11694 - NSPI - Customer Energy Management (CEM) 2022	Review Proceeding: Review of all filed reports and related correspondence.	0.20	$ 50.00	$ -	$ 7.50	$ 57.50				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-160	Nova Scotia Power Incorporated	M11764 - NSPI - 10-Year System Outlook Report 2024	Paper Hearing: Review of all evidence and material filed in matter. Correspondence with Board, NSP, and consultants, as required. Prepared and filed IRs and submissions with Board. Meetings with consultants and interested parties as required.	0.60	$ 157.50	$ -	$ 23.63	$ 181.13				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-166	Nova Scotia Power Incorporated	M12499 - NSPI - Application for Approval of the 2025/26 Tim	Review Proceeding: Review of all evidence and material filed in matter. Correspondence with Board, NSP, and consultants, as required. Prepared and filed submissions with Board. Meetings with consultants and interested parties as required.	0.20	$ 50.00	$ -	$ 7.00	$ 57.00				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-167	Nova Scotia Power Incorporated	M11823 - NSPI - Time-Varying Pricing Pilot Program - 2023/2	Compliance Reporting: Review of all filed reports and related correspondence.	1.10	$ 287.50	$ -	$ 40.25	$ 327.75				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-172	Nova Scotia Power Incorporated	M11874 - NSPI - Renewable to Retail Implementation Costs	Paper Hearing: Review of all evidence and material filed in matter. Correspondence with Board, NSP, and consultants, as required. Prepared and filed Information Requests. Prepared and filed submissions with Board. Meetings with consultants and interested parties as required.	8.20	$ 2,085.00	$ 0.75	$ 311.56	$ 2,397.31				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-175	Nova Scotia Power Incorporated	M11902 - NSPI - 2025 FAM AA/BA Application	Paper Hearing: Review of all evidence and material filed in matter. Correspondence with Board, NSP, and consultants, as required. Prepared and filed comments with Board. Meetings with consultants and interested parties as required.	7.10	$ 1,877.50	$ 1.00	$ 281.78	$ 2,160.28				$ 525.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 525.00	$
0490-180	Nova Scotia Power Incorporated	M11912 - NSPI - 2025 DSM Cost Recovery Rider (DCRR)	Compliance Reporting: Review of all filed reports and related correspondence.	0.30	$ 82.50	$ 1.00	$ 12.53	$ 96.03				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-181	Nova Scotia Power Incorporated	M11911 - NSPI - Application for Approval of the Community	Paper Hearing: Review of all evidence and material filed in matter. Correspondence with Board, NSP, and consultants, as required. Prepared and filed Information Requests. Prepared and filed submissions with Board. Meetings with consultants and interested parties as required.	4.00	$ 1,035.00	$ -	$ 155.25	$ 1,190.25				$ -	$ -	$ 1,192.50	$ -	$ -	$ 35.77	$ -	$ -	$ 184.25	$ 1,412.52	$ -	$
0490-184	Nova Scotia Power Incorporated	M11927 - NSPI - CI 50518 - HYD Ruth Falls Main Dam Refurb	Paper Hearing: Review of all evidence and material filed in matter. Correspondence with Board, NSP, and consultants, as required. Prepared and filed IRs and submissions with Board. Meetings with consultants and interested parties as required.	14.10	$ 3,715.00	$ 1.00	$ 546.88	$ 4,262.88				$ -	$ -	$ 7,817.50	$ -	$ -	$ 234.53	$ -	$ -	$ 1,203.17	$ 9,255.20	$ -	$
0490-190	Nova Scotia Power Incorporated	M11989 - NSPI - 2025 Annually Adjusted Rates (AAR's)	Paper Hearing: Review of all evidence and material filed in matter. Correspondence with Board, NSP, and consultants, as required. Prepared and filed submissions with Board. Meetings with consultants and interested parties as required.	13.00	$ 3,427.50	$ 1.00	$ 513.53	$ 3,942.03				$ 3,150.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,150.00	$
0490-191	Nova Scotia Power Incorporated	M11990 - NSPI - WACC and AFUDC Rates Application for 20	Paper Hearing: Review of all evidence and material filed in matter. Correspondence with Board, NSP, and consultants, as required. Prepared and filed IRs with Board. Meetings with consultants and interested parties as required.	6.50	$ 1,640.00	$ -	$ 246.01	$ 1,886.01				$ -	$ -	$ 4,107.50	$ -	$ -	$ 123.23	$ -	$ -	$ 634.62	$ 4,865.35	$ -	$
0490-192	Nova Scotia Power Incorporated	M12004 - NSPI - PHP - Application seeking confirmation abo	Paper Hearing: Review of all evidence and material filed in matter. Correspondence with Board and consultants, as required. Prepared and filed submissions. Meetings with consultants and interested parties as required.	81.40	$ 17,160.00	$ 1,232.50	$ 2,629.08	$ 21,021.58				$ 350.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 350.00	$
0490-193	Nova Scotia Power Incorporated	M12012 - NSPI - 2025 Annual Capital Expenditure (ACE) Pla	Oral Hearing: Review of all evidence and material filed in matter. Correspondence with Board and NSP, as required. Prepared and filed IRs and submissions. Meetings with consultants and interested parties as required. Attended hearing.	78.60	$ 21,055.00	$ 37.88	$ 3,015.08	$ 24,107.96				$ 13,650.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,650.00	$
0490-194	Nova Scotia Power Incorporated	M12451 - NSPI - 2025 GRA	Oral Hearing: Review of all evidence and material filed in matter. Correspondence with Board and NSP, as required. Meetings with consultants and interested parties as required. Prepared and filed IRs. Formal matter precipitated by intensive discussions, resolution conferences, and negotiations.	239.90	$ 63,087.50	$ 969.00	$ 8,967.93	$ 73,024.43				$ -	$ -	$ 97,586.25	$ -	$ -	$ 2,927.61	$ -	$ -	$ 14,071.95	$ 114,585.81	$ -	$
0490-196	Nova Scotia Power Incorporated	M12022 - NSPI - SAMP and Property and Asset Inquiry Actio	Review Proceeding: Review of all filed reports and related correspondence. Prepared and filed submissions with Board.	2.30	$ 587.50	$ -	$ 83.25	$ 670.75				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-199	Nova Scotia Power Incorporated	M12034 - NSPI - Natural Gas Report November 1, 2023 to O	Review Proceeding: Review of all filed reports and related correspondence.	0.20	$ 50.00	$ -	$ 7.50	$ 57.50				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-201	Nova Scotia Power Incorporated	M12028 - NSPI - NERC 2024-2025 Winter Reliability Report	Review Proceeding: Review of all filed reports and related correspondence.	0.50	$ 132.50	$ -	$ 19.38	$ 151.88				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-204	Nova Scotia Power Incorporated	M12071 - NSPI - December 12, 2024 Outage Analysis Repor	Review Proceeding: Review of all filed reports and related correspondence.	0.60	$ 150.00	$ -	$ 22.50	$ 172.50				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-205	Nova Scotia Power Incorporated	M12074 - NSPI - 2024 COMFIT Annual Report	Review Proceeding: Review of all filed reports and related correspondence.	0.30	$ 75.00	$ -	$ 11.25	$ 86.25				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-206	Nova Scotia Power Incorporated	M12121 - NSPI - Fuel Adjustment Mechanism (FAM) Annual	Review Proceeding: Review of all filed reports and related correspondence.	0.40	$ 100.00	$ 1.00	$ 15.15	$ 116.15				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-207	Nova Scotia Power Incorporated	M12123 - NSPI - Extra Large Industrial Active Demand Contr	Review Proceeding: Review of all evidence and material filed in matter. Correspondence with Board, NSP, and consultants, as required. Prepared and filed IR with Board. Meetings with consultants and interested parties as required.	5.10	$ 1,322.50	$ 3.00	$ 192.18	$ 1,517.68				$ 1,225.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,225.00	$
0490-208	Nova Scotia Power Incorporated	M12117 - NSPI - CI C0061284 - IT - OT Cyber Security Contr	Paper Hearing: Review of all evidence and material filed in matter. Correspondence with Board, NSP, and consultants, as required. Prepared and filed IRs and submissions with Board. Meetings with consultants and interested parties as required.	9.80	$ 2,375.00	$ 3.00	$ 336.33	$ 2,714.33				$ -	$ -	$ 1,855.00	$ -	$ -	$ 55.65	$ -	$ -	$ 267.49	$ 2,178.14	$ -	$
0490-209	Nova Scotia Power Incorporated	M12149 - NSPI - Investigation Arising from Joint Use Agreem	Paper Hearing: Review of all evidence and material filed in matter. Correspondence with Board, NSP, and consultants, as required. Prepared and filed IRs and submissions with Board. Meetings with consultants and interested parties as required.	5.70	$ 1,437.50	$ -	$ 201.25	$ 1,638.75				$ -	$ -	$ 805.00	$ -	$ -	$ 24.16	$ -	$ -	$ 116.09	$ 945.25	$ -	$
0490-211	Nova Scotia Power Incorporated	M12164 - NSPI - Commercial Net Metering 2024 Annual Rep	Paper Hearing: Review of all evidence and material filed in matter. Correspondence with Board, NSP, and consultants, as required.	3.60	$ 900.00	$ -	$ 127.00	$ 1,027.00				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
0490-214	Nova Scotia Power Incorporated	M12177 - NSPI - Distributed Energy Resource Integration Ro	Review Proceeding: Review of all filed reports and related correspondence.	6.40	$ 1,707.50	$ -	$ 239.05	$ 1,946.55				$ -	$ 471.25	$ -	$ -	$ -	$ -	$ -	$ -	$ 471.25	$ -	$ -	$
0490-215	Nova Scotia Power Incorporated	M12178 - NSPI - Smart Grid NS Project - Asset Disposition F	Paper Hearing: Review of all evidence and material filed in matter. Correspondence with Board, NSP, and consultants, as required. Prepared and filed IRs and submissions with Board. Meetings with consultants and interested parties as required.	10.60	$ 2,680.00	$ 1.00	$ 375.34	$ 3,056.34				$ 2,800.00	$ -	$ -	$ -

Appendix B

Company	Consultants	Credentials	Rates	Compensation	Website
			As at Oct. 2025		
Grid Strategies LLC	John Wilson	MPP, BA		USD Hourly	https://gridstrategiesllc.com/our-team/
Green Energy Economics Group, Inc.	Francis Wyatt	PE, BS		CAD Hourly	https://www.geeg.co/company#team
Green Energy Economics Group, Inc.	Theodore Love	BA		CAD Hourly	https://www.geeg.co/company#team
Green Energy Economics Group, Inc.	Thomas Crookham	BA		CAD Hourly	https://www.geeg.co/company#team
InterGroup Consultants	Andrew McLaren	MNRM		CAD Hourly	https://intergroup.ca/about/
InterGroup Consultants	Hayitbay Mahmudov	MA		CAD Hourly	https://intergroup.ca/about/
InterGroup Consultants	Joshua Dyck	MA		CAD Hourly	https://intergroup.ca/about/
InterGroup Consultants	Kyle Morton	MA		CAD Hourly	https://intergroup.ca/about/

2025 ANNUAL REPORT OF THE SMALL BUSINESS ADVOCATE

REDACTED

INTRODUCTION

The Small Business Advocate (the "SBA") represents small business customers of regulated electricity utilities in Nova Scotia, including Nova Scotia Power Inc. ("NSPI"), Nova Scotia Power Maritime Link Inc. ("NSPML") and Efficiency One ("E1"). In October of 2024, the *More Access to Energy Act* was enacted, which created the Nova Scotia Independent Energy System Operator ("IESO-NS"). This organization began taking responsibility for some electricity grid management activities in or around May 2025 and the SBA began working with it with respect to its future plans and applications. In 2025, an application was submitted by Wasoqonatl Transmission Incorporated ("WTI") for the NS-NB Reliability Intertie Project Application, which the SBA participated in.

The SBA's mandate involves working with these 5 entities (NSPI, NSPML, E1, IESO-NS and WTI) through stakeholder engagement, technical conferences, review proceedings, paper and oral Board hearings and advocating on behalf of small business customers to ensure that utility services remain reliable and affordable for the three small business rate classes that the SBA represents – Classes 10 – small business; 11 – small industrial; and 21 – general.

2025 was a particularly busy year within the electrical regulatory field, with the creation of the IESO-NS (which had its first filing for a general rate); the discussion of an upcoming general rate application by NSPI; an application by NSPML that included a review of its return on equity and an application by E1 for an extension of its plan for 2026 as well as one to determine the applicable benefit cost test, and the WTI Intertie application, in addition to the usual annual filings.

In addition to reviewing applications, developing information requests, sponsoring evidence and filing comments and/or submissions, the SBA participated in 4 oral hearings, numerous paper hearings, review proceedings, meetings and discussions. The SBA has worked diligently to advocate on behalf of the small businesses before the Nova Scotia Energy Board ("NSEB"), ensuring that the concerns and issues relevant to the SBA rate classes are clearly and effectively presented and explored.

Please accept the following Report of the Small Business Advocate for the 2025 calendar year.

OVERVIEW

Section 92 of the Nova Scotia *Public Utilities Act* permits the Board to appoint an advocate in a hearing to represent the interests of small business customers, known as the Small Business Advocate. Once appointed, the SBA participates in all aspects of a hearing before the Board and represents the interests of small businesses as a full intervenor with all the powers and authorities necessary to carry out their duties and powers, including the authority to enter into settlement agreements with other parties.

Generally speaking, the mandate of the SBA includes:

- Representing the interests of the small business rate classes, including with respect to appropriate rates, consumer protection, improved planning, appropriate resource decisions, reliability improvements, capital projects and planning.
- Exercising professional judgement about the nature and extent of SBA involvement in a particular matter or hearing. This may include but is not limited to the submission of Information Requests (IRs), the submission of evidence, attendance and participation at oral hearings, participation in paper proceedings and review proceedings, oral or written submissions, oral or written rebuttals, and other filings as required.
- If appropriate, engaging and directing experts to provide evidence, be witnesses, assist with data interpretation and the development of IRs, etc.
- Working with other parties in the matter to ensure an orderly exchange of information.
- Attending hearings, technical conferences, planning meetings, or similar events related to assigned matters.
- If appropriate, entering into settlement or other agreements.
- Fully complying with orders or other directions issued by the Board in a matter.
- Addressing media requests and appropriately communicating with ratepayers and interested parties who contact them.

The activities described above are all undertaken with the purpose of providing a strong voice for the small business customers that the SBA represents before the NSEB.

In 2024, the Nova Scotia government introduced amendments to the Nova Scotia *Public Utilities Act* that require the SBA to file an annual report with the NSEB outlining the SBA's activities during the preceding calendar year (the "Report"). This is the second annual Report, and the SBA hopes it provides all stakeholders with important information to help understand the role the SBA plays in ensuring that the small business ratepayers of NSPI, NSPML, E1, IESO-NS and WTI receive cost effective, affordable, safe and reliable electricity and energy efficiency programs.

Section 94 of the Nova Scotia *Public Utilities Act* (the "*Act*") states the following:

> 94 (1) A consumer advocate appointed pursuant to subsection 91(1) and a small business advocate appointed pursuant to subsection 92(2) shall each file an annual report with the Board no later than March 31st of each year covering the activities of the advocate during the preceding calendar year.
>
> (2) An annual report filed with the Board pursuant to subsection (1) must itemize each matter or proceeding in which the advocate participated with details respecting each matter or proceeding including
>
> (a) the activities carried out by the advocate and the hours spent by the advocate on each activity;

(b) the name and qualifications of, role of and hours spent on an assigned task by any expert or consultant retained by the advocate;

(c) the manner in which an expert or consultant retained by the advocate was compensated, including fixed fee, hourly rate or other compensation structure;

(d) a detailed accounting of the fees and costs submitted for recovery by the advocate, including fees and costs of any expert or consultant; and

(e) such other information as the Board may request or which the Governor in Council may prescribe by regulation.

(3) Upon receipt of an annual report filed pursuant to subsection (1), the Board may set a process to obtain comments on the report.

(4) The Board shall accept the report as filed or undertake such process on the report as the Board determines appropriate and in the public interest.

This Report provides a high-level summary of the SBA's activities during the past calendar year, followed by a detailed summary of the matters in which the SBA and its consultants were involved. The SBA asks that the Board accept this Report as filed, and the SBA is prepared to engage in any further process or provide any other such information as the Board may require.

2025 ANNUAL REPORT

(a) General Comments

Over the course of 2025, the SBA participated in approximately 67 NSPI matters, 3 E1 matters, 5 NSPML matters, 1 IESO-NS matter and 1 WTI matter. These included paper and oral hearings as well as Review Proceedings where there was no formal Board order but there was the opportunity to provide comments/submissions. Some of these matters began and finished in 2025, while others were ongoing matters that were started in 2024 or earlier. Others still were new matters that were commenced in 2025 and carried into 2026. Consistent with its mandate, the SBA filed information requests in 29 matters, evidence in 3 matters and submissions and/or comments in 39 of those matters.

The 2025 calendar year had the SBA participating in 4 in-person hearings before the Board, which were M12394 - NSPML 2026 Assessment Application, M11533 – NSPI FAM Audit, M12012 – NSPI 2025 ACE Plan, and M12282 – EOne New Benefit Cost Analysis Text for Evaluating DSM Plans.

In addition, the SBA also participated in several formal and informal working groups and stakeholder sessions, including:

- FAM Small Working Group (5 meetings, with members of the FAM Small Working Group);

- DSMAG matters (multiple meetings regarding M12282 and M12499, some with the entire DSMAG, some with EOne alone, others with EOne and various stakeholders);
- Technical Conferences were held for a multitude of matters, including M12012, M12451, M12282, M12661, M12217, M12249, M12349, M11307, M12247, M12394, M12412, and M12524;
- Line Loss Update Discussions;
- ELIADC Successor Tariff Development Discussions;
- Climate Adaptation Presentation;
- Hosting Capacity Map Stakeholder Workshops;
- Interconnection Processes Discussions;
- IRP Evergreen Action Plan Update;
- NSPI DER Integration Roadmap Stakeholder Workshops; and
- FERC Order 2023 Review and Recommendations Meeting.

In addition to the above-noted matters, the SBA was involved in the applications by Port Hawkesbury Paper LP for both a judicial review and an appeal of the Board's decision in M12004. This involved multiple court appearances and the preparation of a factum for filing with the Court of Appeal. The Appeal itself occurred in 2026 and is expected to continue through the year.

While there were many beneficial outcomes in relation to the above-noted matters and consultations, some key achievements for the 2025 calendar year include:

- M12451 – NSPI General Rate Application - The SBA was an active participant in the extensive discussions, technical conferences and negotiations that took place with NSPI and multiple intervenors and included the participation of many experts. This includes the Cost of Service Study that began in 2024. The GRA is a complex matter, involving many different issues that have a direct impact on the rate classes that the SBA represents. The SBA believes that its advocacy directly benefitted its rate classes and resulted in a positive outcome for all parties.

- M12412 - IESO-NS 2025-2026 Revenue Requirement Application – 2025 was a unique year, in that it involved the development and standing-up of the IESO-NS, which is going to have a significant impact on the electricity grid and regulatory environment in Nova Scotia. The initial revenue requirement application provided some information about how IESO-NS will operate and the costs that will be required to be paid by ratepayers, but there are still a lot of questions remaining, including the permanent cost recovery mechanism. It is also unclear at this point how the transition from NSPI to IESO-NS will proceed and the impact it will have on ratepayers.

- M12394 - NSPML 2026 Assessment Application – NSPML filed another one-year revenue requirement application, which addressed its Return on Equity, as required by the Board.

The SBA submitted IRs and participated in the hearing, including cross examination, focusing on issues relating to the LTAMP and costs associated with the marine survey.

- M11533 – NSPI FAM Audit – A key issue in this audit was the standard of review for an audit and how the Board and stakeholders should consider the prudency standard when examining previous decisions made by NSPI. The SBA filed IRs and participated in the hearing, including through cross examination.

- M12012 – NSPI 2025 ACE Plan – The SBA sponsored the evidence of John Athas and Tim Pelzer, Daymark Energy Advisors, which addressed issues around the proposed use of normalized SAIDI and the metrics used to measure reliability and resiliency. The SBA recommended that normalized SAIDI not be adopted, which was confirmed by the Board in its decision.

- M12282 – EOne New Benefit Cost Analysis Text for Evaluating DSM Plans – The SBA sponsored the evidence of Melissa Whitten, Daymark Energy Advisors, which focused on the proposed used of proxy values for certain non-energy benefits and the risk of bias due to the lack of the ability to independently measure and verify benefits. While the Board determined that the settlement agreement that was entered into by the SBA, the Consumer Advocate, East Coast Environmental Law and E1 should not be approved, the SBA believes that the information that it requested through the IR process and Ms. Whitten's evidence was of assistance to the Board and other intervenors.

- M12217 – WTI NS-NB Reliability Intertie Project Application – The SBA sponsored the evidence of Jeffrey Bower, Daymark Energy Advisors, which focused on the costs of the project and the risks of working with another party on assets located in another province. The SBA raised concerns with the proposed blended Return on Equity being requested by WTI and the potential for benefits to be obtained by New Brunswick in the future. The SBA also requested that WTI provide additional reporting as the project progressed. This is a significant project, and the SBA believes that its participation benefitted the Board in completing its analysis.

The SBA is pleased with the results it achieved on behalf of its small business classes, working continuously to hold utilities accountable and to ensure they continue to provide their services in a reliable and cost-effective manner, with a focus on rate stability and affordability.

As noted, the requirement to file this Report came into effect last year. As such, there is the opportunity to provide a comparison between the years, as outlined below.

	2024	2025
NSPI Matters	45	67
NSPML Matters	5	5
E1 Matters	3	3
IESO Matters	0	1
WTI Matters	0	1
SBA Hours	871.6	1215
SBA Total Fees	247,377.17	315,579.09
[redacted]	[redacted]	[redacted]
Consultant Total Fees	410,009.10	414,307.00

(b) Detailed Summary of Relevant Matters

As noted above, s. 94 of the *Act* requires the SBA to report on the following:

> (a) the activities carried out by the advocate and the hours spent by the advocate on each activity;
>
> (b) the name and qualifications of, role of and hours spent on an assigned task by any expert or consultant retained by the advocate;
>
> (c) the manner in which an expert or consultant retained by the advocate was compensated, including fixed fee, hourly rate or other compensation structure;
>
> (d) a detailed accounting of the fees and costs submitted for recovery by the advocate, including fees and costs of any expert or consultant; and
>
> (e) such other information as the Board may request or which the Governor in Council may prescribe by regulation.

The table enclosed with this Report as **Appendix A (Confidential)** provides a summary of these activities and associated financial details for reference. Please note that we have requested that the hourly rates and number of hours worked by the experts retained by the SBA (Daymark Energy Advisors Inc., which was acquired by Xodus Group in March 2025) be treated as confidential and have outlined our reasons in the covering letter. The redacted version is also enclosed with this Report.

With regards to s. 94 of the *Act* (a), (b), and (d) above, the SBA confirms that it has submitted invoices to the Board on a monthly basis, which includes specific detail concerning its activities and hours spent on each activity for all matters in which the SBA was engaged.

With regards to (c) above, the SBA can confirm that in all matters where an expert or consultant was retained, they were compensated by an hourly rate, in accordance with usual practices.

CONCLUSION

2025 was an incredibly busy year, both before the Board and working in collaboration with NSP, NSPML, E1, IESO-NS and WTI, as well as other intervenors. There were extensive consultations, discussions and negotiations with all parties as we addressed significant changes in the electricity industry in Nova Scotia. The SBA is pleased with the results of its efforts to engage with other parties in order to reduce the issues and thus reduce the costs incurred by ratepayers. This extends to the SBA's purposeful intention to strategically utilize its experts for the best interests of its rate classes.

In addition, the SBA connected with several individuals representing small businesses operating in, or intending to operate, in Nova Scotia and also spoke with media concerning relevant issues. The SBA attended CAMPUT and heard updates from industry leaders on the coming changes for the electricity grid locally, nationally and internationally.

The SBA believes the results it achieved on behalf of the customer classes it represents (Classes 10 – small business; 11 – small industrial; and 21 – general) has provided great value and benefits, and looks forward to continued involvement in the coming year. One of the challenges in representing three classes is that they experience different outcomes depending on what approach may be taken on a particular issue, therefore the SBA focuses on advocating for outcomes that reflect fairness and equity. The SBA will continue to ensure that all the parties that it deals with (NSPI, NSPML, E1, IESO-NS and WTI) recognize the unique interests and needs of our classes as we move forward with the energy transition and development of IESO-NS.

The SBA asks that the Board accept this report as filed, and is prepared to engage in any further processes or provide any other such information as the Board may require.

Yours very truly,

BLACKBURN LAW INC.

Melissa P. MacAdam
Small Business Advocate

Company	Total Hours for SBA and Consultants	Sum of Fees for SBA	Sum of Costs for SBA	Sum of HST for SBA	Total Sum for SBA	Sum of Fees for Consultants (USD)	Sum of Costs for Consultants (USD)	Total Sum for Consultants
EfficiencyOne	262.35	$ 29,597.50	$ 32.00	$ 4,168.75	$ 33,798.25	$ 47,120.75	$ -	$ 47,120.75
NSPI Matters and Related Matters	1920.3	$ 207,343.50	$ 329.65	$ 29,857.01	$ 237,070.16	$ 316,995.00		$ 316,995.00
NSPML Matters	152	$ 22,730.00	$ -	$ 3,184.48	$ 25,914.48	$ 13,195.00	$ -	$ 13,195.00
IESO-NS	[redacted]	$ 4,472.50	$ 9.00	$ 626.15	$ 5,107.65	$ 7,187.50	$ -	$ 7,187.50
WTI	[redacted]	$ 12,007.50		$ 1,681.05	$ 13,688.55	$ 29,808.75		$ 29,808.75
Total	**2563**	**$ 276,151.00**	**$ 370.65**	**$ 39,517.44**	**$ 315,579.09**	**$ 414,307.00**	**$ -**	**$ 414,307.00**

Matter ID	Matter Description (First Line)	Narrative/Description of Activites	Hours	Fees	Costs	HST	Total Billed by SB	Consultant Hours	Consultant Costs	Consultant Total Billed
EfficiencyOne Matter										
DSMAG	DSM Advisory Group	Review file materials and correspondence; Consultation with experts; Submissions; Attended various meetings with EOne and various Stakeholders; Reviewed reports; Reviewed IRs from various Stakeholders	31.8	$7,635.00		$1,094.00	$8,729.00		$ -	$12,211.25
M12249	2026 DSM Extension Application	Reviewed Application; Filed IRs; Consultation with experts; Reviewed IRs from various Stakeholders; Filed submissions; Reviewed submissions from various Stakeholders	15.6	$ 3,740.00	$ -	$ 523.60	$ 4,263.60		$ -	$ 5,610.00
M12282	New Benefit Cost Analysis Test for Evaluating DSM Plans	Reviewed corespondence from the Board; Reviewed Application; Filed and reviewed submissions; Consultation with experts; Attendance at and participation in E1 BCA hearing; Reviewed Board's Decision & Order	75.7	$ 18,222.50	$ 32.00	$ 2,551.15	$ 20,805.65		$ -	$ 29,299.50
NSPI and Related Matters										
M11556	CI C0050414 - HYD Roseway Asset Decommissioning - $4,915,649	Review Board correspondence; File IRs; Consultation with experts; Reviewed Irs from various Stakeholders; File submissions; Reviewed submissions of various Stakeholders	12.8	$ 3,055.00		$ 446.95	$ 3,501.95			$ 6,880.00
M11220	Decarbonization Deferral Account 2024 Annual Report	Reviewed Board correspondence	0.2	$ 50.00	$ -	$ 7.00	$ 57.00		$ -	$ -
M09596	CI C0013838 Wreck Cove Life Extension and Modernization 2025 Q2 Report	Reviewed various Reports	0.9	$220.00		$32.50	$252.50		$ -	$ -
M11858	Municipal Electric Utilities - Community Solar Projects	Reviewed Board Decision	0.8	$ 200.00	$ 30.00	$ 230.00	$ -		$ -	$ -
M11902	NSP 2025 FAM AA/BA Appication & NSPML 2025 Supplemental Assessments Application	Consultation with experts; Review correspondence; File comments; Review closing submissions; Reviewed Board Decsion and Order	6.9	$ 1,632.50	$ -	$ 244.88	$ 1,877.38		$ -	$ 2,945.00
M11903	DNRR Community Solar PPA	Review Board Decision and correspondence	1.5	$ 362.50	$ -	$ 54.38	$ 416.88		$ -	$ -
M11904	Property & Assets Action Plan Update	Reviewed NSP Action Plan; Reviewed correspondence from Board	1	$ 250.00	$ -	$ 37.50	$ 287.50		$ -	$ -
M12004	Port Hawkesbury Paper Application	File IRs; Reviewed IRs; Consultations with experts; Review evidence and correspondence from Stakeholders; Filed closing submssions; Reviewed submissions from various Stakeholders; Reviewed Board Decision	13.4	$ 3,220.00	$ -	$ 481.33	$ 3,701.33		$ -	$ 2,602.50
M12004	PHP - Judicial Review & Appeal	Reviewed correspondence from various Stakeholders; Notice of Participation; Arranged for service of documents; Attended various court appearances; Consultations with various Stakeholders; Preparation of Court documents; Reviewed court filings of various Stakeholders	74.5	$ 17,625.00	$ 216.65	$ 2,467.50	$ 20,309.15		$ -	$ -
FAM SWG	FAM SWG	Reviewed Reports; Participated in various meetings; Reviewed correspondence; Reviewed IRs from various Stakeholders; Consultation with experts	22.6	$5,485.00		$778.10	$6,263.10		$ -	$12,120.00
M11475	Cost of Service Study	Telephone conference with NSP; Consultations with experts; Submissions regarding NSP's COSS Settlement Proposal; Reviewed correspondence	3.9	$955		$142.78	$1,097.78		$ -	$2,140.00
M10905	NSP Interconnections Process	Review reply evidence	0.7	$175.00		$26.25	$201.25		$ -	$ 320.00
M11307	2023 Evergreen Integrated Resource Plan	Reviewed correspondence; Consulation with experts; Filed submissions	2	$485.00		$71.50	$556.50		$ -	$480.00
M10197	Tusket Dam Refurbishment	Reviewed corespondence; Reviewed various NSP Contingency Reports	0.6	$150.00		$22.00	$172.00		$ -	$ -
M11533	Fuel Adjustment Mechanism Audit 2022 and 2023	Reviewed of all evidence and material filed in matter; Correspondence; Prepared and filed submissions with Board; Attended and participated in FAM Audit Hearing; Reviewed Board Decision and Order	106	$25,315.00	$61.00	$3,750.63	$29,126.63		$ -	$7,850.00
M11539	BESS Grid Scale Battery Projects CI 0045132	Reviewed Report	0	$0.00	$0.00	$0.00	$0.00			$ 465.00
M10416	Fuel Adjustment Mechanism Audit 2020 and 2021	Reviewed Complinance Filings and Action Plan Update; Reviewed Boardd Decision & Order	0.8	$183.50		$27.53	$211.03		$ -	$ -
M11621	Smart Grid	Reviewed Board Decision and Order	0.3	$ 70.00		$ 10.50	$ 80.50		$ -	$ -
M11626	Commercial Net Metering	Reviewed Board Decision; Attendance at Workshops; Reviewed NSP Compliance letter	1.7	$ 405.00		$ 57.65	$ 462.65		$ -	$ -
M11627	2023 Annual Performance Standards	Reviewed Board Decision	0.5	$ 125.00		$ 18.75	$ 143.75		$ -	$ -
M11656	Michelin DVR Application	Reviewed correspondence; Consultation with experts	0.2	$ 50.00		$ 7.00	$ 57.00		$ -	$ 155.00
M11692	Storm Cost Recovery Rider	Reviewed Board Decsion and Order	1.1	$ 275.00		$ 41.25	$ 316.25		$ -	$ -
M11822	2024-2025 Time Varying Pricing Tariffs	Review correspondence and NSP work plan; Attended various TVP Tariff Tech Sessions; Consultation with experts; Conference calls	13.9	$ 3,295.00		$ 483.00	$ 3,778.00		$ -	$ 4,545.00
M11874	Renewable to Retail Implementation Cost	Review rebuttal evidence; Consultations with experts; File submissions; Review submissions; Reviewed Board Decision	4.3	$ 1,035.00	$ -	$ 154.50	$ 1,189.50		$ -	$ 930.00
M11927	HYD Ruth Falls Main Dam Refurbishment	Review evidence; Fileed IRs; Consultation with experts; Reviewed IRs from various Stakeholders; Filed submissions; Reviewed submissions from various Stakeholders; Reviewed Board Decision	14	$ 3,355.00	$ -	$ 494.51	$ 3,849.51		$ -	$ 4,080.00
M11912	2025 DSM Recovery Rider	Review Board Order; Consultation with experts; Reviewed correspondence	0.6	$ 145.00	$ -	$ 21.28	$ 166.28		$ -	$ -
M11911	Community Solar Energy Credit Rider	Consultation with experts; File submissions; Review submissions	3.5	$ 840.00	$ -	$ 126.00	$ 966.00		$ -	$ 1,240.00
M11989	2025 AARs	Review file materials; File IRs; Review Board correspondence; Consultation with experts; File submissions; Reviewed submissions from various Stakeholders; Consultations with NSP and various Stakeholders; Review Board Decision	14.2	$ 3,402.50	$ -	$ 510.38	$ 3,912.88		$ -	$ 3,520.00
M11990	2025 WACC and AFUDC	File IRs; Reviewed IRs; Consultations with experts; File Submissions and review submissions of Stakeholders; Reviewed Board Decision and Order	5.1	$ 1,212.50	$ -	$ 180.94	$ 1,393.44		$ -	$ 2,015.00
M12012	2025 ACE Plan	Review Reports; Consultation with experts; Attendance at Technical Conference; Correspondence with Board and Stakeholders; Filed IRs; Reviewed Irs and responses from various Stakeholders; Filed and reviewed evidence from various Stakeholders; Attendance and participation in ACE Plan hearing; Filed closing submissions; Reviewed submissions from various Stakeholders; Reviewed Board Decision	100.5	$ 23,950.00	$ 22.00	$ 3,508.66	$ 27,480.66		$ -	$ 52,105.00
M12014	ECI - Report on Renewables to Retail Update	Review Board correspondence; File submissions; Reviewed Submissions; Reviewed draft BER Regulations; Consultation with experts	12.4	$ 2,940.00	$ -	$ 437.66	$ 3,377.66		$ -	$ 2,400.00
M12021	2024 Q4 Dispatch Study Action Plan	Reviewed responses to Irs; Reviewed Board correspondence	0.3	$ 75.00	$ -	$ 11.25	$ 86.25		$ -	$ -
M12022	Action Plan Update – Inquiry into NS Power's Property and Assets under s.30(5)(a)	Reviewed reports; Consultation with experts; Filed submissions; Reviewed correspondence	2.3	$ 575.00	$ -	$ 82.00	$ 657.00		$ -	$ 1,280.00
M12028	NERC - 2024 - 2025 Winter Reliability Report	Review correspondence with Board and various Stakeholders; Reviewed Reports; Reviewed Board Decision	1	$ 240.00	$ -	$ 35.28	$ 275.28		$ -	$ -
M12071	Storm Outage Analysis Report - December 12, 2024	Reviewed NSP Reports; Reviewed Irs; Reviewed Board Decision	1.7	$ 425.00	$ -	$ 62.86	$ 487.86		$ -	$ -
M12117	CI C0061284 - IT - OT Cyber Security Control Implementation Ph 1 - $6,826,426	Reviewed correspondence from the Board; Reviewed Application; Consultation with experts; Filed Irs; Reviewed Irs from various Stakeholders; Filed submissions; Reviewed submissions of various Stakeholders; Reviewed Board Decision; Filed Irs; Reviewed Irs from various Stakeholders	6.4	$ 1,527.50	$ -	$ 221.25	$ 1,748.75		$ -	$ 4,640.00
M12123	ELIADC 2024 Annual Report	Reviewed correspondence; File Irs; Consultation with experts; Filed submissions; Reviewed submissions from various Stakeholders	7.2	$ 1,712.50	$ -	$ 239.75	$ 1,952.25		$ -	$ 3,722.50
M12149	Joint Use Agreement	Reviewed correspondence from Board and various Stakeholders; Reviewed IRs from NSP; Filed IRs; Reviewed IRs from various Stakeholders; Consultation with experts; Filed submissions; Reviewed submissions from various stakeholders	6.1	$ 1,470.00	$ -	$ 206.53	$ 1,676.53		$ -	$ 3,680.00
M12164	Commerical Net Metering 2024 Annual Report	Reviewed correspondence with Board and various Stakeholders; Filed Irs; Reviewed IRs from various Stakeholders; Consultation with experts; Reviewed evidence; Filed submissions; Reviewed submissions from various Stakeholders	6.7	$ 1,585.00	$ -	$ 221.90	$ 1,806.90		$ -	$ 2,680.00
M12174	Interconnections Processes Annual Report	Reviewed Reports; Reviewed Board correspondence; Attended and particpated in Stakeholder session; Filed comments; Reviewed comments from various Stakeholders; Reviewed Board's Decision	7.4	$ 1,770.00	$ -	$ 247.80	$ 2,017.80		$ -	$ 960.00
M12177	Distributed Energy Resource Integration Roadmap	Reviewed correspondence; Attended Stakeholder sessions; Consultation with experts; Reviewed reports	13.4	$ 3,205.00	$ -	$ 448.70	$ 3,653.70		$ -	$ 3,370.00
M12178	SGNS Asset Disposition	Reviewed Application; Reviewed correspondence with Board and various Stakeholders; Filed Irs; Reviewed Application; Consultation with experts; Reviewed Irs from various Stakeholders; Reviewed evidence; Filed submissions; Reviewed submissions from various Stakeholders; Reviewed Board's Decision	14.9	$ 3,535.00	$ -	$ 494.90	$ 4,029.90		$ -	$ 10,055.00
M12184	Application for Approval of 3rd Term for ELIADC	Participate in telephone conference with various Stakeholders; Reviewed Application; Filed Irs; Reviewed Irs from various Stakeholders; Consultation with experts; Reviewed correspondence from various Stakeholders; Filed and reviewed submissions from various Stakeholders; Reviewed Board Decision	17.3	$ 4,135.00	$ -	$ 584.38	$ 4,719.38		$ -	$ 6,962.50
M12185	2024 Annual Performance Standards Report	Reviewed Reports; Consultation with experts; Filed IRs; File submissions; Reviewed submissions from various Stakeholders; Reviewed Board Decision	11.1	$ 2,657.50	$ -	$ 372.05	$ 3,029.55		$ -	$ 2,390.00
M12188	2024 Storm Restoration Cost Report	Reviewed reports; Filed IRs; Consultation with experts; Reviewed IRs from various Stakeholders; Filed comments; Reviewed comments from various Stakeholders; Reviewed Board Decision	5.1	$ 1,227.50	$ -	$ 171.85	$ 1,399.35		$ -	$ 3,562.50
M12247	Evergreen IRP Action Plan & Roadmap Update	Reviewed correspondence; Reviewed reports; Participated in Stakeholder sessions; Filed IRs; Reviewed IRs from various Stakeholders; Filed submissions; Reviewed submissions from various Stakeholders; Reviewed Board's Decision	10.5	$ 2,542.50	$ -	$ 355.95	$ 2,898.45		$ -	$ 7,630.00
M12248	2024 Affiliate Code of Conduct Report	Reviewed report; Consultation with experts; Reviewed Board correspondence; Filed Irs; Reviewed Irs from various Stakeholders; Filed comments; Reviewed comments from various Stakeholders	8.6	$ 2,042.50	$ -	$ 285.95	$ 2,328.45		$ -	$ 4,220.00
M12251	CI C0021839 IT - CEM 2024 EM&V Report	Reviewed Board correspondence; Reviewed report; Filed comments; Reviewed Board Decision	1.8	$ 447.50	$ -	$ 62.65	$ 510.15		$ -	$ -
M12253	CI46075 – IT – T&D WAM Phase 2 – Work Management and Scheduling	Reviewed reports; Filed submissions; Reviewed correspondence; Reviewed submissions from NSP	4.2	$ 1,000.00	$ -	$ 140.00	$ 1,140.00		$ -	$ 4,640.00

M12273	Cyber Event Mar 3 2025	Reviewed correspondence; Reviewed reports; Reviewed IRs; Reviewed Reports	6.1	$ 1,472.50	$ -	$ 206.15	$ 1,678.65	[redacted]	$ -	$ 1,120.00
M12275	CI C0021140 - New 138KV – 25KV Substation Stellarton	Consultation with experts; Filed IRs; Reviewed IRs from various Stakeholders; File comments; Reviewed comments from various Stakeholders; Reviewed Board Decision	6.7	$ 1,585.00	$ -	$ 221.90	$ 1,806.90		$ -	$ 5,392.50
M12303	Decarbonization Deferral Account 2024 Annual Report	Reviewed reports; Consultation with experts; Filed IRs; Reviewed IRs from various Stakeholders; Reviewed submissions; Reviewed correspondence from the Board	5.9	$ 1,397.50	$ -	$ 195.65	$ 1,593.15		$ -	$ 3,498.75
M12311	Power Advisory Tidal Stream PPA	Reviewed Application; Consultation with experts; Filed comments with the Board; Reviewed correspondence; Reviewed Board Decision and Order	3.4	$ 822.50		$ 115.15	$ 937.65			$ 1,120.00
M12319	CI Various (ATOs) - Distribution Routines	Reviewed Board Order; Consultation with experts; Filed and reviewed Irs from various Stakeholders; Consultation with experts; Filed submissions; Reviewed submissions from various Stakeholders; Reviewed Board Decision	7.9	$ 1,875.00	$ -	$ 262.50	$ 2,137.50		$ -	$ 4,160.00
M12376	Review of NS Power Performance Standards	Reviewed correspondence and draft Terms of Reference; Consultation with experts; Filed comments	1.6	$ 387.50	$ -	$ 54.25	$ 441.75		$ -	$ -
M12349	2025 Load Forecast Report	Attended Stakeholder sessions; Reviewed reports; Consultation with experts; Filed Irs; Reviewed Irs from various Stakeholders; Filed submissions; Reviewed submissions from various Stakeholders; Reviewed evidence; Reviewed Board's Decision	13.1	$ 3,152.50	$ -	$ 441.35	$ 3,593.85		$ -	$ 6,952.50
M12386	10 Year System Outlook Report - 2025	Filed IRs; Consultation with experts; Reviewed Irs from various Stakeholders; Reviewed correspondence; File submissions; Review submissions from various Stakeholders	8	$ 1,890.00	$ -	$ 264.60	$ 2,154.60		$ -	$ 5,077.50
M12416	CI C00685655 & CI C0073491	Reviewed Application; Consultation with experts; Filed IRs; Reviewed IRs from various stakeholders; Reviewed correspondence	8.1	$ 1,957.50	$ -	$ 274.05	$ 2,231.55		$ -	$ 2,240.00
M12451	2025 General Rate Application	Attended and participated in various settlement negociations; Consultation with experts; Consultations with various Stakeholders; Reviewed correspondence with various Stakeholders; Reviewed IRs	220.5	$ 52,537.50	$ -	$ 7,355.25	$ 59,892.75		$ -	$ 101,520.00
M12499	Approval of 2025/26 TVP Tariffs	Reviewed Board correspondence; Reviewed reports; Consultation with experts; Filed comments; Reviewed comments from various Stakeholders; Filed submissions; Reviewed submissions from various Stakeholders; Reviewed Board's Decision	6.9	$ 1,650.00	$ -	$ 231.00	$ 1,881.00		$ -	$ 6,723.75
M12521	Application for 2026 DSM Cost Recovery Rider (DCRR)	Review Application; Consultation with experts; Filed IRs; Reviewed IRs from various stakeholders; Filed submissions; Reviewed submissions from various Stakeholders	7.7	$ 1,852.50	$ -	$ 259.35	$ 2,111.85		$ -	$ 5,156.25
M12524	Concentric FERC Order 2023 Report	Reviewed report	0.4	$ 100.00	$ -	$ 14.00	$ 114.00		$ -	$ -
M12550	Obtain Cost Reasonableness Review of NSP - CI C0051815 - RTU Program	Reviewed correspondence	0.7	$ 172.50	$ -	$ 24.15	$ 196.65		$ -	$ -
M12551	2026 AARs	Reviewed correspondence; Consultation with experts; Filed IRs; Reviewed IRs from various stakeholders	2.7	$ 645.00	$ -	$ 90.30	$ 735.30		$ -	$ 4,480.00
M12558	Review of NSP's 5 Year Reliability Plan 2025-2029	Reviewed correspondence from the Board	0.3	$ 72.50	$ -	$ 10.15	$ 82.65		$ -	$ -
M12339	Renewable Energy Inc - Request for Tariffs for the RtR market	Reviewed correspondence; Researched legislation; Consultation with experts; Filed submissions; Reviewed submissions from various Stakeholders; Reviewed Board Decision	11	$ 2,652.50	$ -	$ 371.35	$ 3,023.85		$ -	$ 2,968.75
M12619	2026 ACE Plan	Attended Stakeholder sessions; Filed comments and reviewed submissions from various stakeholders; Consultation with experts	3.5	$ 845.00	$ -	$ 118.30	$ 963.30		$ -	$ -
M12306,12307,12308	Communitiy Solar Garden Capital Work Order	Reviewed correspondence; Reviewed submissions from various Stakeholders; Reviewed Application; Filed comments; Reviewed Board Decision	6.9	$ 1,640.00		$ 229.60	$ 1,869.60			
NSPML Matters										
M11791	2025 Assessment Application	Reviewed Board Decision and Order	0.6	$ 135.00	$ -	$ 20.25	$ 155.25		$ -	$ -
M12023	Q4 Quarterly Report	Reviewed Board correspondence	2.6	$ 612.50	$ -	$ 86.68	$ 699.18		$ -	$ -
M12285	2025 Capital Application Submarine Cable Protection Project	Reviewed Application; Reviewed evidence; Consultation with experts; Reviewed correspondence; Filed IRs; Reviewed IRs from various Stakeholders; Filed submissions; Reviewed submissions from various Stakeholders; Reviewed Board's Decision	17.2	$ 4,100.00	$ -	$ 574.00	$ 4,674.00		$ -	$ 6,900.00
M12300	2024 Affiliate Code of Conduct Report	Reviewed report	0.2	$ 50.00	$ -	$ 7.00	$ 57.00		$ -	$ -
M12394	2026 Assessment Application	Reviewed all evidence and material filed in matter; Correspondence; Prepared and filed submissions with Board; Attendance at Hearing	74.4	$ 17,832.50	$ -	$ 2,496.55	$ 20,329.05		$ -	$ 6,295.00
IESO-NS Matters										
M12412	Proposed expenditure and revenue requirements for test year ending March 31, 2026	Attendance at Stakeholder engagement sessions; Reviewed legislation; Reviewed Application; Reviewed correspondence; Consultation with experts; Filed IRs; Reviewed IRs from various stakeholders; Reviewed evidence	18.7	$ 4,472.50	$ 9.00	$ 626.15	$ 5,107.65		$ -	$ 7,187.50
WTI Matters										
M12217	Wasoqonatl Transmission Incorporated - NS-NB Reliability Intertie Project Application	Participate in conference call with various Stakeholders; Consultation with experts; Review Application; Reviewed correspondence; Participated in technical conference; Review reports; Filed Irs; Reviewed IRs from various Stakeholders; Reviewed evidence; Reviewed submissions; Reviewed Board Decision	109.9	$ 12,007.50		$ 1,681.05	$ 13,688.55			$ 29,808.75
			1215	$ 276,151.00	$ 370.65	$ 39,517.44	$ 315,579.09		$ -	$ 414,307.00

Name of Consultant	Qualifications	Hourly Rate	M12004	M11475	M10905	M11533	M11822	M11874	M11927	M11911	M11989	M11990	M11902	DSMAG	FAMSWG	M12014	M12012	M11556	M11307	M12117	M12022	M12184	M12123	M12185	M12217	M12164	M12188	M12451	M12178	M12253	M12174	M12275	M12303	M12285	M12319	M12311	M12247	M12248	M12249	M12282	M12149	M12273	M12349	M12394	M12386	M12412	M12339	M11539	M12416	M12499	M12521	M12177	M11656	M12551
John Athas	P.Eng, M.B.A. Finance , M.S. Mechanical Eng. B.E. Mechanical Eng.	[redacted]																																																					
Melissa Whitten	M.B.A., B.A. in Economics																																																				
Tim Pelzer	M.A. in Economics, B.A. in Economics																																																				
Jeff Bower	Master of Environmental Management, B.A. in Sociology																																																				
Charlotte Gebhard	B.A. in Environmental Studies and Spanish																																																				
Bohdan Melenchuk	Master of Engineering Science, B.S. in Environmental Geoscience																																																				
Dylan Dragan	M.S. in Environmental Studies, M.B.A., B.A. in English																																																				
Timothy Lenell	M.S. in Economics, B.S. in Economics																																																				
Nina Choquette	B.S. in Ocean Engineering, B.A. in French																																																				
Frances Arthur	M.S. in Environment and Sustainability, B.S. in Environmental Science																																																				
Adam Fam	M.S. in Economics, B.A. in Economics																																																				
Vasker Neupane	M.B.A., B.S. in Mechanical Engineering																																																				

Nova Scotia Independent Energy System Operator

Proposed Expenditures, Revenue Requirement, and Fees Application

Appendix 13 – Mercer Compensation Benchmarking Proposal and Barrington Consulting Cost Estimate

This Appendix has been removed for confidentiality purposes.

Nova Scotia Independent Energy System Operator

Proposed Expenditures, Revenue Requirement, and Fees Application

Appendix 14 – Provincial Line of Credit

This Appendix has been removed for confidentiality purposes.

Nova Scotia Independent Energy System Operator

Proposed Expenditures, Revenue Requirement, and Fees Application

Appendix 15 – Office Lease

NON-CONFIDENTIAL

3325398 NOVA SCOTIA LIMITED

- and -

NOVA SCOTIA INDEPENDENT ENERGY SYSTEM OPERATOR

1791 Barrington Street, Suite 1010
Halifax, Nova Scotia

PREMISES LEASE

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This Lease dated this A□ay of J f1{;-¼ 2025.

Between

3325398 NOVA SCOTIA LIMITED

(the **"Landlord")**

of the First Part,

- and -

NOVA SCOTIA INDEPENDENT ENERGY SYSTEM OPERATOR

(the **"Tenant")**

of the Second Part,

is made on the following terms:

ARTICLE 1
DEFINED TERMS

1.1 Defined Terms - General

In this Lease:

"Building" means the building in which the Premises are located, and the part of the Land appurtenant thereto;

"Commencement Date" means the date defined as such in Article 4.1;

"Common Areas" means those parts of the Building designated by the Landlord for common use by or enjoyment of the Landlord and the tenants of the Building, including the public sidewalks and the landscaped portions of the streets adjacent to the Building Land;

"Common Service Areas" means those parts of the Building designated by the Landlord which provide services to the Building;

"Expert" means any architect, engineer, land surveyor or other professional consultant, as the case may be, appointed by the Landlord and qualified in the opinion of the Landlord to perform the particular function;

"Expiration of the Term" means the termination of this Lease by either the operation of any of its provisions or the effluxion of time;

"Landlord's Cost" means with respect to any cost incurred by the Landlord the actual amount thereof and 15% thereof on account of management and overhead;

"Leasehold Improvements" means all items generally considered as leasehold improvements, including, without limitation, all fixtures, equipment, improvements, installations, alterations and additions from time to time made, erected or installed by or on behalf of the Tenant, or any previous occupant of the Leased Premises in the Leased Premises, and by or on behalf of other tenants in other premises in the Building, including any stairways for the exclusive use of the Tenant, all partitions, however affixed and whether or not movable, and all wall-to-wall carpeting other than carpeting laid over finished floors and affixed so as to be readily removable without damage; but excluding trade fixtures, unattached furniture or free-standing partitions and equipment not of the nature of fixtures;

"Net Rent" means the amount payable under Article 5.1(a) (i);

"Notice" means a notice given pursuant to Article 17.1;

"Premises" means the premises of the Tenant specified in Article 3.1, as altered in accordance with this Lease;

"Prime" means the rate of interest from time to time announced by The Royal Bank of Canada as its prime rate;

"Building Land" means the land in the City of Halifax designated as the whole of 1791 Barrington Street;

"Rent" means the amounts payable as specified in Article 5.1;

"**Rentable Area"** means:

(a) with respect to premises on a single tenancy floor, occupiable area;

(b) with respect to premises on a multiple tenancy floor, occupiable area and a proportion of all shared areas on such floor, such proportion being a fraction, the numerator of which is the occupiable area of the Premises and the denominator of which is the total occupiable area on such floor:

For the purpose of this definition:

(a) "occupiable area" means:

(i) with respect to a single tenancy floor the area of the floor measured from the inside surface of the exterior walls, excluding, where applicable, elevators, stairwells, duct shafts, Common Service Areas, the Building lobby, other like areas and their enclosing walls;

(ii) with respect to a multiple tenancy floor, the area of the premises measured from the inside surface of all demising walls except those demising walls separating the Premises from adjoining premises, which shall be measured from the centre lines of such walls;

(b) "shared areas" means the areas included in the measurement made pursuant to part (i) of the term "occupiable area" which are excluded in the measurement made pursuant to part (ii) of such term;

The measurements shall be made partly by reference to building drawings and partly by field measurement, the latter being principally the demising walls separating a premise from other parts of the Building. In the event of any uncertainty as to the principles of measurement of

Rentable Area, reference shall be made to American National Standard Z65.1 - 1996 of **BOMA.**

"Sales Taxes" means the HST and all other goods and services, sales, consumption, value-added and other similar taxes imposed by any government.

"Term" means the term of this Lease as specified in Article 4.1;

"Unavoidable Delay" means a delay caused by an event beyond the control of a party provided that the event is:

(a) not caused by such party;

(b) not avoidable by the exercise of reasonable effort or foresight by such party;

(c) not the result of such party's financial inability.

ARTICLE 2
GENERAL CONDITIONS

2.1 Building Standard.
The Landlord and the Tenant shall perform their respective obligations under this Lease having regard to the general standard prevailing for similar good quality buildings in the City of Halifax and subject to the limitations occasioned by the design of the Building and its basic building systems.

2.2 Reasonableness.
The Landlord and the Tenant shall act reasonably, having regard to the fact that they are the owner and a tenant, respectively, of a good quality building in the City of Halifax, in the performance of their obligations and the exercise of their rights (including the giving of a notice, consent or approval) unless a right is stated to be exercisable at the discretion of a party. The strict enforcement of time limits provided for in this Lease shall be considered to be acting reasonably.

2.3 Timeliness.
The Landlord and the Tenant may, unless expressly stated otherwise, exercise and enforce their respective rights under this Lease at any time and from time to time.

2.4 Lawfulness.
The Landlord and the Tenant shall in the performance of their respective obligations under this Lease, comply with all layvs, by-laws, regulations and orders of any competent authority including any insurer of the interest of the Landlord in the Building.

2.5 Net Lease.
This Lease and the rent derived from it shall be completely net to the Landlord.

2.6 Entire Agreement.
This Lease, including the rider(s), if any, the plan(s) attached to it, the most up to date area certificate issued pursuant to Article 3.2 and the regulations imposed by the Landlord pursuant to Article 9.1 constitute the entire agreement between the Landlord and the Tenant regarding the leasing of the Premises and the Building.

2.7 Amendment.
This Lease may only be amended by an agreement in writing signed by the parties hereto.

ARTICLE 3
PREMISES

3.1 Lease of Premises. Lease of Premises.
The Landlord hereby grants a lease and the Tenant hereby takes a lease for the Term of the premises constituting the portion of the interior of the Building outlined in red on the floor plan(s) attached to this Lease.

3.2 Area of Premises.
The Rentable Area of the Premises (located on the 10th Floor, Suite 1010) and the Building will be determined by an Expert and evidenced by such Expert's Certificate. The Landlord and Tenant agree that the area is +/-8,900 square feet of Rentable Area, subject to final determination and the gross up factor shall be a maximum of 17.5% in addition to the usable area.

3.3 Limits of Premises.
The Premise extends from the top of the floor slab to the underside of the ceiling and to the interior surfaces of demising walls.

3.4 Rights of the Tenant.
The Landlord grants to the Tenant for the Term:

(a) the right in the form of a non-exclusive licence, subject to the control of the Landlord to use those parts of the Common Areas giving access to the Premises;

(b) the right to have its name displayed on the main lobby directory board for the Building, all such signs to be under the exclusive control of the Landlord and to conform to the uniform pattern of identifications signs for tenants of the Building prescribed by the Landlord.

3.5 Quiet Enjoyment.
The Landlord covenants with the Tenant for quiet enjoyment.

3.6 Access by Landlord.
The Tenant hereby grants to the Landlord for the Term the right to enter the Premises in order to:

(a) perform its obligations hereunder;

(b) install, maintain and repair equipment within or about the Premises for the supply of services to other premises in the Building;

(c) make repairs or alterations to the Building;

(d) take such steps as the Landlord may deem necessary for the safety or preservation of the Project;

(e) inspect the Premises.

Prior to the exercise of this right the Landlord whenever possible shall consult with the Tenant in order to minimize inconvenience to the Tenant and in its exercise of this right shall observe where practical the security requirements of the Tenant.

3.7 Relocation of Premises.
Landlord shall have the right at any time and from time to time, either during the term of the Lease or prior to the commencement date thereof, to change the locations of the Premises leased to Tenant as set forth in Section 3.1 and Schedule of Floor Plans attached hereto to comparable premises in the Building. Should Landlord desire to move the Tenant after the commencement date the said move shall be made at Landlord's expense.

ARTICLE 4
TERM

4.1 Term.
The Term of this Lease shall be ten (10) years beginning on January 1, 2026, (the **"Commencement Date")** and ending on December 31, 2035, and any permitted overholding.

4.2 Surrender.
The Tenant shall surrender possession of the Premises by no later than the Expiration of the Term.

4.3 Overholding.
The Tenant may only remain in possession of the Premises after the Expiration of the Term with the approval of the Landlord which may be withheld in its discretion.

If the Tenant remains in possession of the Premises after the Expiration of the Term, it shall be a tenancy from month to month in consideration of a rental equal to that provided in Section 5.1 (a) (i) hereof plus twenty-five per cent (25%) thereof, payable monthly and in advance and otherwise under the same terms and conditions as are herein set forth.

ARTICLE 5
RENT

5.1 Items of Rent.
The Tenant shall pay as rent:

(a) a rent comprising:

(i)

Unit#	S.F. [1]	Net Rent/s.f.	Operating Cost/s.f. (2025 Budget) [2]	Term Begin	Term End	Monthly Rent Payment (Including 14% HST)
Suite 1010	8,900	$22.75	$15.21	1-Oct-26	31-Dec-26	**$32,095.18**
		$23.21	TBD	1-Oct-27	31-Dec-27	**TBD**
		$23.67	TBD	1-Oct-28	31-Dec-28	**TBD**
		$24.14	TBD	1-Oct-29	31-Dec-29	**TBD**
		$24.62	TBD	1-Oct-30	31-Dec-30	**TBD**
		$25.11	TBD	1-Oct-31	31-Dec-31	**TBD**
		$25.61	TBD	1-Oct-32	31-Dec-32	**TBD**
		$26.12	TBD	1-Oct-33	31-Dec-33	**TBD**
		$26.64	TBD	1-Oct-34	31-Dec-34	**TBD**
		$27.17	TBD	1-Oct-35	31-Dec-35	**TBD**

Note 1: This square footage is subject to verification by an Expert using BOMA standards.

Note 2: Operating Costs are revised annually & monthly rent payment adjusted accordingly.

(ii) the Landlord's Cost for the following:

(1) the installation and any change of the name of the Tenant on the main lobby directory board for the Building, on each floor lobby directory board on which the Tenant has its name and on the main door to the Premises;

(2) any additional services and equipment agreed to be provided by the Landlord at the written request of the Tenant;

(3) the amount, if any, by which the Operating Costs and Taxes attributed to the Premises by the Landlord exceeds the Proportionate Share of Operating Cost and Taxes if such excess is occasioned by the use or improvement of the Premises;

(4) any Sales Taxes in respect of the rental of space by the Tenant or of the Rent payable by the Tenant under this Lease;

(5) all other amounts payable by the Tenant to the Landlord under this Lease.

(6) Landlord will have separate power meter installed on the Tenant's floor at the Landlord's expense.

5.2 Defined Terms - Operating Cost and Taxes.

For the purpose of calculating the Proportionate Share of Operating Cost and Taxes attributable to the Premises:

"Fiscal Year" means a calendar year provided that the Landlord may from time to time by Notice specify a different date upon which each subsequent Fiscal Year is to begin, in which event the Fiscal Year shall terminate on the day preceding such date;

"Operating Costs and Taxes" means for a Fiscal Year the aggregate costs paid or payable by the Landlord and established in accordance with good accounting practice applied in the real estate development industry on account of the operation, management, maintenance, administration, repair, taxes and insurance in respect of:

{a) the Building and, in the case of Taxes, the portion of the Building Land attributable thereto;

{b) on a proportionate basis as hereinafter provided, the Common Areas and the Common Service Areas, together with a property management fee equal to 5% of the gross revenue from the Building and, on a proportionate basis as hereinafter provided, the Common Areas and the Common Service Areas; provided that:

{c) the following shall be excluded:

{i) costs directly recoverable from tenants or insurers;

{ii) debt service, depreciation, and interest on any of the foregoing, except as hereinafter provided;

{iii) costs of procuring any lease;

{iv) income, corporate and other taxes of a personal nature of the Landlord to the extent not imposed in lieu of Property Taxes;

{v) costs or expenses directly resulting from repairs or replacements due to inherent structural or non-structural defects or weaknesses in the original construction of the Building.

{d) there shall be included the cost of all improvements made which are properly required by the Landlord, any competent authority, including insurers, or which have the effect of reducing the costs which would otherwise be included in Operating Cost and Taxes or are required for the ongoing upkeep and maintenance of the Building. Such costs will be amortized at Prime plus a reasonable interest premium over an appropriate period of time if necessary;

{e) if there are unoccupied premises in the Building, the Landlord may make an equitable adjustment of the amount of Operating Cost and Taxes by reason of the fact that unoccupied premises occasion lower costs to the end that the tenants of the occupied premises will bear the actual amount of the Operating Cost and Taxes attributable to their premises;

{f) the Landlord may make an equitable adjustment to the amount of Operating Cost and Taxes;

{i) if there is tenant(s) of the Building who provides or pay directly for goods or services (e.g. Janitorial Services) which would normally be part of Operating Cost and Taxes;

{ii) if there is a tenant(s) of the Building who is exempt from costs (e.g. taxes) which would normally be part of Operating Cost and Taxes;

{g) the Landlord shall pay Sales Taxes upon the purchase of goods and services, the costs of which are included in Operating Cost and Taxes, and shall claim credits or refunds of such Sales Taxes as, in the opinion of the Landlord, may be properly claimed in order to reduce the net Sales Taxes payable by the Landlord. The Landlord shall apply such credits and refunds of Sales Taxes, when received by the Landlord, against Operating Cost and Taxes.

"Taxes" means all taxes and other charges imposed by any lawful authority against the Building, or upon the Landlord in respect thereof. Without limiting the generality of the foregoing, Taxes shall include real property taxes, capital taxes, any Sales Taxes, and any costs relating to the appeal of any of them.

If the method or base of taxation is changed, the Landlord shall include such amounts (pro-rated where applicable) in the calculation of Taxes. Examples of such a change would be if the business taxes presently payable by the Tenant are charged against the Landlord.

"Proportionate Share" means the ratio, the numerator of which is the Rentable Area of the Premises and the denominator of which is the aggregate Rentable Area of the Building exclusive of storage areas;

5.3 General.
The Tenant shall pay Rent without deduction, set-off or abatement, except as expressly provided in its lease, in lawful money of Canada to such person and at such address as the Landlord may advise. The Tenant shall pay items of Rent of a recurring nature in advance on the first day of each month of the Term and shall pay other items of Rent within 30 days of the delivery of an invoice thereof.

The Landlord shall estimate items of Rent of a recurring and variable nature and advise the Tenant thereof.

If the Commencement Date is not the first day of a month or if the Expiration of the Term does not occur on the last day of a month, Rent for the broken period shall be pro-rated.

5.4 Annual Statement of Operating Costs, Taxes, Etc.
After the end of the period for which the estimated payments have been made, the Landlord shall issue the Tenant a statement (the **"Statement")** setting out in detail the Proportionate Share of Operating Cost and Taxes and other items of Rent of a recurring and variable nature for such Fiscal Year.

If the aggregate of the Tenant's monthly instalments on account thereof paid during such Fiscal Year differ from the actual amount thereof set forth in the Statement, the Tenant shall pay or the Landlord shall refund the difference within 30 days after the Statement is provided.

The Tenant may, within the 120 day period after the Statement is provided, examine the books and records of the Landlord relating to this aspect of Building. The Tenant may, by Notice given within such 120 day period, but not otherwise, dispute the Statement whereupon the matter shall be finally resolved by an Expert. The costs of such Expert shall be equally split between the Landlord and Tenant.

The Landlord may claim a readjustment of the Proportionate Share of Operating Cost and Taxes or of any other item of Rent based upon any error of computation or allocation by Notice given within 180 days after the Statement is provided, but not otherwise.

Any adjustment required to any previous payment made by the Tenant or the Landlord by reason of any such determination shall be made forthwith and shall bear interest at a rate equal to Prime and 1% per annum from the date the Statement is provided.

5.5 Interest.
The Tenant shall pay to the Landlord simple interest at a rate equal to Prime plus 5% per annum on all arrears of Rent for the period of time it remains unpaid.

ARTICLE 6
OPERATION AND CARE OF THE BUILDING

6.1 Operation and Management.

The Landlord shall operate and manage the Building, the Common Areas, and the Common Service Areas.

Landlord will provide, by operation of the heating or air-conditioning system between the hours of 8:00 A.M. and 5:30 P.M. of each business day, except Saturdays, Sundays and holidays, a constant supply of air that is filtered and either heated or cooled as conditions may require, subject to the following conditions and provisions.

Landlord shall be under no obligation to operate the air conditioning system in excess of what may be, in its opinion, reasonable and normal in the circumstances and, in any event, and withou_t prejudice to the foregoing, Landlord shall be deemed to have fully satisfied its obligations under this sub-section 6.1 if it shalt, when the exterior temperature is higher than 90°F maintain a maximum interior temperature 10°F less and when the exterior temperature is not higher than 90°F and not lower than -20°F, maintain an interior temperature between 70°F and 80°F and, when the exterior temperature is lower than -20°F, maintain a minimum interior temperature 90°F higher than the exterior temperature, provided always, however, that the obligation of the Landlord hereunder shalt be conditional upon the following:

(a) Tenant keeping all exterior windows closed at all times and blinds fully drawn on all windows exposed to the sun during the cooling cycle and keeping all registers free from obstruction so as to permit the proper flow and circulation of air therefrom;

(b) The average amount of electrical energy consumed by lights and machines in the Premises not exceeding two (2) watts per square foot;

(c) The occupancy of the Premises not exceeding one person per 150 square feet of space.

(d) All individual controls and operating costs related thereto required by Tenant shall be installed and maintained at the Tenant's expense.

6.2 Services to Premises.

The Landlord shall provide the following services to the Premises:

(a) electrical power for lighting and office equipment;

(b) HVAC;

(c) access to telecommunication conduits;

(d) janitorial services.

6.3 Services to Building.

The Landlord shall provide for the Tenant and others in the Building the following services:

(a) heat, ventilation, air conditioning, lighting, and janitorial service in the appropriate interior portions of the Common Area;

(b) snow removal and landscape maintenance for the appropriate exterior portions of the Common areas and the Parking Area;

(c) exterior window washing;

(d) garbage removal.

6.4 Maintenance of the Building.
The Landlord shall maintain and repair the following:

(a) the Building and its basic systems but not the Premises or the premises of other tenants;

(b) the structural elements of the Premises;

(c) the Common Areas and the Common Service Areas.

ARTICLE 7
USE AND CARE OF PREMISES

7.1 Use.
The Premises shall be used for general office purposes only. The Tenant shall not permit any part of the Premises to be occupied by any person other than the Tenant and its employees and subtenant and its employees permitted under Article 12.2 and 12.3.

7.2 Maintenance of Premises.
The Tenant shall maintain and repair the Premises and the Leasehold Improvement with the exception of:

(a) those items which the Landlord is obligated to maintain or repair, as the case may be;

(b) wear and tear, but only to the extent consistent with the standards of maintenance and repair for premises in a similar good quality building in the City of Halifax.

7.3 Waste and Nuisance.
The Tenant shall not carry on any business or commit or suffer or permit to be committed any act or thing which, in the Landlord's opinion, may constitute or result in:

(a) a nuisance to the Landlord or the other tenants, users or occupants of the Building;

(b) a disturbance of the quiet enjoyment of any other tenant, user or occupant of the Building;

(c) an environmental hazard to the Building or other tenants of the Building; or

(d) any waste or damage to the Leased Premises or the Building.

Without limiting the foregoing, the Tenant shall not permit or allow any odours, vapours, steam, water, vibrations, noises or other conditions that may interfere with the safety, comfort, convenience or ability to carry on business of any other tenant, user or occupier of the Building to emanate from the Leased Premises or any other part of the Building used by the Tenant or those for whom it is responsible. The Tenant agrees that in the event of any breach of this Section 7.3, the Tenant will, at its own expense, take such steps as may be necessary to rectify such breach and that should the Tenant fail to commence to do so within forty-eight

(48) hours or to complete such rectification within five (5) days, the Landlord may, at its option and without prejudice to any other right or remedies:

(a) require that the Tenant shut down all its operations in the Leased Premises; and/or

(b) the Landlord may proceed forthwith to take reasonable measures to correct the situation and the Landlord shall be entitled to recover the cost thereof from the Tenant, plus an additional amount equal to fifteen percent (15%) of such cost.

7.4 Extraordinary Equipment.
The Tenant shall not install any equipment which might affect the capacity of either the structure or the basic systems of the Building.

ARTICLE 8
LEASEHOLD IMPROVEMENTS

8.1 Procedure for Making Improvement.
The Tenant may make Leasehold Improvements provided that:

(a) the Tenant shall furnish the Landlord with professionally prepared plans and specifications thereof;

(b) if any proposed Leasehold Improvements affect the structure, the walls, the systems or the exterior appearance of the Building, such plans and specifications shall be approved by the Landlord or an Expert;

(c) the Tenant shall advise the Landlord of the identity of its contractors and tradesmen and their respective labour affiliations;

(d) the Landlord shall either approve any contractors proposed by the Tenant to perform any work which may affect the structure, the walls or the systems of the Building or require that any such work be performed by either the Landlord or its contractors in which case the Tenant shall pay the Landlord's cost on account thereof;

(e) the Landlord may refuse to allow the contractors and tradesmen of the Tenant access to the Building:

(i) if their labour affiliations conflict with those of the Landlord or those employed by it;

(ii) if in the opinion of the Landlord they are not competent;

(f) the Tenant shall produce evidence satisfactory to the Landlord that the Tenant has the necessary permits and sufficient insurance coverage;

(g) the Tenant shall pay the Landlord's cost of any Expert appointed to review the plans and specifications whether or not the work proceeds;

(h) construction of the Leasehold Improvements shall be performed:

(i) in accordance with the plans and specifications submitted to the Landlord and, where applicable, approved by the Landlord;

(ii) subject to any conditions or regulations imposed by the Landlord;

(iii) in a good, workmanlike and expeditious manner using good quality materials.

In the event that the Tenant engages the Landlord to supervise Tenant's Improvements, the Landlord will be paid, by the Tenant, a co-ordination fee equal to ten percent (10%) of the cost of the work performed.

If the Tenant fails to observe any of the requirements of this section, the Landlord may require that construction stop and that the Premises be restored to their prior condition, failing which the Landlord may do so and the Tenant shall pay the Landlord's cost on account thereof.

8.2 Liens.
If any lien under the Builder's Lien Act or any successor statute is registered against the title to the Building and such lien relates to material, labour or any service alleged to have been provided to the Tenant, the Tenant shall upon Notice by the Landlord cause such lien to be discharged within 5 business days after such Notice has been given.

8.3 Removal of Leasehold Improvements - During Term.
The Tenant may remove or demolish Leasehold Improvements either:

(a) upon the exercise of its right under Article 8.1, any such demolition to be upon the terms of such Article; or

(b) with the approval of the Landlord, which shall not be unreasonably withheld.

8.4 Removal or Demolition of Leasehold Improvements - Expiration of Term.
The Landlord may upon not less than 30 days' Notice (except in the case of surrender, default or re entry in which case no prior Notice need be given) require the Tenant before the Expiration of the Term for all or portion of the Premises to remo•e all Leasehold Improvements and to restore the Premises to tl□eir original condition. **Intentionally Deleted.**

8.5 Personal Property Left on the Premises
Upon the Expiration of the Term, all personal property of the Tenant remaining in the Premises shall become the property of the Landlord and the Landlord may recover from the Tenant the Landlord's Cost of disposing of same.

ARTICLE 9
REGULATIONS

9.1 Purpose.
The Landlord may by Notice impose regulations not inconsistent with the other provisions of this Lease for the orderly operation of the Building. The present regulations are attached to this Lease.

9.2 Observance.
The Tenant shall observe and shall cause those for whom it is responsible to observe the regulations.

9.3 Enforcement.
The Landlord shall enforce the regulations against all occupants of the Building but in so doing need not institute any legal action.

ARTICLE 10
TAXES

10.1 Landlord's Taxes.
The Landlord shall pay before delinquency the property taxes relating to the Building.

10.2 Tenant's Taxes.
The Tenant shall pay before delinquency all taxes and other charges imposed by any lawful authority against the Tenant or any sub-tenant, licensee or occupant of the Premises which if not paid would constitute either a lien on the Building or a liability of the Landlord.

10.3 Assessment Appeals.
The Tenant shall not conduct any appeal from any governmental assessment or determination of the value of the Land, the Building or the Premises.

ARTICLE 11
INSURANCE

11.1 Insurance Coverage.
The Landlord's and the Tenant's insurance shall be in amounts equal, in the case of the Landlord, to those maintained by prudent owners of like buildings and, in the case of the Tenant, to those maintained by prudent tenants of like premises and shall cover the following risks:

(a} all risks coverage;

(b} comprehensive general liability in the amount of $5,000,000;

(c} in the case of the Landlord:

(i} boiler and machinery;

(ii} loss of rental income by reason of damage;

(iii} such other coverage as the Landlord may determine to maintain;

(d) in the case of the Tenant:

(i) legal liability in the amount of $500,000;

(ii} such other coverage (i.e. contents) as the Landlord may require having regard to the risks which are customarily insured against by prudent tenants of like premises;

(iii) Tenant shall have the Landlord, 3325398 Nova Scotia Limited, and Compass Commercial Realty LP named as Additional Insured on its insurance policy.

11.2 Landlord's Insurance.
The Landlord shall maintain during the Term insurance with respect to its interest in the Building, the Common Areas. Such insurance shall include, if available, a waiver of any right

of subrogation against the Tenant, its employees and those for whom the Tenant is in law responsible.

11.3 Tenant's Insurance.
The Tenant shall maintain during the Term insurance with respect to its interest in the Premises, the Leasehold Improvements and all operations of the Tenant in and from the Premises. Such insurance shall include:

(a) the Landlord and any Mortgagee designated by Notice by the Landlord together with those for whom they are in law responsible as additional insureds as their interests may appear;

(b) if available, a cross-liability clause protecting the Landlord in respect of claims by the Tenant as if the Landlord were separately insured;

(c) a provision prohibiting the insurer from materially altering or canceling the coverage without first giving the landlord at least 30 days' prior written notice thereof.

The Tenant shall at the request of the Landlord provide the Landlord with certificates of such insurance.

11.4 Priority of Claims.
If both the Landlord and the Tenant have claims to be indemnified under any Insurance, the indemnity shall be applied first to the settlement of the claim of the Landlord and the balance to the settlement of the claim of the Tenant.

ARTICLE 12
TRANSFERS BY TENANT

12.1 Successors to Tenant.
This Lease shall enure to the benefit of and be binding upon the executors, administrators, successors and assigns of the Tenant, subject to the limitations of this Article.

12.2 Assignment or Subletting.
The Tenant may assign this Lease or sublet all or a portion of the Premises in whole or in part provided that:

(a) the Tenant shall by Notice first offer to surrender this Lease in respect of the whole or the part of the Premises (the "Subject Area") which the Tenant wishes to assign or sublet. Such offer shall be made not less than 90 days prior to the date on which the Tenant proposes that the surrender be effective. The Landlord shall have a period of 15 days after any such offer is made to accept or to decline by Notice;

(b) if the Landlord accepts the offer of the Tenant made pursuant to paragraph (a) above:

(i) the Tenant shall surrender this Lease in respect of the Subject Area on the date specified in its Notice;

(ii) if part of the Premises is to be surrendered, the Rent attributable thereto shall be paid to the date of surrender and the Rent for the remainder to the Premises shall thereafter be adjusted in accordance with such attribution;

(iii) the Landlord shall perform all work required to separate the surrendered part of the Premises from the remainder thereof and to make such part capable of separate use and the Tenant shall pay the Landlord's Cost on account thereof;

(c) if the Landlord declines such offer or does not respond within the aforesaid period, the Tenant may within the next 180 day period either assign this Lease or sublet the Subject Area provided that:

(i) the Tenant shall have received a bona fide written offer;

(ii) the Tenant shall have provided to the Landlord a true copy of such offer and adequate information to enable the Landlord to assess the creditworthiness, reputation and business of the proposed assignee or subtenant;

(iii) the Tenant shall have obtained the approval of the Landlord (who shall act in this matter in accordance with Article 2.2 of this Lease) to such assignment or sublease (which may be withheld in its discretion in the case of a sublease if the rate of rent either is or might be less than that payable under this Lease or if the proposed sublet or assignment is to: (i) an existing tenant or occupant of the Building or of any other buildings owned or managed by the Landlord or any of its affiliates within the same market area as determined by the Landlord; or (ii) a consulate, embassy, trade commission or other representative of a foreign government; or (iii) a government, quasi-government or public agency, service or office);

(iv) the Tenant shall assign or sublet, as the case may be, only upon the terms of the offer provided to the Landlord;

(v) the proposed assignee or subtenant shall have agreed in writing with the Landlord to observe and perform all the obligations of the Tenant under this Lease limited in the case of the Premises to the Subject Area;

(vi) no such assignment or subletting shall release the Tenant from its obligations hereunder.

If within the 180 day period provided for in paragraph (c) above the Tenant has not assigned this Lease or sublet the Subject Area, the provisions of paragraph (a) above shall again apply.

The Tenant shall pay the Landlord's Cost on account of any request for approval and, if applicable, the preparation of the implementing documentation.

12.3 Assignment or Subletting to an Affiliate.
Notwithstanding the foregoing provisions of Section 12.2, the Tenant may assign this Lease or sublet the whole or a part of the Premises to a company which is its subsidiary or an affiliate body corporate (as those terms are defined in the Business Corporations Act, R.S.O. 1990, c.B.16), for the uses permitted in Section 7.1, without the consent of the Landlord, provided that no such assignment or sublease shall be effective unless the Tenant shall have given prior written notice to the Landlord of any such proposed assignment or sublease;

(a) if requested by the Landlord, the assignee shall have entered into an agreement with the Landlord, in the form required by the Landlord, assuming the obligations of the Tenant hereunder;

(b) the Tenant shall have acknowledged to the Landlord in writing that such assignment or sublease shall not release the Tenant from its obligations hereunder.

The Tenant shall pay the Landlord's Cost on account of the preparation of the implementing documentation.

12.4 Change in Control.
The Tenant shall obtain the approval of the Landlord to any change in the effective control of the Tenant. The Tenant shall provide to the Landlord the information described in Article 12.2 (c) (ii) with respect to the person or persons to whom control is passing. This provision shall not apply to a change of control which results from trading in the shares of the Tenant if such shares are listed and traded on a recognized stock exchange in Canada or the United States.

12.5 Advertising of Premises.
The Tenant shall not advertise or allow the Premises to be advertised as being available for lease without the approval by the Landlord of the form and content of such advertisement which shall not mention any financial terms.

ARTICLE 13
TRANSFER BY LANDLORD, SUBORDINATION AND ATTORNMENT

13.1 Successors to the Landlord
This Lease shall enure to the benefit of and be binding upon the successors and assigns of the Landlord.

13.2 Termination of Landlord's Obligations.
If the Landlord transfers or leases the Building, or any part thereof, and if the transferee or lessee assumes obligations of the Landlord hereunder, the Landlord shall thereupon no longer be liable to the Tenant.

13.3 Attornment.
The Tenant shall attorn to the holder of any encumbrance of the Building or any part thereof or any person to whom the Building or any part thereof is transferred as a result of such encumbrance (a **"Mortgagee")** if requested to do so.

13.4 Subordination and Non-disturbance.
Provided that a Mortgagee agrees to be bound by this Lease, Tenant shall execute and deliver any documents required by the Landlord to subordinate this Lease to the security agreements in favour of the Mortgagee as fully as if such Mortgage had been executed, registered and the money thereby secured advanced before the execution and delivery of this Lease.

Notwithstanding the foregoing, the Mortgagee will only be responsible to the Tenant under this Lease for matters arising after the transfer of the Building or any part thereof to it. After the date the Tenant has received Notice of a Mortgagee's existence, that Mortgagee will only be bound by amendments to this Lease which it has approved.

13.5 Lease Status and Estoppel Certificate.
The Tenant shall certify in writing to the Landlord or as it may direct:

(a) that this Lease is unmodified and in full force and effect (or if modified, stating the modifications and that this Lease is in full force and effect as modified);

(b) the dates to which Rent has been paid;

(c) any claim against or default on the part of the Landlord;

(d) any other requested information pertaining to the performance by the Landlord and the Tenant of their respective obligations hereunder.

13.6 Confirming Agreements.
Any agreement or certificate required by this Article must be requested by the Landlord by giving Notice and shall be executed by the Tenant and returned to the Landlord within 5 business days of receipt thereof by the Tenant. Such notice to contain the form of the agreement or certificate. Any such agreement or certificate may be conclusively relied upon by the Landlord, any successor in title and any Mortgagee.

ARTICLE 14
TERMINATION AND RENT ABATEMENT

14.1 Termination by Tenant.
If the Premises or any other part of the Building, the Common Areas or the Common Service Areas are damaged and the Landlord is thereby unable to fulfill its obligations to the Tenant and if in the opinion of an Expert, which shall be given not more than 45 days after the date of such damage, the damage cannot be repaired within a 180 day period (employing normal construction methods without overtime or other premium unless the Landlord instructs the Expert otherwise) then the Tenant may in its discretion by Notice given not more than 15 days after receipt by the Tenant of the opinion of the Expert terminate this Lease with effect as of the date on which such Notice is given.

14.2 Termination by Landlord.
If any part of the Building, the Common Areas or the Common Service Areas is damaged and the Landlord is thereby unable to fulfill its obligations to the Tenant or to any other tenant of the Project and if in the opinion of an Expert, which shall be given not more than 45 days after the date of such damage, the damage cannot be repaired within a 180 day period (employing normal construction methods without over time or other premium), then the Landlord may in its discretion by Notice given not more than 15 days after receipt by the Landlord of the opinion of the Expert terminate this Lease with effect either as of the date on which such Notice is given, if the Premises have been materially damaged, or if the Premises have not been so damaged, then as of the date stipulated by the Landlord in its Notice which shall be not less than 60 days after the date on which it is given.

14.3 Abatement of Rent.
If the Premises are damaged to the extent that they are incapable, notwithstanding a reasonable amount of inconvenience to the Tenant, of being used by the Tenant for their intended purpose and if the damage has not been caused by any act or omission of either the Tenant or those for whom it is responsible, Rent shall abate with effect as of the date of the damage in proportion to the area of the Premises so damaged until the earlier of:

(a) the Landlord and the Tenant, each acting diligently, have completed their respective obligations to repair; or

(b) the proceeds of any loss of rental income insurance attributable to the damage are no longer available for application on account of the abatement of the Rent payable under this Lease or the period of time during which such proceeds would have been available if the Landlord had performed its obligation to maintain the coverage described in Article 11.1 (c)(ii).

ARTICLE 15
LIABILITY

15.1 Limits of the Liability of the Landlord and the Tenant.
The Landlord may only be held responsible for any claims, liabilities and costs arising from personal injury, death and loss or any damage to property, however caused and no matter whom it was caused by, where the occurrence or damage arises outside of the Premises and outside the premises of other tenants in the Building; provided, however, in no event shall the Landlord be liable for indirect or consequential damage.

The Tenant may only be held responsible for any claims, liabilities and costs arising from personal injury, death and loss or any damage to property, however caused and no matter whom it was caused by, where the occurrence or damage arises in the Premises; provided, however, in no event shall the Tenant be liable for indirect or consequential damage.

Landlord and Tenant mutually release and waive any and all claims against the other and those for whom the other is in law responsible with respect to any claims insured against or required to be insured against by the releasing party or those for whom it is in law responsible. This release and waiver is effective only to the extent of proceeds of insurance actually received by the releasing party and proceeds which would have been received if the releasing party had obtained all insurance required to be obtained by it under this Lease.

15.2 Indemnity.
The Tenant shall indemnify and save the Landlord harmless in respect of all claims and liabilities arising from any act or omission of the Tenant or any person for whose conduct the Tenant is responsible and the costs incurred by the Landlord in connection with any action pertaining thereto;

15.3 Joint Liability.
If the Tenant is more than one person or entity its liability shall be joint and several. If the Tenant is a partnership each person who is or becomes a member of the partnership or any successor partnership shall be jointly and severally liable.

ARTICLE 16
DEFAULT AND REMEDIES

16.1 Default - General.
A party to this Lease is in default if:

{a) it fails in a material way, to perform any of its obligations;

(b) it has been given Notice specifying the default and a period of time to cure the default;

(c) it fails to cure the default prior to expirations of the time period set out in the Notice;

(d) it is in default more than three times in any 12 month period.

16.2 Default - Rent.
The Tenant is in default of this Lease notwithstanding Article 16.1 above, if any item of Rent is outstanding and it has been given Notice of the default and a period of time to cure the default.

In the event of such default the Landlord may by giving Notice demand payment of the accelerated rent (3 month net rent). The accelerated rent is recoverable by the Landlord in the same manner as the Rent.

16.3 Default - Bankruptcy of Tenant.
The Tenant is in default of this Lease notwithstanding Article 16.1 above if:

(a) the Term or a substantial portion of the property of the Tenant on the Premises is seized or taken in execution or attachment by a creditor of the Tenant;

(b) the Tenant makes an assignment for the benefit of creditors;

(c) a receiver-manager is appointed to control the conduct of the business on or from the Premises;

(d) the Tenant becomes bankrupt or insolvent or takes the benefit of any act now or hereafter in force for bankrupt or insolvent debtors;

(e) an order is made for the winding-up of the Tenant.

In the event of such default the Landlord may by giving Notice demand payment of the accelerated rent (3 month net rent). The accelerated rent is recoverable by the Landlord in the same manner as the Rent.

16.4 Unavoidable Delay.
If and to the extent a party to this Lease is delayed by reason of an Unavoidable Delay in fulfilling an obligation hereunder other than the payment of Rent, then the party shall not be in default and the period for the fulfillment of such obligation shall be extended accordingly.

16.5 Landlord's Remedies.
If the Tenant defaults hereunder and the Landlord has given the Tenant its Notice of Default, then the Landlord may among other things:

(a) proceed to cure the default, including the making of any payments due or alleged to be due by the Tenant to third parties, and the Tenant shall pay on demand the Landlord's Cost on account thereof;

(b) at any time thereafter re-enter the premises and terminate this Lease;

(c) pursue its other remedies at law.

16.6 Costs.
If legal action is brought by reason of any default by either party hereunder and a default is established, the defaulting party shall pay to the other party all costs incurred therefore, including legal fees on a solicitor and client basis.

ARTICLE 17
NOTICES, APPROVAL AND REGISTRATION

17.1 Procedure for Notice.
Any Notice given pursuant to this Lease shall be in writing, signed by or on behalf or the party giving Notice and delivered, electronically mailed, faxed or mailed by registered post to the other party as follows:

(a) to the Landlord at:
3325398 NOVA SCOTIA LIMITED
c/o Compass Commercial Realty LP
3 Spectacle Lake Drive, Suite 290
Dartmouth NS B3B 1W8

(b) to the Tenant at the Premises.
Nova Scotia Independent Energy System Operator
1791 Barrington Street, Suite 1010
Halifax, B3J 3Y8

Either party may by Notice change its address.

Any Notice so given shall be deemed to have been given, if delivered, on the first business day following the date of such delivery, electronic mailing or faxing, as the case may be, or, if mailed, on the fifth business day following the date of such mailing. During any interruption, threatened interruption or substantial delay in postal services, all Notices shall be delivered or faxed.

17.2 Procedure for Approval.
Any request for approval shall be made by Notice. In the absence of reply given by Notice not later than 15 days after Notice of the request has been given, or such other period of time as is otherwise expressly provided in this Lease, the approval shall be deemed to have been given unless the approval may by the terms of this Lease be withheld in the discretion of the party whose approval is requested. Each approval shall be in writing unless by operation of the preceding sentence it is deemed to have been given. If either party withholds its approval it shall give Notice of its reason unless the approval may by the terms of this Lease be withheld in its discretion.

17.3 Registration.
The Tenant may register this Lease with the approval of the Landlord which may be withheld at its discretion. If approval is withheld the Landlord and the Tenant shall enter into a short form of lease prepared by the Landlord and the Tenant shall pay the Landlord's Cost on account thereof. Such short form shall be for the purpose only of enabling notice of this Lease to be registered and shall not affect the respective rights and obligations of the parties hereunder.

ARTICLE 18
MISCELLANEOUS

18.1 Exhibiting Premises.
The Landlord may exhibit the Premises to prospective purchasers, prospective Mortgagees and, during the last 6 months of the Term, to prospective tenants.

18.2 Name of Building.
The Landlord may designate the name of the Building and upon not less than 30 days' Notice may change the name of the Building. The Tenant shall only refer to the Building by its designated name and shall only use such name as its business address.

18.3 Divisions.
All references in this Lease to articles, and other subdivisions are to those in this Lease.

18.4 Number and Gender.
The necessary grammatical changes required to make the provisions of this Lease apply in the plural sense where the Tenant comprises more than one entity such as an association, a partnership or individuals, and in the appropriate gender for a male or female, shall be assumed as though in each case fully expressed.

18.5 Outside Broker Services.
The Tenant acknowledges that Compass Commercial Realty LP, as Brokerage, and licensed Salesperson, Duncan Buchanan, and Jonathan Hartlen (collectively the **"Agency")** is the Agent for the Landlord and does not represent and is not an agent for the Tenant.

The Landlord confirms that the Tenant is represented by KW Commercial Advisors, as Brokerage, and Tom Gerard, as Agent (collectively the **"Tenant's Agent").**

18.6 Occupancy Permit.
Prior to taking occupancy of the Premises, the Landlord shall provide the Tenant with a copy of the existing Occupancy Permit relating to the Premises. If the Tenant's Improvements require a new Occupancy Permit, such shall be obtained at the expense of the Tenant.

18.7 Deposit.
Intentionally Deleted.

18.8 Fixturing Period.
The Tenant will be given vacant possession of the Premises upon the execution by both Parties of the Lease to complete any leasehold improvements and install its furniture and fixtures. Tenant must provide to the Landlord proof of adequate insurance, in the Landlord's opinion, prior to receiving'Vacant possession of the Premises.

From the commencement of the fixturing period on November 1, 2025, until the Commencement Date (the **"Fixturing Period"),** the Tenant shall be subject to all terms and conditions of the Lease, save and except the Tenant shall not be required to pay Net Rent or any operating costs or property taxes comprised in Additional Rent. The Tenant shall, however, be fully responsible for all charges for cleaning, refuse removal, maintenance, and utilities consumed in the Premises (whether or not separately metered) during the Early Possession Period, as well as any items comprised in Additional Rent save and except for operating costs or property taxes.

18.9 Landlord and Tenant Improvements.
The Landlord, at its own expense, shall complete the Landlord's Improvements, if any, in the Premises pursuant to the specifications set out in Schedule "A" of this Lease. The Tenant, at its own expense, shall complete the Tenant's Improvements, if any, in the Premises pursuant to the specifications set out in Schedule "A" of this Lease.

In the Event that the Tenant engages the Landlord's contractor to complete Tenant's Improvements, the Landlord will be paid, by the Tenant, a co-ordination fee equal to ten (10%) of the cost of the work performed.

The Landlord shall provide the Tenant with a Cash Allowance of $30.00 per square foot of Rentable Area, plus HST, which shall be utilized by the Tenant at the Tenant's discretion. The Tenant is to invoice the Landlord for said cash allowance which shall be due and payable within 30 days of the duly execution of the formal lease agreement.

18.10 Agency.
The Tenant acknowledges that Compass Commercial Realty LP, as Brokerage, and licensed Salesperson, Duncan Buchanan, and Jonathan Hartlen (collectively the **"Agency")** is the Agent for the Landlord and does not represent and is not an agent for the Tenant.

The Landlord confirms that the Tenant is represented by KW Commercial Advisors, as Brokerage, and Tom Gerard, as Agent (collectively the **"Tenant's Agent").**

18.11 Leasing Commission.
The Landlord agrees to pay the Tenant's Agent a Leasing Commission comprised of $7.50 per square foot, plus HST, payable upon the execution of the Lease Document, so long as the Tenant occupies the Premises for business purposes.

18.12 Execution

3325398 Nova Scotia Limited has executed this Lease as agent for and on behalf of, and with the authority of, the registered owner of the Building (3377750 Nova Scotia Limited (the "Owner") and 3325398 Nova Scotia Limited covenants that it is the duly authorized agent of the Owner with the complete power to execute this Lease as agent for, and on behalf, and in the name of and with the authority of the Owner.

This Lease may be executed and delivered electronically (e.g. by facsimile, PDF, email, DocuSign or any other similar method) and after so executed and delivered shall be deemed to constitute a binding and effective original lease.

IN WITNESS WHEREOF the Parties have properly executed this Addendum as of the date first above written.

SIGNED, SEALED AND DELIVERED

3325398 NOVA SCOTIA LIMITED

(Landlord)

Per: _____
Authorized Signature

NOVA SCOTIA INDEPENDENT ENERGY SYSTEM OPERATOR

(Tenant)

I/We have authority to bind the Company

REGULATIONS
TD Building - 1791 Barrington Street, Halifax, NS

Pursuant to Article 9.1 the Landlord hereby imposes the following regulations:

1. Deliveries of building materials, major pieces of equipment and furniture and bulky goods shall only be made by prior arrangement with the Building management and through the Delivery Facilities.

2. The Tenant shall only use the Building key system and shall obtain all keys and cards providing access to the Building and the Premises from the Landlord. No additional locks shall be installed on the doors to the Premises.

3. Bicycles shall be brought into the Building to the designated bicycle storage area only.

4. No inflammable oils or other dangerous materials shall be kept in the Building.

5. The Tenant shall not obstruct Common Areas.

6. The Tenant shall provide the Landlord with the names of all persons entitled to enter the Premises outside normal business hours. The Landlord shall only be required to allow access to the Premises by such persons.

7. The Tenant shall not install any power or water consuming machinery and equipment, except normal office equipment, without the approval of the Landlord and, if required by the Landlord, shall connect such machinery and equipment to separate meters.

8. The Tenant shall arrange for pest control if required by the Landlord.

9. The Tenant shall leave the Premises in a condition suitable for the performance by the Landlord of its janitorial services.

10. The Tenant shall not remove or alter the Building Standard window coverings or install any additional window coverings without the approval of the Landlord.

SCHEDULE "A"
TD Centre, 1791 Barrington Street
Halifax, Nova Scotia

LANDLORD AND TENANT IMPROVEMENTS

1. LANDLORD IMPROVEMENTS

The Premises will be provided to the Tenant in an "As Is" condition.

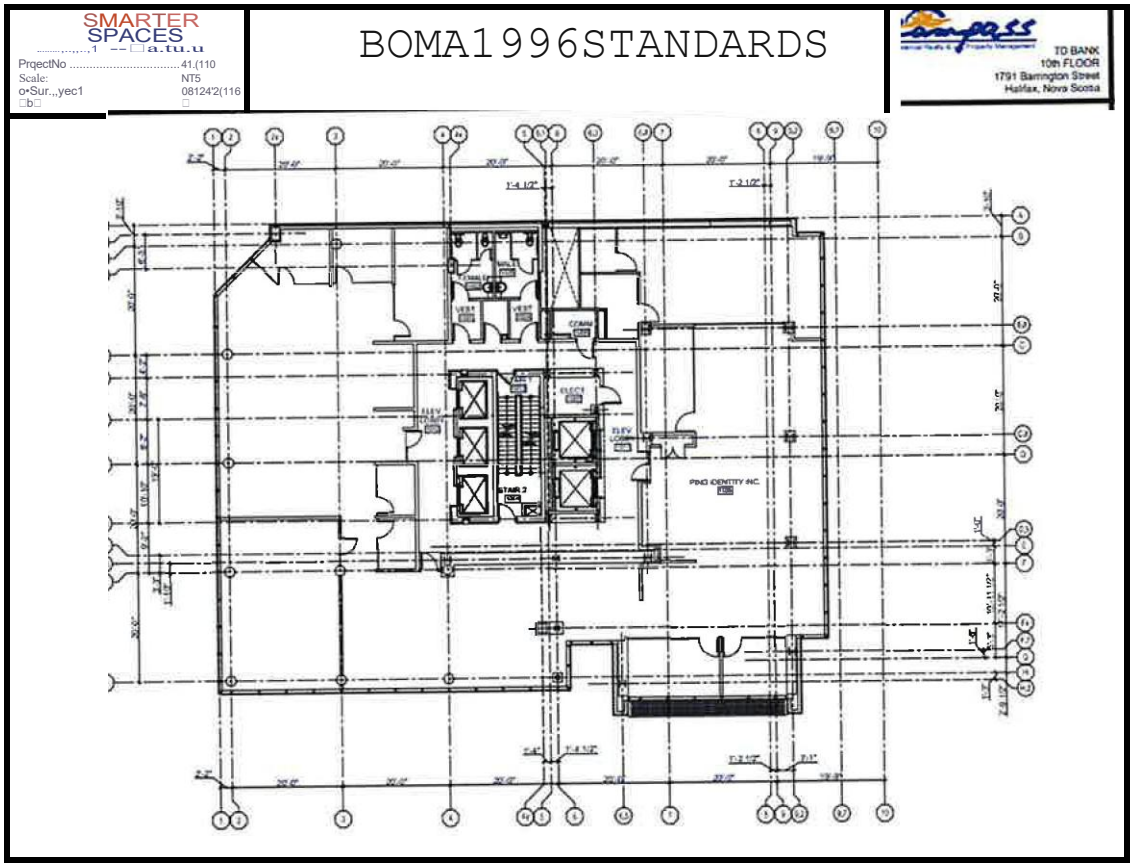
To be clear, current "as-is" condition is to include all of the existing furniture and leasehold improvements as per the Tenant's most recent viewing of the Premises on Monday, September 15, 2025. All existing furniture is to become the property of the Tenant at the end of the Lease Term, provided there has been no Default.

2. TENANT'S IMPROVEMENTS

All further leasehold improvements are the responsibility of the Tenant and shall be at the Tenant's expense. Plans and specifications for leasehold improvements shall be submitted to the Landlord for approval.

SCHEDULE "B"
TD Centre, 1791 Barrington Street
Halifax, Nova Scotia

PREMISES - SUITE 1010
+/- 8,900 Square Feet



SCHEDULE "C"
TD Centre, 1791 Barrington Street
Halifax, Nova Scotia

Option to Renew

Provided the Tenant is not in default hereunder or under the Lease and has duly and regularly paid all Rent and performed all covenants and obligations contained in the Lease, and has been occupying the space for the entirety of the Term, and no Transfer, Assignment or Sublease affecting Tenant, the Premises or the Lease has occurred, the Landlord shall, at the expiration of the Term and upon the Tenant's written request delivered to the Landlord not later than nine (9) months or earlier than twelve (12) months prior to the expiration of the Term, grant to the Tenant one (1) renewal of the Term for a further term of five (5) years on the same terms and conditions of the Lease as are in effect at the time except that Net Rent shall be the then-market rate for comparable premises as agreed by the parties but in no event less than the Net Rent payable during the final year of the Term. The Tenant shall have no further right of renewal unless otherwise mutually agreed upon by the Landlord and the Tenant.

Nova Scotia Independent Energy System Operator

Proposed Expenditures, Revenue Requirement, and Fees Application

Appendix 16 – Power Advisory Fee Calculation Model

This Appendix has been provided in an electronic spreadsheet format

NON-CONFIDENTIAL