October 15, 2025

VIA ELECTRONIC FILING

The Honorable Debbie-Anne Reese, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

RE: ISO New England Inc., Filing of 2026 Capital Budget and Revised Tariff Sheets for Recovery of 2026 Administrative Costs; Docket No. ER26-

Dear Secretary Reese:

Pursuant to Section 205 of the Federal Power Act, Part 35 of the Rules and Regulations of the Federal Energy Regulatory Commission (the "Commission"), Section 12 of the Participants Agreement among ISO New England Inc., the New England Power Pool ("NEPOOL") and any Individual Participants,[1] and Section IV.B.6.1 of the ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff"),[2] ISO New England Inc. (the "ISO" or "ISO-NE") hereby submits its capital budget for calendar year 2026 (the "2026 Capital Budget") and a revised Section IV.A of the Tariff to reflect the collection of its administrative costs for calendar year 2026 (the "2026 Administrative Expenses Tariff"). The ISO requests that the Commission accept the 2026 Capital Budget and the 2026 Administrative Expenses Tariff, as filed, effective January 1, 2026.

Because the ISO is a non-profit entity without equity, it relies totally on collections based on the annual rates contained in its Tariff to fund its operational expenses, including through depreciation. For this reason, the ISO is not in a position to make refunds should the Commission accept the 2026 Capital Budget or the 2026 Administrative Expenses Tariff for filing but set them for hearing subject to refund. That is, the only "refunds" that can be paid to ISO Customers during 2026 would have to be funded by additional charges to other Customers. For this reason, the ISO respectfully requests that the Commission accept the 2026 Capital Budget and the 2026 Administrative Expenses Tariff without suspension and not subject to refund.[3]

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[1] The Participants Agreement is available at https://www.iso-ne.com/static-assets/documents/2015/10/parts_agree.pdf.

[2] Capitalized terms used but not otherwise defined in this filing have the meanings given them in the Tariff.

[3] This approach is consistent with NEPOOL's recommendation to the Commission that "contested budget increases should not be implemented subject to 'refunds'" because of the ISO's non-profit status, which means that any

The current rates contained within Section IV.A of the Tariff to collect administrative expenses are only valid for the 2025 calendar year.[4] Similarly, the capital budget is also filed and approved on a calendar year basis.[5] For these reasons, the ISO respectfully requests that, should the Commission have any concerns regarding the 2026 Capital Budget or the 2026 Administrative Expenses Tariff, such concerns be resolved in an accelerated fashion and addressed in an Order issued prior to January 1, 2026. If the Commission decides to set any issues for hearing, the ISO requests that the Commission set the scope of any such hearing as specifically and narrowly as is feasible, and require a paper hearing process, to ensure conservation of ISO, stakeholder, and Commission staff resources.

I. ISO-NE's 2026 REVENUE REQUIREMENT AND REVISED SHEETS

A. Overview

This filing presents the 2026 Revenue Requirement[6] for operating the ISO. Before incorporating the true-up for 2024's actual expenses and collections, the 2026 Revenue Requirement is $330 million, which is $23.6 million more than in 2025. After the over-collection for 2024 is subtracted, the total 2026 Revenue Requirement decreases to $314.4 million. In comparison, the 2025 total – which was increased by an under-collection – was $311.2 million.

In sum, the 2026 Revenue Requirement is 7.7% higher than in 2025 before the prior years' true-ups. When the two years' operating budgets are compared with inclusion of the true-ups, the 2026 Revenue Requirement is 1.0% higher than the 2025 Revenue Requirement.

The 2026 Core Operating Budget implements the stakeholder-supported workplan, which includes funding for many market and energy adequacy initiatives; implementation of Commission Orders; cloud modernization initiatives; funding for asset condition reviewer work;[7] and forecasting/modeling improvements that will become operational and require ongoing support. The primary drivers of the 2026 Core Operating Budget include salaries for full-time equivalent ("FTE") additions necessary for servicing the workplan; merit and promotion increases to remain competitive in what is still a tight labor market for the unique, in-demand

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money spent "can only be reallocated among the stakeholders, negating any true refund." Comments of the New England Power Pool Participants Committee at 3, Docket No. RM04-12-000 (Nov. 9, 2004) ("NEPOOL RTO Cost Comments").

[4] Tariff § IV.A.2.1 (explaining that the rates and charges for each Service **during a calendar year** are based on the allocation portion of that year's Revenue Requirement).

[5] Tariff § IV.B.6.1 (explaining the annual capital budget process).

[6] As used in this filing, "Revenue Requirement" refers to the combination of: the administrative costs of running the ISO (the "Core Operating Budget"); depreciation and amortization; and the true-up for past over-collection or under-collection in revenues versus expenses. Generally, numbers used herein are rounded for ease of reference and, accordingly, may not sum.

[7] *See infra* Section I.C.1.e of this transmittal letter. Asset condition reviewer funding will not be reallocated for any other purpose if unused, but rather, will be returned in a future budget year. *Id.*

skill sets needed at the ISO; and computer services, including support costs for capital projects that have gone into operation and third-party vendor cost increases. The specific elements of these drivers are discussed in more detail in Section I.C, below (explaining increases related to each strategic goal).

The 2026 Revenue Requirement represents the ISO's continued commitment to supporting the New England region in addressing increasing complexity resulting from electrification, growth of inverter-based resources, and New England's seasonal operating risks. It also funds the needed ramping-up of organizational capacity to carry out the organization's mission of planning the transmission system, administering the region's wholesale markets, and operating the power system to ensure reliable and competitively-priced wholesale electricity, as well as developing new capabilities that will be necessary for supporting the grid of the future.[8]

On the supply side, New England continues to see substantial increases in the number of interconnected and behind-the-meter generating assets, and the shift from larger, dispatchable resources to smaller, non-dispatchable, weather-dependent, inverter-based resources is changing the operation and interaction of the transmission and distribution system. These additional resources connecting to the distribution system – outside of the ISO's current visibility – contribute to load variability and forecasting challenges.

In addition, on the demand side, changing load characteristics caused by the electrification of the heating and transportation sectors exacerbate operational complexity. With this anticipated greater electrification, as well as the supply changes described above, the ISO is observing and projecting new daily and seasonal demand patterns. Overall, ISO-NE projects that, over the next decade, the grid will experience much higher loads, load variability, and intermittent supply resources.

As noted above, the main drivers of the 2026 Revenue Requirement are FTE additions necessary for servicing the stakeholder-requested workplan, compensation increases to remain competitive in a tight labor market, and computer services increases. These drivers include support for the following:

- Continuing capacity market reforms to better ensure power system reliability and cost-efficiency as New England's resource mix evolves;

- Advancements in long-term transmission planning to support interconnection of new resources and to address the evolving system needs;

- Collaborating with stakeholders to operationalize Regional Energy Shortfall Threshold ("REST") and to provide a multiyear outlook;

[8] Additional detail regarding the trends in the New England region that are impacting our budget and increasing the complexity of the ISO's work can be found in the Budget Presentation at Slides 18-22; *see also* Exhibit 3 pp. 12 – 15.

- Enhancing collaboration with NEPOOL, state agencies, and other stakeholders to ensure inclusive and transparent decision making;

- Informing policymakers about the role of retail market designs in mitigating price volatility and promoting resource development;

- Information technology cost increases, including those attributed to staffing and computer services costs related to the operationalization of market, transmission, and emerging technology initiatives; costs include those associated with:
    - Cloud infrastructure and data management costs;
    - Software licensing and subscription fees;
    - Inflation, supply chain disruptions, and tariffs;
    - Modernization of legacy systems and natural hardware refresh cycles; and
    - Governance and compliance requirements

- Investing in advanced technologies and analytics to improve system operations and planning capabilities to improve forecasting and situational awareness around the region's changing resource mix;

- Strengthening cyber security measures and infrastructure to safeguard grid reliability; and

- Developing a new framework to conduct independent reviews of asset condition projects on the transmission system.

Accordingly, the 2026 Core Operating Budget includes net funding for 18.5 additional FTEs to support the complex work noted above. The FTE additions, among other things, will assist with the increasing number of resources to be interconnected, studied, and incorporated into modeling and forecasting; create roles to assist states with transmission requests for proposals ("RFPs"); address increasing compliance needs as a result of Commission Orders (such as Orders 222, 841, 881, 901, 1920, and 2023); serve emergent needs to collect data for Distributed Energy Resources ("DER") to address tripping and low loads; develop new skills and enhance skills to work with the changing technology stack, new data streams, and new applications; provide personnel to communicate increasingly complex information to stakeholders and the public; and provide additional support needed as the workforce grows, including the increase in remote workers.[9]

[9] The 2026 Core Operating Budget includes the recruitment of twenty-five additional positions with funding for 18.5 FTEs with onboarding expected to occur throughout the year. In the 2025 Core Operating Budget, sixteen positions were deferred that are expected to be onboarded by 2026. The funding for the full year of all twenty-five FTEs will be included in the 2027 Core Operating Budget. *See* Budget Presentation at Slides 43-50 (noting the 2026 net FTE funding needs) and Slides 54-55 (noting 2026 gross funding needs).

As indicated in past filing letters, the ISO continually evaluates the most cost-effective way to address the evolving demands on the ISO and the rapidly evolving power system. The ISO supplements staffing needs with contract additions, where practicable and to cover short-term needs. Additionally, the ISO evaluates each position that becomes vacant to determine the continued need in that department and for possible repurposing for use in other areas of the organization. Since 2018, this practice has resulted in forty-eight reallocated positions and, in the five years prior to the proposed 2022 budget, the number of funded FTEs did not increase, on a net basis. However, relying on contract additions and the reallocation of resources is not sufficient to support the increasing demands on the ISO and the region's power system. Although the 2026 operating budget reflects funding for new FTEs, the growth is more modest than in the 2025 operating budget and the ISO will continue to use contract additions and the reallocation of resources as appropriate based on a cost-benefit analysis.

The remainder of this Section I describes:

- the 2026 budget development process (Section B);
- components of the 2026 Revenue Requirement (Section C);
- the three services provided by the ISO and funded by the 2026 Revenue Requirement (Section D); and
- the allocation of costs among the three primary schedules and the development of the rates reflected in the 2026 Administrative Expenses Tariff (Section E).

B. 2026 Budget Development Process

The ISO has always operated in a climate of cost accountability and transparency.[10] The ISO annually files with the Commission updated specific dollar-value, non-formula rates to collect the ISO's Revenue Requirement for each upcoming calendar year. Instead of using a formula rate allowing the automatic collection of every expense as incurred, the ISO revises its specific rates each year from a proposed annual Revenue Requirement that has been reviewed through a multi-stage stakeholder process, voted on by participants, approved by the ISO's independent Board of Directors, and ultimately filed with the Commission for approval in an open process in which any interested party may participate.

The ISO's budgeting process is driven by the ISO's strategic planning process. The strategic planning process includes a purposeful and integrated business planning approach that drives focus towards a common target that management teams and the entire organization can support, with the aim of creating value for ISO stakeholders. Included in the strategic planning process is the development of annual and five-year business plans that outline major priorities and activities in line with the ISO's vision to harness the power of competition and advanced technologies to reliably plan and operate the grid as the region experiences a complex grid transition. The ISO ties its annual budget to resource requirements through goals, objectives, and initiatives, including five strategic goals summarized below:

[10] The NEPOOL Participants Committee, the ISO's primary stakeholder body, has lauded the ISO's budget process, stating that it "works, not only because NEPOOL provides input, but also because ISO-NE is responsive to that input." NEPOOL RTO Cost Comments at 6.

- **Responsive Market Designs**: Advance the competitive wholesale markets to support the investment and new services required for a reliable energy transition;
- **Progress and Innovation**: Expand capabilities to support increasing grid complexity brought about by new technologies and changes to supply mix and customer use;
- **Operational Excellence**: Focus on high quality business operations, prioritize high impact projects, and mitigate implementation risks;
- **Stakeholder Engagement**: Collaboratively understand and anticipate needs, demonstrate thought leadership through high-quality analysis and communication, and nurture productive relationships with regulators and stakeholders in supporting the four pillars of the clean energy transition; and
- **Attract, Develop, and Retain Talent**: Continue to promote our Culture, Mission, Vision, and Goals; develop and position the workforce to support the evolving needs of the organization; recognize and reward employees' success and innovation; tailor programs to retain and attract critical, in-demand skills; and foster an inclusive culture that values diversity of career and life experiences.

These goals formed the foundation for development of the ISO's 2026 Core Operating Budget. Additionally, the full seven-step process, throughout which stakeholder input was sought, requires the ISO to:

- define objectives, activities, and goals;
- identify efficiencies for each department;
- develop priorities;
- determine resource requirements;
- develop budget estimates for each department;
- adjust budgets to ensure that staff resources and activities are aligned with the business plan; and
- conduct senior staff review to ensure alignment of the budget with the business plan and overall fiscal constraint.

ISO-NE reviews the budgets with both NEPOOL and the states. To kick off this year's process, the ISO presented the preliminary budgets at a June 9, 2025 meeting with the New England states and the June 25, 2025 meeting of the NEPOOL Participants Committee. Following these discussions regarding the preliminary budget (which was substantially similar, although approximately $900,000 more than, the 2026 Revenue Requirement described

herein),[11] the ISO did not receive any preliminary comments or questions from stakeholders or state agencies.[12]

The ISO then developed its 2026 Revenue Requirement proposal and posted a detailed budget presentation, which includes approximately 200 slides regarding the 2026 Capital Budget and the 2026 Revenue Requirement (the "Budget Presentation").[13] The ISO reviewed the Budget Presentation at the NEPOOL Budget and Finance Subcommittee's August 8, 2025 meeting and at a separate meeting of state agencies also on August 8, 2025.

Following the August 8 meeting, certain state agencies submitted written questions regarding the budgets. The ISO provided answers, following which certain Massachusetts and Connecticut state agencies submitted joint written comments regarding the budgets.[14] In their comments, the Massachusetts and Connecticut state agencies stated that "[w]e find the proposed 2026 budget proposal appropriate given the increased amount and complexity of the tasks required of ISO-NE as the New England power system transitions to clean energy[,]" and expressed support for the funding included in the 2026 budget for asset condition review work.[15] The Massachusetts and Connecticut state agencies also: (i) asked that the Board rigorously oversee ISO "employee levels, payroll, and executive compensation to ensure that they are no more than necessary and appropriate"; (ii) encouraged the ISO to evaluate the potential for the incorporation of artificial intelligence and automation "to produce efficiency gains … including streamlining staffing needs"; and (iii) asked that "the Board carefully consider how ISO-NE can be more proactive and instrumental in planning, guiding, and improving the transmission system expansion." In its response to this letter, the Board acknowledged the request for oversight of the ISO budget and explained the rigorous periodic reviews that are in place by Board and its committees. The Board also noted that: (i) the ISO is carefully assessing and implementing

[11] Before incorporating the true-up, the 2026 Revenue Requirement presented in the preliminary budget was approximately $330.9 million. The final 2026 Revenue Requirement (before true-up) was decreased to $330 million as a result of: changes in Salary and Overhead estimates with savings related to lower new hire salaries, lower incentive compensation, and other small estimate refinements with some offset as a result of a lower budgeted vacancy rate for 2026; and lower Depreciation Expense due to changes in planned capital projects and/or estimated completion date. These decreases were slightly offset by increases for Professional and Legal Services, including funding for research and implementation of enhanced workforce security best practices, Capacity Auction Reforms support, Transmission Planning work, and external regulatory counsel fees. *See* Budget Presentation at Slide 32.

[12] *See* Exhibit 3 at p. 9.

[13] The Budget Presentation (as updated) is available at https://www.iso-ne.com/static-assets/documents/100027/6_isone_2026_proposed_op_cap_budget_updated_09_30_2025.pdf.

[14] The Massachusetts and Connecticut state agencies that provided joint comments on the 2026 operating and capital budgets are the Connecticut Public Utilities Regulatory Authority and Office of Consumer Counsel; and the Massachusetts Department of Public Utilities.

[15] The joint comments of the Massachusetts and Connecticut state agencies incorrectly cited the change in the preliminary (top-down) budget to the proposed (bottom-up) 2026 budget. The joint letter noted a $300,000 decrease from the preliminary budget. In actuality, the detailed bottom-up budget resulted in a $900,000 decrease from the preliminary budget. *See* Budget Presentation, Slide 32.

artificial intelligence with the hope that it can produce net efficiency gains; and (2) the ISO looks forward to working with the states on the asset condition reviewer work.

In addition to the Massachusetts and Connecticut state agencies' joint letter, the ISO also received separate comments from the Maine Office of the Public Advocate. The Maine Office of the Public Advocate indicated it was disappointed that the proposed 2026 budget increase exceeds inflation, but also expressed an understanding of "the complex nature of the tasks that the ISO must undertake to ensure the reliability of the regional electric grid, and the efficiency of regional electricity markets." The Maine Office of the Public Advocate also expressed appreciation of "the ISO's ongoing efforts with respect to capacity auction reform and the development of an asset condition reviewer" and stated that they "are hopeful … that in the future such new initiatives can be more fully staffed and funded within existing resources." In its response to the Maine Office of the Public Advocate letter, the Board acknowledged that the budget increase exceeds inflation, but that the Board, after careful scrutiny and consideration of competing considerations, determined the increase was warranted. The Board also noted that the ISO looks forward to working with the states on the asset condition reviewer work. The states' comments and the ISO's responses are located at Exhibits 9 and 10 to this filing letter.[16]

The ISO reviewed the 2026 Capital Budget and the 2026 Revenue Requirement at the NEPOOL Participants Committee's meetings on September 4 and October 9, 2025. At the October 9 meeting, the two budgets were unanimously supported by the Participants Committee (with abstentions recorded).

Contemporaneously with the stakeholder processes, the Board of Directors undertakes its review of the budgets. The Board process includes review of particular elements of the budgets by Board committees with responsibility in a defined area. For example, compensation matters are reviewed by the Compensation and Human Resources Committee and projects with reliability implications are reviewed by the System Planning and Reliability Committee. The Audit and Finance Committee advises management throughout the development of the budgets and engages in a detailed review of the budgets in both May and August.

In addition to receiving updates throughout the process from management regarding the stakeholder process and from the Audit and Finance Committee, the Board discusses the budgets at its September meeting. At that meeting, the Board also reviewed the questions and comments of the participating state agencies. As a final step, after receiving any additional feedback from stakeholders, including the results of the Participants Committee's vote, the Board votes on the budgets.[17] In the instant case, after reviewing all input from stakeholders, including the vote of the Participants Committee, the ISO's Board of Directors approved the 2026 budgets effective October 13, 2025.

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[16] Pursuant to a settlement agreement entered into among certain state agencies and the ISO regarding the 2013 budgets, ISO-NE is required to include these comments and its response in its budget filing.

[17] The ISO must report the results of all Participants Committee votes on the budgets to the Board of Directors and to the Commission. Participants Agreement at §§ 12.3, 12.5.

C. The 2026 Revenue Requirement

This section provides an overview of the 2026 Revenue Requirement and detail regarding its significant components. Additional detail can be found at Exhibit 3 in the testimony of Robert C. Ludlow, the ISO's Chief Financial Officer, and the exhibits thereto.

As noted above, the 2026 Revenue Requirement, after the true-up for 2024, is $314.4 million.[18] It includes the following components, each of which is discussed below.

- the 2026 core operating budget ($281.8 million);
- depreciation/amortization and regulatory fees ($48.2 million); and
- a true-up for 2024 that decreases the 2026 revenue requirement by $15.6 million as a result of an over-collection of ISO rates in 2024.[19]

While the ISO has amassed a consistent track record of spending integrity – since the inception of its self-funding tariff for calendar year 1998, the ISO's annual spending has never exceeded its budget – the risk exists that the ISO may have to incur additional expenditures during 2026 that exceed the allocated amounts and contingencies. Specific potential risks include: additional funding required to enhance new models to study extreme weather and contingencies, to conduct new studies related to the integration of variable resources and emerging technologies, for completing requirements on implementing Capacity Auction Reforms, and for long-range transmission planning studies, including the request for proposals process for finding competitive solutions to identified transmission needs in the region; additional resources required as operations evolve (*e.g.*, energy forecasting, load management) due to the evolving and changing resource mix; additional information technology funding for software licensing, maintenance costs, and cloud migration; higher than anticipated insurance policy renewals; unforeseeable litigation; interest rates that may impact the ISO's floating rates on tax exempt debt, pension and post-retirement benefit plan costs, and interest income on the ISO's settlement float balance; costs related to workforce sourcing challenges and related pay rates; costs related to supply chain disruption; and funding required for additional or changing federal and/or state policy directives that could result in new requirements.

In general, the demands placed on the ISO by Market Participants and regulators will determine the extent of additional work and the resources the ISO will require. In any case, should the need ever arise for the ISO to spend more than a given year's Revenue Requirement, the ISO will first seek stakeholder support and then file a rate increase with the Commission, thus allowing stakeholder and Commission review before approving such increases.

1. Components of the Core Operating Budget Increase

[18] *See* Appendices 1 and 5 to the Budget Presentation for a breakdown of the Revenue Requirement by category (Slides 79-91) and functional area (Slides 123-148).

[19] *See* the Budget Presentation (Slides 84-85) for a breakdown of the true-up amount.

As related to the strategic goals identified above, the ISO proposes to increase its Core Operating Budget from 2025 levels for: (i) Goal 5: Attract, Develop, and Retain Talent ($10.0 million); (ii) Goal 3: Operational Excellence ($8.4 million); (iii) Goal 1: Responsive Market Designs ($4.6 million); (iv) Goal 2: Progress and Innovation ($2.9 million); (v) Goal 4: Stakeholder Engagement ($2.1 million); and (vi) other miscellaneous increases ($0.5 million). Below, the ISO discusses the costs in each of these categories and then reviews the savings, efficiencies, and non-recurring work that offset these increases by $6.9 million.[20]

a. Increases Related to Attract, Develop, and Retain Talent (Strategic Goal 5)

The funding increase of $10.0 million for this goal is attributable to funding in six categories: (i) to maintain competitive compensation ($6.0 million); (ii) increases in employee benefits costs, primarily because of medical trends, and an increased number of employees in the Defined Contribution Benefit Plan[21] ($1.5 million); (iii) an increase in funding related to the decrease of the employee vacancy rate from 6.0% to 5.0%[22] ($1.6 million); (iv) funding related to the relocation of approximately ninety ISO employees to the Windsor campus ($400,000); (v) funding for consulting services, data, and research to support critical Human Resources initiatives ($200,000); and (vi) funding for Board of Director search fees to recruit for a scheduled vacancy ($200,000) and an increase in Board of Director retainer fees ($100,000).

As noted above, the changing grid is increasing both the amount of work and the complexity of the work that the ISO is undertaking. As a result, it has become critically important for the ISO to remain competitive in the labor market and keep pace with compensation market changes (including inflationary effects) to attract and retain the necessary personnel to support the ISO's complex workplan. The funding in this category to maintain competitive compensation includes a 4.0% increase in salaries based on merit and a 1.5% increase for promotions and adjustments.

These increases reflect the objectives of the ISO's compensation program: to offer competitive compensation, coupled with a robust total rewards offering, that enables the ISO to attract and retain the highly-skilled employees needed to lead the ISO and meet its business goals for the New England region.[23] Meeting this objective is vital, particularly in the face of high demand for technical and seasoned talent as the ISO's workload increases in volume and

[20] *See* the Budget Presentation (Slides 41-50) for more information on all of these year-over-year budget changes.

[21] *See* Budget Presentation, Slide 101 (explaining that in 2014 the pension plan became closed to new participants; as a result, all new hires in the organization are eligible under the Defined Contribution Benefit Plan).

[22] As noted in the budget filing for the 2025 budget year, the ISO increased the employee vacancy rate from 5% to 6% (which resulted in a budget reduction of $1.6 million), but it was also noted that the region's energy transition and the impact of the transition on the ISO's work flow would result in increased variability in the ISO's budgeting assumptions, including but not limited to assumptions regarding turnover rates and headcount needs. Because of recent success in ISO hiring efforts and a reduction in the ISO's turnover rate, the ISO has determined it is now appropriate to reduce the vacancy rate back to 5.0%. *See* Exhibit 4 at pp. 12-13.

[23] *See* Exhibit 4 at p. 3.

complexity.[24] With an increasing demand for critical talent and inefficiencies that come with critical turnovers, the ISO's focus on its compensation objectives is critical to enable the ISO to fulfill its mission.[25]

Because of high turnover rates in 2021 and 2022, the ISO hired a compensation consultant to perform a job specific, one-for-one compensation benchmarking analysis.[26] The benchmarking study, conducted in phases, highlighted certain competitive pay discrepancies for some of the ISO's most critical roles. The heaviest budgetary impacts of the benchmarking study occurred in the 2024 Core Operating Budget, but the overall results have become important as we accurately target compensation amounts to meet our key objective of hiring and retaining critical talent.[27]

To establish the amounts of the merit and promotional increases, ISO management develops a recommendation for the ISO's Compensation and Human Resources Committee of the Board of Directors based on the results of the compensation benchmarking study, expected increases by the other RTOs/ISOs, and survey data from national compensation consultants on expected compensation increases.[28] For the 2026 Revenue Requirement, the data reviewed indicated that the ISO's proposed budget increases for merit and promotional/adjustment increases were consistent with industry specific data.[29]

The ISO also complies with the standards of the Internal Revenue Service when determining executive compensation. These standards encompass all aspects of compensation, including base salary and all bonuses, and require that the ISO's executive and Board compensation fall within a range of competitive practices for total compensation paid by similarly-situated organizations, both taxable and tax-exempt, for functionally comparable positions.[30]

To ensure compliance with these standards, the ISO has engaged a nationally recognized, independent consulting firm, which evaluates the compensation offered by similarly-situated entities. This evaluation includes other system operators and select for-profit "peer" utility organizations (chosen for organizational size, complexity, and scope of responsibilities). It also incorporates a broader comparison across all industries for positions not unique to utilities (again, comparators are selected for organizational size, complexity, and scope of responsibilities). The resulting opinion each year has been that the ISO's executive and Board

[24] *See* Exhibit 4 at pp. 3-9.

[25] *See* Exhibit 4 at p. 3.

[26] *See* Exhibit 4 at pp. 15-16, 21-23 for a more detailed explanation of the benchmarking survey and results.

[27] *See* Exhibit 4 at pp. 3; 21-23.

[28] *See* Exhibit 4 at pp. 19-24.

[29] *See* Exhibit 4 at pp. 23-24.

[30] *See* Internal Revenue Code § 4958.

compensation is within a reasonable range of competitive practice for functionally comparable positions among similarly-situated entities. The Commission has found that this process results in just and reasonable compensation.[31]

The testimony of Kathleen deCastro, the ISO's Vice President, Human Resources and Chief People Officer (located at Exhibit 4), provides more detail on the ISO's compensation and benefits practices, as does the Budget Presentation (Appendix 2 at slides 92-108).

b. Increases Related to Operational Excellence (Strategic Goal 3)

The cost increase of $8.4 million related to Operational Excellence is related to headcount increases in various departments; computer services and leasing increases; professional fees for various parts of the organization; data services costs; and communications costs. Specifically, the 15 headcount increases will fund positions in: (i) System Operations and System Planning to address technical challenges and to perform system assessments and studies related to the continued installation of inverter-based resources and for responsibilities related to North American Electric Reliability Corporation ("NERC") and Northeast Power Coordinating Council ("NPCC") requirements; (ii) Information and Cyber Security Services for the ISO's transition to cloud computing, including architecture and service delivery and for IT forecasting tool support; (iii) Project Management Office for support of the increased number of sophisticated capital projects; and (iv) Finance and Market & Credit Risk to support the growth and sophistication within these departments. Professional fees included in the funding for Goal 3 include consulting support to provide research, recommendations, and implementation of enhanced security best practices for the ISO workforce (including senior management), an increase in regulatory counsel fees for Commission Order filings and responses, and consulting support to perform audits or assist the Internal Audit department with various engagements, including systems and cyber security related work.

The funding to support Goal 3 related to computer services includes cyber security improvements (security log management, network detection and response tools, zero trust access and protection enhancements, and cloud monitoring), network collaboration software fees, leasing of servers as part of the ISO's data center refresh, fees for computing and storage capacity applications, licensing fees for System Planning and Operations applications, and inflationary and vendor increases across our portfolio of computer services products. Also included in Goal 3 are Network Operations increases for the transition of communication lines to new technologies, for data redundancy, and for inflationary and communication line increases. Finally, Goal 3 cost increases include funding for data services subscriptions for the Market Monitoring department and for a vendor third party risk assessment.

c. Increases Related to Responsive Market Design (Strategic Goal 1)

[31] ISO New England Inc., 117 FERC ¶ 61,310 at P 18 (2006); Order on paper hearing and finding rehearing to be moot, 119 FERC ¶ 61, 178 (2007).

The $4.6 million cost increase in this category is related to headcount increases in various departments; funding for nGEM vendor support; and funding for modeling and analysis work.

Specifically, the headcount increases will fund 6.5 FTEs in: Market Development to assist in the design of market overhauls, including Capacity Auction Reforms (such as the design of a prompt, seasonal capacity market, resource capacity accreditation work, and flexible response services); Operations Training and Integration to design and support trainings for the Operations and Market Administration staff regarding new market features; Information and Cyber Security Services and Advanced Technology Solutions to support and integrate new market features into applications and tools; and Planning and Transmission Services to align with new market designs, identify enhancements to existing reliability modeling and research, and develop modeling techniques for emerging technologies.

The nGEM vendor support included in the funding for Goal 1 is to support the Real-Time Market Clearing Engine application, which is at a higher cost than the legacy Real-Time application.

Finally, the funding for Goal 1 related to modeling and analysis work is to support: the Information Technology and System Planning departments' efforts related to resource adequacy and capacity market modeling, which are essential to the redesign of the capacity market; the Advanced Technology Solutions and Market Development departments' Capacity Auction Reforms work, including gas modeling and other analyses; the Tariff-required Net Cost of New Entry (CONE) recalculation; and the Market Monitoring department's technology assessments and artificial intelligence development for use in the detection and mitigation of energy market activity.

d. Increases Related to Progress and Innovation (Strategic Goal 2)

The cost increase of $2.9 million to support the Progress and Innovation strategic goal will support headcount additions; computer service-related costs for compliance with NERC Critical Infrastructure Protection ("CIP") synchrophasor standards; and costs related to photovoltaic data and forecasting service.

The 9.0 FTEs headcount increases to support Goal 2 include positions in Information Technology and Advanced Technology Solutions to support the development of advanced technologies in the operating environment to increase situational awareness capabilities, and in Information Technology to support the migration of applications to the cloud. In System Operations and System Planning, additional positions are needed for forecasting and energy analysis across different timespans as the system's resource mix continues to evolve; modeling and electromagnetic transient analysis for market and reliability operating limits of inverter-based resources; expansion of both short-term and long-term forecasting needs; and support of the continued growth and development of Power System Computer Aided Design (PSCAD) modeling capability (including database development and maintenance) for inverter-based resources.

e. Increases Related to Stakeholder Engagement (Strategic Goal 4)

The cost increase of $2.1 million to support the Stakeholder Engagement strategic goal will support headcount additions, consulting support, and asset condition review work. Headcount additions will include 2.5 FTE positions in the Participant Relations and Services department for project services (*e.g.*, gathering, managing, and supporting the assessment of participant requests), to provide technical readiness and real-time support on corporate initiatives (*e.g.*, initiatives related to Commission Orders 2222, 881, 2023), and to support the Capacity Auction Reforms project; 0.5 FTE position in the Legal department to support the implementation of the Long-Term Transmission Planning ("LTTP") rules; and 0.5 FTE in the System Planning department to perform economic evaluations in support of the new LTTP processes and potential requests for proposal solution reviews, and to accommodate requests from the New England states and the New England States Committee on Electricity. Additionally, funding to support Goal 4 will include consulting support for LTTP proposals and other transmission planning work.

Finally, $1.0 million of funding is included in furtherance of Goal 4 to support asset condition review work. Over the past year, the ISO has received requests from states and stakeholders to consider taking a reviewer role in the Transmission Owners' current asset condition projects process. After agreeing with the states and Transmission Owners on certain threshold matters,[32] the ISO has begun work to identify the scope of the Asset Condition Reviewer role, including the resourcing and responsibilities of such role. As a result, the ISO has used approximately $300,000 of contingency funding from the 2025 budget and has budgeted $1.0 million as part of the 2026 Core Operating Budget for asset condition review work, but if any of 2026 funding is not needed for such work, it will be returned in a subsequent budget year.

f. Miscellaneous Increases

The cost increase of $0.5 million in this category is attributable to: (i) increases in building services costs due to cyclical maintenance items that are due for completion in 2026, higher utility expense largely for delivery service fees at the ISO's Windsor facility, and inflationary and other small increases across line items; and (ii) lower forecasted interest income due to the projection of a lower operating cash balance because of expected withdrawals by customers pursuant to Commission Order 2023 (which will be partially offset by higher miscellaneous revenue).

g. Offsetting Savings; Direct Charge Activities

[32] The ISO was only willing to agree to evaluate asset condition review work if the Transmission Owners indemnify the ISO for any related liability; the asset condition reviewer role is solely advisory; and the asset condition reviewer role will not make any legal finding or issue an opinion on whether costs on any given asset condition project are prudent. *See* Update on Asset Condition Project Process Memo, available at https://notification.iso-ne.com/l/405752/2025-05-15/2ccp755/405752/1747327348SH2DPfNj/Status_update_ACR_5_15_2025.pdf.

The ISO works to offset increased costs through cost-cutting, eliminating discontinued or non-repetitive work, and to the extent possible, reallocation of resources. For 2026, the ISO has realized $6.9 million of efficiencies, reductions, and other non-recurring costs.

The $6.9 million reflects reductions for consulting professional fees for 2025 studies or other non-recurring work, including: the completion of regional study work with PJM and NYISO regarding the appropriateness of the current 1,200MW single source contingency limit and to determine the upgrades required to support a 2,000 MW single source limit; the completion of a transmission planning system assessment under NERC Transmission Planning Standard TPL-001; the removal of medium-term energy adequacy related work; the removal of wind, solar, and generation dataset information that will be obtained via other sources; the reduction in Advanced Technology Solutions external research and development support; lower relocation expense reimbursements; and other miscellaneous reductions.

Reductions also include lower salary rates and related incentive compensation due to employee turnover and retirements, and a reduction given the expectation that there will be no borrowings on the working capital line based on 2026 projections.

The ISO will also offset its costs through certain direct charges. Section IV.A of the Tariff includes provisions for the ISO to assess direct charges to collect reasonable administrative costs for performing certain discrete functions, including transmission studies,[33] information requests,[34] non-standard contract provisions,[35] and non-standard billing.[36] Expected revenues to reimburse ISO staff efforts for studies (as opposed to revenues that are flowed through to contractors actually performing the studies) have been used to reduce the relevant schedule's 2026 Revenue Requirement.

2. Depreciation

As a non-profit entity without equity, the ISO must recover revenues consistent with its obligation to repay the loans funding its projects. In fact, the ability to obtain and maintain independent financing is dependent upon the ISO's being able to recover the principal portion of debt service through depreciation and amortization.

For 2026, the ISO's depreciation and amortization costs are $38.3 million, which is approximately $1.3 million more (3.5% increase) than in 2025.[37] Increases in depreciation

[33] Tariff § IV.A.6.1 (Transmission Studies). This provision permits, for example, charging for the performance of System Impact Studies, Facilities Studies and FCM qualification studies.

[34] Tariff § IV.A.6.2 (Information Requests).

[35] Tariff § IV.A.6.3 (Non-Standard Provisions).

[36] Tariff § IV.A.6.4 (Non-Standard Billing Service).

[37] The $38.3 million of depreciation and amortization costs cited here is different from the amount specified in Section I.C of this transmittal letter, which notes $48.2 million of depreciation and amortization costs *and regulatory fees*. The inclusion of regulatory fees (such as NERC and NPCC dues) accounts for the different figures. See also Exhibit 3, RCL-5, Schedule 1, Line 17.

expense are primarily due to 2025 or 2026 project implementations including nGEM Real-Time Market Clearing Engine, Enterprise Resource Planning System Replacement, CIP Electronic Security Perimeter Redesign Phase II, and FERC Order 841.[38]

The ISO's depreciation rates remain unchanged from those previously accepted by the Commission.[39] The ISO uses the straight-line depreciation methodology based on no net salvage value and the various average service lives described below. These service lives reflect the ISO's historical experience and forecasted expectations for capital projects placed into service, are necessary to comply with the ISO's funding mechanisms, are consistent with the ISO's historical experience, and have been repeatedly determined by independent auditors to be reasonable. The service lives are:

- Computer hardware, software and accessories: 3 to 5 years
- Software development costs: 3 to 5 years
- Furniture and fixtures: 7 years
- Machinery and equipment: 7 years
- Building: average of 25 years (based on the opinion of independent bond counsel and analysis of the service lives of the different aspects of the building (*e.g.*, the building's steel and concrete at 40 years, mechanical and electrical work at 25 years, and high wear-and-tear elements at 15 years))
- Leasehold/Building Improvements: lesser of 1 to 25 years or remaining life of the lease or building, as determined at the time of the purchase based on the nature of each such improvement (*e.g.*, rooftop railing at 25 years, air conditioning unit at 15 years)
- Vehicles: 3 to 7 years

3. True-Up Mechanism

As set forth in Section IV.A.2.2 of the Tariff, the 2026 Revenue Requirement includes an adjustment for deviations between actual collections and expenses for calendar year 2024. In general, the amount of the true-up is added to (in the case of a revenue shortfall) or subtracted from (in the case of a revenue over-recovery) the ISO's total estimated budgeted amounts for the upcoming budget year. In the case of the 2024 true-up, the ISO collected $15,601,720 more than it needed to pay its expenses.

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[38] *See* Exhibit 3, RCL-5, Schedule 4, page 2 of 2. Partially offsetting the depreciation expense increase are projects that will be fully depreciated in 2025 or 2026 including nGEM Market Clearing Engine Implementation, nGEM Software Development Parts I and II, nGEM Hardware Phase II, and Security Information & Event Management Log Monitoring Replacement.

[39] In 2006, the Commission examined and accepted the ISO's depreciation rates after holding a paper hearing. *ISO New England Inc.*, 117 FERC ¶ 61,310 at P 18 (2006), *Order on paper hearing and finding rehearing to be moot*, 119 FERC § 61,178 (2007).

With respect to Schedule 1, the ISO had expenses of $56.0 million, and collected revenues of $58.5 million, resulting in an over-collection for Schedule 1 (*i.e.*, the decrease to the 2026 Revenue Requirement for Schedule 1) of about $2.5 million.[40] With respect to Schedule 2, the ISO had expenses of $127.6 million and collected revenues of $134.0 million, resulting in an over-collection for Schedule 2 (*i.e.*, the decrease to the 2026 Revenue Requirement for Schedule 2) of approximately $6.3 million.[41] Finally, with respect to Schedule 3, the ISO had expenses of $78.7 million and collected revenues of $85.5 million, resulting in an over-collection for Schedule 3 (*i.e.*, the decrease to the 2026 Revenue Requirement for Schedule 3) of approximately $6.8 million.[42]

D. Services Funded by the 2026 Revenue Requirement

This section discusses the three services the ISO provides, which correspond to the rate schedules through which the ISO recovers its Revenue Requirement: Schedule 1 – Scheduling, System Control and Dispatch Service ("Scheduling Service"); Schedule 2 – Energy Administration Service; and Schedule 3 – Reliability Administration Service.

1. Scheduling Service (Schedule 1)

Scheduling Service includes the transmission-related service required to schedule at the pool level the movement of power through, out of, within, or into the New England Control Area. It does not cover expenses of dispatching Energy, which are collected as part of the charges in Schedule 2. Scheduling Service can be provided only by the ISO, and all Transmission Customers must purchase Scheduling Service from the ISO. The 2026 Revenue Requirement for Schedule 1 (including true-ups) is $65.6 million.

Functions performed by the ISO in connection with Scheduling Service include:

- processing and implementation of requests for Regional Transmission Service, including support of the Open Access Same-Time Information System node;
- coordination of transmission system operation (including administration of reactive power requirements under Schedule 2 of Section II of the Tariff) and implementation of necessary control actions by the ISO and support for these functions;
- billing associated with regional transmission services provided under the Tariff;
- transmission system planning that supports Scheduling Service; and
- administrative costs associated with the aforementioned functions.

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[40] *See* Exhibit 3, RCL-2, Schedule 2, page 2 of 2.

[41] *See* Exhibit 3, RCL-2, Schedule 2, page 2 of 2. Pursuant to Section IV.A.2.2 of the Tariff, the true-up is calculated separately for Schedule 2. *See also* Section I.E.4.b of this transmittal letter.

[42] See Exhibit 3, RCL-2, Schedule 2 page 2 of 2.

2. Energy Administration Service (Schedule 2)

Energy Administration Service is the service provided by the ISO to administer the Energy Market. The 2026 Revenue Requirement for Schedule 2 (including true-ups) is $154.8 million.

The ISO's functions that comprise Energy Administration Service include:

- core operation of the Energy Market;
- generation and demand dispatch related to the Energy Market;
- energy accounting;
- loss determination and allocation;
- billing preparation;
- market power monitoring and mitigation for the Energy Market;
- sanctions activities;
- operation of Financial Transmission Rights auctions;
- market assessment and reports; and
- formulation of additional market rules and proposals to modify existing rules.

3. Reliability Administration Service (Schedule 3)

The ISO provides Reliability Administration Service to administer the Reliability Markets, including the Forward Capacity Market, in accordance with Market Rule 1 and to provide other reliability and informational services. These services are of a type not directly related to the services provided under Schedules 1 and 2, and are expenses of operating the New England Control Area generally, rather than expenses attributable to serving a particular Customer. The 2026 Revenue Requirement for Schedule 3 (including true-ups) is $94.1 million.

Examples of the functions performed (in addition to the core operation of the Reliability Markets) include:

- generation and demand dispatch associated with Reliability Markets;
- Reliability Markets accounting;
- billing preparation;
- generation emissions analysis;
- risk profile updates;
- triennial review of resource adequacy;

- studies and qualification of resources under the Forward Capacity Market;
- preparation of regional reports and load forecasts and profiles (Capacity, Energy, Load and Transmission ("CELT") Reports; reports to the Energy Information Administration of the United States Department of Energy; reports to NERC; Regional System Plan);
- support of power supply, environmental, and market reliability planning activities;
- market power monitoring, mitigation, and assessment for the Reliability Markets; and
- formulation of additional market rules and proposals to modify existing rules.

E. Cost Allocation and Rate Development

This section describes the new rates proposed herein by: (i) detailing how the ISO generally allocates its costs among the three core rate schedules; (ii) explaining the billing determinants used by each schedule; (iii) explaining how the ISO adjusted the billing determinants for 2026; (iv) describing the rates ultimately derived for 2026 for each schedule; and (v) explaining how and why the Revenue Requirement for each schedule shifted.

1. Cost Allocation Among the ISO's Services

Most of the ISO's operating costs are fixed and do not vary based on the volume of a Customer's activity—a fact recognized by the Commission itself.[43] The ISO established the core rate design for its first three schedules through an uncontested settlement approved by the Commission in 2001,[44] with additional modifications reflecting necessary changes upon the commencement of Standard Market Design in New England. Although the 2001 settlement is no longer binding, the ISO followed the same cost allocation among the three primary schedules when establishing the rates proposed herein.

The Tariff structure relies upon the activity-based allocation of the ISO's costs to its three rate schedules, namely Scheduling Service, Energy Administration Service, and Reliability Administration Service. These rate schedules coincide with the main "service categories" of the ISO. Exhibit 3, RCL-3, Schedule 1 contains a Test Year 2026 cost of service for the three rate schedules. This exhibit lays out in detail how the ISO's costs were assigned to the schedules.

In assessing how costs should be assigned to the various categories of service that the ISO provides to its Customers, the objective is to reflect cost causation principles as much as possible. All costs that could be assigned to the three rate schedules using direct allocators were

[43] *ISO New England Inc.*, 89 FERC ¶ 61,339 at p. 62, 019 (199), *reh'g denied*, 91 FERC ¶ 61,016 (2000) (finding that the ISO's expenses "are essentially fixed" and that the issue of rate design involves "not so much cost causation, as it does the equitable allocation of an essentially fixed amount of expenses among many users of the grid").

[44] *See* Settlement Agreement in Docket No. ER01-316-000 (filed June 1, 2001).

so allocated. Most activity costs consist of direct labor costs, employee benefits, and other non labor-related costs (*i.e.*, office supplies, software, hardware, depreciation, interest, etc.). For each activity code, both the labor-related and non labor-related costs are assigned to the rate schedule using the same allocator. Within a given department, known allocators (Alloc-Fixed) for specific cost categories or activities were used to allocate those labor costs that were specifically attributable to a schedule. All remaining labor costs within that department were allocated in proportion to the distribution of the summed Alloc-Fixed labor costs among the three schedules. Labor costs within all departments were allocated in this manner and summed for the entire company.

2. Rate Design and Billing Determinants

As discussed below, each Schedule utilizes different billing determinants and attempts to reflect cost causation principles, to the extent possible. The ISO is not proposing any changes to the overall design of the billing determinants for 2026.

a. Schedule 1

The billing determinants for Schedule 1 are Monthly Regional Network Load and Reserved Capacity. Monthly Regional Network Load is measured in kilowatts. The determinant based on Reserved Capacity uses the highest amount of Reserved Capacity for an hour for each transaction scheduled to occur during the month as Through or Out Service, other than Coordinated External Transactions.[45] Schedule 1 revenues collected from Through or Out Service Customers are credited to each Network Customer that month in proportion to each Network Customer's Monthly Regional Network Load. Revenues from the Non-Participant Financial Transmission Rights ("FTR") fee described in Market Rule 1 and non-refundable Long Lead Facility deposits will be credited to the Schedule 1 Revenue Requirement through future true-ups.

b. Schedule 2

The Schedule 2 Revenue Requirement is allocated 15% to Transaction Units ("TUs") and 85% to Volumetric Measures ("VMs"), subject to the special true-up described below. TUs measure the frequency and duration of activity and are indifferent to the size (*e.g.*, capacity) of any particular transaction. Conversely, VMs seek to capture a Customer's "physical" reliance on the system administered by the ISO and thus the benefit received.

[45] Coordinated External Transactions are defined in Section I of the Tariff as transactions at external interfaces to which the enhanced scheduling procedures in the Coordinated Transaction Scheduling ("CTS") rules apply. These rules were adopted jointly with the NYISO to enhance the market efficiency of external transactions (*i.e.*, energy imports and exports) between the two regions through economic clearing of external transactions. *See* Tariff Section III.1.10.7.A.

Schedule 2 utilizes three types of TUs: (i) those associated with Energy Market transactions ("Energy TU Based Charges"), (ii) those associated with Increment Offers and Decrement Bids, and (iii) those associated with FTR auction bids.

Energy TU Based Charges: These charges equal the sum per month of a Customer's Bilateral Contract Block-Hours, Demand Bid Block-Hours, Asset Related Demand Bid Block-Hours, Supply Offer Block-Hours, Demand Reduction Offer Block-Hours, Day-Ahead Ancillary Services Offer Block-Hours, and Energy Non-Zero Spot Market Settlement Hours, without reference to Coordinated External Transactions. Under the ISO's current rate design, a Customer's total monthly Energy TUs are priced under a three-tiered declining block rate structure. Under this regime, the highest unit rate applies to the first 12,500 Energy TUs incurred in a month. The Customer's next 27,000 Energy TUs are priced approximately 10% lower, with the balance of monthly Energy TUs (*i.e.*, those in excess of 39,500) priced at an additional savings of approximately 10%.

TU Charges Based on Increment Offers and Decrement Bids: These charges are based on both of the following: (i) a charge multiplied by the total number of Increment Offers and Decrement Bids submitted; plus (ii) a charge multiplied by the total number of Increment Offer and Decrement Bids that clear the Day-Ahead Energy Market. This category is sometimes referred to as "virtual activity."

TU Charges Based on FTR Auction Bids Submitted and Cleared: These charges are intended to recover all costs for operating the monthly, multi-month, and annual FTR auctions. The charges consist of: (i) a unitized charge multiplied by the total number of bids submitted to the FTR auctions; plus (ii) a unitized charge multiplied by the total number of bids that clear the FTR auctions.

Schedule 2 Volumetric Measures consist of the sum of a Customer's Monthly Real-Time Load Obligation, Monthly Real-Time Generation Obligation, and Monthly Real-Time Demand Reduction Obligation (each measured in megawatt hours (MW)) excluding any Monthly Real-Time Generation Obligation associated with certain energy imports and Coordinated External Transactions. Under the ISO's current rate regime, Schedule 2 VMs are priced under a three-tiered declining block wherein the highest unitized rate is assessed to the first 250,000 MWh each month. The Customer's next 1,250,000 MWh are priced at a discount of approximately 10% from the tier-1 unitized rate, and VMs in excess of 1,500,000 MWh incur the lowest unitized monthly rate.

c. Schedule 3

Schedule 3 allocates internal load activity based on Real-Time NCP [Non-Coincident Peak] Load Obligation. For Exports other than Coordinated External Transactions, Schedule 3 assesses a volumetric (per MWh) charge.[46] Specifically, the ISO divides the Schedule 3 Revenue Requirement by the real-time load obligation forecasted for the upcoming year in the

[46] The Commission accepted the current form of the Schedule 3 rate design that distinguishes Exports from internal activity in a June 2, 2006 Letter Order issued in Docket No. ER06-926-000.

most recent CELT Report to yield the unitized rate per kW-month.[47] The remaining revenue requirement for Schedule 3 (*i.e.*, net of that allocated to Exports) is then divided by the total Real-Time NCP Load Obligation forecast to yield the unitized rate per kW-month.

3. Adjusting Billing Determinants for 2026

The data used in designing the proposed rates in the 2026 Administrative Expenses Tariff was taken from the ISO markets system for the 12-month period ending July 2025. Consistent with the practice reflected in the ISO's Tariff filings for 1999 through 2025, the ISO also relied on information contained in the annual CELT Report. The development of the escalation factors is shown in Exhibit 3, RCL-7, Schedules 1 and 2.

In sum, the ISO's analysis of CELT Report data, other load data, and transaction data through July 2025 suggests that the estimated data for August 2025 through December 2025 should be based on 2024 data.

The ISO's analysis of the data led to an increase of 0.5% in the projected data for 2026 (compared to 2025 levels) for the Schedule 1 (*i.e.*, Regional Network Load) billing determinant, the load-related (volumetric) measures in Schedule 2, and the Schedule 3 billing determinant related to Real-Time NCP Load Obligation.[48]

The Schedule 2 Energy TUs billing determinant was increased by 2.9% and escalated additionally by 112,625 TUs per month to reflect the impact of Day-Ahead Ancillary Services Offers that commenced in March 2025. As explained in Mr. Ludlow's testimony, the number of Energy TUs has increased consistently over the past several years, with an average increase over the past three years of 2.9% excluding the impact of Day-Ahead Ancillary Service Offers.[49] Because the data from the past three years did not include Day-Ahead Ancillary Services Offers (since those offers only began in March 2025), the escalation based on August 2022 through July 2025 TUs did not include Day-Ahead Ancillary Services Offers. To properly incorporate the impact of Day-Ahead Ancillary Services Offers, the ISO took the average amount of such offers during the period of March 2025 through July 2025 and used that average as a further escalation.[50] The Schedule 2 transaction unit determinants for virtual transactions and FTRs were left flat for 2026 due to historical inconsistent bidding patterns and fluctuating results of cleared bids; as explained in Mr. Ludlow's testimony, although there has been some fluctuation in virtual transactions over the past several years, the ISO has not identified any specific market change or participant behavior causing such fluctuation.[51] Similarly, there has been no clear

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[47] ISO New England Inc., *2025-2034 Forecast Report of Capacity, Energy, Loads, and Transmission* (May 1, 2025). *See* https://www.iso-ne.com/static-assets/documents/100023/2025_celt.xlsx. The 2026 Forecast is based on the May 2025 CELT Report Forecast Data Tab 1.5.2 (Net Annual Energy reduced for behind-the-meter photovoltaic).

[48] Exhibit 3, RCL-7, Schedule 2, columns (c), (i) & (j), Lines 16-27.

[49] *See* Exhibit 3 at pp. 42-46.

[50] *See id.* at pp. 42-43.

[51] *See id.* at pp. 42-46.

pattern to FTR bidding activity with historical variation in activity, including over the past twelve months.[52] Data regarding these calculations appears in Exhibit 3, RCL-7.

Finally, the Schedule 3 volumetric charges for Exports were left flat for 2026, as shown in Exhibit 3, RCL-7, Schedule 2, column (k). The remainder of the Schedule 3 revenue requirement is assessed via a billing determinant related to NCP Load Obligation. This billing determinant, like the Schedule 2 volumetric measures and the Schedule 1 billing determinants, is increased by 0.5% based on CELT Report load data, as shown in column (j) of RCL-7, Schedule 2. NCP Load Obligation absorbs the remaining Schedule 3 revenue requirement.

4. Deriving the 2026 Rates

a. Rate Development for Scheduling Service (Schedule 1)

The ISO's Revenue Requirement for Schedule 1 totals $65.6 million.[53] The total underlying annual billing determinants for Schedule 1 are 223,165,587 kilowatt-months,[54] reflecting the escalation factor discussed above, based on actual plus forecasted activity in 2025. The resulting rate is $0.29382 per kilowatt-month, which is billed as $0.00040 per kilowatt-hour.[55]

b. Rate Development for Energy Administration Service (Schedule 2)

In determining the ISO's Revenue Requirement for 2026, the ISO includes a true-up for 2024 based on both the TU and VM portions of Schedule 2.[56] In implementing the true-up adjustment for revenue differences in the VM portion of Schedule 2, the differences will be added to (in the case of a revenue shortfall) or subtracted from (in the case of a revenue over-recovery) the ISO's total estimated budgeted amounts for Schedule 2 for the coming year.

Revenue over-recoveries attributable to the TUs in Schedule 2 are treated in the same manner. However, if there is a revenue shortfall attributable to the TUs in Schedule 2, half of the shortfall will be subtracted from the 2026 Revenue Requirement for Schedule 2. An additional percentage of the shortfall will be added to the ISO's projected revenue requirement for the Schedule 2 VMs for each percentage decrease that was deemed to have occurred between the number of TUs used in the true-up and the number of TUs that the ISO had used in the original projection of the rates for that year. The maximum percentage of the shortfall that will be added

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[52] *See id.*

[53] Exhibit 3, RCL-3, Schedule 1.

[54] Exhibit 3, RCL-7, Schedule 3, Line 2.

[55] Exhibit 3, RCL-7, Schedule 3, Line 2-3.

[56] Consistent with the 2001 Settlement, injections associated with energy imported into the New England Control Area by Bangor Hydro-Electric Company (up to 300 MW) across the New Brunswick Tie are excluded for billing and rate calculation purposes from Energy Administration Service VMs.

to the VMs is 100%, which would result if the percentage difference between the actual and forecasted TUs was 50% or greater. Any remaining revenue shortfalls will be added to the ISO's projected revenue requirement for the Schedule 2 TUs.

The TU recovery for 2024 was an over-collection of TU revenue in the amount of $768,585.[57] Accordingly, there is no variation for 2026 to the 15/85 allocation of the Schedule 2 revenue requirement between TUs and VMs.[58]

The ISO's Revenue Requirement for Energy Administration Service consists of its expenses for the functions required to provide the Service, as described above. The year 2026 budget costs assigned to Schedule 2 total approximately $154.8 million after true-up.[59] Of this total cost, $23.2 million (*i.e.*, 15.00% of the Energy Administration Service Revenue Requirement) is projected to be recovered pursuant to the rate design through user charges related to TUs.[60] Included in this amount is $21.6 million of costs assessed to Energy TUs under a declining block rate, billed as follows: $0.86039 per TU for Block 1; $0.78217 per TU for Block 2; and $0.70396 per TU for Block 3.[61] Total projected Energy TUs for 2026 are 26,406,536.[62] In addition, $1.5 million has been budgeted for operating the FTR auction, and will be recovered through the following rates: $3.87023 per FTR bid submitted; and $6.17635 per FTR bid that clears the auction.[63] Finally, the TU Revenue Requirement includes $133,688 for the submission and clearing of Increment Offers and Decrement Bids, which is billed as $0.00500 per submitted offer or bid, and $0.06000 per cleared offer or bid.[64]

The remainder of the total Schedule 2 cost for 2026, approximately $131.5 million[65] (*i.e.*, 85.00% of the Energy Administration Service Revenue Requirement), is projected to be recovered pursuant to the existing rate design through user charges related to VMs incurred under three different declining block rates. The rates are as follows: $0.58201 per VM for

[57] Exhibit 3, RCL-7, Schedule 5.

[58] Exhibit 3, RCL-7, Schedule 6. *See also* RCL-2, Schedule 2 and Section I.C.3. The overall Schedule 2 true-up is an over-collection of $6,336,845. *Id.*

[59] Exhibit 3, RCL-3, Schedule 1.

[60] Exhibit 3, RCL-7, Schedule 3, Line 6.

[61] Exhibit 3, RCL-7, Schedule 3, Lines 16-19.

[62] Exhibit 3, RCL-7, Schedule 3, Line 20.

[63] Exhibit 3, RCL-7, Schedule 3, Lines 11-13.

[64] Exhibit 3, RCL-7, Schedule 3, Lines 7-9.

[65] Exhibit 3, RCL-7, Schedule 3, Line 22.

Block 1; $0.52910 per VM for Block 2; and $0.47619 per VM for Block 3.[66] Total projected Schedule 2 VMs for 2026 are 238,317,902.[67]

c. Rate Development for Reliability Administration Service (Schedule 3)

The ISO's 2026 Revenue Requirement for Reliability Administration Service consists of its expenses for the functions required to provide the Service, as described above. These expenses, totaling $94.1 million after true-up, are detailed in Exhibit 3, RCL-3, Schedule 1 to this filing. The ISO recovers its Schedule 3 Revenue Requirement from Market Participants through two separate rates: (i) a Real-Time NCP Load Obligation charge (assessed to internal load); and (ii) a per-MWh rate for Exports. The total underlying Real-Time NCP Load Obligation is 253,266,481 kilowatt-months.[68] The resulting rate is $0.36072 per kilowatt-month.[69] The Export rate is $0.80 per MWh.[70]

Schedule 3 also includes Reliability Administration Service fees applicable to Non-Market Participant Transmission Customers that take Through or Out Service under the OATT. The proposed Reliability Administration Service fees were developed by applying a ratio of the Schedule 3 forecasted 2026 Revenue Requirement to the Schedule 3 forecasted Revenue Requirement for 2002 to the 2002 Reliability Administration Service Fee, to obtain a monthly fee of $3,935.82, or an hourly rate of $5.39. *See* Mr. Ludlow's testimony at Exhibit 3 (pages 50-51) for more details on the calculation of this hourly rate.

5. Analysis of Cost Shifts Across Schedules

Before true-up, the breakdown by schedule shows an increase in Schedule 1 of $4,340,828 (from $63,669,206 to $68,040,034), an increase in Schedule 2 of $11,948,139 (from $149,150,469 to $161,098,608), and an increase in Schedule 3 of $7,297,637 (from $93,555,211 to $100,852,848). Several factors contributed to this result.[71]

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[66] Exhibit 3, RCL-7, Schedule 3, Line 23-25.

[67] Exhibit 3, RCL-7, Schedule 3, Line 26.

[68] Exhibit 3, RCL-7, Schedule 3, Line 31.

[69] *Id.*

[70] Exhibit 3, RCL-7, Schedule 3, Line 32.

[71] For more information on the factors discussed below, *see* memo to NEPOOL Budget & Finance Subcommittee and Participants Committee from Bob Ludlow and Kelly Reyngold dated September 23, 2025. The memo is located at https://www.iso-ne.com/static-assets/documents/100028/npc-2025-10-09-supp.pdf (item 5a) and at https://www.iso-ne.com/static-assets/documents/100028/projected_2026_revenue_requirement_for_iso_ne_administrative_cost_tariff_schedules.pdf.

Schedule 1. The increase in the Revenue Requirement for Schedule 1 results from 2026 cost increases and changes that impact all three schedules, including for: compensation (merit and promotion/adjustment) increases, employee benefits for medical trend, and a reduction in budgeted employee vacancy; Information Technology and Advanced Technology Solutions for personnel and products related to support the operationalization of market, transmission, and emerging technology initiatives and impacts related to cloud infrastructure and data management, software licensing and subscription fees, inflationary increases, modernization of legacy systems and hardware refresh cycles, and governance and compliance requirements; funding to provide research, recommendations, and implementation of enhanced security best practices for the ISO workforce; and an increase in regulatory counsel fees for Commission Order filings and responses to supplement ISO-NE Legal staff. Also contributing to the increase in the Revenue Requirement for Schedule 1 is Transmission Planning support for RFP processing and long-term studies, and funding for asset condition review work. These increases were partially offset by the non-recurrence, in 2026, for an assessment being done in 2025 under NERC Transmission Planning Standard TPL-001 to establish facility out transfer capability for northern New England and NECEC.

Schedule 2. The increase in the Schedule 2 Revenue Requirement is due to the increases that impact all three schedules, as discussed in the preceding paragraph. Also affecting the Schedule 2 Revenue Requirement increase, is depreciation expense increases for mid-2026 go-live of the nGEM Real-Time Market Clearing Engine Implementation project. The increase in the Schedule 2 Revenue Requirement is also attributable to funding for technical writing and instructional design work for broader and deeper training of new market features and initiatives scheduled for 2026; and for work that affects Schedules 2 and 3, including Market Development design work for flexible response services; Transmission Planning Economic Study related work with the continued installation of inverter-based resources and for NPCC and NERC requirement responsibilities; and a full year of Depreciation Expense for the Day-Ahead Ancillary Services Improvements and Day-Ahead Ancillary Services Benchmark Levels projects that had mid-2025 go-live dates.

Schedule 3. The increase in the Schedule 3 Revenue Requirement is attributable to increases that impact all three schedules and funding for items that impact Schedules 2 and 3, each as noted above. Additionally, the Schedule 3 Revenue Requirement increase is attributable to funding for Market Development design work in 2026 to complete conceptual and detailed design of Capacity Auction Reforms ("CAR") Seasonal Accreditation and CAR Impact Analysis, increases in NPCC and NERC dues, and funding for the tariff required Net Cost of New Entry (CONE) recalculation.

II. ISO-NE'S 2026 CAPITAL BUDGET

The 2026 Capital Budget is a list of the ISO's planned capital expenditures in 2026. The ISO does not make any collections through its capital budget; rather, the capital projects reflected in the budget are funded through private placement financing.[72] The ISO funds the

[72] The debt was approved by the Commission in Docket No. ES24-41-000, 188 FERC ¶ 62,038 (2024).

capitalized portion of the interest on that financing through recovery of depreciation under its annual operating budget, as discussed in Section I.C.2 above. In sum, the costs of these projects are collected once only, through the depreciation recovery in the Revenue Requirement.

Before describing the projects that comprise the 2026 Capital Budget, the ISO provides context for the Capital Budget in the following Sections II.A and B.

A. The 2026 Capital Funding Arrangements

By way of review and introduction, Section IV.B of the Tariff (called the Capital Funding Arrangements) permits the ISO to collect from Market Participants:

(1) the costs of budgeted capital items, through a Capital Funding Charge, if the costs are not financed by the ISO;

(2) through an Early Amortization Charge, the remaining unamortized costs of assets financed by the ISO in the event of termination, acceleration or required repayment of private financing or, in the case of non-amortizing private financing, payment at maturity if the ISO is unable to refinance such financing;

(3) the working capital amount required by the ISO, if financing arranged by the ISO to meet working capital requirements is terminated early or repayment is accelerated (and no replacement financing has been obtained by the ISO), through an Early Amortization Working Capital Charge; and

(4) The costs that would be required to be paid by the ISO in the event of termination, acceleration or required prepayment of private financing entered into by the ISO in support of weekly billing of a portion of the market settlement system (and no replacement financing has been obtained by the ISO), through an Early Payment Shortfall Funding Charge.

The "backstopping" reflected in the foregoing Capital Funding Arrangements is necessary to help the ISO obtain and/or maintain private financing. When approving the establishment of an independent system operator in New England, the Commission expressed its concern that financial arrangements directly relying on Market Participant support for capital projects could compromise the ISO's independence.[73] Although the Commission allowed the ISO to initially rely on contractual provisions with the NEPOOL to fund then-existing capital assets, the Commission made clear that, [t]o the extent the ISO required additional, similar facilities in the future, these facilities should be funded by the ISO, not NEPOOL…."[74]

[73] *New England Power Pool*, 79 FERC ¶ 61,374 at p. 62,590 (1997).

[74] *Id*.

After the ISO commenced operations in 1997, it spent several years trying to obtain third-party private financing consistent with the Commission's directive to maintain independence from NEPOOL participants. The ISO, however, faced a key problem: an inability to provide banks the assurances they needed that the ISO would have the funds to repay a loan in the event of its early termination or acceleration. As a non-profit, non-stock Delaware corporation that is tax-exempt under Section 501(c)(3) of the Internal Revenue Code, the ISO has no equity capital (or ability to raise capital) to fund capital expenditures or working capital. Substantially all of the ISO's revenues are derived from charges to Customers under Commission-approved arrangements.

Ultimately, a bank expressed willingness to lend to the ISO based on the "backstopping" provisions of the Tariff and the ability to recover debt service through depreciation and amortization charges. Thus, the ISO funds its capital projects with third-party financing to maintain independence from Market Participants, while banks rely on Sections IV.B and IV.A of the Tariff to provide sufficient assurances to finance the ISO.

Given the structure and terms of the Capital Funding Arrangements (which remain unchanged for calendar year 2026 from those on file with and accepted by the Commission), if no termination or acceleration of that financing occurs, then none of the charges described above will be collected for these purposes. The ISO currently has planned financing for all elements of the 2026 Capital Budget given the structure of its existing Capital Funding Arrangements, and at this time, the ISO does not foresee the need to obtain capital funds from Market Participants pursuant to these arrangements in calendar year 2026. As a result, the ISO does not anticipate assessing charges to Market Participants under the Capital Funding Arrangements in calendar year 2026.

B. The Transparency of the 2026 Capital Budget

The ISO's process outlined below makes the ISO's capital budgeting process transparent to stakeholders and the Commission and keeps them well informed of changes in forecasts or actual expenditures. The process includes regular reviews with stakeholders, a vote on the annual capital budget by the ISO's independent Board of Directors, and quarterly and annual filings with the Commission pursuant to Section 205 of the Federal Power Act.

The annual capital budgeting process includes review with the NEPOOL Budget and Finance Subcommittee, the NEPOOL Participants Committee,[75] and representatives of the New England states' public utilities commissions.[76] Following this review, the ISO Board of Directors approves the annual capital budget.[77] These steps are precursors to a Section 205 filing of the annual capital budget.

[75] The process for Market Participant review of ISO budgets is specified in Section IV.B.6.1 of the Tariff.

[76] *See* Section I.B above for a description of the 2026 process.

[77] *See* Section IV.B.6.1 of the Tariff.

In addition, on a quarterly basis, the ISO reviews updates to the capital budget at meetings of the NEPOOL Budget and Finance Subcommittee and then files these updates with the Commission under Section 205. These updates are described in Section IV.B.6.2 of the Tariff, which requires the ISO to file with the Commission under Section 205 on a quarterly basis: (i) a report specifying by project prior-year spending on multi-year projects, year to date spending, and a forecast of the spending to complete the project in each future calendar year; and (ii) a schedule of the unamortized costs of the ISO's funded capital expenditures at the end of the quarter and the allocation of those costs to the ISO's rates (*i.e.*, Schedules 1, 2, and 3 to Section IV.A of the Tariff).

Roughly contemporaneously with the instant filing, the ISO will make a separate quarterly filing for the third quarter of 2025. The accounting is consistent for those capital projects that are reported both in the quarterly update and in the 2026 Capital Budget, although the focus of the two filings is different (*i.e.*, 2025 versus 2026).

In sum, the ISO's capital budgeting practices create a high degree of transparency and accountability that is unparalleled among other independent system operators and regional transmission organizations—and even among other public utilities.

C. Elements of the 2026 Capital Budget

The 2026 Capital Budget is $42.5 million, consistent with the 2025 Capital Budget. As explained in Mr. Ludlow's testimony, the capital budget has been incrementally increasing over the past several years from the previously consistent $28 million capital budget largely as a result of inflation, of both labor and hardware costs, and longer lead times on the more complex projects, especially projects supporting cyber security and/or electric grid transition initiatives.[78] The 2026 Capital Budget is necessitated by four primary drivers: (i) the nGem platform replacement of the current market system (which will conclude in 2026); (ii) major market and reliability related efforts that will have significant software requirements; (iii) cyber security needs; and (iv) required information technology asset and infrastructure replacements. *See* Mr. Ludlow's testimony at Exhibit 3 (pages 52-57) for more details on these factors.

As described above, the ISO's capital project costs are largely funded by private placement debt, and as a result of the planned increase in the amount of capital budget spending, in 2024, the ISO increased the amount of private placement debt from $50 million to $75 million, which amount is sufficient to fund the increased Capital Budget.[79]

The primary elements of the 2026 Capital Budget are anticipated to be the projects outlined below. The primary deliverables for a majority of the 2026 Capital Budget projects are application software and requisite hardware needed to maintain and improve bulk-power system

[78] *See* Exhibit 3 at pp. 52-53.

[79] Exhibit 3 at p. 25; and the Budget Presentation (Slides 75-77) for a breakdown of the ISO's capital structure and cash flow; 188 FERC ¶ 62,038 (July 19, 2024).

reliability and/or wholesale electric markets.[80] Typically, the ISO's capital projects stem from market initiatives, identified in conjunction with stakeholders, to improve the energy, ancillary services and capacity markets. Other capital projects are driven by the need for increased reliability and information, increased cyber security, operational excellence activities that aim to improve the efficiency of the organization through measures such as automation of manual business processes, or regulatory requirements imposed by the Commission. In each case, the ISO has determined that the capital project will benefit the region's stakeholders by improving the ISO's ability to maintain bulk-power system reliability, administer fair and efficient markets, and provide information to stakeholders to increase transparency and facilitate decision-making.

The following are the material projects that are anticipated to comprise the 2026 Capital Budget. The projects listed in Sections 1 through 11 are well-defined and have had charters approved by management;[81] the remainder are still in the planning stages or are subject to further Commission action.

1. nGEM Real-Time Market Clearing Engine Implementation ($3,200,000)

The ISO's Market Management System ("MMS") is based on GE Grid Solution's suite of market applications known as the Next Generation Markets (nGEM) program. GE is redeveloping the Market Clearing Engine ("MCE"), a central component of the MMS.

Pursuant to a separate capital project, the Day-Ahead MCE has been developed and is in production. The nGEM Real-Time Market Clearing Engine ("RT MCE") Implementation project will build on the Day-Ahead MCE to develop and deploy the Real-Time MCE, including ISO customizations.

As part of this project, two of the legacy RT MCE study modes (the Real-Time Unit Commitment and Coordinated Transaction Scheduling Pricing Engine functions) will be replaced and continue the transition from Energy Management System to MMS interfaces. The nGEM RT MCE project will provide performance improvements by enabling more intensive market clearing formulations; eliminate reliance on .CSV flat files for communication of data between the MCE and other parts of the MMS; and enhance installation, patching, and upgrades of MCE's in ISO infrastructure.

The targeted completion date for this project is May 2026.

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[80] Capital projects also include project management and design work. If a project's design is approved and built, this work becomes part of the asset on which the ISO collects depreciation when the asset is placed in service and in future years via the operating budget. On the other hand, if the capital project is abandoned, the ISO writes off the entire project cost, including management and design work and recovers it in full in the year of abandonment.

[81] All capital projects, prior to approval, must have a completed project charter. This charter documents the project's goals and objectives, schedule and milestones, and budget. The charters are reviewed to ensure that the cost estimates are reasonable and that no costs were double-counted. Before approving a new capital project, the ISO's senior management team reviews each project charter.

2. Distributed Energy Resources – Order 2222 ($2,600,000)

The Commission's Order 2222 requires that independent system operators and regional transmission organizations remove barriers to the participation of distributed energy resource aggregations ("DERAs") in wholesale electricity markets. In accordance with Order 2222, the ISO proposes to expand its current energy market models and add two new energy market participation models for DERAs: Settlement Only Distributed Energy Aggregation, and Demand Response Distributed Resource Aggregation. Additionally, the introduction of a new resource type, Distributed Energy Capacity Resource, will allow DERAs to participate in the Forward Capacity Market.

Compliance with Order 2222 will span two projects. The first project, Forward Capacity Market Order 2222, which was completed in February 2024, implemented the necessary software changes to support the qualification and participation of Distributed Energy Capacity Resources in the Forward Capacity Market. The Distributed Energy Resources - Order 2222 project will include the software changes to allow for the integration of DERAs in the wholesale markets and operations systems and any remaining compliance obligations of the Order.

The targeted completion date for this project is November 2026.

3. Oracle Platform Replacement ($2,200,000)

The ISO's Oracle Platform license is nearing its end of life. The Oracle Platform Replacement project will update the ISO's license to the latest version and bring in Oracle Exadata servers with the Cloud@Customer technology. Oracle Exadata is a pre-configured, integrated hardware and software system optimized for running Oracle databases that will enhance the work our database management team is able to do.

The project scope includes configuring and migrating data to Oracle Exadata; readying our data center, deploying to virtual machines, implementing network support, and integrating with other necessary software; and testing of migrated data by various IT groups and impacted business units.

The targeted completion date for this project is November 2026.

4. Managing Transmission Line Ratings ($1,000,000)

Commission Order 881 included obligations and compliance requirements for transmission providers and public utility transmission owners with respect to transmission line ratings in order to ensure wholesale rates more accurately reflect the cost of the wholesale service being provided.

The ISO will implement various Order 881 requirements as part of the Manage Transmission Line Ratings project, including implementation of a new GE product for submission of line ratings and other system improvements to the Real-Time and Day-Ahead

energy markets and the network model application which provides authorized users an entry system with real-time access to one-line diagrams.

As part of this project, GE will provide four deliverables: a Limit Exchange Portal (LEP), which serves as an exchange portal to allow submission of new ratings and query of current/resolved ratings; an enhanced EMS to address Order 881 compliance requirements; network modeling customizations, including modifications to various forms and customizations; and customizations to support WebFG modeling, which is the software used for modeling one-line diagrams.

The targeted completion date for this project is December 2026.

5. Adoption of NERC CIP Compliance of Synchrophasor Systems ($1,000,000)

Phasor Measurement Units ("PMUs") are essential for monitoring real-time grid dynamics. This is increasingly important as the electrical grid faces more uncertainties, operates closer to stability limits, and integrates more inverter-based resources at unprecedented levels. Although the ISO has made significant progress in adopting synchrophasor technology in both planning and operations, the organization has not fully utilized its potential in real-time operations due to NERC CIP requirements.

The Adoption of NERC CIP Compliance of Synchrophasor Systems project aims to enhance the infrastructure related to synchrophasor applications and ensure they adhere to NERC CIP compliance protocols. Doing so will help the ISO utilize the full potential of synchrophasor technology in real-time operations while maintaining compliance with the necessary security standards.

The targeted completion date for this project is August 2026.

6. Internal Market Monitoring (IMM) Datamart Improvement ($400,000)

The Internal Market Monitoring ("IMM") department performs analysis on power and energy market data to identify possible misconduct or rule violations by market participants that may compromise the efficiency or distort the outcomes of the markets. To perform these tasks, IMM is required to work with data across the ISO enterprise, managed by Operations and System Planning. The IMM Datamart allows analysts to pull data together more efficiently. This initiative will add subject matter on physical withholdings, external markets, and external transactions to improve the data within the Datamart and reduce the amount of external data that needs to be imported, making this process more effective and efficient.

The targeted completion date for this project is October 2026.

7. CIP Electronic Security Perimeter Redesign Phase III ($300,000)

This project will improve the Critical Infrastructure Protection ("CIP") compliance of the ISO's Electronic Security Perimeter ("ESP") networks and will enhance the ISO's overall network security posture. While these changes are primarily focused on meeting specific CIP requirements, they also align with general industry best practices that will result in the ISO's network infrastructure being more resilient to failure, recovery, and change. This project will focus on the hardware, network, and virtual environment foundation for the production ESP network. This project is a continuation of the network modernization efforts started in CIP ESP Phases 1 and 2 and will bring the production ESP network into parity with the integration ESP network.

The targeted completion date for this project is June 2026.

8. Voltage Ampere Reactive (VAR) Capability Testing ($100,000)

Reactive resources must perform periodic reactive capability auditing. Currently, reactive capability auditing data is submitted by participants to the ISO in excel spreadsheets via email. Without a centralized data repository, the audit test data is then further disseminated through email to multiple ISO departments involved in the data review process. The lack of a centralized data repository accessible by ISO staff and external participants with the appropriate validations leaves the ISO vulnerable to audit findings and billing errors.

The VAR Capability Testing project will implement a new external facing reactive capability auditing application accessible by both external participants and ISO staff that will support participant submission of audit data results to a centralized data repository with appropriate validations and versioning, basic internal ISO workflow for reviewing and approving/rejecting audit results, and participant visibility to submitted data and to audit results as determined by the ISO.

The targeted completion date for this project is March 2026.

9. Energy Management System Communication Front End (EMS CFE) Refresh ($100,000)

The Energy Management System Communication Front End ("EMS CFE") Refresh project will upgrade the hardware and software platforms supporting the ISO's Energy Management System ("EMS") and Communication Front End ("CFE") platforms, which support real-time operation of the regional power grid and market systems.

The EMS CFE Refresh project will replace aging server infrastructure that is nearing end of life and modernize software environments to ensure system reliability, maintainability, and performance. As part of the project scope, approximately 37 new physical servers and 32 virtual servers will be deployed across development, integration, and production environments. These upgrades are necessary to improve system performance and support future scalability.

The EMS CFE Refresh project will also involve updating the underlying technology framework to align with current internal standards, reduce maintenance demands, and enhance overall system compatibility and efficiency.

The targeted completion date for this project is June 2026.

10. Enterprise Core Network Refresh ($100,000)

The Enterprise Core Network Refresh is a multi-phase effort that will modernize the ISO's enterprise core network, which serves as the backbone for the ISO's market and business operations. The current infrastructure will be replaced with a more secure, scalable, and resilient network architecture designed to support evolving operational needs and industry best practices. This project will be executed in four strategic phases (with an overall cost spanning budget years of $1.8 million, including a substantial portion for network hardware expected to be purchased during 2025).

The first phase will focus on upgrading the optical transport layer by replacing legacy Dense Wavelength Division Multiplexing systems with a modern platform. Key activities will include reviewing and finalizing the new topology, deploying new equipment, and retiring outdated infrastructure.

The second phase will involve preparing physical and logical infrastructure at ISO's campuses, which will include evacuating outdated cabling and installing new single-mode fiber, and reconfiguring key intermediate distribution facilities. It will also cover the groundwork for transitioning to the refreshed network by preparing data center spaces and routing paths for the new core infrastructure.

The third phase will execute the transition to the new core network and will include migrating to the new fiber backbone, interconnecting legacy and modern infrastructure to ensure seamless cutover, relocating critical equipment, and migrating applications and services with minimal disruption.

The final phase will focus on fully decommissioning legacy campus and data center infrastructure that was replaced during earlier phases. This will include updating system documentation, revising disaster recovery, and conducting a lessons-learned review to inform future infrastructure initiatives.

Through these four phases, the ISO will enhance the performance, security, and sustainability of its enterprise network while improving its ability to support business continuity and growth.

The targeted completion date for this project is August 2026.

11. Centralized Application Security ($100,000)

Cyber security risk in application security has become more complex and multifaceted because of increased application complexity, threat sophistication, and technological advancements. As a result, the ISO has begun using a new tool to provide a more dynamic and integrated approach to application security by embedding security measures directly into the application development lifecycle.

The Centralized Application Security project will integrate the new platform into all ISO applications allowing full use of instrumentation technology to detect vulnerabilities and threats from within applications, offering more accurate and efficient protection.

The targeted completion date for this project is February 2026.

12. Single Interval MCE Improvements (SIMI) ($5,000,000)

As noted above, the ISO's Market Management System ("MMS") is based on GE Grid Solution's suite of market applications known as nGEM and GE is redeveloping the MCE, a central component of the MMS. A separate capital project (noted in paragraph 1 above), the nGEM Real-Time Market Clearing Engine (RT MCE) project, will develop and deploy the Real-Time MCE, including ISO-NE customizations. During the first phase of the nGEM RT MCE project, which will go into production in 2026, two of the legacy RT MCE study modes (the Real-Time Unit Commitment ("RTUC") and Coordinated Transaction Scheduling Pricing Engine ("CTSPE") functions) will be replaced and continue the transition from the Energy Management System to MMS interfaces.

The nGEM Single Interval MCE Improvements Project (SIMI) will continue the efforts from Phase I and fully transition the remaining seven Real-Time study modes to the nGEM MCE platform. At the conclusion of this project, ISO-NE will be performing all production Day-Ahead and Real-Time market clearing using the nGEM version of the MCE, allowing for the retirement of the classical MCE and its underlying infrastructure.

The targeted completion date for this project is June 2028.

13. EMP 3.5 Upgrade - GridOS ($3,500,000)

The ISO's Energy Management System ("EMS") relies on GE's suite of Energy Management Platform ("EMP") applications. Customizations to GE's EMP software are necessary in order to meet the business requirements of the ISO's System Operations and Market Operation groups. GE released a new version of its EMP application (EMP 3.5) in the third quarter of 2025 and the ISO must upgrade to GE's latest platform to continue receiving support. The upgrade will involve significant effort to port the ISO's customized software to the new EMP platform.

The targeted completion date for this project is September 2027.

14. MW Dependent Fuel Price Adjustment ($2,500,000)

The ISO is proposing changes to the energy market mitigation rules that govern the fuel price adjustment ("FPA") process. These changes, known as "MW-dependent FPAs," will allow resources to reflect up to two different fuel prices in their cost-based reference levels, which will improve the accuracy of energy market mitigation and enhance energy market efficiency. The MW Dependent Fuel Price Adjustment project involves updating the ISO's energy market software to allow participants to submit an FPA with one or two fuel prices and to allow for participants to specify how the requested price(s) apply to their supply offer. The software enhancements will address issues raised in the Commission's May 5, 2023, Show Cause Order.[82]

The targeted completion date for this project is December 2026.

15. Advanced Technology Initiatives ($2,000,000)

The Advanced Technology Initiatives ("ATI") project is a supplement to the recently completed nGEM development program with GE, the ISO's MMS vendor. The ISO plans to continue partnering with GE on an extended basis to improve and enhance functionality within the MMS. The initial focus of this partnership is anticipated to be the implementation of time-coupled functionality within the nGEM MCE. Time-coupled functionality offers more advanced mathematical formulations for market clearing. This gives the ISO another tool to handle market clearing complexities (*e.g.*, proliferation of storage resources). The time-coupled functionality will first be implemented in a standalone version of the MCE for a limited-bus model and Day-Ahead Market ("DAM") study modes. Eventually, the time-coupled functionality will be implemented in the integrated MCE application and be available for DAM and Real-Time Market clearing, though this product work will require a phased approach and take 1-2 years to complete.

The targeted completion date for this project is December 2027.

16. Order 2023 Interconnection Reforms ($2,000,000)

Commission Orders 2023 and 2023-A implement significant reforms to generator interconnection procedures and agreements to ensure that interconnection customers can interconnect to the transmission system in a reliable, efficient, transparent, timely, and fair manner. The Interconnection Request Tracking Tool ("IRTT") is the current external facing application through which interconnection customers submit and manage Interconnection Requests, and through which the ISO communicates with interconnection customers throughout the interconnection process.

The Order 2023 reforms dramatically change the manner in which the ISO administers the interconnection process, as well as how interconnection customers are expected to participate in that process, which necessitates significant updates to the IRTT or alternatively, the purchase

[82] *ISO New England Inc.*, Order Granting Cost Recovery Request in Part and Denying in Part and Establishing a Show Cause Proceeding, 183 FERC ¶ 61,091 (May 5, 2023).

and configuration of a commercial interconnection life cycle management application. Additionally, a new Commercial Readiness Deposit cost allocation methodology and withdrawal penalties will also necessitate new processes in Market & Credit Risk and Finance, and interactions with System Planning.

The targeted completion date for this project is September 2026.

17. Atlassian Cloud Migration ($2,000,000)

Jira, an Atlassian project management application currently utilized is maintained on several on-premise ISO servers and databases. Because these applications are on-premise, there is an associated overhead in maintaining and updating them. ISO support teams spend a significant amount of time supporting application patching, reviewing and monitoring security vulnerabilities, and upgrading the underlying infrastructure. Moving these application workflows to a cloud environment will help the ISO gain operational maintenance efficiencies and provide ISO support staff greater access and visibility across all Jira ticketing systems that the ISO uses.

The targeted completion date for this project is December 2026.

18. Day-Ahead Market Simulator (DAMKTSIM) ($1,800,000)

The Internal Market Monitoring ("IMM") group requires the development of an application capable of modeling and simulating Day-Ahead Market behavior to effectively assess market performance and market competitiveness and to evaluate the impacts of uncompetitive or manipulative participant behavior on market outcomes. The complexity of the market clearing process and market interactions requires a sophisticated tool to perform robust data analyses. The developed application will allow IMM to run simulations based on historical data and to develop counterfactual scenarios while simulating the associated market outcomes. Once available, the ISO expects to utilize the Day-Ahead Markets Simulator to analyze and report upon the performance of the Day-Ahead Ancillary Services market.

The targeted completion date for this project is December 2026.

19. GridOS Connect ($1,500,000)

In 2026, the ISO will start upgrading the Energy Management System ("EMS") to GE Vernova's EMP3.5 Platform. EMP3.5 introduces advanced network and generation features, including voltage ride-through contingency analysis, constrained power group monitoring, and Distributed Energy Resource ("DER") forecasting integration. These capabilities are essential for ensuring grid stability as the ISO transitions to an evolving energy future.

An early adoption of GridOS Connect, which is GE Vernova's comprehensive software suite designed for managing electric grids, will aid in accelerating the implementation of EMP3.5. It integrates data analytics, artificial intelligence, and advanced grid management tools to optimize grid operations, enhance reliability, and support the transition to renewable energy

sources. GridOS Connect is a new integration layer that will allow the ISO to access distributed data in their existing architecture.

The targeted completion date for this project is December 2026.

20. Storage as Transmission Only Asset (SATOA) ($500,000)

In October 2023, the Commission approved a proposal from the ISO, which enables electric storage facilities to be planned and operated as transmission only-assets to address system needs identified in the regional system planning process.[83] The rules allow transmission companies to own and maintain energy storage assets for supporting the transmission system. These assets are called Storage as Transmission Only Assets ("SATOAs").

SATOAs are different from energy storage assets that participate in the ISO's wholesale markets in that they serve a transmission function only. Unlike energy storage assets, SATOAs are selected as transmission solutions through the regional system planning process administered by the ISO, and are subject to the ISO's operational authority. They do not participate in the wholesale markets other than for limited purposes specified in the rules. This project will integrate the operation of SATOAs into the ISO's operation applications.

The targeted completion date for this project is October 2026.

21. Replace Employee & Pager Application ($500,000)

The access rights and employee request applications are essential for managing identity and access within the organization. These applications allow workforce members to model, request, approve, and implement access to various information technology assets, such as servers, systems, shared drives, and badged physical access. To adhere to industry best practices and to address several recommendations from ISO staff, these systems required new functionality.

Phase I of the project, known as Identity and Access Management Phase I, involved purchasing and implementing the necessary hardware and software to update the current access rights process. Phase II, known as Identity and Access Management Phase II, focused on integrating the new hardware and software with ISO systems. This phase also implemented new authorization roles and added features to protect the system from unauthorized access.

The Replace Employee & Pager Application project is the third phase and will replace the current employee and pager applications, develop one or more new applications to enhance system capabilities, and identify potential automation efficiencies.

The targeted completion date for this project is December 2026.

22. Circuit Inventory Management Platform Phase II ($500,000)

[83] *ISO New England Inc.*, Order Accepting Tariff Revisions, 185 FERC ¶ 61,044 (Oct. 19, 2023).

The ISO IT Communications Projects team ("ITComms") requires a centralized platform for Communications and Information Management ("CIM") that meets the everyday needs of the ITComms team and facilitates the sharing of telecom data with other departments within the organization.

When complete in November 2025, Phase I of the Circuit Inventory Management Platform project will acquire and implement a centralized platform, ensuring it is tailored for optimal use by the ITComms team and capable of effectively integrating and distributing telecom data across the organization. Completion of this project will allow for enhanced collaboration, streamlined processes, and improved overall efficiency in managing communications and information.

The second phase of the Circuit Inventory Management Platform project will include integrating the centralized platform that is being implemented in Phase I with the ISO's Customer and Asset Management System to share data back and forth between the two applications and with multiple business units at the ISO. This will include building data bridges and changing the underlying data structure to improve how data is shared between the applications.

The targeted completion date for this project is October 2026.

23. Tie Line Telemetry Replacement ($500,000)

Tie line telemetry is a key input for calculating area control error, which is critical to the ISO's ability to balance generation and load in New England. System Operations' current audio tone transmitter and receiver equipment that supports the instantaneous tie line telemetry reached its end-of-life status in June 2022 and there is limited ability to procure replacement parts. In addition, the existing tie line telemetry system lacks redundancy which is inconsistent with other systems used for reliability by ISO System Operations. The project will replace the existing analog system with a fully redundant digital system.

The targeted completion date for this project is October 2026.

24. Solar Do Not Exceed Dispatch Phase III ($500,000)

The amount of solar energy generation in New England is growing and expected to continue increasing. Integrating these solar resources requires developing rules, processes, forecasts, and tools to incorporate them into the Do-Not-Exceed ("DNE") dispatch processes.

In Phase I, GE enhanced the ISO's Renewable Plan (Rplan) software. This allows Market Participants to submit medium- and long-term data on future power generation availability. The upgrades support the inclusion of solar power forecasts, alongside wind forecasts from multiple vendors. In Phase II, remote terminal units were installed and tested at solar units to support DNE dispatch signals. Additionally, several applications, including PWRFLOW and RTGEN were also updated to support the new DNE functionality.

To accommodate the anticipated growth of solar resources, further development is needed. This involves aligning ISO internal applications with changes from the initial project phases. In Phase III, updates are planned for TARA Case Builder, STOCM, Jasper Reports, and the Operator Training Simulator.

The targeted completion date for this project is December 2026.

25. Operations Document Management System MS 365 Conversion ($300,000)

The Operations Document Management System is a SharePoint based application used by the System Operations department to manage the lifecycle of documents that are referenced by the Control Room Operators, ISO Employees, and Local Control Center employees. These documents include ISO New England Operating Procedures, Master/Local Control Center Procedures, ISO New England System Operating Procedures, Transmission Operating Guides, ISO New England Control Room Operating Procedures, and Temporary Operating Guides.

The document repository and its workflows are currently at end of Microsoft support and need to be updated. Due to system limitations, the existing workflows cannot be migrated directly to the version of SharePoint Online and must be rewritten in accordance with the business requirements.

The targeted completion date for this project is October 2026.

26. Non-Project Capital Expenditures ($5,500,000), Other Emerging Work ($1,700,000), and Capitalized Interest ($1,200,000)

The 2026 Capital Budget includes a total of $5,500,000 for non-project capital expenditures. Non-project capital expenditures fund external and internal capitalized labor necessary to program System Improvement Requests ($3,000,000); non-project related hardware purchases ($2,000,000); and building improvements, machinery & equipment, and furniture & fixtures ($500,000).[84]

The "Other Emerging Work" category ($1,700,000) is primarily intended to address emerging work requests during 2026 that result from operational needs, compliance obligations, or regulatory/stakeholder feedback.

Last, $1,200,000 is allocated to capitalized interest. Accounting conventions require that interest be capitalized for capital projects that cross years. In addition, loan fees associated with borrowings to fund capital assets are also capitalized.

D. Caveats

[84] *See* Appendix 7 to the Budget Presentation for additional detail regarding Non-Project Capital Expenditures (Slides 178-179).

The 2026 Capital Budget cannot accurately predict the ISO's actual capital expenditures for 2026. For example, protracted stakeholder review of a proposal or extensive litigation contesting a proposal can delay implementation of market improvements, thereby affecting when the ISO might incur a capital expenditure and the amount of that expenditure, as well as the ISO's cost recovery and ability to fund future projects due to constraints on available lines of credit. It is also likely that the ISO's capital project priorities will change during the course of the year. Emerging needs that are difficult to anticipate in advance will likely require a shift in priorities. In such situations, it is likely that the distribution of the 2026 Capital Budget will change. The quarterly filings under Section IV.B.6.2 of the Tariff will keep stakeholders and the Commission apprised of necessary adjustments.

III. ADDITIONAL SUPPORTING INFORMATION

The ISO submits the following additional information pursuant to Sections 205 of the FPA and 35.13 of the Code of Federal Regulations:

35.13(b)(1) – In addition to this transmittal letter, the ISO provides the following materials:

- Clean Section IV.A of the Tariff (Exhibit 1);
- Blacklined version of Section IV.A of the Tariff (Exhibit 2);
- Prepared testimony and exhibits of Robert C. Ludlow regarding the 2026 Administrative Expenses Tariff (Exhibit 3);
- Prepared testimony of Kathleen deCastro regarding the 2026 Administrative Expenses Tariff (Exhibit 4);
- 2026 Capital Budget (Exhibit 5);
- Table showing cross-references for Statement AA-BM data (Exhibit 6);
- Excerpts (income statement, balance sheet, cash flow, notes to the financial statements, and other schedules) from the ISO's Form 1 for 2024 (Exhibit 7);
- List of the governors and electric utility regulatory agencies for the six New England states to which the ISO has sent electronic copies of this filing (Exhibit 8);
- Comments of state agencies on proposed 2026 Budgets (Exhibit 9); and
- ISO-NE response to comments of state agencies on proposed 2026 Budgets (Exhibit 10).

As in the past, the ISO has included the cost of service data required by Statements AA-BM and relevant to the ISO through these exhibits, with Exhibit 6 showing the location in each exhibit by statement. Exhibit 6 also identifies those statements requiring data that are not

relevant to the ISO's development of a Revenue Requirement, due to the ISO's nature as a not-for-profit RTO that does not own any generation or transmission assets. The Commission repeatedly has accepted the ISO's rates as supported in this manner, including an explicit acknowledgement that such data is sufficient.[85]

35.13(b)(2) – The ISO requests that the Commission accept the 2026 Capital Budget and the 2026 Administrative Expenses Tariff as filed, effective January 1, 2026.

35.13(b)(3) – Pursuant to Section 17.11(e) of the Participants Agreement, Governance Participants will be served electronically. The names and addresses of the Governance Participants are available through the ISO's website at https://www.iso-ne.com/participate/participant-asset-listings/directory. A copy of this transmittal letter and the accompanying materials have also been e-mailed to the governors and electric utility regulatory agencies for the six New England states and to the New England Conference of Public Utilities commissioners and the New England States Committee on Electricity. The names and e-mail addresses of these governors and regulatory agencies are shown in Exhibit 8. In accordance with Commission rules and practice, there is no need for the Governance Participants or the entities identified on Exhibit 8 to be included on the Commission's official service list in the captioned proceeding unless such entities become intervenors in this proceeding.

35.13(b)(4) – A description of the materials submitted pursuant to this filing is contained in this transmittal letter.

35.13(b)(5) – This transmittal letter and supporting materials provide a statement of the reasons the Commission should accept the 2026 Capital Budget and the 2026 Administrative Expenses Tariff.

35.13(b)(6) – The ISO Board of Directors has approved the 2026 Capital Budget, the 2026 Revenue Requirement, and resulting rates herein. The ISO also notes that the NEPOOL Participants Committee voted to support the 2026 Capital Budget and the Revenue Requirement.

35.13(b)(7) – The ISO does not have any knowledge of any relevant expenses or costs of service that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

35.13(c)(1) – See Exhibit 3 for a comparison of the sales, services and revenues from the rate schedule to be superseded and under the rate schedule change.

35.13(c)(2) – The ISO has no other rates for similar services.

35.13(c)(3) – No specifically assignable facilities have been or will be installed or modified in order for the Commission to accept this filing.

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[85] *ISO New England Inc.*, 86 FERC ¶ 61,453 at p. 62,680 (1998) (rejecting a protestor's request to require the ISO to file the cost of service statements set forth in Section 35.13(h) of the Commission's Rules and Regulations, "find[ing] that the ISO has provided sufficient information to meet the minimum filing requirements").

IV. COMMUNICATIONS

Correspondence and communications regarding this filing should be addressed to the undersigned for the ISO as follows:

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V. CONCLUSION

The current rates contained within Section IV.A of the Tariff to collect administrative expenses are only valid for the 2025 calendar year. Similarly, the capital budget is also filed and approved for a calendar year. Accordingly, the ISO requests that the Commission accept the 2026 Capital Budget and the 2026 Administrative Expenses Tariff, as filed, without suspension or hearing, with an effective date of January 1, 2026.

Respectfully submitted,

/s/ Jennifer M. Recht
Jennifer M. Recht
Assistant General Counsel – Corporate
ISO New England Inc.

Enclosures

EXHIBIT 1

SECTION IV.A
RECOVERY OF ISO ADMINISTRATIVE EXPENSES

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IV.A.1 Definitions:

Whenever used in this Section IV.A, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I.

IV.A.2 Purpose of Section IV.A; Adjustments to Rates

IV.A.2.1 Purpose of Section IV.A

Section IV.A of the Tariff is the means by which the ISO collects the revenues necessary to carry out its administrative functions in each calendar year, and contains rates, charges, terms and conditions for the following Services, which together encompass the functions carried out by the ISO:

(1) Scheduling, System Control and Dispatch Service (Schedule 1 hereto);

(2) Energy Administration Service (Schedule 2 hereto); and

(3) Reliability Administration Service (Schedule 3 hereto).

The rates and charges for each Service during a calendar year are based on the allocated portion of that year's Revenue Requirement. "Revenue Requirement" refers to the budgeted total expense for the year as adjusted by true-ups described herein.

IV.A.2.2 True-Ups

(1) Schedule 2 True-Up

(i) Each year (Year X), in determining the ISO's Revenue Requirement for the subsequent year (Year X+1), the ISO will make a true-up of the Schedule 2 portion of the Revenue Requirement for the prior year (Year X-1). Any difference between the actual Year X-1 Schedule 2 revenues and amounts budgeted for Schedule 2 revenues in the Year X-1 Revenue Requirement will be reflected in the projected Schedule 2 rates for Year X+1 as stated in paragraph (ii) below.

(ii) In implementing the true-up adjustment for revenue differences in the volumetric portion of Schedule 2, the differences will be added to (in the case of a revenue shortfall) or subtracted from (in the case of a revenue over-recovery) the ISO's total estimated budgeted amounts for

Schedule 2 for Year X+1. For revenue over-recoveries attributable to the TUs in Schedule 2, the ISO will treat them in the same manner as revenue adjustments for the volumetric portion of Schedule 2. For revenue shortfalls attributable to the TUs in Schedule 2, the ISO will allocate them according to the following method:

(a) 50% of the shortfall will be added to the ISO's projected Revenue Requirement for the Schedule 2 volumetric component (85% of the projected Schedule 2 Revenue Requirement prior to true-ups).

(b) An additional percentage of the shortfall will be added to the ISO's projected Revenue Requirement for the Schedule 2 volumetric component for each percentage decrease which was deemed to have occurred between the number of TUs used in the true-up and the number of TUs that the ISO had used in the original projection of the rates for that year.

(c) The maximum percentage of the shortfall to be added to the Schedule 2 volumetric component is 100%, which would result if the percentage difference between the actual and forecasted TUs were 50% or greater.

(d) Any remaining shortfall revenues after allocation of the shortfall to the Schedule 2 volumetric component will be added to the ISO's projected Revenue Requirement for the Schedule 2 TU component (15% of the projected Schedule 2 Revenue Requirements prior to true-ups).

(iii) True-Ups Collected in Future Rates. To the extent the ISO proposes to change its rate design for Section IV.A, the ISO will continue to implement the true-up procedures stated in this section to recover under- or over-collections of TUs for then-current and prior years. For example, when, on a going-forward basis effective January 1, 2012, the ISO eliminated the inclusion of an estimated true-up for the current year (Year X) in the Revenue Requirement for the subsequent year (Year X+1), the ISO was still required to include in the Revenue Requirement for 2013 the difference between the estimated 2011 true-up filed with the 2012 Revenue Requirement and the final 2011 true-up calculated based on historical data.

(2) General True-Up

Each year (Year X), in determining its Revenue Requirement for Year X+1, the ISO will include in such Revenue Requirement a true-up of Year X-1's Revenue Requirement for Schedules 1, 3 and 5. Specifically, the Revenue Requirement for Year X+1 will include deviations between collections under this Section IV.A and the ISO's actual expenses for Year X-1. For example, when filing the Revenue Requirement for 2014, the ISO will compute the total actual expenses for Schedules 1, 3 and 5 in 2012 and will compare these totals with the total charges actually collected under the Tariff for each of these Schedules during calendar year 2012. Based on these comparisons, the ISO will adjust the otherwise-projected Revenue Requirement for calendar year 2014 for one or more of Schedules 1, 3 and 5, as needed, downward or upward to reflect the actual calendar year 2012 surplus or deficit, respectively. From these figures the ISO will calculate rates for calendar year 2014, and make a rate change filing for calendar year 2014 and succeeding years, as required, to reflect the budget amount for the applicable calendar year and the true-up calculated by means of the foregoing analysis and adjustments. Notwithstanding the foregoing, for any instance of special purpose funding, in which funds are allocated and not to be used for any other purpose, the ISO may maintain any surplus amounts in a segregated ledger account to be applied in a future year for such specific purpose without application of the true-up mechanism described above until such time as the special purpose needs are completed, at which time the ISO will include any remaining funds in the Revenue Requirement adjustment being made pursuant to this Section (2).

(3) Indemnification

The Revenue Requirement does not reflect any amounts received by the ISO due to indemnification payments.

IV.A.3 Billing and Payment

IV.A.3.1 Billing Procedure:

With respect to charges under this Section IV.A., the ISO will apply the ISO Billing Policy as set forth in Exhibit ID to Section I of the Tariff.

IV.A.3.2 Working Capital Advances:

In the event that working capital financing arranged by the ISO is terminated early or repayment is accelerated (and no replacement funding has been obtained by the ISO) and Early Amortization Working

Capital Charges have been assessed to Market Participants by the ISO, each month, each Market Participant shall be required to advance to the ISO an amount (each, an "Advance") equal to the ISO's reasonable projection of such Market Participant's charges under the Tariff for three succeeding months. The Advances shall be held in an interest bearing account. In each succeeding month, the ISO shall adjust each Market Participant's Advance so that, in each calendar month, each Market Participant's Advance is equal to the ISO's reasonable projection of such Market Participant's charges under Section IV.A of the Tariff for such month and the next two succeeding months. If, in the reasonable judgment of the ISO, a cash deficiency is likely to occur at any time as a result of a depletion of the Advances (but not as a result of the failure of any Market Participant to pay its Advance), the ISO shall, at its option, have the right to require each Market Participant to pay the ISO its pro rata share (based on such Market Participant's projected charges under Section IV.A of the Tariff for the instant month and the next two succeeding months compared to projected charges to all Market Participants under Section IV.A of the Tariff for the instant month and the next two succeeding months) of any additional Advances required for the ISO's operations. If any Market Participant withdraws from the ISO or has its membership terminated, its Advance will be returned to it at the end of the month in which its withdrawal or termination is effective, provided that all of the departing Market Participant's liabilities under the Tariff have been satisfied, and all of the other Market Participants will have their Advances adjusted accordingly.

IV.A.4 Regulatory Filings

Nothing contained in the Tariff or any Service Agreement thereunder shall be construed as affecting in any way the right of the ISO to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation.
Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Customer receiving a Service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

IV.A.5 Creditworthiness

For purposes of Section IV.A of the Tariff, the ISO will apply the ISO New England Financial Assurance Policy attached to Section I of the Tariff. Each Customer shall comply with the requirements of this policy, as applicable.

IV.A.6 Direct Billing; Sanctions

IV.A.6.1 Transmission Studies:

The ISO will conduct and coordinate certain System Impact Studies and Facilities Studies pursuant to, and in accordance with, the Tariff. The costs of System Impact Studies and Facilities Studies will be charged directly to the pertinent Eligible Customers or interconnection applicants. The ISO will also conduct studies as part of the Forward Capacity Market qualification process and will charge those costs directly through Qualification Process Cost Reimbursement Deposits.

IV.A.6.2 Information Requests:

In fulfilling information requests of a significant and non-routine nature, the ISO will charge its associated direct and indirect costs to the requestor. Revenue from these charges will be credited to Revenue Requirements for the Service to which the information request is most closely related.

IV.A.6.3 Non-Standard Provisions:

If there is a significant direct or indirect cost associated with the ISO's implementation of non-standard provisions for energy or other products in a bilateral contract, the ISO will charge those costs to the contract submitter. Revenue from these charges will be credited to Revenue Requirements for the Service to which the submitted contract is most closely related.

IV.A.6.4 Non-Standard Billing Service:

Market Participants and other Customers who require non-standard billing payment arrangements, pursuant to the terms of the ISO New England Financial Assurance Policy shall be charged the ISO's associated direct and indirect costs for these arrangements. Fees collected will be credited to Revenue Requirements for all three Services, in proportion to the relative Revenue Requirements for those Services.

IV.A.6.5 [Reserved for Future Use]

IV.A.6.6 Re-billing Requests:

In fulfilling re-billing requests of a significant and non-routine nature as a result of data revisions not being received in a timely fashion from a Customer, the ISO will charge its associated direct and indirect costs to that Customer. Revenue from these charges will be credited to Revenue Requirements for the Service to which the information request is most closely related.

IV.A.7 Metering

IV.A.7.1 Customer Obligations:

The Customer shall be responsible for compliance with metering requirements under the Tariff and the ISO New England Operating Documents and to communicate the metering information to the ISO.

IV.A.7.2 RTO Access to Metering Data:

The ISO will have access to such metering data as may reasonably be required to facilitate measurements and billing under the ISO New England Operating Documents, the Tariff or any Service Agreement thereunder.

IV.A.8 Collection of Commission Annual Charges:

The ISO's collection of amounts necessary to pay annual charges to the Commission is addressed in Schedule 4 hereof.

Schedule 1

Scheduling, System Control and Dispatch Service

Scheduling, System Control and Dispatch Service ("Scheduling Service") is the service required to schedule at the regional level the movement of power through, out of, within, or into the New England Control Area. For regional transmission service under the Tariff, Scheduling Service is an Ancillary Service that can be provided only by the ISO. All Transmission Customers must be Customers for Scheduling Service under this Tariff and purchase this Service from the ISO. The ISO's charges stated herein for Scheduling Service are based on the expenses incurred by the ISO in providing this Service. In addition, the ISO acts as a billing agent for the operators of the Local Control Centers and certain Market Participants in order to collect expenses incurred in providing this Service pursuant to this Schedule 1.

The ISO's expenses are based on the functions and activities required to provide this Service and include, but are not limited to:

- Processing and implementation of requests for regional transmission service, including support of the OASIS node;
- Coordination of transmission system operation (including administration of reactive power requirements under Schedule 2 of Section II of the Tariff) and implementation of necessary control actions by the ISO and support for these functions;
- Billing associated with regional transmission services provided under the Tariff;
- Transmission system planning which supports this Service; and
- Administrative costs associated with the aforementioned functions.

For the ISO's expenses in providing transmission-related Scheduling Service:

(A) each Customer that is obligated to pay the Regional Network Service rate shall pay each month, in arrears, an amount equal to the product of $0.29382 per kilowatt month times its Monthly Regional Network Load for that month.

(B) each Customer that is a Transmission Customer receiving Through or Out Service shall pay each month, in arrears, an amount equal to the product of the Transmission Customer's highest amount of Reserved Capacity (expressed in kilowatts) for an hour for each transaction, other than a Coordinated

External Transaction, that is scheduled to occur during the month as Through or Out Service multiplied by $0.00040 per kilowatt for each hour of service.

Schedule 1 revenues collected from Through or Out Service customers shall be credited to each Network Customer receiving Regional Network Service that month in proportion to each Network Customer's Monthly Regional Network Load in that month.

Non-Market Participant FTR fees and any portions of Long Lead Facility deposits collected by the ISO under Schedule 22 and Schedule 25 of Section II of the Tariff that become non-refundable will be credited to Schedule 1 Revenue Requirements and will be included in the Schedule 1 true-up calculations.

All general terms and conditions of the Tariff apply to this Service.

Schedule 2

Energy Administration Service

Energy Administration Service ("EAS") is the Service provided by the ISO to administer the Energy Market.

The ISO's expenses are based on the functions required to provide EAS and include, but are not limited to:

- Core operation of the Energy Market;
- Generation and demand dispatch related to the Energy Market;
- Energy accounting;
- Loss determination and allocation;
- Billing preparation;
- Market power monitoring and mitigation for the Energy Market;
- Sanctions activities;
- Operation of FTR auctions;
- Market assessment and reports; and
- Formulation of additional market rules and proposals to modify existing rules.

Each Market Participant that has an account for Energy that is settled by the ISO for the current month shall pay each month an amount based on Energy Transaction Units (Energy TUs), Increment Offers, Decrement Bids, Volumetric Measures, submitted FTR auction bids, and cleared FTR auction bids.

Energy TU Based Charges: For purposes of this Schedule 2, Energy TUs shall be calculated without reference to contributions from Coordinated External Transactions. Each Customer that has, during a month, incurred Energy TUs exceeding zero shall pay an amount, in arrears, equal to the sum of the products of:

(1) $0.86039 times the Customer's first 12,500 Energy TUs for that month; plus

(2) $0.78217 times the amount of Energy TUs that exceed 12,500 but are less than or equal to 39,500; plus

(3) $0.70396 times the amount of Energy TUs that exceed 39,500.

Charges Based on Increment Offers and Decrement Bids: Each Customer submitting Increment Offers and/or Decrement Bids shall pay, in arrears, amounts equal to:

(1) $0.00500 times the number of Increment Offers and Decrement Bids submitted by the Customer for that month; plus

(2) $0.06000 times the number of Increment Offers and Decrement Bids submitted by the Customer for that month that clear in the Day-Ahead Energy Market.

Volumetric Measure Based Charges: A Customer shall be considered an EAS VM Customer if the sum of Monthly Real-Time Load Obligation, Monthly Real-Time Generation Obligation, and Monthly Real-Time Demand Reduction Obligation (measured in megawatthours, MWh and excluding Coordinated External Transactions) assessed to that Customer during the month exceeds zero (0), in which case, the total EAS VM charges for that Customer shall be equal to the sum of:

(1) Monthly Real-Time Load Obligation (MWh), excluding Monthly Real-Time Load Obligation associated with Coordinated External Transactions;

(2) Monthly Real-Time Generation Obligation (MWh); provided, however, that Monthly Real-Time Generation Obligation associated with energy imported into the New England Control Area by Bangor Hydro-Electric Company across the New Brunswick ties shall be excluded (up to 300 MW) for billing and rate calculation purposes from EAS VMs, and provided further that Monthly Real-Time Generation Obligation associated with Coordinated External Transactions shall be excluded; and

(3) Monthly Real-Time Demand Reduction Obligation (MWh).

Subject to the foregoing, each Market Participant that is identified as an EAS VM Customer for that month shall pay an amount, in arrears, based on total EAS VM, equal to:

(a) $0.58201 per MWh for the first 250,000 MWh of EAS VM for that month; plus

(b) $0.52910 per MWh for each VM that exceeds 250,000 EAS VM but is less than or equal to 1,500,000 MWh for that month; plus

(c) $0.47619 per MWh for each EAS VM in excess of 1,500,000 MWh for that month.

Charges Based on Submitted and Cleared FTR Bids: Each Customer submitting FTR auction bids shall pay, in arrears, amounts equal to:

(1) $3.87023 times the number of bids submitted by the Customer into any FTR auctions held for that month; plus

(2) $3.87023 times the number of bids submitted by the Customer into any annual or multi-month FTR auctions (billed with the invoice for the first month of the annual or multi-month FTR auction); plus

(3) $6.17635 times the number of bids submitted by the Customer during that month that clear any FTR auctions held for that month; plus

(4) $6.17635 times the number of bids submitted by the Customer that clear any annual or multi-month FTR auctions (billed with the invoice for the first month of the annual or multi-month FTR auction).

Schedule 3

Reliability Administration Service

Reliability Administration Service ("RAS") is the Service provided by the ISO to administer the Reliability Markets (and facilitate reliability-associated transactions and arrangements) in accordance with the Tariff and the corresponding rules promulgated thereunder, and to provide other reliability and informational services. The Reliability Markets are also a means by which certain Ancillary Services are obtained under Section II of the Tariff. Each Customer must enter into a Service Agreement.

The ISO's administrative expenses are based on the functions required to provide this Service and include, but are not limited to:

- Generation and demand dispatch associated with Reliability Markets;
- Reliability Markets accounting;
- Billing preparation;
- The ISO generation emissions analysis;
- Risk profile updates;
- Triennial review of resource adequacy;
- Studies and qualification of resources under Forward Capacity Market;
- Preparation of regional reports and load forecasts and profiles (Capacity, Energy, Load and Transmission reports; reports to the Energy Information Administration (EIA) of the United States Department of Energy; reports to the North American Electric Reliability Corporation; Regional System Plan);
- Support of power supply, environmental and market reliability planning activities;
- Market power monitoring, mitigation and assessment for the Reliability Markets;
- Formulation of additional market rules and proposals to modify existing rules.

(A) Each Transmission Customer taking Through or Out Service that is not a Market Participant shall be considered a RAS Customer and shall pay each month, in arrears, a RAS fee equal to the product of $5.39 times the number of hourly Through or Out reservations made for that month.

(B) Each Customer that is a Market Participant shall be considered a RAS Customer and shall pay each month, in arrears, an amount equal to the product of $0.36072 per kilowatt month times the Market Participant's Real-Time NCP Load Obligation (measured in kilowatts) for that month.

(C) For Exports other than Coordinated External Transactions, each RAS Customer shall pay each month, in arrears, an amount equal to $0.80000 per MWh per Export, where MWh represents the hourly scheduled MWs of associated Export.

In order to preserve the settlement approved in Docket No. ER01-316, Market Participants engaging in "through" transactions using Through or Out Service will not be deemed to have a Real-Time Load Obligation on account of those transactions.

Charges collected under Schedule 3 for RAS do not include any amounts paid by the ISO on behalf of the Market Participants to purchase emergency power.

Charges collected under Schedule 3 for RAS do not include the recovery of costs associated with disclosure or tracking obligations. If one or more states require Market Participants to undertake such activity the ISO will separately charge the expenses associated with such obligations.

All general terms and conditions of the Tariff apply to this Service.

Schedule 4

Collection of Commission Annual Charges

Each Transmission Owner that is jurisdictional to the Commission shall provide to the ISO under oath, sixty days in advance of the due date for the Commission's Reporting Requirement No. 582 ("FERC-582"), data for the pertinent period concerning the Transmission Owner's megawatt-hours of all unbundled transmission (including MWh delivered in wheeling transactions and MWh delivered in exchange transactions) and the Transmission Owner's megawatt-hours of all bundled wholesale power sales (to the extent these latter MWh were not separately reported as unbundled transmission) for the pertinent period, in the level of detail required by Commission regulations and necessary for the ISO to make and support a FERC-582 report by the ISO for the New England Control Area. These amounts are reported on the Commission's Form 1 in connection with accounts 447, 456, and 555.

Upon the ISO's receipt of the Commission's bill for the annual charges for the New England Control Area, the ISO will promptly calculate the allocable portion of that annual charge payable by each Transmission Owner. To determine the amount payable by each Transmission Owner for the annual charge for the then-current Commission fiscal year, the ISO will divide each Transmission Owner's total reported megawatt-hours of transmission of electric energy in interstate commerce by the total megawatt-hours of transmission of electric energy in interstate commerce reported for the prior calendar year by the ISO in FERC-582 for the New England Control Area, and multiply the resulting figure by the Commission's annual charge to the New England Control Area for the then-current Commission fiscal year. The allocation among Transmission Owners of any adjustments for the prior Commission fiscal year reflected in the current-year Commission bill will be calculated by multiplying (x) each Transmission Owner's adjusted sales (i.e., megawatt-hours of transmission of electric energy in interstate commerce) for the calendar year on which that prior Commission fiscal year's annual charges were based by (y) the final Commission charge factor for that prior fiscal year, as indicated in the Commission bill. This amount will be compared with the amount originally paid by the corresponding Transmission Owner for the prior fiscal year and any difference (positive or negative) will be an adjustment to the payment required from that Transmission Owner for current-year Commission annual charges. The ISO will promptly notify each Transmission Owner of the required payment, and each Transmission Owner shall pay to the ISO, within fifteen (15) days of the Transmission Owner's receipt of the notice, the amount specified in the notice.

Each Transmission Owner will provide the ISO with assistance reasonably required in responding to information requests and audits by the Commission in connection with the Form 582 Reporting Requirement and payment of annual charges.

Schedule 5

Collection of NESCOE Budget

The ISO acts as the billing and collection agent for the New England States Committee on Electricity (NESCOE) for recovery of amounts reflected in the annual NESCOE budget through the rates set forth below. Each year, NESCOE will develop an annual budget, including supporting documentation and justification and a collection schedule, and present it to the ISO in final form no later than October 20 for the following calendar year, following the budget review process set forth in understandings among NESCOE, the ISO, and NEPOOL, which process is anticipated to begin in June each year. NESCOE shall not exceed its budget in any given calendar year. The "General True-Up Provision" in Section IV.A.2.2.(2) of this Tariff shall apply to this Schedule 5.

The ISO will calculate the Schedule 5 rate based on the rate design specified below. The ISO will submit the NESCOE-provided materials and any revised tariff sheets to the Commission separately but contemporaneously with the ISO's annual filing of rates to recover ISO's other administrative expenses.

For the calendar year 2025, the six New England states shall bear NESCOE's budgeted costs as follows. Each Customer that is obligated to pay the Regional Network Service rate shall pay each month, in arrears, an amount equal to the product of $0.00716 per kilowatt times its Monthly Regional Network Load for that month.

EXHIBIT 2

SECTION IV.A
RECOVERY OF ISO ADMINISTRATIVE EXPENSES

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Schedule 2 Energy Administration Service

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Schedule 4 Collection of Commission Annual Charges

Schedule 5 Collection of NESCOE Budget

IV.A.1 Definitions:

Whenever used in this Section IV.A, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I.

IV.A.2 Purpose of Section IV.A; Adjustments to Rates

IV.A.2.1 Purpose of Section IV.A

Section IV.A of the Tariff is the means by which the ISO collects the revenues necessary to carry out its administrative functions in each calendar year, and contains rates, charges, terms and conditions for the following Services, which together encompass the functions carried out by the ISO:

(1) Scheduling, System Control and Dispatch Service (Schedule 1 hereto);

(2) Energy Administration Service (Schedule 2 hereto); and

(3) Reliability Administration Service (Schedule 3 hereto).

The rates and charges for each Service during a calendar year are based on the allocated portion of that year's Revenue Requirement. "Revenue Requirement" refers to the budgeted total expense for the year as adjusted by true-ups described herein.

IV.A.2.2 True-Ups

(1) Schedule 2 True-Up

(i) Each year (Year X), in determining the ISO's Revenue Requirement for the subsequent year (Year X+1), the ISO will make a true-up of the Schedule 2 portion of the Revenue Requirement for the prior year (Year X-1). Any difference between the actual Year X-1 Schedule 2 revenues and amounts budgeted for Schedule 2 revenues in the Year X-1 Revenue Requirement will be reflected in the projected Schedule 2 rates for Year X+1 as stated in paragraph (ii) below.

(ii) In implementing the true-up adjustment for revenue differences in the volumetric portion of Schedule 2, the differences will be added to (in the case of a revenue shortfall) or subtracted from (in the case of a revenue over-recovery) the ISO's total estimated budgeted amounts for

Schedule 2 for Year X+1. For revenue over-recoveries attributable to the TUs in Schedule 2, the ISO will treat them in the same manner as revenue adjustments for the volumetric portion of Schedule 2. For revenue shortfalls attributable to the TUs in Schedule 2, the ISO will allocate them according to the following method:

(a) 50% of the shortfall will be added to the ISO's projected Revenue Requirement for the Schedule 2 volumetric component (85% of the projected Schedule 2 Revenue Requirement prior to true-ups).

(b) An additional percentage of the shortfall will be added to the ISO's projected Revenue Requirement for the Schedule 2 volumetric component for each percentage decrease which was deemed to have occurred between the number of TUs used in the true-up and the number of TUs that the ISO had used in the original projection of the rates for that year.

(c) The maximum percentage of the shortfall to be added to the Schedule 2 volumetric component is 100%, which would result if the percentage difference between the actual and forecasted TUs were 50% or greater.

(d) Any remaining shortfall revenues after allocation of the shortfall to the Schedule 2 volumetric component will be added to the ISO's projected Revenue Requirement for the Schedule 2 TU component (15% of the projected Schedule 2 Revenue Requirements prior to true-ups).

(iii) True-Ups Collected in Future Rates. To the extent the ISO proposes to change its rate design for Section IV.A, the ISO will continue to implement the true-up procedures stated in this section to recover under- or over-collections of TUs for then-current and prior years. For example, when, on a going-forward basis effective January 1, 2012, the ISO eliminated the inclusion of an estimated true-up for the current year (Year X) in the Revenue Requirement for the subsequent year (Year X+1), the ISO was still required to include in the Revenue Requirement for 2013 the difference between the estimated 2011 true-up filed with the 2012 Revenue Requirement and the final 2011 true-up calculated based on historical data.

(2) General True-Up

Each year (Year X), in determining its Revenue Requirement for Year X+1, the ISO will include in such Revenue Requirement a true-up of Year X-1's Revenue Requirement for Schedules 1, 3 and 5. Specifically, the Revenue Requirement for Year X+1 will include deviations between collections under this Section IV.A and the ISO's actual expenses for Year X-1. For example, when filing the Revenue Requirement for 2014, the ISO will compute the total actual expenses for Schedules 1, 3 and 5 in 2012 and will compare these totals with the total charges actually collected under the Tariff for each of these Schedules during calendar year 2012. Based on these comparisons, the ISO will adjust the otherwise-projected Revenue Requirement for calendar year 2014 for one or more of Schedules 1, 3 and 5, as needed, downward or upward to reflect the actual calendar year 2012 surplus or deficit, respectively. From these figures the ISO will calculate rates for calendar year 2014, and make a rate change filing for calendar year 2014 and succeeding years, as required, to reflect the budget amount for the applicable calendar year and the true-up calculated by means of the foregoing analysis and adjustments. Notwithstanding the foregoing, for any instance of special purpose funding, in which funds are allocated and not to be used for any other purpose, the ISO may maintain any surplus amounts in a segregated ledger account to be applied in a future year for such specific purpose without application of the true-up mechanism described above until such time as the special purpose needs are completed, at which time the ISO will include any remaining funds in the Revenue Requirement adjustment being made pursuant to this Section (2).

(3) Indemnification

The Revenue Requirement does not reflect any amounts received by the ISO due to indemnification payments.

IV.A.3 Billing and Payment

IV.A.3.1 Billing Procedure:

With respect to charges under this Section IV.A., the ISO will apply the ISO Billing Policy as set forth in Exhibit ID to Section I of the Tariff.

IV.A.3.2 Working Capital Advances:

In the event that working capital financing arranged by the ISO is terminated early or repayment is accelerated (and no replacement funding has been obtained by the ISO) and Early Amortization Working

Capital Charges have been assessed to Market Participants by the ISO, each month, each Market Participant shall be required to advance to the ISO an amount (each, an "Advance") equal to the ISO's reasonable projection of such Market Participant's charges under the Tariff for three succeeding months. The Advances shall be held in an interest bearing account. In each succeeding month, the ISO shall adjust each Market Participant's Advance so that, in each calendar month, each Market Participant's Advance is equal to the ISO's reasonable projection of such Market Participant's charges under Section IV.A of the Tariff for such month and the next two succeeding months. If, in the reasonable judgment of the ISO, a cash deficiency is likely to occur at any time as a result of a depletion of the Advances (but not as a result of the failure of any Market Participant to pay its Advance), the ISO shall, at its option, have the right to require each Market Participant to pay the ISO its pro rata share (based on such Market Participant's projected charges under Section IV.A of the Tariff for the instant month and the next two succeeding months compared to projected charges to all Market Participants under Section IV.A of the Tariff for the instant month and the next two succeeding months) of any additional Advances required for the ISO's operations. If any Market Participant withdraws from the ISO or has its membership terminated, its Advance will be returned to it at the end of the month in which its withdrawal or termination is effective, provided that all of the departing Market Participant's liabilities under the Tariff have been satisfied, and all of the other Market Participants will have their Advances adjusted accordingly.

IV.A.4 Regulatory Filings

Nothing contained in the Tariff or any Service Agreement thereunder shall be construed as affecting in any way the right of the ISO to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation.
Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Customer receiving a Service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

IV.A.5 Creditworthiness

For purposes of Section IV.A of the Tariff, the ISO will apply the ISO New England Financial Assurance Policy attached to Section I of the Tariff. Each Customer shall comply with the requirements of this policy, as applicable.

IV.A.6 Direct Billing; Sanctions

IV.A.6.1 Transmission Studies:

The ISO will conduct and coordinate certain System Impact Studies and Facilities Studies pursuant to, and in accordance with, the Tariff. The costs of System Impact Studies and Facilities Studies will be charged directly to the pertinent Eligible Customers or interconnection applicants. The ISO will also conduct studies as part of the Forward Capacity Market qualification process and will charge those costs directly through Qualification Process Cost Reimbursement Deposits.

IV.A.6.2 Information Requests:

In fulfilling information requests of a significant and non-routine nature, the ISO will charge its associated direct and indirect costs to the requestor. Revenue from these charges will be credited to Revenue Requirements for the Service to which the information request is most closely related.

IV.A.6.3 Non-Standard Provisions:

If there is a significant direct or indirect cost associated with the ISO's implementation of non-standard provisions for energy or other products in a bilateral contract, the ISO will charge those costs to the contract submitter. Revenue from these charges will be credited to Revenue Requirements for the Service to which the submitted contract is most closely related.

IV.A.6.4 Non-Standard Billing Service:

Market Participants and other Customers who require non-standard billing payment arrangements, pursuant to the terms of the ISO New England Financial Assurance Policy shall be charged the ISO's associated direct and indirect costs for these arrangements. Fees collected will be credited to Revenue Requirements for all three Services, in proportion to the relative Revenue Requirements for those Services.

IV.A.6.5 [Reserved for Future Use]

IV.A.6.6 Re-billing Requests:

In fulfilling re-billing requests of a significant and non-routine nature as a result of data revisions not being received in a timely fashion from a Customer, the ISO will charge its associated direct and indirect costs to that Customer. Revenue from these charges will be credited to Revenue Requirements for the Service to which the information request is most closely related.

IV.A.7 Metering

IV.A.7.1 Customer Obligations:

The Customer shall be responsible for compliance with metering requirements under the Tariff and the ISO New England Operating Documents and to communicate the metering information to the ISO.

IV.A.7.2 RTO Access to Metering Data:

The ISO will have access to such metering data as may reasonably be required to facilitate measurements and billing under the ISO New England Operating Documents, the Tariff or any Service Agreement thereunder.

IV.A.8 Collection of Commission Annual Charges:

The ISO's collection of amounts necessary to pay annual charges to the Commission is addressed in Schedule 4 hereof.

Schedule 1

Scheduling, System Control and Dispatch Service

Scheduling, System Control and Dispatch Service ("Scheduling Service") is the service required to schedule at the regional level the movement of power through, out of, within, or into the New England Control Area. For regional transmission service under the Tariff, Scheduling Service is an Ancillary Service that can be provided only by the ISO. All Transmission Customers must be Customers for Scheduling Service under this Tariff and purchase this Service from the ISO. The ISO's charges stated herein for Scheduling Service are based on the expenses incurred by the ISO in providing this Service. In addition, the ISO acts as a billing agent for the operators of the Local Control Centers and certain Market Participants in order to collect expenses incurred in providing this Service pursuant to this Schedule 1.

The ISO's expenses are based on the functions and activities required to provide this Service and include, but are not limited to:

- Processing and implementation of requests for regional transmission service, including support of the OASIS node;
- Coordination of transmission system operation (including administration of reactive power requirements under Schedule 2 of Section II of the Tariff) and implementation of necessary control actions by the ISO and support for these functions;
- Billing associated with regional transmission services provided under the Tariff;
- Transmission system planning which supports this Service; and
- Administrative costs associated with the aforementioned functions.

For the ISO's expenses in providing transmission-related Scheduling Service:

(A) each Customer that is obligated to pay the Regional Network Service rate shall pay each month, in arrears, an amount equal to the product of $0.~~29582~~ 29382 per kilowatt month times its Monthly Regional Network Load for that month.

(B) each Customer that is a Transmission Customer receiving Through or Out Service shall pay each month, in arrears, an amount equal to the product of the Transmission Customer's highest amount of Reserved Capacity (expressed in kilowatts) for an hour for each transaction, other than a Coordinated

External Transaction, that is scheduled to occur during the month as Through or Out Service multiplied by $0.~~00041~~ 00040 per kilowatt for each hour of service.

Schedule 1 revenues collected from Through or Out Service customers shall be credited to each Network Customer receiving Regional Network Service that month in proportion to each Network Customer's Monthly Regional Network Load in that month.

Non-Market Participant FTR fees and any portions of Long Lead Facility deposits collected by the ISO under Schedule 22 and Schedule 25 of Section II of the Tariff that become non-refundable will be credited to Schedule 1 Revenue Requirements and will be included in the Schedule 1 true-up calculations.

All general terms and conditions of the Tariff apply to this Service.

Schedule 2

Energy Administration Service

Energy Administration Service ("EAS") is the Service provided by the ISO to administer the Energy Market.

The ISO's expenses are based on the functions required to provide EAS and include, but are not limited to:

- Core operation of the Energy Market;
- Generation and demand dispatch related to the Energy Market;
- Energy accounting;
- Loss determination and allocation;
- Billing preparation;
- Market power monitoring and mitigation for the Energy Market;
- Sanctions activities;
- Operation of FTR auctions;
- Market assessment and reports; and
- Formulation of additional market rules and proposals to modify existing rules.

Each Market Participant that has an account for Energy that is settled by the ISO for the current month shall pay each month an amount based on Energy Transaction Units (Energy TUs), Increment Offers, Decrement Bids, Volumetric Measures, submitted FTR auction bids, and cleared FTR auction bids.

Energy TU Based Charges: For purposes of this Schedule 2, Energy TUs shall be calculated without reference to contributions from Coordinated External Transactions. Each Customer that has, during a month, incurred Energy TUs exceeding zero shall pay an amount, in arrears, equal to the sum of the products of:

(1) $0.~~81457~~ 86039 times the Customer's first 12,500 Energy TUs for that month; plus

(2) $0.~~74051~~ 78217 times the amount of Energy TUs that exceed 12,500 but are less than or equal to 39,500; plus

(3) $0.~~66646~~ 70396 times the amount of Energy TUs that exceed 39,500.

Charges Based on Increment Offers and Decrement Bids: Each Customer submitting Increment Offers and/or Decrement Bids shall pay, in arrears, amounts equal to:

(1) $0.00500 times the number of Increment Offers and Decrement Bids submitted by the Customer for that month; plus

(2) $0.06000 times the number of Increment Offers and Decrement Bids submitted by the Customer for that month that clear in the Day-Ahead Energy Market.

Volumetric Measure Based Charges: A Customer shall be considered an EAS VM Customer if the sum of Monthly Real-Time Load Obligation, Monthly Real-Time Generation Obligation, and Monthly Real-Time Demand Reduction Obligation (measured in megawatthours, MWh and excluding Coordinated External Transactions) assessed to that Customer during the month exceeds zero (0), in which case, the total EAS VM charges for that Customer shall be equal to the sum of:

(1) Monthly Real-Time Load Obligation (MWh), excluding Monthly Real-Time Load Obligation associated with Coordinated External Transactions;

(2) Monthly Real-Time Generation Obligation (MWh); provided, however, that Monthly Real-Time Generation Obligation associated with energy imported into the New England Control Area by Bangor Hydro-Electric Company across the New Brunswick ties shall be excluded (up to 300 MW) for billing and rate calculation purposes from EAS VMs, and provided further that Monthly Real-Time Generation Obligation associated with Coordinated External Transactions shall be excluded; and

(3) Monthly Real-Time Demand Reduction Obligation (MWh).

Subject to the foregoing, each Market Participant that is identified as an EAS VM Customer for that month shall pay an amount, in arrears, based on total EAS VM, equal to:

(a) $0.~~56227~~ 58201 per MWh for the first 250,000 MWh of EAS VM for that month; plus

(b) $0.~~51116~~ 52910 per MWh for each VM that exceeds 250,000 EAS VM but is less than or equal to 1,500,000 MWh for that month; plus

(c) $0.~~46004~~ 47619 per MWh for each EAS VM in excess of 1,500,000 MWh for that month.

Charges Based on Submitted and Cleared FTR Bids: Each Customer submitting FTR auction bids shall pay, in arrears, amounts equal to:

(1) $3.~~26750~~ 87023 times the number of bids submitted by the Customer into any FTR auctions held for that month; plus

(2) $3.~~26750~~ 87023 times the number of bids submitted by the Customer into any annual or multi-month FTR auctions (billed with the invoice for the first month of the annual or multi-month FTR auction); plus

(3) $~~5.323836~~.17635 times the number of bids submitted by the Customer during that month that clear any FTR auctions held for that month; plus

(4) $~~5.323836~~.17635 times the number of bids submitted by the Customer that clear any annual or multi-month FTR auctions (billed with the invoice for the first month of the annual or multi-month FTR auction).

Schedule 3

Reliability Administration Service

Reliability Administration Service ("RAS") is the Service provided by the ISO to administer the Reliability Markets (and facilitate reliability-associated transactions and arrangements) in accordance with the Tariff and the corresponding rules promulgated thereunder, and to provide other reliability and informational services. The Reliability Markets are also a means by which certain Ancillary Services are obtained under Section II of the Tariff. Each Customer must enter into a Service Agreement.

The ISO's administrative expenses are based on the functions required to provide this Service and include, but are not limited to:

- Generation and demand dispatch associated with Reliability Markets;
- Reliability Markets accounting;
- Billing preparation;
- The ISO generation emissions analysis;
- Risk profile updates;
- Triennial review of resource adequacy;
- Studies and qualification of resources under Forward Capacity Market;
- Preparation of regional reports and load forecasts and profiles (Capacity, Energy, Load and Transmission reports; reports to the Energy Information Administration (EIA) of the United States Department of Energy; reports to the North American Electric Reliability Corporation; Regional System Plan);
- Support of power supply, environmental and market reliability planning activities;
- Market power monitoring, mitigation and assessment for the Reliability Markets;
- Formulation of additional market rules and proposals to modify existing rules.

(A) Each Transmission Customer taking Through or Out Service that is not a Market Participant shall be considered a RAS Customer and shall pay each month, in arrears, a RAS fee equal to the product of $5.~~58~~ 39 times the number of hourly Through or Out reservations made for that month.

(B) Each Customer that is a Market Participant shall be considered a RAS Customer and shall pay each month, in arrears, an amount equal to the product of $0.~~37690~~ 36072 per kilowatt month times the Market Participant's Real-Time NCP Load Obligation (measured in kilowatts) for that month.

(C) For Exports other than Coordinated External Transactions, each RAS Customer shall pay each month, in arrears, an amount equal to $0.~~82000~~ 80000 per MWh per Export, where MWh represents the hourly scheduled MWs of associated Export.

In order to preserve the settlement approved in Docket No. ER01-316, Market Participants engaging in "through" transactions using Through or Out Service will not be deemed to have a Real-Time Load Obligation on account of those transactions.

Charges collected under Schedule 3 for RAS do not include any amounts paid by the ISO on behalf of the Market Participants to purchase emergency power.

Charges collected under Schedule 3 for RAS do not include the recovery of costs associated with disclosure or tracking obligations. If one or more states require Market Participants to undertake such activity the ISO will separately charge the expenses associated with such obligations.

All general terms and conditions of the Tariff apply to this Service.

Schedule 4

Collection of Commission Annual Charges

Each Transmission Owner that is jurisdictional to the Commission shall provide to the ISO under oath, sixty days in advance of the due date for the Commission's Reporting Requirement No. 582 ("FERC-582"), data for the pertinent period concerning the Transmission Owner's megawatt-hours of all unbundled transmission (including MWh delivered in wheeling transactions and MWh delivered in exchange transactions) and the Transmission Owner's megawatt-hours of all bundled wholesale power sales (to the extent these latter MWh were not separately reported as unbundled transmission) for the pertinent period, in the level of detail required by Commission regulations and necessary for the ISO to make and support a FERC-582 report by the ISO for the New England Control Area. These amounts are reported on the Commission's Form 1 in connection with accounts 447, 456, and 555.

Upon the ISO's receipt of the Commission's bill for the annual charges for the New England Control Area, the ISO will promptly calculate the allocable portion of that annual charge payable by each Transmission Owner. To determine the amount payable by each Transmission Owner for the annual charge for the then-current Commission fiscal year, the ISO will divide each Transmission Owner's total reported megawatt-hours of transmission of electric energy in interstate commerce by the total megawatt-hours of transmission of electric energy in interstate commerce reported for the prior calendar year by the ISO in FERC-582 for the New England Control Area, and multiply the resulting figure by the Commission's annual charge to the New England Control Area for the then-current Commission fiscal year. The allocation among Transmission Owners of any adjustments for the prior Commission fiscal year reflected in the current-year Commission bill will be calculated by multiplying (x) each Transmission Owner's adjusted sales (i.e., megawatt-hours of transmission of electric energy in interstate commerce) for the calendar year on which that prior Commission fiscal year's annual charges were based by (y) the final Commission charge factor for that prior fiscal year, as indicated in the Commission bill. This amount will be compared with the amount originally paid by the corresponding Transmission Owner for the prior fiscal year and any difference (positive or negative) will be an adjustment to the payment required from that Transmission Owner for current-year Commission annual charges. The ISO will promptly notify each Transmission Owner of the required payment, and each Transmission Owner shall pay to the ISO, within fifteen (15) days of the Transmission Owner's receipt of the notice, the amount specified in the notice.

Each Transmission Owner will provide the ISO with assistance reasonably required in responding to information requests and audits by the Commission in connection with the Form 582 Reporting Requirement and payment of annual charges.

Schedule 5

Collection of NESCOE Budget

The ISO acts as the billing and collection agent for the New England States Committee on Electricity (NESCOE) for recovery of amounts reflected in the annual NESCOE budget through the rates set forth below. Each year, NESCOE will develop an annual budget, including supporting documentation and justification and a collection schedule, and present it to the ISO in final form no later than October 20 for the following calendar year, following the budget review process set forth in understandings among NESCOE, the ISO, and NEPOOL, which process is anticipated to begin in June each year. NESCOE shall not exceed its budget in any given calendar year. The "General True-Up Provision" in Section IV.A.2.2.(2) of this Tariff shall apply to this Schedule 5.

The ISO will calculate the Schedule 5 rate based on the rate design specified below. The ISO will submit the NESCOE-provided materials and any revised tariff sheets to the Commission separately but contemporaneously with the ISO's annual filing of rates to recover ISO's other administrative expenses.

For the calendar year 2025, the six New England states shall bear NESCOE's budgeted costs as follows. Each Customer that is obligated to pay the Regional Network Service rate shall pay each month, in arrears, an amount equal to the product of $0.00716 per kilowatt times its Monthly Regional Network Load for that month.

EXHIBIT 3

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.	**)**	**Docket No. ER26-_____-000**

DIRECT TESTIMONY

OF

ROBERT C. LUDLOW

Filed on: October 15, 2025

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO NEW ENGLAND INC.) Docket No. ER26-_____-000

Direct Testimony of Robert C. Ludlow

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Robert C. Ludlow. My business address is One Sullivan Road, Holyoke, Massachusetts 01040-2841.

Q. WHAT IS YOUR OCCUPATION?

A. I am a Vice President and the Chief Financial and Compliance Officer of ISO New England Inc. (the "ISO"). I served in the role of Vice President and Chief Financial Officer from the time the ISO commenced its operations on July 1, 1997 until September 2000. At that time, I began working as an outside consultant for the ISO until August 2002, when I rejoined the ISO as Vice President and Chief Financial Officer. In July of 2008 my title changed to reflect my expanded responsibility for compliance. The compliance organization is responsible for developing and maintaining the Company's compliance management system. This system captures the Company's compliance obligations, including those of the North American Electric Reliability Corporation ("NERC"), North American Energy Standards Board, and the Northeast Power Coordinating Council ("NPCC").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I hold a B.B.A. in Accounting from St. Bonaventure University. Prior to joining the ISO, I was a Partner at the accounting firm of Marden, Harrison & Kreuter, CPAs. I also served as the Chief Financial Officer of Western Beef, Inc. I am a Certified Public Accountant.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY COMMISSION?

A. Yes. I previously have testified before the Commission to support prior administrative rate filings by the ISO in Docket Nos. ER25-110-000 (rates proposed for 2025); ER24-90-000 (rates proposed for 2024); ER23-94-000 (rates proposed for 2023); ER22-113-000 (rates proposed for 2022); ER21-106-000 (rates proposed for 2021); ER20-106-000 (rates proposed for 2020); ER19-107-000 (rates proposed for 2019); ER18-77-000 (rates proposed for 2018); ER17-116-000 (rates proposed for 2017); ER16-92-000 (rates proposed for 2016); ER15-112-000 (rates proposed for 2015); ER14-90-000 (rates proposed for 2014); ER13-185-000 (rates proposed for 2013); ER12-191-000 (rates proposed for 2012); ER11-1943-000 (rates proposed for 2011); ER10-154-000 (rates proposed for 2010); and others.

PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am providing this testimony primarily to support the ISO's proposed revenue requirement for 2026 ("2026 Revenue Requirement") and the updated rates to collect it. My Direct Testimony presents the ISO's 2026 Revenue Requirement as reflected in the proposed revised tariff sheets attached as **Exhibits 1 and 2** (clean and blacklined versions, respectively) to the filing letter.

Specifically, I will describe the ISO's budget process, summarize the elements of the ISO's 2026 Revenue Requirement (including the true-up mechanism), present the ISO's 2026 Core Operating Budget (*i.e.*, the administrative costs of running the ISO), and describe the ISO's activity accounting system. I will also present the development of the Test Year 2026 cost of service study associated with the ISO providing service under the three primary rate schedules included in Section IV.A of the ISO's Transmission, Markets, and Services Tariff (the "Tariff").

Section IV.A of the Tariff provides for recovery of the ISO's administrative expenses. The three primary rate schedules are: (1) Schedule 1 – Scheduling, System Control and Dispatch Service ("Scheduling Service"); (2) Schedule 2 – Energy Administration Service; and (3) Schedule 3 – Reliability Administration Service.

Finally, I will present proposed escalation factors to adjust actual load data for the 12-month period ending July 2025 to the Test Year 2026 for the purpose of rate

design, discuss the rate design utilized, and the proposed rates, including certain fixed fees.

In addition to the aforementioned testimony to support the proposed 2026 Revenue Requirement, I will also provide testimony to support the proposed capital budget for 2026 (the "2026 Capital Budget") which is $42.5 million, consistent with the 2025 Capital Budget.

Q. HOW WILL YOUR TESTIMONY BE ORGANIZED?

A. Before offering a conclusion, I will describe:

(i) the current operations and organizational structure of the ISO;

(ii) the budget development process;

(iii) the various elements of the 2026 Revenue Requirement;

(iv) the ISO's activity accounting system;

(v) how the ISO allocated its costs among the rates it proposes to charge in the Tariff's Schedules 1, 2, and 3;

(vi) the 2026 rate design and escalation factors;

(vii) the 2026 billing determinants;

(viii) a rate summary;

(x) fixed fees; and

(xi) the proposed 2026 Capital Budget.

CURRENT OPERATIONS AND ORGANIZATIONAL STRUCTURE OF THE ISO

Q. WHAT ARE THE CURRENT OPERATIONS AND ORGANIZATIONAL STRUCTURE OF THE ISO?

A. The ISO provides three basic services to its customers:

1. Scheduling Service (Schedule 1): Through this service, the ISO schedules at the pool level the movement of power through, out of, within, or into the New England Control Area.

2. Energy Administration Service (Schedule 2): Through this service, the ISO administers the energy markets and facilitates generation and demand dispatch, auctions for Financial Transmission Rights ("FTRs"), and other services (*i.e.*, under Section III of the Tariff).

3. Reliability Administration Service (Schedule 3): Through this service, the ISO administers the reliability markets (and facilitates reliability-related transactions and arrangements) in accordance with Market Rule 1 and provides other reliability and informational services.

The ISO is governed by an independent Board of Directors with a cross-section of skills and experience, including financial markets, law, electric power operations, and regulation. The ISO is overseen by a President and Chief Executive Officer ("CEO") who has seven direct reports. An Executive Vice President and Chief Operating Officer is responsible for System Operations & Market Administration, System Planning, Market Development & Settlements, Program Management,

Advanced Technology Solutions, Participant Relations & Services, and Information & Cyber Security Services. The other direct reports of the CEO are: Vice President and General Counsel; Vice President, Chief External Affairs & Communications Officer; Vice President, Chief Financial & Compliance Officer; Vice President, Human Resources & Chief People Officer; Executive Director, Market Monitoring; and Executive Director, Internal Audit. The latter two positions report to the CEO for administrative purposes only. See RCL-1, attached to this testimony.

THE BUDGET DEVELOPMENT PROCESS

Q. HOW WERE THE ISO'S BUDGETS DEVELOPED FOR 2026?

A. The ISO's budgeting process is driven by the ISO's strategic planning process. The strategic planning process includes a purposeful and integrated business planning approach that drives focus towards a common target that management teams and the entire organization can support, with the aim of creating value for ISO stakeholders. Included in the strategic planning process is the development of annual and five-year business plans that outline major priorities and activities in line with the ISO's vision to harness the power of competition and advanced technologies to reliably plan and operate the grid as the region experiences a complex grid transition. The ISO ties its annual budget to resource requirements by goals, objectives, and initiatives, including five strategic goals summarized below:

- **Responsive Market Designs**: Advance the competitive wholesale markets to support the investment and new services required for a reliable energy transition;

- **Progress and Innovation**: Expand capabilities to support increasing grid complexity brought about by new technologies and changes to supply mix and customer use;

- **Operational Excellence**: Focus on high quality business operations, prioritize high impact projects, and mitigate implementation risks;

- **Stakeholder Engagement**: Collaboratively understand and anticipate needs, demonstrate thought leadership through high-quality analysis and communication, and nurture productive relationships with regulators and stakeholders in supporting the four pillars of the clean energy transition; and

- **Attract, Develop, and Retain Talent**: Continue to promote our Culture, Mission, Vision, and Goals; develop and position the workforce to support the evolving needs of the organization; recognize and reward employees' success and innovation; tailor programs to retain and attract critical, in-demand skills; and foster an inclusive culture that values diversity of career and life experiences.

These goals formed the foundation for the development of the 2026 Core Operating Budget. Additionally, the ISO prepares budgets in advance of each

upcoming year using a seven-step business planning process, throughout which stakeholder input is sought. Through this process, the ISO employs a rigorous budgeting methodology in arriving at the final budget. The process includes senior management presenting in May/June an estimated budget to discuss with stakeholders based on priorities and initiatives for the budget year. Incorporating the feedback from those discussions, the detailed budgets are developed using the following seven-step process:

1) define objectives, activities, and goals;
2) identify efficiencies for each department;
3) develop priorities;
4) determine resource requirements;
5) develop budget estimates for each department;
6) adjust budgets to ensure that staff resources and activities are aligned with the business plan; and
7) conduct senior staff review to ensure alignment of budget with the ISO's business plan and overall fiscal constraint.

Q. PLEASE SUMMARIZE THE STAKEHOLDER PROCESS USED TO REVIEW THE 2026 BUDGET.

A. After reviewing preliminary budgets with state agencies and the New England Power Pool ("NEPOOL") at meetings in June, the ISO presented the 2026 Revenue Requirement at the NEPOOL Budget and Finance Subcommittee's August 8, 2025 meeting and at a separate meeting for state agencies also on

August 8, 2025. The ISO also presented the budgets to the NEPOOL Participants Committee at the Committee's meetings on September 4 and October 9, 2025. At the October 9 meeting, the ISO's 2026 Revenue Requirement was unanimously supported by the Participants Committee (with abstentions recorded). The terms of the NEPOOL Participants Committee's action are reflected in the resolution in RCL-8, attached to this testimony. In that same resolution, the NEPOOL Participants Committee also supported the capital budget for 2026. The ISO Board of Directors approved the budgets effective on October 13, 2025.

Q. DESCRIBE STAKEHOLDER FEEDBACK TO THE ISO'S PRELIMINARY BUDGET.

A. Following the discussions regarding the preliminary budget (which was substantially similar, but approximately $900,000 less than the 2026 Revenue Requirement described herein), the ISO did not receive any preliminary comments from stakeholders or state agencies.

Q. DESCRIBE THE ISO'S HISTORY OF STAYING WITHIN ITS BUDGET.

A. The ISO has amassed a consistent track record of spending integrity; since the inception of its self-funding tariff for calendar year 1998, the ISO's annual spending has never exceeded the budget used to calculate the revenue requirement accepted by the Commission that forms the basis for the rates for the year in question. Should the need ever arise for the ISO to spend beyond a given year's budget (including contingencies), the ISO will first seek stakeholder support and

then file a rate increase with the Commission, thus allowing stakeholder and Commission review before approving such increases.

DESCRIPTION OF THE 2026 REVENUE REQUIREMENT[1]

Q. WHAT IS THE 2026 REVENUE REQUIREMENT AND WHAT ARE ITS ELEMENTS?

A. As shown in RCL-2, Schedule 2, the 2026 Revenue Requirement is approximately $314.4 million (after true-up). The 2026 Revenue Requirement contains the following components, each of which is discussed below: (1) the 2026 operating budget ($278.0 million) (*i.e.*, the administrative costs of running the ISO); (2) depreciation/amortization and regulatory fees ($48.2 million); (3) interest expense of $3.8 million; and (iv) a final true-up adjustment for 2024 (the "2024 True-Up Amount") calculated pursuant to Section IV.A.2.2 of the Tariff (a decrease in the 2026 Revenue Requirement of approximately $15.6 million resulting from an over-collection in 2024).

Q. WHAT IS THE APPROXIMATE IMPACT OF THE REVENUE REQUIREMENT ON CONSUMER COSTS?

A. If the ISO's Revenue Requirement were fully passed through to end-use customers, their cost would average $1.89 per month.[2] (*See* slide 38 of the Budget Presentation (as defined in the filing letter).)

[1] Generally, numbers used herein are rounded for ease of reference and, accordingly, may not sum.

Q. WHAT ARE THE MOST SIGNIFICANT CHANGES IN THE 2026 OPERATING EXPENSE BUDGET COMPARED WITH THE 2025 OPERATING EXPENSE BUDGET?

A. As described in more detail below, the 2026 Core Operating Budget implements the stakeholder-supported workplan, which includes funding for many market and energy adequacy initiatives; implementation of Commission Orders; cloud modernization initiatives; funding for asset condition reviewer work; and forecasting/modeling improvements that will become operational and require ongoing support. More specifically, the most significant increases to the 2026 Core Operating Budget include salaries for full-time equivalent ("FTE") additions necessary for servicing the workplan; merit and promotion increases to remain competitive in what is still a tight labor market for the unique, in-demand skill sets needed at the ISO; and computer services, including support costs for capital projects that have gone into operation and third-party vendor cost increases. The ISO has also realized efficiencies and savings of $6.9 million, reducing the net increase to approximately $21.6 million.

To support the ISO's increasingly complex and demanding workload, the 2026 Core Operating Budget includes net funding for 18.5 FTE employees in addition

[2] The 2026 forecast, used to calculate these passed through rates, is based on the May 2025 CELT Report Forecast Data Tab 1.5.2 (Schedule 1.5.2 - Net Annual Energy - Gross (without reductions)). *See* https://www.iso-ne.com/static-assets/documents/100023/2025_celt.xlsx. The 2026 cost average is based on different data than prior years because of data availability; 2022 through 2024 used weather normalized annual energy without reduction for BTMPV which is an equivalent basis for May 2025 CELT report Net Annual Energy - Gross (without reductions), and as a result, comparison to prior year's Budget Presentations will show slightly different data.

to the sixteen positions that were deferred from the approved 2025 Core Operating Budget. The 2026 Core Operating Budget includes the recruitment of twenty-five additional positions with funding for 18.5 FTEs with onboarding expected to occur throughout the year. In the 2025 Core Operating Budget, sixteen positions were deferred that are expected to be onboarded by 2026. The ISO expects that the funding for the full year of all twenty-five FTEs will be included in the 2027 Core Operating Budget.

The ISO continually evaluates the most cost-effective way to address the evolving demands on the ISO and the rapidly evolving power system. In the past several years, the ISO supplemented staffing needs with contract additions, where practicable and to cover short term needs. Additionally, the ISO evaluates each position that becomes vacant to determine the continued need in that department and for possible repurposing for use in other areas of the organization. Since 2018, this has resulted in forty-eight reallocated positions. Although the 2026 operating budget reflects funding for new FTEs, the growth is more modest than in the 2025 operating budget and the ISO will continue to use contract additions and the reallocation of resources as appropriate based on a cost-benefit analysis.

Q. PLEASE DESCRIBE HOW THE REGION'S GRID TRANSITION IS IMPACTING THE 2026 BUDGET.

A. The New England electric grid is undergoing a dramatic transformation as complexity increases from, among other things, increased renewable energy and

storage. The 2026 Revenue Requirement represents the ISO's continued commitment to supporting the New England region in addressing increasing complexity resulting from electrification, growth of inverter-based resources, and New England's seasonal operating risks. It also funds the needed ramping-up of organizational capacity to carry out the organization's mission of planning the transmission system, administering the region's wholesale markets, and operating the power system to ensure reliable and competitively-priced wholesale electricity, as well as developing new capabilities that will be necessary for supporting the grid of the future.

On the supply side, New England continues to see substantial increases in the number of interconnected and behind-the-meter generating assets, and the shift from larger, dispatchable resources to smaller, non-dispatchable, weather-dependent, inverter-based resources is changing the operation and interaction of the transmission and distribution system. These additional resources connecting to the distribution system – outside of the ISO's current visibility – contribute to load variability and forecasting challenges.

In addition, on the demand side, changing load characteristics caused by the electrification of the heating and transportation sectors, exacerbate operational complexity. With this anticipated greater electrification, as well as the supply changes described above, the ISO is observing and projecting new daily and seasonal demand patterns. Overall, ISO-NE projects that, over the next decade,

the grid will experience much higher loads, load variability, and intermittent supply resources.

As noted above, the main drivers of the 2026 Revenue Requirement are FTE additions necessary for servicing the stakeholder-requested workplan, compensation increases to remain competitive in a tight labor market, and computer services increases. These drivers include support for the following:

- Continuing capacity market reforms to better ensure power system reliability and cost-efficiency as New England's resource mix evolves;
- Advancements in long-term transmission planning to support interconnection of new resources and to address the evolving system needs;
- Collaborating with stakeholders to operationalize Regional Energy Shortfall Threshold ("REST") and to provide a multiyear outlook;
- Enhancing collaboration with NEPOOL, state agencies, and other stakeholders to ensure inclusive and transparent decision making;
- Informing policymakers about the role of retail market designs in mitigating price volatility and promoting resource development;
- Information technology cost increases, including those attributed to staffing and computer services costs related to the operationalization

of market, transmission, and emerging technology initiatives; costs include those associated with:

  - Cloud infrastructure and data management costs;
  - Software licensing and subscription fees;
  - Inflation, supply chain disruptions, and tariffs;
  - Modernization of legacy systems and natural hardware refresh cycles; and
  - Governance and compliance requirements

- Investing in advanced technologies and analytics to improve system operations and planning capabilities to improve forecasting and situational awareness around the region's changing resource mix;

- Strengthening cyber security measures and infrastructure to safeguard grid reliability; and

- Developing a new framework to conduct independent reviews of asset condition projects on the transmission system.

Q. PLEASE DESCRIBE THE INCREASES RELATED TO ATTRACT, DEVELOP, AND RETAIN TALENT (STRATEGIC GOAL 5).

A. The funding increase of $10.0 million for this goal is attributable to funding in six categories: (i) to maintain competitive compensation ($6.0 million); (ii) increases in employee benefits costs, primarily because of medical trends, and an increased

number of number of employees in the Defined Contribution Benefit Plan[3] ($1.5 million); (iii) an increase in funding related to the decrease of the employee vacancy rate from 6.0% to 5.0% ($1.6 million); (iv) funding related to the relocation of approximately ninety ISO employees to the Windsor campus ($400,000); (v) funding for consulting services, data, and research to support critical Human Resources initiatives ($200,000); and (vi) funding for Board of Director search fees to recruit for a scheduled vacancy ($200,000) and an increase in Board of Director retainer fees ($100,000).

The funding in this category to maintain competitive compensation includes a 4.0% increase in salaries based on merit and a 1.5% increase for promotions and adjustments. The budgeted amounts for merit and promotion/adjustment budgets were developed based on the Mercer benchmarking compensation analysis (as described in Ms. deCastro's testimony), using data from several national compensation consultants, and review of planned budget increases of other independent system operators and regional transmission organizations. Please see Ms. deCastro's testimony for details on the development of these allocations, compensation practices in general, the decrease of the vacancy rate, health insurance costs, funding for the other components contributing to the increased funding to support Goal 5, and the ISO's compliance with the standards of the

[3] *See* Budget Presentation, Slide 101 (explaining that in 2014 the pension plan became closed to new participants; as a result, all new hires in the organization are eligible under the Defined Contribution Benefit Plan).

Internal Revenue Service regarding the reasonableness of executive compensation, and director compensation.

Q. PLEASE DESCRIBE THE INCREASES RELATED TO OPERATIONAL EXCELLENCE (STRATEGIC GOAL 3).

A. The funding increase of $8.4 million related to Operational Excellence is related to headcount increases in various departments; computer services and leasing increases; professional fees for various parts of the organization; data services costs; and communications costs.

Specifically, the 15 headcount increases will fund positions in: (i) System Operations and System Planning to address technical challenges and to perform system assessments and studies related to the continued installation of inverter-based resources and for responsibilities related to NERC and NPCC requirements; (ii) Information and Cyber Security Services for the ISO's transition to cloud computing, including architecture and service delivery and for IT forecasting tool support; (iii) Project Management Office for support of the increased number of sophisticated capital projects; and (iv) Finance and Market & Credit Risk to support the growth and sophistication within these departments. Professional fees included in the funding for Goal 3 include consulting support to provide research, recommendations, and implementation of enhanced security best practices for the ISO workforce (including senior management), an increase in regulatory counsel fees for Commission Order filings and responses, and consulting support to

perform audits or assist the Internal Audit department with various engagements, including systems and cyber security related work.

The funding to support Goal 3 related to computer services includes cyber security improvements (security log management, network detection and response tools, zero trust access and protection enhancements, and cloud monitoring), network collaboration software fees, leasing of servers as part of the ISO's data center refresh, fees for computing and storage capacity applications, licensing fees for System Planning and Operations applications, and inflationary and vendor increases across our portfolio of computer services products. Also included in Goal 3 are Network Operations increases for the transition of communication lines to new technologies, for data redundancy, and for inflationary and communication line increases. Finally, Goal 3 cost increases include funding for data services subscriptions for the Market Monitoring department and for a vendor third party risk assessment.

Q. PLEASE DESCRIBE THE INCREASES RELATED TO RESPONSIVE MARKET DESIGNS (STRATEGIC GOAL 1).

A. The $4.6 million cost increase in this category is related to headcount increases in various departments; funding for nGEM vendor support; and funding for modeling and analysis work.

Specifically, the headcount increases will fund 6.5 FTEs in: Market Development to assist in the design of market overhauls, including Capacity Auction Reforms

(such as the design of a prompt, seasonal capacity market, resource capacity accreditation work, and flexible response services); Operations Training and Integration to design and support trainings for the Operations and Market Administration staff regarding new market features; Information and Cyber Security Services and Advanced Technology Solutions to support and integrate new market features into applications and tools; and Planning and Transmission Services to align with new market designs, identify enhancements to existing reliability modeling and research, and develop modeling techniques for emerging technologies.

The nGEM vendor support included in the funding for Goal 1 is to support the Real-Time Market Clearing Engine application, which is at a higher cost than the legacy Real-Time application.

Finally, the funding for Goal 1 related to modeling and analysis work is to support: the Information Technology and System Planning departments' efforts related to resource adequacy and capacity market modeling, which are essential to the redesign of the capacity market; the Advanced Technology Solutions and Market Development departments' Capacity Auction Reforms work, including gas modeling and other analyses; the Tariff required Net Cost of New Entry (CONE) recalculation; and the Market Monitoring department's technology assessments and artificial intelligence development for use in the detection and mitigation of energy market activity.

Q. PLEASE DESCRIBE THE INCREASES RELATED TO PROGRESS AND INNOVATION (STRATEGIC GOAL 2).

A. The cost increase of $2.9 million to support the Progress and Innovation strategic goal will support headcount additions; computer service-related costs for compliance with NERC Critical Infrastructure Protection ("CIP") synchrophasor standards; and costs related to photovoltaic data and forecasting service.

The 9.0 FTEs headcount increases to support Goal 2 include positions in Information Technology and Advanced Technology Solutions to support the development of advanced technologies in the operating environment to increase situational awareness capabilities, and in Information Technology to support the migration of applications to the cloud. In System Operations and System Planning, additional positions are needed for: forecasting and energy analysis across different timespans as the system's resource mix continues to evolve; modeling and electromagnetic transient analysis for market and reliability operating limits of inverter-based resources; expansion of both short-term and long-term forecasting needs; and support of the continued growth and development of Power System Computer Aided Design (PSCAD) modeling capability (including database development and maintenance) for inverter-based resources.

Q. PLEASE DESCRIBE THE INCREASES RELATED TO STAKEHOLDER ENGAGEMENT (STRATEGIC GOAL 4)

A. The cost increase of $2.1 million to support the Stakeholder Engagement strategic goal will support headcount additions, consulting support, and asset condition review work. Headcount additions will include 2.5 FTE positions in the Participant Relations and Services department for project services (*e.g.*, gathering, managing, and supporting the assessment of participant requests), to provide technical readiness and real-time support on corporate initiatives (*e.g.*, initiatives related to Commission Orders 2222, 881, 2023), and to support the Capacity Auction Reforms project; 0.5 FTE position in the Legal department to support the implementation of the Long-Term Transmission Planning ("LTTP") rules; and 0.5 FTE in the System Planning department to perform economic evaluations in support of the new LTTP processes and potential requests for proposal solution reviews, and to accommodate requests from the New England states and the New England States Committee on Electricity. Additionally, funding to support Goal 4 will include consulting support for LTTP proposals and other transmission planning work.

Finally, $1.0 million of funding is included in furtherance of Goal 4 to support asset condition review work. Over the past year, the ISO has received requests from states and stakeholders to consider taking a reviewer role in the Transmission Owners' current asset condition projects process. After agreeing

with the states and Transmission Owners on certain threshold matters,[4] the ISO has begun work to identify the scope of the Asset Condition Reviewer role, including the resourcing and responsibilities of such role. As a result, the ISO has used approximately $300,000 of contingency funding from the 2025 budget and has budgeted $1.0 million as part of the 2026 Core Operating Budget for asset condition review work, but if any of 2026 funding is not needed for such work, it will be returned in a subsequent budget year.

Q. PLEASE DESCRIBE THE MISCELLANEOUS INCREASES.

A. The cost increase of $0.5 million in this category is attributable to: (i) increases in building services costs due to cyclical maintenance items that are due for completion in 2026, higher utility expense largely for delivery service fees at the ISO's Windsor facility, and inflationary and other small increases across line items; and (ii) lower forecasted interest income due to the projection of a lower operating cash balance because of expected withdrawals by customers pursuant to Commission Order 2023 (which will be partially offset by higher miscellaneous revenue).

[4] The ISO was only willing to agree to evaluate asset condition review work if the Transmission Owners indemnify the ISO for any related liability; the asset condition reviewer role is solely advisory; and the asset condition reviewer role will not make any legal finding or issue an opinion on whether costs on any given asset condition project are prudent. *See* Update on Asset Condition Project Process Memo, available at https://notification.iso-ne.com/l/405752/2025-05-15/2ccp755/405752/1747327348SH2DPfNj/Status_update_ACR_5_15_2025.pdf.

Q. PLEASE DESCRIBE THE BUDGET CUTS AND DEFERRALS THAT OFFSET THESE INCREASED COSTS.

A. For 2026, the ISO has realized $6.9 million by reallocating resources, identifying efficiencies, and eliminating discontinued or non-repetitive work.

The $6.9 million reflects reductions for consulting professional fees for 2025 studies or other non-recurring work, including: the completion of regional study work with PJM and regarding the appropriateness of the current 1,200 MW single source contingency limit and to determine the upgrades required to support a 2,000 MW single source limit; the completion of a transmission planning system assessment under NERC Transmission Planning Standard TPL-001; the removal of medium-term energy adequacy related work; the removal of wind, solar, and generation dataset information that will be obtained via other sources; the reduction in Advanced Technology Solutions external research and development support; lower relocation expense reimbursements; and other miscellaneous reductions.

Reductions also include lower salary rates and related incentive compensation due to employee turnover and retirements, and a reduction given the expectation that there will be no borrowings on the working capital line based on 2026 projections.

Q. DOES THE REVENUE REQUIREMENT INCLUDE DEPRECIATION ON ITEMS IN THE CAPITAL BUDGET THAT ARE PLACED IN SERVICE IN 2026?

A. Yes. The ISO's depreciation rates remain unchanged from those accepted by the Commission in the ISO's 2025 Revenue Requirement. The ISO uses the straight-line depreciation methodology based on no net salvage value and the various average service lives described below. These service lives reflect the ISO's historical experience and forecasted expectations for capital projects placed into service, are necessary to comply with the ISO's funding mechanisms, are consistent with the ISO's historical experience, and have been repeatedly determined by independent auditors to be reasonable. The service lives are:

- Computer hardware, software and accessories: 3 to 5 years
- Software development costs: 3 to 5 years
- Furniture and fixtures: 7 years
- Machinery and equipment: 7 years
- Building: average of 25 years (based on the opinion of independent bond counsel and analysis of the service lives of the different aspects of the building (*e.g.*, the building's steel and concrete at 40 years, mechanical and electrical work at 25 years, and high wear-and-tear elements at 15 years))
- Leasehold/Building Improvements: lesser of 1 to 25 years or remaining life of the lease or building, as determined at the time of the purchase

based on the nature of each such improvement (*e.g.*, rooftop railing at 25 years, air conditioning unit at fifteen years)

- Vehicles: 3 to 7 years

The ISO uses private placement debt, issued pursuant to Commission authorization under Section 204 of the Federal Power Act, to fund its capital program. In 2024, the Commission approved an increase in the ISO's private placement debt from $50 million to $75 million to fund the increased capital expenditures program.[5] The ISO funds future capital expenditures by using amounts collected for depreciation, with the private placement notes covering the delay between project expenditures and the collection of depreciation through rates. In addition, the ISO funds its working capital needs through a revolving line of credit.

The private placement notes are non-amortizing, with interest-only payments due semi-annually throughout the life of the notes, and the principal due at the end of the term. Revenue reserved for the depreciation of capital assets, as well as assets placed in service in prior years and still depreciable, will be available to repay the remaining principal amounts on outstanding debt.

Please note that capital projects include the cost of the necessary work performed by the project manager, test coordinator, and business analyst in the Program

[5] The debt was approved by the Commission in Docket No. ES24-41-000, 188 FERC ¶ 62,038 (2024).

Management Office and design work. If the design is approved and built, this project management and design work is part of the asset on which depreciation is collected when the asset is placed in service in future years via the Revenue Requirement. On the other hand, if the capital project is abandoned, the ISO writes off the entire project cost, including the project management and design work and recovers it in full in the year of abandonment. In addition, each capital project also includes the first year's maintenance cost for both hardware and software, and license fees for any newly capitalized software.

Q. HOW DOES THE ISO ADDRESS UNEXPECTED COSTS THAT MIGHT MATERIALIZE DURING 2026?

A. The 2026 Core Operating Budget includes two line items to address unexpected needs: (i) the CEO Emerging Work allowance of $3.0 million; and (ii) the Operating Contingency of $700,000. Inclusion of these contingency amounts recognizes that circumstances may arise that the ISO does not foresee in setting its 2026 Revenue Requirement for its various departments and programs.

The CEO Emerging Work Allowance covers new or deferred activities and initiatives that emerge or become priorities during the year. Approval from both the CEO and CFO is required before the ISO may draw upon these funds.

The Operating Contingency provides a funding source of last resort. ISO management cannot access this fund without first obtaining approval from the ISO's independent Board of Directors.

Q. DO YOU FORESEE ANY PARTICULAR CONTINGENCIES THAT WILL WARRANT THE ISO TAPPING INTO THESE FUNDS?

A. I cannot say for sure what type of contingencies might arise. There are, however, several ongoing issues that might require additional funds not included in the 2026 Core Operating Budget. Specific potential risks include: additional funding required to enhance new models to study extreme weather and contingencies, to conduct new studies related to the integration of variable resources and emerging technologies, for completing requirements on implementing Capacity Auction Reforms, and for long-range transmission planning studies, including the RFP process for finding competitive solutions to identified transmission needs in the region; additional resources required as operations evolve (*e.g.*, energy forecasting, load management) due to the evolving and changing resource mix; additional information technology funding for software licensing, maintenance costs, and cloud migration; higher than anticipated insurance policy renewals; unforeseeable litigation; interest rates that may impact the ISO's floating rates on tax exempt debt, pension and post-retirement benefit plan costs, and interest income on the ISO's settlement float balance; costs related to workforce sourcing challenges and related pay rates; costs related to supply chain disruption; and funding required for additional or changing federal and/or state policy directives that could result in new requirements.

Q. HOW IS THE ISO PROTECTED AGAINST THE RISK OF A CHANGING INTEREST RATE ENVIRONMENT?

A. The ISO's primary risk involving variable interest rates, arises from the ISO's variable rate debt: tax-exempt bonds. The ISO issued tax-exempt bonds in Massachusetts to fund the refurbishing of the Main Control Center (Holyoke facility) and in Connecticut to fund the development of the Back-Up Control Center (Windsor facility). Both sets of bonds are priced at a weekly variable rate. By opting for variable rates on both sets of bonds, the ISO has saved more than $20,400,000 since 2005 when the ISO first issued the Massachusetts tax-exempt bonds (the Connecticut bonds were issued in 2012). The interest rate risk on the balance remaining on the tax-exempt bonds is naturally covered by settlement float. More specifically, the ISO earns interest on the settlement float that the ISO has through the normal course of participant settlement, billing, and payment. The interest earned on the balance carried in the settlement account (as amounts are due two days before they are paid out to customers) offsets the interest due on the bonds.

Q. PLEASE DESCRIBE THE CALCULATION OF THE 2024 TRUE-UP.

A. As set forth in Section IV.A.2.2 of the Tariff, the ISO has reconciled calendar year 2024's actual expenses and collections under Schedules 1, 2, and 3 of the Tariff by means of a true-up. The actual difference between 2024 expenses and collections is an over-collection of approximately $15.6 million, which decreases the 2026 Revenue Requirement by that amount. *See* RCL–2, Schedule 2.

Q. HOW IS THE 2024 TRUE-UP AMOUNT ALLOCATED AMONG THE THREE SCHEDULES?

A. Schedule 1 decreases by about $2,470,000; Schedule 2 decreases by about $6,337,000; and Schedule 3 decreases by about $6,795,000. *See* RCL-2, Schedule 2.

ACTIVITY ACCOUNTING SYSTEM

Q. DESCRIBE THE ISO'S ACTIVITY ACCOUNTING SYSTEM AND THE EXTENT TO WHICH IT PROVIDES COST OF SERVICE INFORMATION FOR EACH OF THE THREE PRIMARY SCHEDULES.

A. The activity accounting system was implemented at the ISO's inception in 1997 and refined in 1998. All operating charges recorded in the general ledger system must be cross-referenced to an activity. Each department has identified its major activities. Most activities are department-specific, but some activities may be cross-charged if they are of a project nature. Activities within a department are known as either "direct" activities or "indirect" activities. Direct activities are of an operational nature and are allocated to one or more of the three schedules based on a fixed percentage. This fixed allocation is provided by the department manager annually in preparation for the next year's budget and tariff filing. Indirect activities are of an administrative nature and are allocated based on current direct labor charges. In addition, the majority of activities for administrative departments (Finance, Human Resources, etc.) are allocated based on the total labor charges within the Company.

The activity accounting system is largely manual, meaning that timesheets and invoices are coded manually. The ISO found that it would not be prudent to overly expand the system to require each employee to specify the schedule serviced through the week. Further, the ISO does not pre-code employees' time because duties change often with seasonality or new projects. Therefore, the allocation of activities to the schedules is made at the manager level.

The activity system is not designed to track costs to individual markets or transaction units. An employee's time is not driven by the number of transaction units or markets, but by the number of tasks and projects.

If the activity accounting system were expanded to provide for accounting cost in more detail, it would be more costly and difficult to manage without substantially increasing its accuracy.

Q. HOW WAS THE TARIFF SCHEDULE ALLOCATION VERIFIED?

A. In developing the Revenue Requirement for each schedule, managers with cost center responsibilities are required to review the allocation of each and every activity under their control as to the appropriateness of the allocation. During this lengthy evaluation process, all of the activities used by the ISO are reviewed. It is this activity allocation structure that formed the basis of the revenue requirements for each of the three primary schedules.

2026 COST ALLOCATION AMONG SCHEDULES 1, 2, AND 3

Q. HAVE YOU PREPARED AN EXHIBIT THAT SHOWS THE DEVELOPMENT OF THE COST OF SERVICE ("COS") ANALYSIS?

A. Yes. The following schedules support the COS shown in RCL-3:

Schedule 1	Total Cost Allocation to Schedules by Department
Schedule 2	Total Direct Labor Allocation to Schedules by Department
Schedule 3	Total Cost Allocations to Schedules by Cost Category
Schedule 4	Direct Labor Cost Allocations to Schedules by Cost Category
Schedule 5	Allocation Factors by Cost Category
Schedule 6	Allocation on Depreciation and Amortization Expense

Q. WHAT IS THE ISO'S MAIN EXPENSE?

A. As a non-profit entity that operates, but does not own, generation or transmission assets, the ISO's main expense in the Core Operating Budget is personnel. As shown in RCL-5, Schedule 1, the ISO has budgeted $191.2 million of the ISO's 2026 Core Operating Budget for salaries and overhead. This category includes fees for the Board of Directors, as well.

Q. WOULD YOU PLEASE DESCRIBE YOUR RCL-3?

A. RCL-3, Schedule 1 contains the Test Year 2026 COS for each of the three primary rate schedules. The exhibit lays out in detail how the ISO's costs were assigned to the three schedules.

Most activity costs consist of direct labor costs, employee benefits, and other non-labor-related costs (*e.g.*, office supplies, software, hardware, depreciation, interest, consulting, etc.). For each Activity Code, both the labor-related and non-labor-related costs are assigned to the rate schedule using the same allocator.

Q. PLEASE EXPLAIN HOW LABOR RATIOS WERE DEVELOPED AND USED TO ALLOCATE COSTS IN RCL-3.

A. Schedule 4 of RCL-3 shows an allocation to the three schedules of all ISO direct labor costs as projected for Test Year 2026. Within a given department, known allocators ("Alloc-Fixed") for specific cost categories were used to allocate those labor costs that were specifically attributable to a schedule. The Alloc-Fixed labor costs were summed for that department and all remaining labor costs within that department were allocated in proportion to the summed Alloc-Fixed costs. Labor costs within all departments were allocated in this manner and summed for the entire company. Schedule 5 of RCL-3 summarizes the labor allocation factors or labor ratios for each Activity Code. These ratios were then used to allocate various cost items in Schedules 3, 4, and 6 of RCL-3.

Q. PLEASE SUMMARIZE YOUR PROPOSED 2026 COS RESULTS FROM RCL-3 FOR EACH OF THE THREE RATE SCHEDULES.

A. Table 1 below summarizes the results of all the allocations contained in Schedule 1 of RCL-3, at Lines 45, 47, and 49. The totals demonstrate an initial 2026 Operating Expense Revenue Requirement (also provided on line 10 to RCL-2,

Schedule 2, page 1) decreased by the true-up amount (also provided on line 14 to RCL-2, Schedule 2, page 1) to result in the total 2026 Revenue Requirement (also provided on line 17 to RCL-2, Schedule 2, page 1).

Table 1
2026 Cost of Service Results (1)

Description	Test Year	True-Up	Total
(a)	(b)	(c)	(d)
Schedule 1, Scheduling, System Control and Dispatch Service	$ 68,040,034	$ (2,470,230)	$ 65,569,804
Schedule 2, Energy Administration Service	161,098,608	(6,336,845)	154,761,763
Schedule 3, Reliability Administration Service	100,852,848	(6,794,645)	94,058,203
Total	$ 329,991,490	$ (15,601,720)	$ 314,389,770

(1) From Exhibit 3 (RCL-3), Schedule 1.0.

Q. EXCLUDING TRUE-UP AMOUNTS, HOW DO THE COS RESULTS IN SCHEDULE 1 OF RCL-3 COMPARE WITH THE TEST YEAR 2025 COS RESULTS, ON WHICH THE CURRENT ISO RATES ARE BASED?

A. Table 2 below compares, before taking into account any true-ups, the 2026 COS results from Schedule 1 of RCL-3 to the 2025 COS results. Table 2 demonstrates how, excluding the true-up amounts, the 2026 COS constitutes a $23.6 million increase from the 2025 COS accepted by the Commission last year.

Table 2
Comparison for Cost of Service Results

(Before True-Ups)

Description	Total	ISO Tariff Schedules Schedule 1	Schedule 2	Schedule 3
(a)	(b)	(c)	(d)	(e)
2026 COS (1)	$329,991,490	$68,040,034	$161,098,608	$100,852,848
2025 COS (2)	$306,404,886	$63,699,206	$149,150,469	$93,555,211
Difference -$	$23,586,604	$4,340,828	$11,948,139	$7,297,637
-%	7.7%	6.8%	8.0%	7.8%

(1) From Table 1, Column (b).

(2) From Exhibit 3 (RCL-3), Sch. 1.0, Line 45, in FERC Docket No. ER25-110-000.

Q. HAVE YOU IDENTIFIED SPECIFIC ACTIVITY ITEMS THAT GIVE RISE TO THE INCREASES AND/OR DECREASES SHOWN ABOVE FOR THE THREE SCHEDULES?

A. Yes. Table 3 below highlights key activity items from Test Year 2026 allocated among the three primary schedules by cost category (RCL-3, Schedule 3), along with various depreciation/amortization items (RCL-3, Schedule 6), which changed from 2025. The identified activity items account for the majority of the cost shifts within each of the three schedules.

Table 3
Examples of Differences in 2026 Operating Expenses

Activity Code (a)	Description (b)	Total (c)	ISO Tariff Schedules Schedule 1 (d)	Schedule 2 (e)	Schedule 3 (f)
		Test Year 2026			
99995	NPCC/NERC Dues	$ 9,955,133	-	-	9,955,133
920XX	Depreciation	38,152,545	4,942,759	22,555,289	10,654,497
12664	Building Maintenance (and Security)	2,982,305	642,687	1,543,343	796,275
12508	Energy Markets / Complaints / Rule Changes	2,181,856	-	2,181,856	-
12559	General Corporate	2,159,747	465,426	1,117,669	576,653
16021	Training Development	1,558,628	-	779,314	779,314
18402	Transmission Planning/Economic Studies Initiative	1,308,466	-	654,233	654,233
21201	Advanced Technology Solutions	5,907,731	1,273,116	3,057,251	1,577,364
22614	PR&S Project Development	517,762	111,578	267,942	138,242
22662	Flexible Response Services	2,427,517	-	1,213,758	1,213,758
21011	Capacity Market	837,311	-	-	837,311
Various	Transmission Planning	12,749,258	12,460,318	-	288,939
Various	Capacity Auction Reforms	6,579,109	-	-	6,579,109
Various	Information Tech (excl. Cyber and Energy Mgt Systems)	74,602,932	10,818,420	43,061,605	20,722,907
Various	Information Technology Energy Management Systems	13,225,859	4,517,950	6,585,714	2,122,195
Various	Information Technology Cyber Security	9,350,390	2,015,009	4,838,827	2,496,554
	Totals	$ 184,496,549	$ 37,247,263	$ 87,856,801	$ 59,392,485
		Test Year 2025			
99995	NPCC/NERC Dues	$ 9,253,473	-	-	9,253,473
920XX	Depreciation	36,876,000	5,462,555	21,885,199	9,528,246
12664	Building Maintenance (and Security)	2,670,768	575,550	1,382,122	713,095
12508	Energy Markets / Complaints / Rule Changes	1,704,267	-	1,704,267	-
12559	General Corporate	1,911,304	411,886	989,100	510,318
16021	Training Development	1,116,926	-	558,463	558,463
18402	Transmission Planning/Economic Studies Initiative	779,874	-	389,937	389,937
21201	Advanced Technology Solutions	5,266,550	1,134,942	2,725,440	1,406,169
22614	PR&S Project Development	154,458	33,286	79,932	41,240
22662	Flexible Response Services	1,312,863	-	656,431	656,431
21011	Capacity Market	181,993	-	-	181,993
Various	Transmission Planning	11,350,337	11,136,634	-	213,704
Various	Capacity Auction Reforms	5,856,834	-	-	5,856,834
Various	Information Tech (excl. Cyber and Energy Mgt Systems)	68,245,747	9,719,885	39,120,988	19,404,874
Various	Information Technology Energy Management Systems	10,918,338	3,973,872	5,267,091	1,677,375
Various	Information Technology Cyber Security	8,253,646	1,778,661	4,271,262	2,203,724
	Totals	$ 165,853,377	$ 34,227,270	$ 79,030,232	$ 52,595,875
		Test Year 2026 Costs Minus Test Year 2025 Costs			
99995	NPCC/NERC Dues	$ 701,660	-	-	701,660
920XX	Depreciation	1,276,545	(519,796)	670,090	1,126,251
12664	Building Maintenance (and Security)	311,537	67,136	161,220	83,180
12508	Energy Markets / Complaints / Rule Changes	477,589	-	477,589	-
12559	General Corporate	248,443	53,540	128,569	66,334
16021	Training Development	441,703	-	220,851	220,851
18402	Transmission Planning/Economic Studies Initiative	528,592	-	264,296	264,296
21201	Advanced Technology Solutions	641,181	138,175	331,811	171,195
22614	PR&S Project Development	363,304	78,292	188,010	97,002
22662	Flexible Response Services	1,114,654	-	557,327	557,327
21011	Capacity Market	655,318	-	-	655,318
Various	Transmission Planning	1,398,921	1,323,685	-	75,236
Various	Capacity Auction Reforms	722,275	-	-	722,275
Various	Information Tech (excl. Cyber and Energy Mgt Systems)	6,357,185	1,098,535	3,940,617	1,318,033
Various	Information Technology Energy Management Systems	2,307,521	544,078	1,318,622	444,821
Various	Information Technology Cyber Security	1,096,743	236,348	567,565	292,830
	Totals	$ 18,643,172	$ 3,019,993	$ 8,826,569	$ 6,796,610
	All Other Unidentified Changes	$ 4,943,432	$ 1,320,835	$ 3,121,570	$ 501,027
	Total Change in Cost of Service	$ 23,586,604	$ 4,340,828	$ 11,948,139	$ 7,297,637
	% of Difference shown on Table 2	79.04%	69.57%	73.87%	93.13%

Q. PLEASE EXPLAIN IN FURTHER DETAIL HOW THE REVENUE REQUIREMENTS CHANGED FOR EACH SCHEDULE FROM THOSE UTILIZED IN THE FILING SUPPORTING THE 2025 RATE TO THOSE UTILIZED HERE FOR TEST YEAR 2026.

A. Schedule 1: The increase in the Revenue Requirement for Schedule 1 results from 2026 cost increases and changes that impact all three schedules, including for: compensation (merit and promotion/adjustment) increases, employee benefits for medical trend, and a reduction in budgeted employee vacancy; Information Technology and Advanced Technology Solutions for personnel and products to support the operationalization of market, transmission, and emerging technology initiatives and impacts related to cloud infrastructure and data management, software licensing and subscription fees, inflationary increases, modernization of legacy systems and hardware refresh cycles, and governance and compliance requirements; funding to provide research, recommendations, and implementation of enhanced security best practices for the ISO workforce; and an increase in regulatory counsel fees for Commission Order filings and responses to supplement ISO Legal staff. Also contributing to the increase in the Revenue Requirement for Schedule 1 is funding for Transmission Planning support for RFP processing and long-term studies, and for asset condition review work. These increases were partially offset by the non-recurrence, in 2026, for an assessment under NERC Transmission Planning Standard TPL-001, to establish facility out transfer capability for northern New England and NECEC.

Schedule 2: The increase in the Schedule 2 Revenue Requirement is due to the increases that impact all three schedules, as discussed in the preceding paragraph. The increase in the Schedule 2 Revenue Requirement is also attributable to funding for work that affects Schedules 2 and 3, including Market Development design work for flexible response services, Transmission Planning Economic Study related work with the continued installation of inverter-based Resources, and for NPCC and NERC requirement responsibilities; and a full year of Depreciation Expense for the Day-Ahead Ancillary Services Improvements and Day-Ahead Ancillary Services Benchmark Levels projects that had mid-2025 go-live dates. Additionally, the Schedule 2 Revenue Requirement increase is attributable to depreciation expense for mid-2026 go-live of the nGEM Real-Time Market Clearing Engine Implementation project and funding for technical writing and instructional design work for broader and deeper training of new market features and initiatives in 2026.

Schedule 3: The increase in the Schedule 3 Revenue Requirement is attributable to increases that impact all three schedules and funding for items that impact Schedules 2 and 3, each as noted above. Additionally, the Schedule 3 Revenue Requirement increase is attributable to funding for Market Development design work in 2026 to complete conceptual and detailed design of Capacity Auction Reforms (CAR) Seasonal Accreditation and CAR Impact Analysis; increases in NPCC and NERC dues; and funding for the commencement of work on Tariff required Net Cost of New Entry (CONE) recalculation.

THE ISO RATE DESIGN AND ESCALATION FACTORS

Q. HOW DID YOU DEVELOP THE ESCALATION FACTORS?

A. Consistent with the practice reflected in the filings establishing the ISO's rates to collect its administrative costs for 1999-2025, escalation factors rely on information contained in the 2025-2034 Forecast Report of Capacity, Energy, Loads, and Transmission (the "CELT Report"), dated May 1, 2025. The CELT Report contains actual and estimated energy and peak loads for 2025-2034. The ISO also relied on information in the ISO markets system for the 12-month period ending July 2025. The development of the escalation factors is shown in RCL-7, Schedule 1.

Q. ARE YOU PROPOSING ANY CHANGES TO THE RATE DESIGN?

A. The ISO is not proposing any changes to the overall rate design from that in place in 2025.

Q. PLEASE OUTLINE THE CURRENT RATE DESIGN BEFORE DESCRIBING THE VARIOUS ESCALATION FACTORS.

A. As previously indicated, Section IV.A of the Tariff has three rate schedules to cover the ISO's expenses for providing its three services: Schedule 1 - Scheduling Service; Schedule 2 – Energy Administration Service; and Schedule 3 – Reliability Administration Service.

- ***Schedule 1***

  The Schedule 1 revenue requirement is allocated 100% to Monthly Regional Network Load and the Reserved Capacity. The determinant based on Reserved Capacity uses the highest amount of Reserved Capacity for an hour for each transaction scheduled to occur during the month as Through or Out Service, other than Coordinated External Transactions.[6] Schedule 1 revenues collected from Through and Out Service Customers are credited to each Network Customer that month in proportion to each Network Customer's Monthly Regional Network Load. Revenues from the Non-Participant FTR fee described in Market Rule 1 and non-refundable Long Lead Facility deposits will be credited to the Schedule 1 Revenue Requirement through future true-ups.

- ***Schedule 2***

  The Schedule 2 revenue requirement is allocated 15% to Transaction Units ("TUs") and 85% to Volumetric Measures ("VMs"), subject to the special true-up described below. TUs measure the frequency and duration of activity and are indifferent to the size (*e.g.*, capacity) of any particular transaction. Conversely, VMs seek to capture a customer's "physical" reliance on the system administered by the ISO and thus the benefit received.

[6] Coordinated External Transactions are defined in Section I of the Tariff as transactions at external interfaces to which the enhanced scheduling procedures in the Coordinated Transaction Scheduling rules apply. These rules were adopted jointly with the NYISO to enhance the market efficiency of external transactions (*i.e.*, energy imports and exports) between the two regions through economic clearing of external transactions. *See* Tariff Section III.1.10.7.A.

A. Transaction Units

Schedule 2 currently utilizes three types of TUs: those associated with Energy Market transactions (Energy TU Based Charges), those associated with Increment Offers and Decrement Bids, and those associated with FTR auction submitted and cleared bids.

Energy TUs equal the sum per month of a Customer's Bilateral Contract Block-Hours, Demand Bid Block-Hours, Asset Related Demand Bid Block-Hours, Supply Offer Block-Hours, Demand Reduction Offer Block-Hours, Day-Ahead Ancillary Services Offer Block-Hours, and Energy Non-Zero Spot Market Settlement Hours, without reference to Coordinated External Transactions. Under the ISO's current rate design, a Customer's total monthly Energy TUs are priced under a three-tiered declining block rate structure. Under this regime, the highest unit rate applies to the first 12,500 Energy TUs incurred in a month; the Customer's next 27,000 Energy TUs are priced approximately 10% lower; and the balance of monthly Energy TUs, *i.e.*, those in excess of 39,500, are priced at an additional savings of approximately 10% on average.

TU Charges Based on Increment Offers and Decrement Bids are assessed based on both of the following: (i) a charge multiplied by the total number of Increment Offers and Decrement Bids submitted, plus (ii) a charge multiplied by the total number of Increment Offers and Decrement Bids that clear the Day-Ahead Energy Market. This category is sometimes referred to as "virtual activity," distinguishing it from physical activity.

TU Charges Based on FTR Auction Submitted and Cleared Bids are assessed through both of the following: (i) a charge multiplied by the total number of FTR auction bids submitted for that period, plus (ii) a charge multiplied by the total number of FTR auction bids cleared for that period. The FTR charges are designed to recoup the costs the ISO incurs for administering the FTR auctions. The FTR revenue offsets other Schedule 2 TU charge revenues.

B. Volumetric Measures

Schedule 2 Volumetric Measures consist of the sum of a Customer's Monthly Real-Time Load Obligation, Monthly Real-Time Generation Obligation, and Monthly Real-Time Demand Reduction Obligation (each measured in megawatt hours, MWh), excluding any Monthly Real-Time Generation Obligation associated with certain energy imports and Coordinated External Transactions. Under the ISO's current rate regime, Schedule 2 VMs are priced under a three-tiered declining block rate structure wherein the highest unitized rate is assessed to the first 250,000 MWh each month; the Customer's next 1,250,000 MWh are priced at a discount of approximately 10% from the tier-1 unitized rate; and VMs in excess of 1,500,000 MWh incur the lowest unitized monthly rate.

- ***Schedule 3***

Schedule 3 allocates internal load activity based on Real-Time NCP [Non-Coincident Peak] Load Obligation. For Exports other than Coordinated External Transactions, Schedule 3 assesses a volumetric (per MWh) charge. Specifically, the ISO divides the Schedule 3 Revenue Requirement by the real-time load

obligation forecasted for the upcoming year in the most recent CELT Report.[7] The remaining revenue requirement for Schedule 3 (*i.e.*, net of that allocated to Exports) is then divided by the total Real-Time NCP Load Obligation forecast to yield the unitized rate per kW-month.

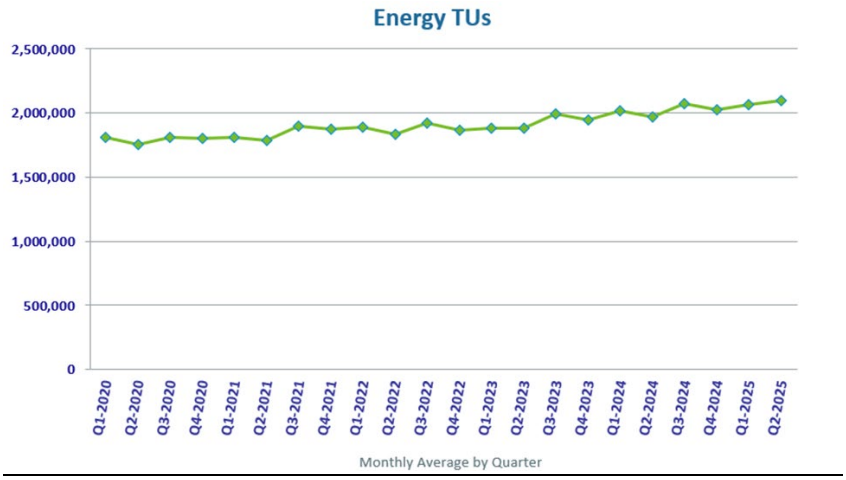
Q. PLEASE EXPLAIN THE ESCALATION FACTORS UTILIZED TO DEVELOP THE BILLING DETERMINANTS FOR 2026.

A. The Schedule 1 Network Load, the Schedule 2 Volumetric, and Schedule 3 Real-Time NCP Load Obligation billing determinants for 2026, were increased by an escalation factor of 1.005 based on CELT Report load data. See columns (c), (i), and (j), respectively, of RCL-7, Schedule 2.

The Schedule 2 transaction unit determinants for Energy TUs, shown in column (d) of RCL-7, Schedule 2, were increased by an escalation factor of 1.029. As shown in Table 4A below (actual Energy TU data from 2020 through the second quarter of 2025), excluding Day-Ahead Ancillary Services Offers (explained below), the number of Energy TUs has increased consistently over the past several years, with an average increase over the past 3 years of 2.9%.

Table 4A

[7] The 2026 Forecast is based on the May 2025 CELT Report Forecast Data Tab 1.5.2 (Net Annual Energy reduced for behind-the-meter photovoltaic). *See* https://www.iso-ne.com/static-assets/documents/100023/2025_celt.xlsx.

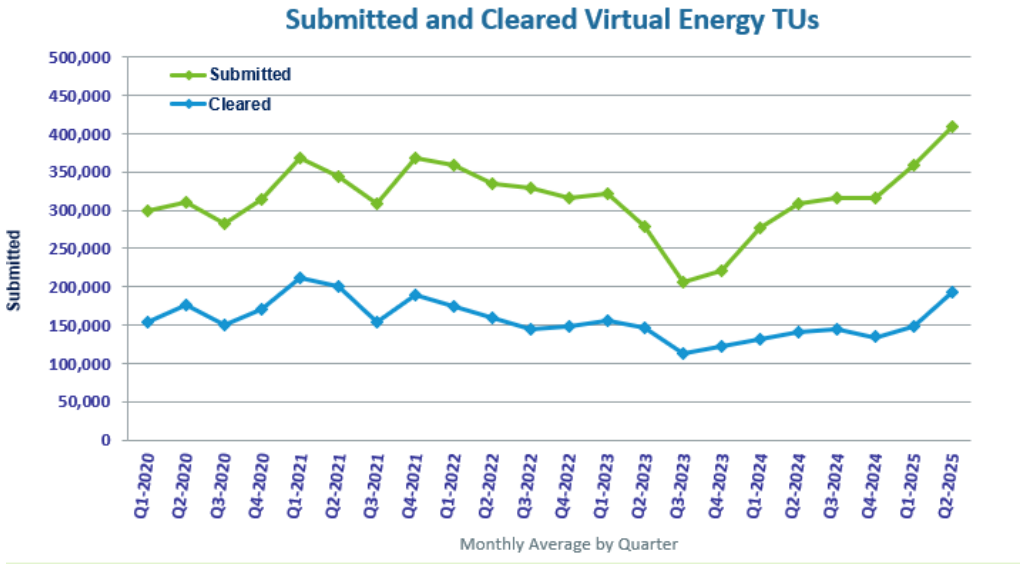


Furthermore, the Schedule 2 Energy TUs billing determinant was increased to reflect the estimated impact of Day-Ahead Ancillary Services Offers, which commenced in March 2025. As noted above, Table 4A excluded Day-Ahead Ancillary Services Offers because three years of data does not yet exist from which to estimate the average increase over the past three years. As a result, to incorporate Day-Ahead Ancillary Services Offers into the billing determinants, the ISO looked at the average Day-Ahead Ancillary Services Offers in the five month period of March 2025 through July 2025 (average of 112,625 per month) and used that average to further escalate the Schedule 2 Energy TU billing determinant. For example, the March 2025 Energy TUs (reflected in column (d) of RCL-7, Schedule 2) was escalated by 2.9% as noted above, and then 112,625 TUs were added to such amount to arrive at the amount of estimated March 2026 Energy TUs.

For 2026, the Schedule 2 virtual transactions have been left flat from 2025 levels (see columns (e) and (f) of RCL-7, Schedule 2). As shown in Table 4B below,

the number of submitted virtual transactions has fluctuated over the past several years without an observable trend and, overall, has not changed significantly during this period. Therefore, the escalation factor for Submitted Virtual TU remains flat. Similarly, the number of Cleared Virtual Transactions has not shown an observable trend and the ISO has not been able to identify any specific market change or participant behavior that can be attributed to the increase and, therefore, the ISO decided to leave the Cleared Virtual TU determinant flat. Table 4B below provides actual Virtual Energy TU data from 2020 through the second quarter of 2025.

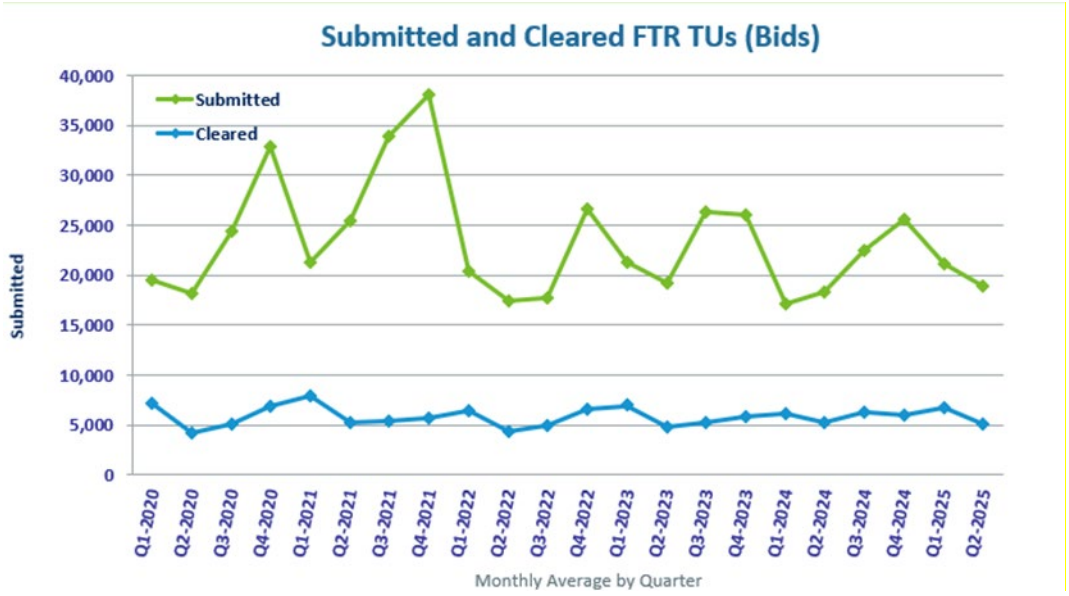
Table 4B



The Schedule 2 FTR determinants were left flat (see columns (g) and (h) of RCL-7, Schedule 2). The number of FTR transactions have fluctuated over the past several years and while overall FTR costs have consistently reflected the costs to

operate the FTR market, submitted and cleared FTRs have historically fluctuated in an inconsistent manner. Although monthly reconfiguration auctions were implemented in October 2019, it is unclear if such auctions have resulted in different FTR bidding behavior. In sum the FTR billing determinants for 2026 were left flat due to the lack of a clear pattern in FTR bidding activity. Table 5 below provides actual FTR TU data from 2020 through the second quarter of 2025.

Table 5



Finally, the Schedule 3 billing determinant based on export volumes remains flat from 2025 levels as shown in RCL-7, Schedule 2, column (k). The remainder of the Schedule 3 revenue requirement is assessed via a billing determinant related to NCP Load Obligation which was escalated as noted above.

Leaving the billing determinants flat for the Schedule 2 virtual and FTR transactions and the Schedule 3 determinant based on export volumes does not pose a material risk to 2026 tariff over or under collection because the combined amount of collections for these determinants is forecasted to be 1.4% of total collections.

THE 2026 BILLING DETERMINANTS

Q. PLEASE DESCRIBE THE SCHEDULE 1 RATE CALCULATION.

A. RCL-7, Schedule 3, lines 1 through 3 show the Schedule 1 Billing Determinants and the Revenue Requirement allocated thereto. Dividing the Revenue Requirement by the forecasted billing units yields the rate for 2026 of $0.00040/kW-hour.

Q. PLEASE DESCRIBE THE SCHEDULE 2 RATE CALCULATION.

A. Schedule 2 employs a declining blocked rate structure for Energy TUs and VMs. The three-tiered declining block structure is discussed earlier in my testimony. Increment Offers and Decrement Bid TUs and FTR TUs incur unitized charges. RCL-7 (Schedule 3) and Table 6 (below) provide the Schedule 2 rates proposed

for 2026.

TABLE 6

Description		TY 2026	
(a)		(b)	
Transaction Units			
INC Offers/DEC Bids			
Submitted		$ 0.00500	/Offer or Bid
Cleared		$ 0.06000	/Offer or Bid
Financial Transmission Rights			
Submitted		$ 3.87023	/Bid
Cleared		$ 6.17635	/Bid
Energy Transaction Units			
Block 1 - 1st	12,500TUs	$ 0.86039	/TU-hour
Block 2 – Next	27,000TUs	$ 0.78217	/TU-hour
Block 3 – Over	39,500TUs	$ 0.70396	/TU-hour
Volumetric Measures			
Block 1 - 1st	250,000MWH	$ 0.58201	/MWh
Block 2 – Next	1,250,000MWH	$ 0.52910	/MWh
Block 3 – Over	1,500,000MWH	$ 0.47619	/MWh

Q. PLEASE EXPLAIN HOW THE RATES FOR EACH BLOCK ARE CALCULATED.

A. The rate components in all cases reflect an approximate 10% differential from the average rate.

Q. PLEASE DESCRIBE THE SCHEDULE 3 RATE CALCULATION.

A. RCL-7, Schedule 3 at lines 30 through 33 and Table 7 below list the billing rate calculation. Exports are assessed a unitized charge per MWh based on the Schedule 3 Revenue Requirement using the CELT Report's real-time load

obligation forecast for 2026.[8] The export rate is then applied to the total MWh of Exports forecasted for the test year to determine the portion of the Schedule 3 Revenue Requirement assessed to exports. The remaining Revenue Requirement for Schedule 3 (*i.e.*, net of that allocated to exports) is then divided by the total Real-Time NCP Load Obligation forecast to yield the unitized rate per kW-month.

TABLE 7

Description	TY 2026	
	Amount	%
Revenue Requirement ($)	$ 94,058,203	100.0%
Real-Time NCP Load Obligation	$ 91,357,350	97.1%
Export Rate	$ 2,700,853	2.9%
Billing Units		
Real-Time NCP Load Obligation	253,266,481 /kW-Mo.	
Export Rate	3,376,066 /MWh	
Rates		
Real-Time NCP Load Obligation	$ 0.36072 /kW-Mo.	
Rate on Exports	$ 0.80000 /MWh	

RATE SUMMARY

Q. WOULD YOU PLEASE SUMMARIZE THE RATES FOR 2026 THAT YOU ARE SPONSORING?

A. Yes. These rates are summarized in Table 8.

[8] The 2026 Forecast is based on the May 2025 CELT Report Forecast Data Tab 1.5.2 (Net Annual Energy reduced

Table 8
2026 Rate Components (1)

Tariff Schedule	Jan. 1, 2026
Schedule 1	
Network Load (per kW-hour)	$0.00040
Schedule 2	
TU Bids (Virtual Inc/Dec)	
Submitted	$0.00500
Cleared	$0.06000
FTR Bids	
Submitted	$3.87023
Cleared	$6.17635
TU's	
Block 1 - 1st 12,500	$0.86039
Block 2 - Next 27,000	$0.78217
Block 3 - Over 39,500	$0.70396
Volumetric	
Block 1 - 1st 250,000	$0.58201
Block 2 - Next 1,250,000	$0.52910
Block 3 - Over 1,500,000	$0.47619
Schedule 3	
R-T NCP Load Obligation	$0.36072
Export Rate	$0.80000

(1) From Exh 3, RCL-7, Sch. 3

Q. PLEASE EXPLAIN THE SPECIAL CALCULATION FOR A REVENUE SHORTFALL ATTRIBUTABLE TO TUs USED IN SCHEDULE 2.

for behind-the-meter photovoltaic). *See* https://www.iso-ne.com/static-assets/documents/100023/2025_celt.xlsx.

A. In the event of a revenue shortfall attributable to TUs in the true-up year (in this case, 2024), the shortfall allocation has two components. The first component allocates the first 50% of the shortfall to Schedule 2 VMs rather than the usual 15/85 allocation of Schedule 2 Revenue Requirements between TUs and VMs, respectively. The second component increases the percentage of the shortfall allocated to VMs by an additional percentage for each percentage decrease which occurred between the number of TUs used in the current true-up (based on year-to-date actual data through July of the current year) and the number of TUs that the ISO had used in the original projection of the rates for that year.

As shown in RCL-7, Schedule 6, the final 2024 amount is an over-collection of $768,585. Accordingly, there is no variation for 2026 to the 15/85 allocation of the Schedule 2 revenue requirement between TUs and VMs.

FIXED FEES

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THE RATES INCLUDED IN THE PROPOSED 2026 TARIFF?

A. Yes. Schedule 3 includes certain RAS Fees that are applicable to Transmission Customers who are non-Market Participants. This fee is currently $5.58 (hourly). For 2026, I am proposing to decrease this hourly fee to $5.39.

Q. PLEASE EXPLAIN HOW YOU DERIVED THE PROPOSED HOURLY RAS FEE.

A. The proposed RAS Fee was developed by applying a ratio of the Schedule 3 forecasted revenue requirement for 2026 to the Schedule 3 forecasted revenue requirement for 2002 to the 2002 RAS Monthly (($671 x ($94,058,203/$16,035,649) = $3,935.80), and breaking that down to an hourly rate ($3,935.82/730), which for 2026 is $5.39.

Q. DID YOU DEVELOP THE APPROPRIATE RAS FEES FOR THOSE CUSTOMERS WHO TAKE SERVICE FOR PERIODS OF LESS THAN ONE MONTH?

A. Yes. These charges are shown below in Table 9.

Table 9
RAS Fees

Line No.	Item	Current	Proposed Jan. 1, 2026
	(a)	(b)	(c)
1	Monthly Calculation	$ 4,071.50	$ 3,935.82
2	Hourly Fee	$ 5.58	$ 5.39

Q. UNDER THE RATES PROPOSED IN THIS FILING, WHAT HAPPENS TO THE REVENUE DERIVED FROM THESE RAS FEES?

A. Any revenue derived from the RAS Fees will be credited back on a monthly basis to all Market Participants who take service under Schedule 3 in proportion to the total charges incurred by the Market Participants for that month.

DESCRIPTION OF 2026 CAPITAL BUDGET

Q. PLEASE GENERALLY DESCRIBE THE PURPOSE OF THE CAPITAL BUDGET AND THE PROPOSED 2026 CAPITAL BUDGET.

A. As described in the filing letter, the 2026 Capital Budget is a list of the ISO's planned capital expenditures in 2026. The ISO does not make any collections through its capital budget; rather, the capital projects reflected in the budget are funded through private placement financing. The ISO funds the capitalized portion of the interest on that financing through recovery of depreciation under its annual operating budget, as discussed in Section I.C.2 of the filing letter. In sum, the costs of these projects are collected once only, through the depreciation recovery in the Revenue Requirement. The proposed 2026 Capital Budget is $42.5 million, consistent with the 2025 Capital Budget.

Q. PLEASE EXPLAIN THE 2026 CAPITAL BUDGET DRIVERS.

A. The 2026 Capital Budget is $42.5 million. As explained in my testimony in support of the 2022, 2023, 2024, and 2025 capital budgets, the ISO's capital budget had remained constant at $28 million per year for several years, but the ISO's capital budget needs were increasing. As a result, the capital budget has steadily, but incrementally, increased from 2021 ($28 million) to $42.5 in 2025. Although the ISO had previously expected the capital budget to level out, based on the ISO's updated cash flow analysis (which includes a 10 year cash flow estimation with a focus on major capital project spending), the ISO has revised its

expectation and anticipates that the capital budget may continue to increase. This revised expectation continues to be as a result of inflation, of both labor and hardware costs, and longer lead times on the more complex projects, especially projects supporting cyber security and/or electric grid transition initiatives. Longer lead times on projects delay when they are placed into production which is the trigger allowing the ISO to begin collecting depreciation under the operating budget.

The 2026 Capital Budget is consistent with these expectations and the proposed $42.5 million is necessitated by four primary drivers: (i) the nGem platform replacement of the current market system which will conclude in 2026; (ii) major market and reliability related efforts that will have significant software requirements; (iii) cyber security needs; and (iv) required information technology asset and infrastructure replacements.

Q. PLEASE PROVIDE DETAILS REGARDING THE REPLACEMENT OF THE CURRENT MARKET SYSTEMS PLATFORM AS IT RELATES TO THE 2026 CAPITAL BUDGET.

A. As I have previously testified, for several years, the ISO has been involved in various stages of the nGEM project. General Electric (GE) proposed the nGEM program (next Generation Markets) to upgrade core market software, replacing the ISO's current market system. The upgraded system will support a growing number and types of grid assets, support new and more complex market features,

include more advanced cyber security protections, and include updated technology. The cost of this upgrade is being shared among three independent system operators (ISO New England, PJM, and MISO) while the portion of the software upgrade unique to each entity will be shouldered by each independent system operator individually.

In mid-2023 the infrastructure and implementation of the day-ahead version of the new market clearing engine software was completed. The next phases of the nGEM project will include a real-time version of the market clearing engine software and is expected to continue until 2026 with an estimated cost of $15.0 million. This final phase will complete the platform replacement projects. As we continue to develop our three – five year work plan around market products and reforms, further customization to the nGem platform may be required impacting capital spending. The ISO will continue to inform the NEPOOL Budget and Finance Subcommittee of the capital budget impacts of such work as part of the periodic capital budget discussions.

Q. PLEASE PROVIDE DETAILS REGARDING THE MAJOR MARKET AND RELIABILITY EFFORTS AS IT RELATES TO THE 2026 CAPITAL BUDGET.

A. The capital budget supports the ISO's efforts to build or incorporate major market and reliability services and reforms and will continue to support the ISO's market design objectives for 2026 and beyond, including the four pillars to support a

successful energy transition.[9] Many of the market and reliability projects are complex efforts that will have long lead times to complete and have various external dependencies, such as stakeholder and Commission approval. The following projects have currently been identified for 2026 and beyond, but priorities may fluctuate based on the stakeholder and regulatory process: Significant Capacity Market Reforms (work to move from a forward capacity auction construct to a prompt and seasonal capacity auction construct to mitigate energy adequacy risks as the power system evolves); Commission Order 2222 (software systems to integrate distributed energy resources into the wholesale markets); Transmission Line Ratings Enhancements (in response to Commission orders and will require substantial information technology and database work to collect and appropriately use data in planning and operations); Market Simulator/21 Day Energy Simulator/Inverter-Based Resource Modeling (research and development efforts that will result in significant improvements to ISO modeling capabilities and situational awareness); and other projects as identified through the stakeholder prioritization progress, the rolling annual work plan process (including improvements to the existing ancillary services products), and Commission orders. Based on the scope of the foregoing, these efforts are expected to cost approximately $40 million to $60 million, on a rolling basis, over the next five years. Major market and reliability efforts may extend beyond the

[9] *See* the Budget Presentation, Slide 13, for an explanation of the four pillars of supporting a successful energy transition.

five years and the ISO will continue to inform the NEPOOL Budget and Finance Subcommittee of the capital budget impacts as part of the periodic capital budget discussions.

Q. PLEASE PROVIDE DETAILS REGARDING CYBER SECURITY AS IT RELATES TO THE 2026 CAPITAL BUDGET.

A. As noted in prior filings, and in further support of the ISO's Operational Excellence (Goal 3) and Progress and Innovation (Goal 2) strategic goals, the ISO's cyber security efforts will need to continue to evolve and adapt to emerging threats and new attack vectors. The ISO expects that it will continue to invest in improved monitoring, detection, and recovery tools to keep pace with increasingly sophisticated attack threats. The ISO has greatly benefited from earlier investments in this area and is now able to layer improved defense, network segmentation, email and web filtering to improve monitoring, detection, and recovery tools to keep pace with the increased sophistication of attacks. The combined costs for information technology asset and infrastructure upgrades (described below) and cyber security initiatives are expected to cost approximately $20 million to $40 million, on a rolling basis, over the next five years. Cyber security efforts will likely extend beyond the five years and the ISO will continue to inform the NEPOOL Budget and Finance Subcommittee of the capital budget impacts as part of the periodic capital budget discussions.

Q. PLEASE PROVIDE DETAILS REGARDING INFORMATION TECHNOLOGY ASSET AND INFRASTRUCTURE UPGRADES AS IT RELATES TO THE 2026 CAPITAL BUDGET.

A. In support of the ISO's Operational Excellence (Goal 3) and Progress and Innovation (Goal 2) strategic goals, the ISO has recently begun the process of a major hardware upgrade which includes moving a portion of the ISO's information technology services to web services. Specifically, the reliability of operating a modern system comprised of renewable and storage resources requires the processing, transfer, and storage of vast amounts of data. As a result, the ISO will be implementing cloud-computing infrastructure and virtualization technology to reduce reliance on energy-heavy data centers and enable a more dynamic expansion of computing capability, while maintaining reliability. As the ISO migrates to a cloud environment, the ISO also must comply with NERC CIP requirements that prohibit certain functions from being hosted in a cloud environment, resulting in the ISO needing to maintain on premise infrastructure for certain functions. The combined costs for information technology asset and infrastructure upgrades and cyber security initiatives (as described above) are expected to cost approximately $20 million to $40 million, on a rolling basis, over the next five years. Information technology asset and infrastructure upgrades may extend beyond the five years and the ISO will continue to inform the NEPOOL Budget and Finance Subcommittee of the capital budget impacts as part of the periodic capital budget discussions.

CONCLUSION

Q. DO YOU WISH TO OFFER ANY FURTHER TESTIMONY OR EXHIBITS?

A. I would like to incorporate the Cross Reference Table regarding Statements AA-BM (Exhibit 6 to the filing letter) into my sworn testimony. This table identifies where the cost-of-service data identified in the Commission's Statements AA-BM can be found in my attached exhibits. The table also identifies what data identified in the Commission's Statements AA-BM is inapplicable to the ISO as a non-profit RTO that does not own any generation or transmission assets and is therefore not included in this filing.

Q. DOES THAT CONCLUDE YOUR PRE-FILED TESTIMONY?

A. Yes.

I declare under penalty of perjury that the foregoing is true and correct.

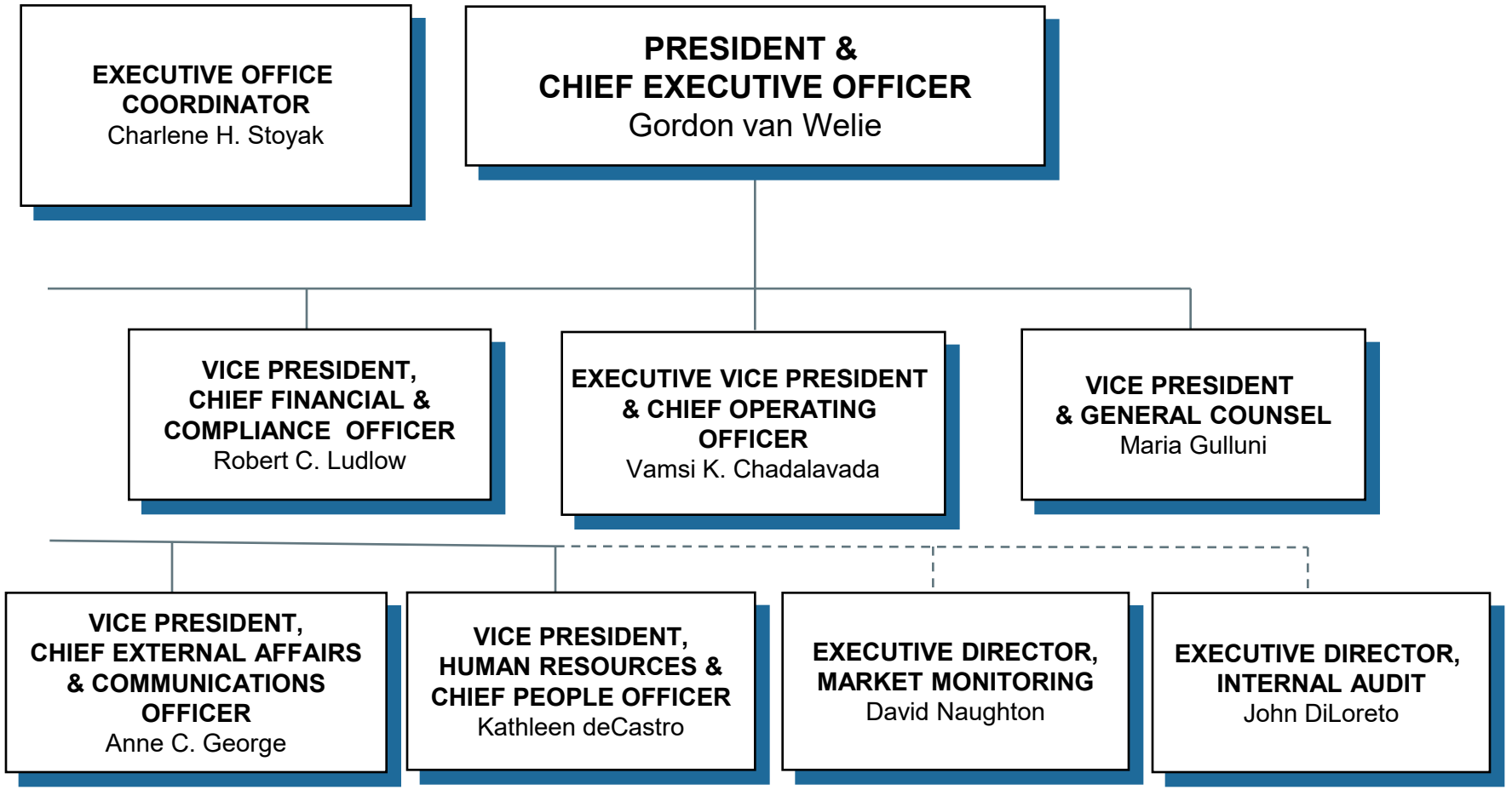
Executed on October 15 2025

Robert C. Ludlow

Chief Executive Officer

Exhibit 3

RCL-1



ISO NEW ENGLAND INC.
2026 REVENUE REQUIREMENT

(in thousands of dollars)

Line No.				
	Operating Expense Budget:			
1	**Operating Budget**		$	278,016.6
2				
3	**Depreciation, interest expense and Regulatory Fees**			
4	Depreciation and Regulatory Fees	48,207.0		
5	Interest	3,767.9		
6				51,974.9
7				
8	**Total 2026 Operating Expense Budget**		**$**	**329,991.5**
9				
10	**2026 Operating Expense Revenue Requirement**		**$**	**329,991.5**
11				
12	**True-Up Amount**			
13				
14	2024 (Over)/ Under Collection		**$**	**(15,601.7)**
15				
16				
17	**Total 2026 ISO Revenue Requirement**		**$**	**314,389.8**

ISO New England Inc.
2024 True-Up Amount

Line No.		Total	Schedule 1	Schedule 2	Schedule 3
1	2024 Total Operating Expense	$ 262,337,608	$ 56,000,847	$ 127,645,129	$ 78,691,631
2	2024 Total Collections	$ 277,939,328	$ 58,471,078	$ 133,981,974	$ 85,486,276
3					
4	2024 Total (Over) / Under Collection	$ (15,601,720)	$ (2,470,230)	$ (6,336,845)	$ (6,794,645)

Exhibit 3 (RCL-3)

ISO NEW ENGLAND INC.

FERC DOCKET NO. ER26-___-000

COST ALLOCATIONS

TEST YEAR 2026

Exhibits For Robert C. Ludlow

ISO NEW ENGLAND INC.

FERC DOCKET NO. ER26-___-000
TOTAL COST ALLOCATION TO SCHEDULES BY DEPARTMENT
TEST YEAR 2026

Line No.	Department Description	Self-Funding Tariff			
		Total	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)
1	**Administration-CEO**	$ 15,138,422	$ 3,262,330	$ 7,834,133	$ 4,041,959
2					
3	**Finance**	85,836,083	13,067,861	42,083,386	30,684,836
4					
5	**Facilities & Security**	2,982,305	642,687	1,543,343	796,275
6					
7	**Strategy, Risk & Operations Compliance**	3,044,338	1,043,611	967,840	1,032,887
8					
9	**Market & Credit Risk**	356,366	76,797	184,419	95,150
10					
11	**Human Resources**	13,921,000	2,999,976	7,204,118	3,716,907
12					
13	**Legal Department**	15,315,226	2,181,836	8,194,964	4,938,426
14					
15	**Internal Audit**	3,800,713	680,259	2,277,626	842,827
16					
17	**ISO Operations**				
18	COO-Adm	1,449,040	338,335	605,342	505,363
19	System Operations & Market Administration	1,044,707	313,033	517,591	214,082
20	Operations	11,219,364	3,269,760	6,210,846	1,738,758
21	Operational Performance Trng and Integration	7,303,832	2,654,222	3,250,305	1,399,305
22	Operations Support Services	6,767,443	3,182,140	1,167,065	2,418,238
23	Market Monitoring	6,300,109	-	4,387,813	1,912,296
24	Market Administration & Auctions	2,287,119	205,666	2,056,840	24,613
25	Market Analysis & Settlements	3,802,329	487,417	1,668,076	1,646,836
26	Market Operations Support Services	1,810,884	276,264	1,025,439	509,181
27	Participant Support & Solutions	3,548,601	524,039	2,791,216	233,347
28	Participant Training Services	1,913,273	-	1,133,959	779,314
29	System Planning	1,452,242	35,700	679,725	736,818
30	Planning Services	4,924,218	369,887	837,487	3,716,845
31	Transmission Planning	12,749,258	12,460,318	-	288,939
32	Program Management	2,858,515	499,767	1,577,654	781,094
33	Advanced Technology Solutions	7,052,212	1,275,894	3,063,921	2,712,397
34	Market Development & Settlements Admin.	13,190,456	315,831	3,934,593	8,940,033
35	Participant Relations & Services	2,744,254	525,024	1,414,762	804,468
36	IT Management	8,344,734	1,853,820	4,237,425	2,253,489
37	IT Infrastructure Services	34,336,745	4,089,052	20,943,130	9,304,562
38	IT Architecture & Analytics	20,306,769	3,011,860	11,469,895	5,825,014
39	IT Enterprise Applications Development	5,718,773	25,657	4,541,384	1,151,731
40	IT Energy Management Systems	13,225,859	4,517,950	6,585,714	2,122,195
41	IT Cyber Security	9,350,390	2,015,009	4,838,827	2,496,554
42	IT Power System Modeling Management	5,895,912	1,838,031	1,869,771	2,188,110
43	Total ISO Operations	189,597,037	44,084,678	90,808,779	54,703,581
44					
45	Total ISO Revenue Requirement	$ 329,991,490	$ 68,040,034	$ 161,098,608	$ 100,852,848
46	True-up from 2024	(15,601,720)	(2,470,230)	(6,336,845)	(6,794,645)
47	Total True-up	$ (15,601,720)	$ (2,470,230)	$ (6,336,845)	$ (6,794,645)
48					
49	ISO Net Revenue Requirement	$ 314,389,770	$ 65,569,804	$ 154,761,763	$ 94,058,203

(1) From Exhibit 3 (RCL-3), Schedule 3.0.

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER26-___-000
TOTAL DIRECT LABOR ALLOCATION TO SCHEDULES BY DEPARTMENT
TEST YEAR 2026

Line No.	Department Description	Self-Funding Tariff			
		Total	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)
1	**Administration-CEO**	$ 4,431,147	$ 954,912	$ 2,293,119	$ 1,183,116
2					
3	**Finance**	29,941,347	6,452,999	15,494,463	7,993,884
4					
5	**Facilities & Security**	737,637	158,961	381,727	196,949
6					
7	**Strategy, Risk & Operations Compliance**	2,879,672	992,306	901,220	986,146
8					
9	**Market & Credit Risk**	356,366	76,797	184,419	95,150
10					
11	**Human Resources**	8,141,897	1,754,579	4,213,432	2,173,886
12					
13	**Legal Department**	10,170,604	1,767,590	4,419,635	3,983,380
14					
15	**Internal Audit**	2,154,196	424,700	1,203,303	526,194
16					
17	**ISO Operations**				
18	COO-Adm	996,540	267,073	477,841	251,626
19	System Operations & Market Administration	970,461	287,405	483,115	199,941
20	Operations	11,093,153	3,304,108	6,051,313	1,737,733
21	Operational Performance Trng and Integration	7,292,051	2,575,953	3,339,477	1,376,621
22	Operations Support Services	6,630,273	3,129,185	1,129,927	2,371,161
23	Market Monitoring	5,119,788	-	3,583,852	1,535,936
24	Market Administration & Auctions	2,285,185	205,666	2,054,967	24,552
25	Market Analysis & Settlements	3,792,528	485,968	1,663,302	1,643,258
26	Market Operations Support Services	1,809,366	276,264	1,023,920	509,181
27	Participant Support & Solutions	1,631,366	424,155	1,076,702	130,509
28	Participant Training Services	3,692,688	68,944	2,760,523	863,221
29	System Planning	1,443,084	34,955	676,114	732,016
30	Planning Services	4,323,635	317,898	677,168	3,328,569
31	Transmission Planning	10,711,082	10,481,424	-	229,658
32	Program Management	2,802,501	493,704	1,551,732	757,064
33	Advanced Technology Solutions	6,045,527	1,142,244	2,742,975	2,160,308
34	Market Development & Settlements Admin.	10,854,802	311,196	3,796,943	6,746,663
35	Participant Relations & Services	2,688,765	521,550	1,386,736	780,479
36	IT Management	8,176,070	1,817,472	4,150,142	2,208,456
37	IT Infrastructure Services	10,293,521	1,875,345	5,299,051	3,119,125
38	IT Architecture & Analytics	9,052,312	1,550,281	4,880,335	2,621,696
39	IT Enterprise Applications Development	4,846,442	20,462	3,850,331	975,650
40	IT Energy Management Systems	6,401,306	2,217,165	3,181,207	1,002,934
41	IT Cyber Security	3,082,180	664,210	1,595,028	822,942
42	IT Power System Modeling Management	4,591,344	1,372,779	1,457,602	1,760,964
43	Total ISO Operations	130,625,970	33,845,406	58,890,299	37,890,265
44					
45	Total ISO Direct Labor	$ 189,438,836	$ 46,428,249	$ 87,981,617	$ 55,028,971

(1) From Exhibit 3 (RCL-3), Schedule 4.0.

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER26-___-000
TOTAL COST ALLOCATIONS TO SCHEDULES BY COST CATEGORY
TEST YEAR 2026

Line No.	Activity Code No.	Activity Code Description	Allocation Factor (1)	Self-Funding Tariff Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Administration-CEO**					
2	12651	Indirect Administrative Support	Total Dir Labor	$ 13,298,076	$ 2,865,735	$ 6,881,754	$ 3,550,586
3	12652	NEPOOL Committee Support	Total Dir Labor	8,925	1,923	4,619	2,383
4	12653	Adm/Finance/HR - Regional Committee Support	Total Dir Labor	225	48	116	60
5	12654	National Committee Support	Total Dir Labor	22,226	4,790	11,502	5,934
6	12657	Indirect Administrative Support for BCC	Total Dir Labor	1,808,969	389,833	936,142	482,995
7		Total		15,138,422	3,262,330	7,834,133	4,041,959
8							
9		**Finance**					
10	11601	Payroll Administration	Total Dir Labor	983,679	211,983	509,054	262,642
11	11701	Accounts Payable	Total Dir Labor	362,333	78,083	187,507	96,743
12	11702	Procurement	Total Dir Labor	490,330	105,666	253,746	130,918
13	11901	Settle for Power Transactions	Total Dir Labor	89,092	19,199	46,105	23,787
14	12001	Budgeting and Forecasting	Total Dir Labor	723,495	155,913	374,409	193,173
15	12005	Credit Administration	Total Dir Labor	2,445,911	527,094	1,265,759	653,058
16	12101	Ledger Closing, Financial Statements and Tax Reporting	Total Dir Labor	579,095	124,795	299,682	154,618
17	12201	Treasury and Cash Management	Total Dir Labor	2,843,109	612,690	1,471,309	759,110
18	25554	Generation Information System	Alloc-Fixed	2,726	1,227	1,227	273
19	92004	Depreciation Expense 2004 Assets	Alloc-Fixed	43,160	8,988	22,535	11,637
20	92005	Depreciation Expense 2005 Assets	Alloc-Fixed	773,169	163,467	402,125	207,577
21	92006	Depreciation Expense 2006 Assets	Total Dir Labor	568,947	122,608	294,430	151,909
22	92007	Depreciation Expense 2007 Assets	Total Dir Labor	156,427	33,710	80,951	41,766
23	92008	Depreciation Expense 2008 Assets	Total Dir Labor	548	118	284	146
24	92009	Depreciation Expense 2009 Assets	Total Dir Labor	1,230	265	637	328
25	92010	Depreciation Expense 2010 Assets	Total Dir Labor	-	-	-	-
26	92012	Depreciation Expense 2012 Assets	Total Dir Labor	80,431	17,333	41,623	21,475
27	92013	Depreciation Expense 2013 Assets	Total Dir Labor	827,131	178,247	428,040	220,844
28	92014	Depreciation Expense 2014 Assets	Total Dir Labor	73,004	15,732	37,780	19,492
29	92015	Depreciation Expense 2015 Assets	Total Dir Labor	-	-	-	-
30	92016	Depreciation Expense 2016 Assets	Alloc-Fixed	24,623	5,306	12,742	6,574
31	92017	Depreciation Expense 2017 Assets	Alloc-Fixed	204,793	13,222	175,190	16,381
32	92018	Depreciation Expense 2018 Assets	Alloc-Fixed	187,203	454	186,187	562
33	92019	Depreciation Expense 2019 Assets	Alloc-Fixed	248,828	3,787	240,349	4,692
34	92020	Depreciation Expense 2020 Assets	Alloc-Fixed	837,935	45,388	778,639	13,907
35	92021	Depreciation Expense 2021 Assets	Alloc-Fixed	1,756,067	136,432	1,444,947	174,688
36	92022	Depreciation Expense 2022 Assets	Alloc-Fixed	3,880,288	462,288	2,218,212	1,199,788
37	92023	Depreciation Expense 2023 Assets	Alloc-Fixed	8,386,105	1,126,773	4,358,811	2,900,522
38	92024	Depreciation Expense 2024 Assets	Alloc-Fixed	8,251,294	1,044,920	4,487,461	2,718,913
39	92025	Depreciation Expense 2025 Assets	Alloc-Fixed	9,083,835	1,138,581	5,677,606	2,267,648
40	92026	Depreciation Expense 2026 Assets	Alloc-Fixed	2,767,527	425,140	1,666,741	675,646
41	99707	Amortization of Land Recovery	Alloc-Fixed	39,300	2,460	24,170	12,670
42	99995	NPCC/NERC Dues	Alloc-Fixed	9,955,133	-	-	9,955,133
43	99996	Operating Contingency	Total Dir Labor	700,000	150,850	362,250	186,900
44	99996	Operating Contingency	Total Dir Labor	3,000,000	646,500	1,552,500	801,000
45	99998	Payroll & Other Accruals	Total Dir Labor	25,469,336	5,488,642	13,180,381	6,800,313
46		Total		85,836,083	13,067,861	42,083,386	30,684,836
47							
48		**Facilities & Security**					
49	12664	Building Maintenance	Total Dir Labor	2,982,305	642,687	1,543,343	796,275
50		Total		2,982,305	642,687	1,543,343	796,275
51							
52		**Strategy, Risk & Operations Compliance**					
53	14806	Employee Development	Alloc-Fixed	25,470	14,149	4,923	6,398
54	14807	NERC RSAW Update and Audit Prep	Alloc-Fixed	1,084,973	542,487	-	542,487
55	14809	ROC - Tariff Compliance	Alloc-Fixed	296,073	88,822	177,644	29,607
56	14816	Support NE Compliance Groups	Total Dir Labor	107,663	23,201	55,716	28,746
57	22704	Record Retention Services	Alloc-Fixed	122,007	40,628	40,628	40,750
58	22705	Corporate Scorecard	Alloc-Fixed	53,833	17,926	17,926	17,980
59	22706	Document Management Services	Alloc-Fixed	120,193	48,077	36,058	36,058
60	22719	Human Performance Improvement	Total Dir Labor	12,819	2,762	6,634	3,423
61	22721	Corp Strategic Risk	Total Dir Labor	776,524	167,341	401,851	207,332
62	23006	Business Continuity Planning	Total Dir Labor	424,645	91,511	219,754	113,380
63	25011	Corrective Action/Preventive Action	Alloc-Fixed	20,138	6,706	6,706	6,726
64		Total		3,044,338	1,043,611	967,840	1,032,887
65							
66		**Market & Credit Risk**					
67	22714	FAP Analysis	Total Dir Labor	356,366	76,797	184,419	95,150
68		Total		356,366	76,797	184,419	95,150
69							
70		**Human Resources**					
71	12661	Employee Affairs (Recreation Committee)	Total Dir Labor	88,211	19,010	45,649	23,552
72	12701	Recruiting/Interviewing	Total Dir Labor	1,602,611	345,363	829,351	427,897
73	12702	Intern Expense	Total Dir Labor	333,346	71,836	172,506	89,003
74	12801	Employee Relations	Total Dir Labor	1,750	377	906	467
75	12901	Benefit Administration	Total Dir Labor	2,041,891	440,028	1,056,679	545,185
76	12951	Compensation	Total Dir Labor	1,528,289	329,346	790,890	408,053
77	12961	HR - General	Total Dir Labor	975,249	210,166	504,691	260,391
78	12962	HR - Training	Total Dir Labor	1,822,310	392,708	943,046	486,557
79	13410	Power Training & Development	Total Dir Labor	2,113,357	455,428	1,093,662	564,266
80	13411	Markets Training & Development	Total Dir Labor	529,163	114,035	273,842	141,287
81	13412	People Training & Development	Total Dir Labor	1,690,151	364,227	874,653	451,270
82	13413	Business Skills Training & Development	Total Dir Labor	301,142	64,896	155,841	80,405
83	13414	Technology Training & Development	Total Dir Labor	888,721	191,519	459,913	237,289
84	13602	Enterprise Learning - Cyber Security Training & Documentation Worl	Total Dir Labor	353	76	183	94
85	22311	Employee Development	Total Dir Labor	4,455	960	2,305	1,189
86		Total		13,921,000	2,999,976	7,204,118	3,716,907

(1) From Exhibit 3 (RCL-3), Schedule 5.0.
(2) Provided by ISO-NE.

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER26-___-000
TOTAL COST ALLOCATIONS TO SCHEDULES BY COST CATEGORY
TEST YEAR 2026

Line No.	Activity Code No.	Activity Code Description	Allocation Factor (1)	Self-Funding Tariff Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Legal Department**					
2	12422	Interconnection Queue	Alloc-Fixed	318,510	-	-	318,510
3	12502	Board of Directors	Total Dir Labor	341,224	73,534	176,583	91,107
4	12508	Energy Markets / Complaints / Rule Changes	Alloc-Fixed	2,181,856	-	2,181,856	-
5	12513	Miscellaneous Labor Matters	Total Dir Labor	151,893	32,733	78,605	40,555
6	12514	NEPOOL Participants Committee	Total Dir Labor	175,232	37,763	90,683	46,787
7	12517	Administrative and Clerical Support	Total Dir Labor	663,562	142,998	343,393	177,171
8	12543	Independent Market Advisor	Alloc-Fixed	1,425,000	-	997,500	427,500
9	12559	General Corporate	Total Dir Labor	2,159,747	465,426	1,117,669	576,653
10	12587	Capacity Market Development	Alloc-Fixed	929,107	-	-	929,107
11	12588	GC- Web Content Management	Total Dir Labor	690,681	148,842	357,427	184,412
12	12606	GC - NERC	Alloc-Fixed	120	54	12	54
13	12611	GC - Ancillary Services Markets	Alloc-Fixed	132,712	-	-	132,712
14	12617	GC - IRC Activities	Total Dir Labor	10,283	2,216	5,321	2,745
15	12619	Compliance	Alloc-Fixed	398,137	159,255	159,255	79,627
16	12622	Open Access Transmission Tariff	Alloc-Fixed	225	225	-	-
17	12627	GC - State Relations/Programs/Task Force Comm	Total Dir Labor	315	68	163	84
18	12631	GC - FERC Order 1000 (Legal Only)	Alloc-Fixed	545,325	-	-	545,325
19	12663	Public Information	Total Dir Labor	2,374,899	511,791	1,229,010	634,098
20	12669	Government Affairs	Total Dir Labor	2,816,398	606,934	1,457,486	751,978
21		Total		15,315,226	2,181,836	8,194,964	4,938,426
22							
23		**Internal Audit**					
24	15001	Indirect Management Duties	Total Dir Labor	96,193	20,730	49,780	25,684
25	15002	Personnel Management	Total Dir Labor	48,540	10,460	25,120	12,960
26	15003	Budget & Forecasting	Total Dir Labor	32,360	6,974	16,746	8,640
27	15004	Audit Follow-up Activities	Total Dir Labor	16,180	3,487	8,373	4,320
28	15005	Audit & Finance Committee	Total Dir Labor	32,360	6,974	16,746	8,640
29	15006	Internal Audit Business Process Update	Total Dir Labor	16,180	3,487	8,373	4,320
30	15007	Annual Audit Work Plan	Total Dir Labor	462,750	99,723	239,473	123,554
31	15011	Internal Audit Meetings	Total Dir Labor	177,981	38,355	92,105	47,521
32	15013	Indirect Adminstrative Support	Total Dir Labor	2,700	582	1,397	721
33	15014	GRC Tool Admin and Development	Total Dir Labor	349,325	75,280	180,776	93,270
34	15020	Audit- Internal Audit-Finance	Total Dir Labor	83,602	18,016	43,264	22,322
35	15021	Performance Measurements	Total Dir Labor	16,180	3,487	8,373	4,320
36	15022	Vendor Contracts	Total Dir Labor	16,180	3,487	8,373	4,320
37	15023	Wire Transfers	Total Dir Labor	16,180	3,487	8,373	4,320
38	15028	Audit - Executive Compensation and Expense Reporting	Total Dir Labor	16,180	3,487	8,373	4,320
39	15029	Audit - Payroll	Total Dir Labor	16,180	3,487	8,373	4,320
40	15040	Audit-Operations	Total Dir Labor	258,882	55,789	133,971	69,121
41	15085	Audit - Information Technology	Total Dir Labor	898,502	193,627	464,975	239,900
42	15133	Satellite Operations Reviews	Total Dir Labor	35,356	7,619	18,297	9,440
43	15150	Audit - Internal Audit Other	Total Dir Labor	144,400	31,118	74,727	38,555
44	15161	External Audit- Pension Audit	Total Dir Labor	85,609	18,449	44,303	22,858
45	15162	External Audit- Financial Audit	Total Dir Labor	201,144	43,347	104,092	53,705
46	15165	External Audit - Operations	Total Dir Labor	16,180	3,487	8,373	4,320
47	15166	External Audit -Pricing Module Certification	Alloc-Fixed	26,624	-	26,624	-
48	15176	External Audit - ISO Internet Vulnerability Assessment	Total Dir Labor	14,790	3,187	7,654	3,949
49	15186	External Audit - SSAE 18 Direct Support	Total Dir Labor	32,360	6,974	16,746	8,640
50	25702	External Audit - SSAE 18 Direct Management	Alloc-Fixed	617,433	-	617,433	-
51	28005	Fraud, Waste & Abuse Program	Total Dir Labor	46,580	10,038	24,105	12,437
52	28007	Contractor/Consultant Review	Total Dir Labor	23,780	5,125	12,306	6,349
53		Total		3,800,713	680,259	2,277,626	842,827
54							
55		**COO-Adm**					
56	19001	NEPOOL Committee Support	Total OPS Labor	114,245	30,618	54,781	28,847
57	19003	National Committee Support	Total OPS Labor	23,229	6,225	11,138	5,865
58	19005	Indirect Supervision/Clerical Support	Total OPS Labor	1,124,971	301,492	539,424	284,055
59	19009	Renewable Resource Integration	Alloc-Fixed	186,595	-	-	186,595
60		Total		1,449,040	338,335	605,342	505,363
61							
62		**System Operations & Market Administration**					
63	14404	NEPOOL Committee Support	SOA Labor	9,366	3,235	4,348	1,783
64	14405	Indirect Supervision/Clerical Support	SOA Labor	615,570	212,618	285,748	117,205
65	14407	Regional Committee Support	SOA Labor	9,366	3,235	4,348	1,783
66	14408	National Committee Support	SOA Labor	271,990	93,945	126,258	51,787
67	19101	NEPOOL Committee Support	MOA Labor	138,414	-	96,890	41,524
68		Total		1,044,707	313,033	517,591	214,082

(1) From Exhibit 3 (RCL-3), Schedule 5.0.
(2) Provided by ISO-NE.

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER26-___-000
TOTAL COST ALLOCATIONS TO SCHEDULES BY COST CATEGORY
TEST YEAR 2026

Line No.	Activity Code No.	Activity Code Description	Allocation Factor (1)	Self-Funding Tariff Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Operations**					
2	14001	Generation Dispatch	Alloc-Fixed	4,158,253	-	3,492,932	665,320
3	14002	Transmission Operations	Alloc-Fixed	2,737,851	2,190,281	136,893	410,678
4	14304	Advanced Scheduling and Forecasting	Alloc-Fixed	2,375,043	118,752	1,876,284	380,007
5	14562	Ops - Regional Committee Support	OPS Labor	19,276	5,390	10,671	3,215
6	14563	National Committee Support	OPS Labor	641,968	179,494	355,394	107,080
7	14565	Employee Development	OPS Labor	17,112	4,784	9,473	2,854
8	14582	Ops - Recurring Analysis and Reporting	Total Dir Labor	634,355	136,704	328,279	169,373
9	14586	Ops - Other External Support Meetings	Alloc-Fixed	1,151	-	921	230
10	14589	Ops - OPTI Control Performance Monitor	Alloc-Fixed	634,355	634,355	-	-
11		Total		11,219,364	3,269,760	6,210,846	1,738,758
12							
13		**Operational Performance Trng and Integration**					
14	14402	Operations Training	Alloc-Fixed	1,713,229	685,291	685,291	342,646
15	14462	OSS - General Systems Operations Support	TSO Labor	636,657	206,086	304,386	126,185
16	14564	Indirect Supervision/Clerical Support	OPS Labor	1,816,725	507,956	1,005,739	303,030
17	14574	OPTI Continuing Training	Alloc-Fixed	634,615	253,846	253,846	126,923
18	14575	Ops - OPTI System Operator Initial Training	Alloc-Fixed	599,542	239,817	239,817	119,908
19	14576	Ops - OPTI Internal/External Operations Training	Alloc-Fixed	634,355	253,742	253,742	126,871
20	14577	Ops - OPTI Training Program Administration	Alloc-Fixed	634,355	253,742	253,742	126,871
21	14579	Ops - OPTI TTSE Maintenance	Alloc-Fixed	634,355	253,742	253,742	126,871
22		Total		7,303,832	2,654,222	3,250,305	1,399,305
23							
24		**Operations Support Services**					
25	14453	National Committee Support	TSO Labor	370,537	119,943	177,154	73,440
26	14454	Indirect Supervision/Clerical Support	TSO Labor	1,744,935	564,835	834,253	345,846
27	14467	OSS - Nuclear Plant Liaison	TSO Labor	13,687	-	-	13,687
28	14477	Participant project and outage coordination support	Alloc-Fixed	13,687	6,844	-	6,844
29	14756	OSS - Human Performance Improvement Program	Alloc-Fixed	134,484	-	-	134,484
30	18361	Transmission Studies, Operations, OASIS Support	Alloc-Fixed	1,736,184	1,388,947	86,809	260,428
31	18381	Transmission Outage Application - Short Term	Alloc-Fixed	1,376,964	1,101,572	68,848	206,545
32	18382	Transmission Outage Application - Long Term	Alloc-Fixed	1,376,964	-	-	1,376,964
33		Total		6,767,443	3,182,140	1,167,065	2,418,238
34							
35		**Market Monitoring**					
36	16101	Market Power Monitoring and Mitigation	Alloc-Fixed	6,263,948	-	4,384,764	1,879,184
37	16102	Regulatory Activities	Alloc-Fixed	4,357	-	3,050	1,307
38	16121	FCM Market Monitoring	Alloc-Fixed	31,804	-	-	31,804
39		Total		6,300,109	-	4,387,813	1,912,296
40							
41		**Market Administration & Auctions**					
42	21901	Day Ahead Price Monitoring	Alloc-Fixed	365,629	-	365,629	-
43	21902	Real Time Price Verification	Alloc-Fixed	548,443	-	548,443	-
44	21904	MA - NEPOOL Committee Support	Alloc-Fixed	741	-	717	23
45	21907	Indirect Supervision/Clerical Support	MA Labor	548,759	-	531,418	17,341
46	21908	Employee Development	MA Labor	228,971	-	221,736	7,235
47	21909	Customer Support	Alloc-Fixed	430	-	416	14
48	21917	Real Time Price Finalization	Alloc-Fixed	182,814	-	182,814	-
49	21915	FTR/Auction Administration	Alloc-Fixed	411,332	205,666	205,666	-
50		Total		2,287,119	205,666	2,056,840	24,613
51							
52		**Market Analysis & Settlements**					
53	1701	Billing Statements - Energy	Alloc-Fixed	205,646	-	205,646	-
54	1702	Billing Statements - Transmission	Alloc-Fixed	111,758	111,758	-	-
55	1713	Billing Statements - ISO Tariff	Total Dir Labor	11,812	2,545	6,113	3,154
56	1717	Inventoried Energy Program	Alloc-Fixed	6,663	-	-	6,663
57	1718	Mystic COS	Alloc-Fixed	30,287	-	-	30,287
58	1719	FCM Daily	Alloc-Fixed	8,783	-	-	8,783
59	2047	Score Card	STLM Labor	5,149	761	2,508	1,879
60	2048	FCM	Alloc-Fixed	439,156	-	-	439,156
61	2049	Product Testing	Alloc-Fixed	14,840	-	11,872	2,968
62	2051	Legal Support	Alloc-Fixed	3,634	-	1,817	1,817
63	2005	Customer Service	STLM Labor	18,456	2,730	8,990	6,737
64	2007	Admin support - NEPOOL Committees	STLM Labor	15,125	2,237	7,367	5,521
65	2009	Indirect Supervision/Clerical Support	STLM Labor	980,431	145,006	477,568	357,857
66	2010	Employee Development	STLM Labor	216,947	32,086	105,675	79,186
67	2013	FTR Administration	Alloc-Fixed	34,224	-	34,224	-
68	2014	Billing Statements - NCPC	Alloc-Fixed	545,462	-	272,731	272,731
69	2020	Billing Disputes	Total Dir Labor	9,086	1,958	4,702	2,426
70	2021	Analysis & Reporting	Total Dir Labor	802,406	172,918	415,245	214,242
71	2024	ASM Regulation	Alloc-Fixed	143,861	-	-	143,861
72	2025	ASM Locational Forward Reserve	Alloc-Fixed	43,310	-	-	43,310
73	2026	Batch Processing	Total Dir Labor	44,521	9,594	23,040	11,887
74	2032	Billing	STLM Labor	39,373	5,823	19,178	14,371
75	2033	Market Analysis	Alloc-Fixed	71,400	-	71,400	-
76		Total		3,802,329	487,417	1,668,076	1,646,836

(1) From Exhibit 3 (RCL-3), Schedule 5.0.
(2) Provided by ISO-NE.

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER26-___-000
TOTAL COST ALLOCATIONS TO SCHEDULES BY COST CATEGORY
TEST YEAR 2026

Line No.	Activity Code No.	Activity Code Description	Allocation Factor (1)	Self-Funding Tariff Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Market Operations Support Services**					
2	3000	Hourly Settlements Support	Alloc-Fixed	241,569	-	120,784	120,784
3	3002	Monthly Settlements Support	Alloc-Fixed	328,265	164,133	-	164,133
4	3003	MOSS - Market Analysis Support	Alloc-Fixed	13,420	-	13,420	-
5	3004	MOSS - Asset Registration and Auditing Support	Alloc-Fixed	13,420	-	13,420	-
6	3006	Customer Service	Alloc-Fixed	230,911	-	230,911	-
7	3008	Admin Support	Alloc-Fixed	416,572	-	416,572	-
8	3009	Indirect Supervision (Principal Analysts only)	Alloc-Fixed	53,682	-	53,682	-
9	3010	Employee Development	Alloc-Fixed	64,516	-	64,516	-
10	3017	Project MAS (Market Analysis & Settlements)	Alloc-Fixed	448,527	112,132	112,132	224,264
11		Total		1,810,884	276,264	1,025,439	509,181
12							
13		**Participant Support & Solutions**					
14	16001	Participant/membership support	Alloc-Fixed	9,734	-	4,867	4,867
15	16006	Call Support (Ask ISO)	Alloc-Fixed	1,750,366	455,095	1,155,242	140,029
16	16024	Training Delivery	Alloc-Fixed	6,061	-	3,030	3,030
17	16419	Asset Registration Implemented	Alloc-Fixed	502,740	-	502,740	-
18	16420	Asset Registration Review	Alloc-Fixed	45,704	-	45,704	-
19	16422	Claimed Capability Audits	Alloc-Fixed	548,443	-	548,443	-
20	16432	New Generation Coordination and Registration	Alloc-Fixed	365,629	-	365,629	-
21	16434	QMS/CAPA Process and Procedure Updates	Total Dir Labor	319,925	68,944	165,561	85,420
22		Total		3,548,601	524,039	2,791,216	233,347
23							
24		**Participant Training Services**					
25	16021	Training Development	Alloc-Fixed	1,558,628	-	779,314	779,314
26	16436	Mkt Trng/Cus Serv Indirect Supervision	Alloc-Fixed	354,645	-	354,645	-
27		Total		1,913,273	-	1,133,959	779,314
28							
29		**Planning Services**					
30	17101	Analysis	Alloc-Fixed	668,001	-	467,600	200,400
31	17131	Calculate Objective Capability	Alloc-Fixed	692,217	-	-	692,217
32	17403	TCA Application Review	Alloc-Fixed	132,615	-	-	132,615
33	17409	Environmental/Emissions Supp	Alloc-Fixed	125,112	-	-	125,112
34	17503	FCA - New Resource Qualification Support	Alloc-Fixed	437,170	-	-	437,170
35	17504	FCA - Perform Transmission / Topology Assessments	Alloc-Fixed	48,526	-	-	48,526
36	17507	FCA - Auctions & Filings	Alloc-Fixed	91,421	-	-	91,421
37	17508	FCA - Annual Reconfiguration Auction Support/Reliability Reviews	Alloc-Fixed	679,259	-	-	679,259
38	18101	Develop Load Forecast	Alloc-Fixed	948,054	189,611	189,611	568,832
39	18121	Operations Forecast Support	Alloc-Fixed	250,222	50,044	50,044	150,133
40	18131	Other Load Forecasting Activities	Alloc-Fixed	88,151	17,630	17,630	52,891
41	18133	Solar Load Forecast Development	Alloc-Fixed	375,339	75,068	75,068	225,203
42	18134	Electrification Forecasts	Alloc-Fixed	187,667	37,533	37,533	112,600
43	18135	CELT Rep-Res Outage Analysis	Alloc-Fixed	200,465	-	-	200,465
44		Total		4,924,218	369,887	837,487	3,716,845
45							
46		**System Planning**					
47	18402	Transmission Planning/Economic Studies Initiative	Alloc-Fixed	1,308,466	-	654,233	654,233
48	18531	SP - Indirect Supervision/Clerical Support	Alloc-Fixed	143,776	35,700	25,491	82,585
49		Total		1,452,242	35,700	679,725	736,818
50							
51		**Transmission Planning**					
52	21660	Stability Case Building	Alloc-Fixed	97,036	-	-	97,036
53	14715	Non DOE Funded/Unallowable	Alloc-Fixed	191,903	-	-	191,903
54	18201	Transmission System Assessment	Alloc-Fixed	8,103,281	8,103,281	-	-
55	18301	NEPOOL Administrative Support - Schedule 1 Tariff	Alloc-Fixed	137,305	137,305	-	-
56	18333	General SIS/FS	Alloc-Fixed	1,326,868	1,326,868	-	-
57	18334	Indirect Supervision/Clerical Support	Alloc-Fixed	1,062,622	1,062,622	-	-
58	18335	Regulatory Activities - NPCC	Alloc-Fixed	260,357	260,357	-	-
59	18336	National Activities	Alloc-Fixed	337,097	337,097	-	-
60	18337	TR - Regulatory Activities	Alloc-Fixed	291,122	291,122	-	-
61	18346	OATT and Oper. Agreement Dev., Adm. and Support	Alloc-Fixed	97,666	97,666	-	-
62	18349	TR - Process CEII Requests	Alloc-Fixed	48,518	48,518	-	-
63	18351	Resource Integration	Alloc-Fixed	795,480	795,480	-	-
64		Total		12,749,258	12,460,318	-	288,939
65							
66		**Program Management**					
67	801	Program Management - Administration	Total Dir Labor	1,120,098	241,381	579,651	299,066
68	1661	ISO Program Management	Alloc-Fixed	428,784	-	300,149	128,635
69	1665	Product and Test Mgmt.	Total Dir Labor	999,031	215,291	516,999	266,741
70	25003	Emerging Work Initiatives	Total Dir Labor	185,866	40,054	96,186	49,626
71	26125	Real-time Market Clearing Engine Phase I	Alloc-Fixed	4,283	-	4,283	-
72	26133	Day Ahead Ancillary Services	Alloc-Fixed	23,979	-	7,194	16,785
73	26153	CAMS Tech Upgrade	Alloc-Fixed	82,365	-	65,892	16,473
74	26187	Distributed Energy Resources (DER)	Total Dir Labor	14,109	3,040	7,301	3,767
75		Total		2,858,515	499,767	1,577,654	781,094

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ISO NEW ENGLAND INC.
FERC DOCKET NO. ER26-___-000
TOTAL COST ALLOCATIONS TO SCHEDULES BY COST CATEGORY
TEST YEAR 2026

Line No.	Activity Code No.	Activity Code Description	Allocation Factor (1)	Self-Funding Tariff Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Advanced Technology Solutions**					
2	21201	Advanced Technology Solutions	Total Dir Labor	5,907,731	1,273,116	3,057,251	1,577,364
3	21203	Employee Development	Total Dir Labor	12,889	2,778	6,670	3,441
4	21207	ATS - Capacity Auction Reforms	Alloc-Fixed	1,131,592	-	-	1,131,592
5		Total		7,052,212	1,275,894	3,063,921	2,712,397
6							
7		**Market Development & Settlements Admin.**					
8	16607	National Committee Support	Total Dir Labor	19,075	4,111	9,871	5,093
9	19104	Indirect Supervision/Clerical Support	MOA Labor	329,898	-	230,929	98,969
10	21001	Market Development	Alloc-Fixed	1,227,784	-	613,892	613,892
11	21002	Administration	Total Dir Labor	1,116,658	240,640	577,870	298,148
12	21003	Employee Development	Total Dir Labor	125,299	27,002	64,842	33,455
13	21007	Budget/Forecast Support	Total Dir Labor	204,542	44,079	105,850	54,613
14	21010	MD - Day-Ahead Reserve Market	Alloc-Fixed	179,808	-	170,817	8,990
15	21011	Capacity Market	Alloc-Fixed	837,311	-	-	837,311
16	22656	Energy, Reserve, and Regulation Markets	Alloc-Fixed	806,708	-	605,031	201,677
17	22661	Project: DER Participation	Alloc-Fixed	38,096	-	19,048	19,048
18	22662	Flexible Response Services	Alloc-Fixed	2,427,517	-	1,213,758	1,213,758
19	22663	Energy Shortage Pricing	Alloc-Fixed	430,243	-	322,682	107,561
20	22664	Capacity Auction Reforms	Alloc-Fixed	5,447,517	-	-	5,447,517
21		Total		13,190,456	315,831	3,934,593	8,940,033
22							
23		**Participant Relations & Services**					
24	22602	NEPOOL Committee Meetings & Support	Alloc-Fixed	307,948	-	153,974	153,974
25	22607	NEPOOL Committee Administration	Total Dir Labor	1,640,600	353,549	849,010	438,040
26	22613	PR&S Indirect Supervision	Total Dir Labor	277,945	59,897	143,836	74,211
27	22614	PR&S Project Development	Total Dir Labor	517,762	111,578	267,942	138,242
28		Total		2,744,254	525,024	1,414,762	804,468
29							
30		**IT Management**					
31	6517	Employee Development - Hardware/Software	Total Dir Labor	81,117	17,481	41,978	21,658
32	6519	Indirect Supervision and Clerical Support	Total Dir Labor	7,486,905	1,613,428	3,874,473	1,999,004
33	6556	Budget Preparation, Tracking & Forecast	Total Dir Labor	324,648	69,962	168,005	86,681
34	6557	Information Technology Committee	Total Dir Labor	14,250	3,071	7,374	3,805
35	22501	Change Management Support	Alloc-Fixed	9,291	4,181	4,181	929
36	22505	Administrative	Alloc-Fixed	428,523	145,698	141,413	141,413
37		Total		8,344,734	1,853,820	4,237,425	2,253,489
38							
39		**IT Infrastructure Services**					
40	6510	Desktop Support - Hardware	Total Dir Labor	1,113,575	239,975	576,275	297,324
41	6511	Desktop Support - Software	Total Dir Labor	513,760	110,715	265,871	137,174
42	6512	Host Computer - Hardware	Alloc-Fixed	3,851,313	-	2,888,485	962,828
43	6513	Host Computer - Software	Alloc-Fixed	9,919,488	-	7,439,616	2,479,872
44	6514	Networking - Hardware	Total Dir Labor	3,506,147	755,575	1,814,431	936,141
45	6516	Communications	Total Dir Labor	3,937,176	848,461	2,037,489	1,051,226
46	6602	Help Desk Support	Total Dir Labor	207,598	44,737	107,432	55,429
47	6615	Host Computer Monitoring	Alloc-Fixed	1,591,224	-	795,612	795,612
48	6616	Desktop Support	Total Dir Labor	1,350,287	290,987	698,774	360,527
49	6622	CIP & Systems Compliance	Total Dir Labor	2,690,529	579,809	1,392,349	718,371
50	6623	Asset Management	Total Dir Labor	955,350	205,878	494,394	255,079
51	6627	IT - Infrastructure Support Request	Total Dir Labor	4,017,108	865,687	2,078,853	1,072,568
52	6630	IT - Infrastructure Operation Enhancement Effort	Total Dir Labor	683,189	147,227	353,550	182,412
53		Total		34,336,745	4,089,052	20,943,130	9,304,562
54							
55		**IT Cyber Security**					
56	6539	IT Policy/Procedures Program	Total Dir Labor	125,000	26,937	64,687	33,375
57	6540	Security Compliance and Reporting	Total Dir Labor	4,305,611	927,859	2,228,154	1,149,598
58	6540A	Cyber Security Controls Assessment	Total Dir Labor	4,042	871	2,092	1,079
59	6540D	Intrusion Monitoring and Response	Total Dir Labor	1,787,961	385,306	925,270	477,386
60	6540E	IT System Compliance, Response and Reporting	Total Dir Labor	13,394	2,886	6,932	3,576
61	6541	Security SW Tools Program	Total Dir Labor	2,619,835	564,574	1,355,765	699,496
62	6543	Critical Infrastructure Protection WG (NERC)	Total Dir Labor	41,844	9,017	21,654	11,172
63	6546	IT Internal Audit Support	Total Dir Labor	10,197	2,197	5,277	2,722
64	6547	Cyber Security Training	Total Dir Labor	334,314	72,045	173,007	89,262
65	6548	CIP Compliance & Monitoring	Total Dir Labor	108,193	23,315	55,990	28,887
66		Total		9,350,390	2,015,009	4,838,827	2,496,554

(1) From Exhibit 3 (RCL-3), Schedule 5.0.
(2) Provided by ISO-NE.

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER26-___-000
TOTAL COST ALLOCATIONS TO SCHEDULES BY COST CATEGORY
TEST YEAR 2026

Line No.	Activity Code No.	Activity Code Description	Allocation Factor (1)	Self-Funding Tariff Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**IT Architecture & Analytics**					
2	6571	DBA Support - MOPS	Total Dir Labor	3,746,667	807,407	1,938,900	1,000,360
3	6581	IT Bridge Support	Total Dir Labor	41,580	8,960	21,518	11,102
4	6591	Data Architect - MOPS	Total Dir Labor	415,704	89,584	215,127	110,993
5	6594	IT Data Analyst	Total Dir Labor	1,028,863	221,720	532,437	274,707
6	6595	IT WEB Application Support	Total Dir Labor	1,841,666	396,879	953,062	491,725
7	6596	IT Data Governance	Total Dir Labor	540,442	116,465	279,679	144,298
8	6597	IT - BI IT Commitments	Total Dir Labor	171,477	36,953	88,739	45,784
9	21706	Enterprise Software Support	Total Dir Labor	2,793,693	602,041	1,445,736	745,916
10	21801	Software Support - Settlements	Alloc-Fixed	1,580,073	-	1,264,058	316,015
11	21802	Software Support - Publishing	Alloc-Fixed	58,876	-	47,101	11,775
12	21803	Software Support - Finance	Alloc-Fixed	710,353	-	568,282	142,071
13	21804	Software Support - Mitigation	Alloc-Fixed	882,345	-	705,876	176,469
14	21805	Software Support - TSO	Total Dir Labor	716,818	154,474	370,953	191,390
15	21806	Software Support - Enterprise	Total Dir Labor	1,990,076	428,861	1,029,864	531,350
16	21807	Software Support - Planning	Alloc-Fixed	1,067,065	-	853,652	213,413
17	21808	Training Delivery to NON-IT	Alloc-Fixed	301,054	-	240,843	60,211
18	21810	IT Issue Resolution	Alloc-Fixed	763	-	611	153
19	21811	Single Sign On Support	Alloc-Fixed	65,718	-	52,574	13,144
20	21812	GADS Support	Alloc-Fixed	148,177	-	118,542	29,635
21	21814	IT - Manual Database Edit	Total Dir Labor	14,496	3,124	7,502	3,870
22	21816	CMS Support	Total Dir Labor	28,280	6,094	14,635	7,551
23	21818	Discoverer Support	Total Dir Labor	81,839	17,636	42,352	21,851
24	21824	FCTS Support	Alloc-Fixed	1,034,072	-	-	1,034,072
25	21825	eTariff Support	Alloc-Fixed	454,010	-	363,208	90,802
26	21830	Annual Software Maintenance for Enterpirse Wide Software	Total Dir Labor	559,972	120,674	289,786	149,513
27	21832	GDMA/Gateway Support	Alloc-Fixed	28,113	-	22,490	5,623
28	21834	Federated SSO support	Total Dir Labor	4,576	986	2,368	1,222
29		Total		20,306,769	3,011,860	11,469,895	5,825,014
30							
31		**IT Energy Management Systems**					
32	21600	Indirect Supervision and Administration	Total Dir Labor	98,141	21,149	50,788	26,204
33	21601	Power System Modeling	Total Dir Labor	455	98	235	121
34	21602	Applications Support	Total Dir Labor	425,530	91,702	220,212	113,616
35	21603	EMS Power System Applications Support	Total Dir Labor	879,335	189,497	455,056	234,782
36	21604	Dispatcher Training Simulatory Support	Alloc-Fixed	3,085,041	2,468,033	617,008	-
37	21605	DAM FTR/ARR Support	Alloc-Fixed	3,210,310	642,062	1,926,186	642,062
38	21606	Real-time Market Support	Alloc-Fixed	4,837,583	967,517	2,902,550	967,517
39	21607	Forecast Support	Alloc-Fixed	689,465	137,893	413,679	137,893
40		Total		13,225,859	4,517,950	6,585,714	2,122,195
41							
42		**IT Enterprise Applications Development**					
43	6518	Employee Development - Software	Total Dir Labor	24,110	5,196	12,477	6,437
44	21701	IT Settlement Application Support	Alloc-Fixed	1,527	-	1,222	305
45	21702	IT Corporate Application Support	Alloc-Fixed	683,091	-	546,473	136,618
46	21707	Application Analysis and Conceptual Design	Alloc-Fixed	377,785	-	302,228	75,557
47	21708	Application Design Evaluation and Selection	Alloc-Fixed	635,392	-	508,314	127,078
48	21709	Technology Evaluation and Selection	Alloc-Fixed	2,185,443	-	1,748,355	437,089
49	21710	Indirect Supervision and Administration	Alloc-Fixed	1,631,042	-	1,304,834	326,208
50	21711	EWR and CAPA Analysis	Alloc-Fixed	85,432	-	68,346	17,086
51	21712	Automated Testing	Total Dir Labor	94,949	20,462	49,136	25,351
52		Total		5,718,773	25,657	4,541,384	1,151,731
53							
54		**IT Power System Modeling Management**					
55	21650	Indirect Supervision and Administration	Total Dir Labor	325,034	70,045	168,205	86,784
56	21651	Power System Modeling	Alloc-Fixed	2,518,907	1,007,563	1,007,563	503,781
57	21652	System Application Support	Alloc-Fixed	37,053	14,821	14,821	7,411
58	21653	PSMM-TTSE Support	Alloc-Fixed	88,471	70,777	17,694	-
59	21654	NX9 Administration	Alloc-Fixed	266,952	106,781	106,781	53,390
60	21655	ICCP Support	Alloc-Fixed	1,321,224	528,489	528,489	264,245
61	21656	Transmission Project Management	Alloc-Fixed	22,229	17,783	4,446	-
62	21657	Model On Demand Admin	Alloc-Fixed	1,024,589	-	-	1,024,589
63	21658	PSMM- Model on Demand Case Requests	Alloc-Fixed	49,270	-	-	49,270
64	21659	Synchrophasor Applications	Alloc-Fixed	145,147	21,772	21,772	101,603
65	21661	MAS Software Dev and Support	Alloc-Fixed	97,037	-	-	97,037
66		Total		5,895,912	1,838,031	1,869,771	2,188,110
67							
68							
69		**Total ISO**		$ 329,991,490	$ 68,040,034	$ 161,098,608	$ 100,852,848

(1) From Exhibit 3 (RCL-3), Schedule 5.0.
(2) Provided by ISO-NE.

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER26-___-000
DIRECT LABOR COST ALLOCATIONS TO SCHEDULES BY COST CATEGORY
TEST YEAR 2026

Line No.	Activity Code No. (a)	Activity Code Description (b)	Allocation Factor (1) (c)	Self-Funding Tariff Total (2) (d)	Schedule 1 (e)	Schedule 2 (f)	Schedule 3 (g)
1		**Administration-CEO**					
2	12651	Indirect Administrative Support	Total Dir Labor	$ 4,431,147	$ 954,912	$ 2,293,119	$ 1,183,116
3		Total		4,431,147	954,912	2,293,119	1,183,116
4							
5		**Finance**					
6	11601	Payroll Administration	Total Dir Labor	400,912	86,397	207,472	107,043
7	11701	Accounts Payable	Total Dir Labor	356,366	76,797	184,419	95,150
8	11702	Procurement	Total Dir Labor	490,003	105,596	253,577	130,831
9	11901	Settle for Power Transactions	Total Dir Labor	89,092	19,199	46,105	23,787
10	12001	Budgeting and Forecasting	Total Dir Labor	579,119	124,800	299,694	154,625
11	12005	Credit Administration	Total Dir Labor	1,707,700	368,009	883,735	455,956
12	12101	Ledger Closing, Financial Statements and Tax Reporting	Total Dir Labor	579,095	124,795	299,682	154,618
13	12201	Treasury and Cash Management	Total Dir Labor	267,275	57,598	138,315	71,362
14	25554	Generation Information System	Alloc-Fixed	2,726	1,227	1,227	273
15	99998	Payroll & Other Accruals	Total Dir Labor	25,469,060	5,488,582	13,180,239	6,800,239
16		Total		29,941,347	6,452,999	15,494,463	7,993,884
17							
18		**Facilities & Security**					
19	12664	Building Maintenance	Total Dir Labor	737,637	158,961	381,727	196,949
20		Total		737,637	158,961	381,727	196,949
21							
22		**Strategy, Risk & Operations Compliance**					
23	14807	NERC RSAW Update and Audit Prep	Alloc-Fixed	1,084,973	542,487	-	542,487
24	14809	ROC - Tariff Compliance	Alloc-Fixed	296,073	88,822	177,644	29,607
25	14816	Support NE Compliance Groups	Total Dir Labor	107,663	23,201	55,716	28,746
26	22704	Record Retention Services	Alloc-Fixed	80,748	26,889	26,889	26,970
27	22705	Corporate Scorecard	Alloc-Fixed	53,833	17,926	17,926	17,980
28	22706	Document Management Services	Alloc-Fixed	107,664	43,066	32,299	32,299
29	22721	Corp Strategic Risk	Total Dir Labor	751,759	162,004	389,035	200,720
30	23006	Business Continuity Planning	Total Dir Labor	376,821	81,205	195,005	100,611
31	25011	Corrective Action/Preventive Action	Alloc-Fixed	20,138	6,706	6,706	6,726
32		Total		2,879,672	992,306	901,220	986,146
33							
34		**Market & Credit Risk**					
35	22714	FAP Analysis	Total Dir Labor	356,366	76,797	184,419	95,150
36		Total		356,366	76,797	184,419	95,150
37							
38		**Human Resources**					
39	12701	Recruiting/Interviewing	Total Dir Labor	727,932	156,869	376,705	194,358
40	12702	Intern Expense	Total Dir Labor	99,344	21,409	51,410	26,525
41	12901	Benefit Administration	Total Dir Labor	727,932	156,869	376,705	194,358
42	12951	Compensation	Total Dir Labor	727,932	156,869	376,705	194,358
43	12961	HR - General	Total Dir Labor	727,932	156,869	376,705	194,358
44	12962	HR - Training	Total Dir Labor	727,932	156,869	376,705	194,358
45	13410	Power Training & Development	Total Dir Labor	1,916,381	412,980	991,727	511,674
46	13411	Markets Training & Development	Total Dir Labor	486,306	104,799	251,663	129,844
47	13412	People Training & Development	Total Dir Labor	1,448,750	312,206	749,728	386,816
48	13413	Business Skills Training & Development	Total Dir Labor	65,734	14,166	34,017	17,551
49	13414	Technology Training & Development	Total Dir Labor	481,266	103,713	249,055	128,498
50	22311	Employee Development	Total Dir Labor	4,455	960	2,305	1,189
51		Total		8,141,897	1,754,579	4,213,432	2,173,886
52							
53		**Legal Department**					
54	12422	Interconnection Queue	Alloc-Fixed	318,510	-	-	318,510
55	12502	Board of Directors	Total Dir Labor	318,513	68,640	164,831	85,043
56	12508	Energy Markets / Complaints / Rule Changes	Alloc-Fixed	398,137	-	398,137	-
57	12514	NEPOOL Participants Committee	Total Dir Labor	159,255	34,319	82,414	42,521
58	12517	Administrative and Clerical Support	Total Dir Labor	663,562	142,998	343,393	177,171
59	12559	General Corporate	Total Dir Labor	1,567,226	337,737	811,040	418,449
60	12587	Capacity Market Development	Alloc-Fixed	928,987	-	-	928,987
61	12588	GC- Web Content Management	Total Dir Labor	690,681	148,842	357,427	184,412
62	12611	GC - Ancillary Services Markets	Alloc-Fixed	132,712	-	-	132,712
63	12619	Compliance	Alloc-Fixed	398,137	159,255	159,255	79,627
64	12631	GC - FERC Order 1000 (Legal Only)	Alloc-Fixed	530,850	-	-	530,850
65	12661	Employee Affairs (Recreation Committee)	Total Dir Labor	10,178	2,193	5,267	2,717
66	12663	Public Information	Total Dir Labor	1,904,551	410,431	985,605	508,515
67	12669	Government Affairs	Total Dir Labor	2,149,304	463,175	1,112,265	573,864
68		Total		10,170,604	1,767,590	4,419,635	3,983,380

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ISO NEW ENGLAND INC.
FERC DOCKET NO. ER26-___-000
DIRECT LABOR COST ALLOCATIONS TO SCHEDULES BY COST CATEGORY
TEST YEAR 2026

Line No.	Activity Code No. (a)	Activity Code Description (b)	Allocation Factor (1) (c)	Self-Funding Tariff Total (2) (d)	Schedule 1 (e)	Schedule 2 (f)	Schedule 3 (g)
1		**Internal Audit**					
2	15001	Indirect Management Duties	Total Dir Labor	80,905	17,435	41,869	21,602
3	15002	Personnel Management	Total Dir Labor	48,540	10,460	25,120	12,960
4	15003	Budget & Forecasting	Total Dir Labor	32,360	6,974	16,746	8,640
5	15004	Audit Follow-up Activities	Total Dir Labor	16,180	3,487	8,373	4,320
6	15005	Audit & Finance Committee	Total Dir Labor	32,360	6,974	16,746	8,640
7	15006	Internal Audit Business Process Update	Total Dir Labor	16,180	3,487	8,373	4,320
8	15007	Annual Audit Work Plan	Total Dir Labor	462,750	99,723	239,473	123,554
9	15011	Internal Audit Meetings	Total Dir Labor	177,981	38,355	92,105	47,521
10	15014	GRC Tool Admin and Development	Total Dir Labor	213,596	46,030	110,536	57,030
11	15021	Performance Measurements	Total Dir Labor	16,180	3,487	8,373	4,320
12	15022	Vendor Contracts	Total Dir Labor	16,180	3,487	8,373	4,320
13	15023	Wire Transfers	Total Dir Labor	16,180	3,487	8,373	4,320
14	15028	Audit - Executive Compensation and Expense Reporting	Total Dir Labor	16,180	3,487	8,373	4,320
15	15029	Audit - Payroll	Total Dir Labor	16,180	3,487	8,373	4,320
16	15040	Audit-Operations	Total Dir Labor	258,882	55,789	133,971	69,121
17	15085	Audit - Information Technology	Total Dir Labor	404,502	87,170	209,330	108,002
18	15133	Satellite Operations Reviews	Total Dir Labor	32,360	6,974	16,746	8,640
19	15161	External Audit- Pension Audit	Total Dir Labor	32,365	6,975	16,749	8,641
20	15165	External Audit - Operations	Total Dir Labor	16,180	3,487	8,373	4,320
21	15186	External Audit - SSAE 18 Direct Support	Total Dir Labor	32,360	6,974	16,746	8,640
22	25702	External Audit - SSAE 18 Direct Management	Alloc-Fixed	183,433	-	183,433	-
23	28005	Fraud, Waste & Abuse Program	Total Dir Labor	16,180	3,487	8,373	4,320
24	28007	Contractor/Consultant Review	Total Dir Labor	16,180	3,487	8,373	4,320
25		Total		2,154,196	424,700	1,203,303	526,194
26							
27		**COO-Adm**					
28	19005	Indirect Supervision/Clerical Support	Total OPS Labor	996,540	267,073	477,841	251,626
29		Total		996,540	267,073	477,841	251,626
30							
31		**System Operations & Market Administration**					
32	14405	Indirect Supervision/Clerical Support	SOA Labor	581,970	201,012	270,150	110,807
33	14408	National Committee Support	SOA Labor	250,124	86,393	116,107	47,624
34	19101	NEPOOL Committee Support	MOA Labor	138,367	-	96,857	41,510
35		Total		970,461	287,405	483,115	199,941
36							
37		**Operations**					
38	14001	Generation Dispatch	Alloc-Fixed	4,142,837	-	3,479,983	662,854
39	14002	Transmission Operations	Alloc-Fixed	2,722,436	2,177,949	136,122	408,365
40	14304	Advanced Scheduling and Forecasting	Alloc-Fixed	2,367,336	118,367	1,870,195	378,774
41	14575	Ops - OPTI System Operator Initial Training	Alloc-Fixed	591,834	236,734	236,734	118,367
42	14582	Ops - Recurring Analysis and Reporting	Total Dir Labor	634,355	136,704	328,279	169,373
43	14589	Ops - OPTI Control Performance Monitor	Alloc-Fixed	634,355	634,355	-	-
44		Total		11,093,153	3,304,108	6,051,313	1,737,733
45							
46		**Operational Performance Trng and Integration**					
47	14402	Operations Training	Alloc-Fixed	1,699,656	679,862	679,862	339,931
48	14462	OSS - General Systems Operations Support	TSO Labor	634,355	205,341	303,285	125,729
49	14563	National Committee Support	OPS Labor	634,355	177,366	351,179	105,810
50	14564	Indirect Supervision/Clerical Support	OPS Labor	1,794,769	501,817	993,584	299,367
51	14574	OPTI Continuing Training	Alloc-Fixed	625,851	250,340	250,340	125,170
52	14576	Ops - OPTI Internal/External Operations Training	Alloc-Fixed	634,355	253,742	253,742	126,871
53	14577	Ops - OPTI Training Program Administration	Alloc-Fixed	634,355	253,742	253,742	126,871
54	14579	Ops - OPTI TTSE Maintenance	Alloc-Fixed	634,355	253,742	253,742	126,871
55		Total		7,292,051	2,575,953	3,339,477	1,376,621
56							
57		**Operations Support Services**					
58	14453	National Committee Support	TSO Labor	331,846	107,419	158,656	65,772
59	14454	Indirect Supervision/Clerical Support	TSO Labor	1,708,811	553,142	816,982	338,686
60	14756	OSS - Human Performance Improvement Program	Alloc-Fixed	126,871	-	-	126,871
61	18361	Transmission Studies, Operations, OASIS Support	Alloc-Fixed	1,708,817	1,367,053	85,441	256,323
62	18381	Transmission Outage Application - Short Term	Alloc-Fixed	1,376,964	1,101,572	68,848	206,545
63	18382	Transmission Outage Application - Long Term	Alloc-Fixed	1,376,964	-	-	1,376,964
64		Total		6,630,273	3,129,185	1,129,927	2,371,161

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ISO NEW ENGLAND INC.
FERC DOCKET NO. ER26-___-000
DIRECT LABOR COST ALLOCATIONS TO SCHEDULES BY COST CATEGORY
TEST YEAR 2026

Line No.	Activity Code No. (a)	Activity Code Description (b)	Allocation Factor (1) (c)	Self-Funding Tariff Total (2) (d)	Schedule 1 (e)	Schedule 2 (f)	Schedule 3 (g)
1		**Market Monitoring**					
2	16101	Market Power Monitoring and Mitigation	Alloc-Fixed	5,119,788	-	3,583,852	1,535,936
3		Total		5,119,788	-	3,583,852	1,535,936
4							
5		**Market Administration & Auctions**					
6	21901	Day Ahead Price Monitoring	Alloc-Fixed	365,629	-	365,629	-
7	21902	Real Time Price Verification	Alloc-Fixed	548,443	-	548,443	-
8	21907	Indirect Supervision/Clerical Support	MA Labor	548,443	-	531,112	17,331
9	21908	Employee Development	MA Labor	228,523	-	221,302	7,221
10	21915	FTR/Auction Administration	Alloc-Fixed	411,332	205,666	205,666	-
11	21917	Real Time Price Finalization	Alloc-Fixed	182,814	-	182,814	-
12		Total		2,285,185	205,666	2,054,967	24,552
13							
14		**Market Analysis & Settlements**					
15	1701	Billing Statements - Energy	Alloc-Fixed	205,646	-	205,646	-
16	1702	Billing Statements - Transmission	Alloc-Fixed	111,758	111,758	-	-
17	1713	Billing Statements - ISO Tariff	Total Dir Labor	11,812	2,545	6,113	3,154
18	1717	Inventoried Energy Program	Alloc-Fixed	6,663	-	-	6,663
19	1718	Mystic COS	Alloc-Fixed	30,287	-	-	30,287
20	1719	FCM Daily	Alloc-Fixed	8,783	-	-	8,783
21	2005	Customer Service	STLM Labor	17,566	2,598	8,557	6,412
22	2007	Admin support - NEPOOL Committees	STLM Labor	14,235	2,105	6,934	5,196
23	2009	Indirect Supervision/Clerical Support	STLM Labor	978,864	144,774	476,804	357,285
24	2010	Employee Development	STLM Labor	210,492	31,132	102,531	76,830
25	2013	FTR Administration	Alloc-Fixed	34,224	-	34,224	-
26	2014	Billing Statements - NCPC	Alloc-Fixed	545,462	-	272,731	272,731
27	2020	Billing Disputes	Total Dir Labor	9,086	1,958	4,702	2,426
28	2021	Analysis & Reporting	Total Dir Labor	802,406	172,918	415,245	214,242
29	2024	ASM Regulation	Alloc-Fixed	143,861	-	-	143,861
30	2025	ASM Locational Forward Reserve	Alloc-Fixed	43,310	-	-	43,310
31	2026	Batch Processing	Total Dir Labor	44,521	9,594	23,040	11,887
32	2032	Billing	STLM Labor	39,373	5,823	19,178	14,371
33	2033	Market Analysis	Alloc-Fixed	71,400	-	71,400	-
34	2047	Score Card	STLM Labor	5,149	761	2,508	1,879
35	2048	FCM	Alloc-Fixed	439,156	-	-	439,156
36	2049	Product Testing	Alloc-Fixed	14,840	-	11,872	2,968
37	2051	Legal Support	Alloc-Fixed	3,634	-	1,817	1,817
38		Total		3,792,528	485,968	1,663,302	1,643,258
39							
40		**Market Operations Support Services**					
41	3000	Hourly Settlements Support	Alloc-Fixed	241,569	-	120,784	120,784
42	3002	Monthly Settlements Support	Alloc-Fixed	328,265	164,133	-	164,133
43	3003	MOSS - Market Analysis Support	Alloc-Fixed	13,420	-	13,420	-
44	3004	MOSS - Asset Registration and Auditing Support	Alloc-Fixed	13,420	-	13,420	-
45	3006	Customer Service	Alloc-Fixed	230,833	-	230,833	-
46	3008	Admin Support	Alloc-Fixed	416,572	-	416,572	-
47	3009	Indirect Supervision (Principal Analysts only)	Alloc-Fixed	53,682	-	53,682	-
48	3010	Employee Development	Alloc-Fixed	63,076	-	63,076	-
49	3017	Project MAS (Market Analysis & Settlements)	Alloc-Fixed	448,527	112,132	112,132	224,264
50		Total		1,809,366	276,264	1,023,920	509,181
51							
52		**Participant Support & Solutions**					
53	16006	Call Support (Ask ISO)	Alloc-Fixed	1,631,366	424,155	1,076,702	130,509
54		Total		1,631,366	424,155	1,076,702	130,509
55							
56		**Participant Training Services**					
57	16021	Training Development	Alloc-Fixed	1,549,542	-	774,771	774,771
58	16024	Training Delivery	Alloc-Fixed	6,061	-	3,030	3,030
59	16419	Asset Registration Implemented	Alloc-Fixed	502,740	-	502,740	-
60	16420	Asset Registration Review	Alloc-Fixed	45,704	-	45,704	-
61	16422	Claimed Capability Audits	Alloc-Fixed	548,443	-	548,443	-
62	16432	New Generation Coordination and Registration	Alloc-Fixed	365,629	-	365,629	-
63	16434	QMS/CAPA Process and Procedure Updates	Total Dir Labor	319,925	68,944	165,561	85,420
64	16436	Mkt Trng/Cus Serv Indirect Supervision	Alloc-Fixed	354,645	-	354,645	-
65		Total		3,692,688	68,944	2,760,523	863,221

(1) From Exhibit 3 (RCL-3), Schedule 5.0.
(2) Provided by ISO-NE.

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER26-___-000
DIRECT LABOR COST ALLOCATIONS TO SCHEDULES BY COST CATEGORY
TEST YEAR 2026

Line No.	Activity Code No. (a)	Activity Code Description (b)	Allocation Factor (1) (c)	Self-Funding Tariff Total (2) (d)	Schedule 1 (e)	Schedule 2 (f)	Schedule 3 (g)
1		**Planning Services**					
2	17101	Analysis	Alloc-Fixed	513,243	-	359,270	153,973
3	17131	Calculate Objective Capability	Alloc-Fixed	688,112	-	-	688,112
4	17403	TCA Application Review	Alloc-Fixed	132,614	-	-	132,614
5	17409	Environmental/Emissions Supp	Alloc-Fixed	125,112	-	-	125,112
6	17503	FCA - New Resource Qualification Support	Alloc-Fixed	255,394	-	-	255,394
7	17504	FCA - Perform Transmission / Topology Assessments	Alloc-Fixed	48,526	-	-	48,526
7	17507	FCA - Auctions & Filings	Alloc-Fixed	91,420	-	-	91,420
8	17508	FCA - Annual Reconfiguration Auction Support/Reliability Reviews	Alloc-Fixed	679,259	-	-	679,259
9	18101	Develop Load Forecast	Alloc-Fixed	688,113	137,623	137,623	412,868
10	18121	Operations Forecast Support	Alloc-Fixed	250,222	50,044	50,044	150,133
11	18131	Other Load Forecasting Activities	Alloc-Fixed	88,151	17,630	17,630	52,891
12	18133	Solar Load Forecast Development	Alloc-Fixed	375,339	75,068	75,068	225,203
13	18134	Electrification Forecasts	Alloc-Fixed	187,667	37,533	37,533	112,600
14	18135	CELT Rep-Res Outage Analysis	Alloc-Fixed	200,465	-	-	200,465
15		Total		4,323,635	317,898	677,168	3,328,569
16							
17		**System Planning**					
18	18402	Transmission Planning/Economic Studies Initiative	Alloc-Fixed	1,302,308	-	651,154	651,154
19	18531	SP - Indirect Supervision/Clerical Support	Alloc-Fixed	140,776	34,955	24,960	80,862
20		Total		1,443,084	34,955	676,114	732,016
21							
22		**Transmission Planning**					
23	14715	Non DOE Funded/Unallowable	Alloc-Fixed	132,622	-	-	132,622
24	18201	Transmission System Assessment	Alloc-Fixed	6,325,781	6,325,781	-	-
25	18301	NEPOOL Administrative Support - Schedule 1 Tariff	Alloc-Fixed	136,676	136,676	-	-
26	18333	General SIS/FS	Alloc-Fixed	1,216,209	1,216,209	-	-
27	18334	Indirect Supervision/Clerical Support	Alloc-Fixed	1,062,622	1,062,622	-	-
28	18335	Regulatory Activities - NPCC	Alloc-Fixed	246,361	246,361	-	-
29	18336	National Activities	Alloc-Fixed	329,330	329,330	-	-
30	18337	TR - Regulatory Activities	Alloc-Fixed	291,122	291,122	-	-
31	18346	OATT and Oper. Agreement Dev., Adm. and Support	Alloc-Fixed	97,036	97,036	-	-
32	18349	TR - Process CEII Requests	Alloc-Fixed	48,518	48,518	-	-
33	18351	Resource Integration	Alloc-Fixed	727,770	727,770	-	-
34	21660	Stability Case Building	Alloc-Fixed	97,036	-	-	97,036
35		Total		10,711,082	10,481,424	-	229,658
36							
37		**Program Management**					
38	801	Program Management - Administration	Total Dir Labor	1,091,964	235,318	565,091	291,554
39	1661	ISO Program Management	Alloc-Fixed	428,784	-	300,149	128,635
40	1665	Product and Test Mgmt.	Total Dir Labor	999,031	215,291	516,999	266,741
41	25003	Emerging Work Initiatives	Total Dir Labor	185,866	40,054	96,186	49,626
42	26133	Day Ahead Ancillary Services	Alloc-Fixed	381	-	114	267
43	26153	CAMS Tech Upgrade	Alloc-Fixed	82,365	-	65,892	16,473
44	26187	Distributed Energy Resources (DER)	Total Dir Labor	14,109	3,040	7,301	3,767
45		Total		2,802,501	493,704	1,551,732	757,064
46							
47		**Advanced Technology Solutions**					
48	21201	Advanced Technology Solutions	Total Dir Labor	5,300,435	1,142,244	2,742,975	1,415,216
49	21207	ATS - Capacity Auction Reforms	Alloc-Fixed	745,092	-	-	745,092
50		Total		6,045,527	1,142,244	2,742,975	2,160,308
51							
52		**Market Development & Settlements Admin.**					
53	16607	National Committee Support	Total Dir Labor	6,610	1,424	3,421	1,765
54	19104	Indirect Supervision/Clerical Support	MOA Labor	329,898	-	230,929	98,969
55	21001	Market Development	Alloc-Fixed	975,778	-	487,889	487,889
56	21002	Administration	Total Dir Labor	1,116,656	240,639	577,869	298,147
57	21003	Employee Development	Total Dir Labor	116,259	25,054	60,164	31,041
58	21007	Budget/Forecast Support	Total Dir Labor	204,540	44,078	105,849	54,612
59	21010	MD - Day-Ahead Reserve Market	Alloc-Fixed	179,806	-	170,816	8,990
60	21011	Capacity Market	Alloc-Fixed	218,859	-	-	218,859
61	22656	Energy, Reserve, and Regulation Markets	Alloc-Fixed	806,023	-	604,517	201,506
62	22661	Project: DER Participation	Alloc-Fixed	38,096	-	19,048	19,048
63	22662	Flexible Response Services	Alloc-Fixed	2,427,517	-	1,213,758	1,213,758
64	22663	Energy Shortage Pricing	Alloc-Fixed	430,243	-	322,682	107,561
65	22664	Capacity Auction Reforms	Alloc-Fixed	4,004,517	-	-	4,004,517
66		Total		10,854,802	311,196	3,796,943	6,746,663
67							
68		**Participant Relations & Services**					
69	22602	NEPOOL Committee Meetings & Support	Alloc-Fixed	268,579	-	134,289	134,289
70	22607	NEPOOL Committee Administration	Total Dir Labor	1,626,040	350,412	841,475	434,153
71	22613	PR&S Indirect Supervision	Total Dir Labor	277,945	59,897	143,836	74,211
72	22614	PR&S Project Development	Total Dir Labor	516,202	111,242	267,134	137,826
73		Total		2,688,765	521,550	1,386,736	780,479

(1) From Exhibit 3 (RCL-3), Schedule 5.0.
(2) Provided by ISO-NE.

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER26-___-000
DIRECT LABOR COST ALLOCATIONS TO SCHEDULES BY COST CATEGORY
TEST YEAR 2026

Line No.	Activity Code No. (a)	Activity Code Description (b)	Allocation Factor (1) (c)	Self-Funding Tariff Total (2) (d)	Schedule 1 (e)	Schedule 2 (f)	Schedule 3 (g)
1		**IT Management**					
2	6517	Employee Development - Hardware/Software	Total Dir Labor	48,013	10,347	24,847	12,820
3	6519	Indirect Supervision and Clerical Support	Total Dir Labor	7,365,599	1,587,287	3,811,697	1,966,615
4	6556	Budget Preparation, Tracking & Forecast	Total Dir Labor	324,648	69,962	168,005	86,681
5	22501	Change Management Support	Alloc-Fixed	9,288	4,180	4,180	929
6	22505	Administrative	Alloc-Fixed	428,522	145,697	141,412	141,412
7		Total		8,176,070	1,817,472	4,150,142	2,208,456
8							
9		**IT Infrastructure Services**					
10	6510	Desktop Support - Hardware	Total Dir Labor	1,334	288	690	356
11	6602	Help Desk Support	Total Dir Labor	207,551	44,727	107,408	55,416
12	6615	Host Computer Monitoring	Alloc-Fixed	1,591,224	-	795,612	795,612
13	6616	Desktop Support	Total Dir Labor	1,349,081	290,727	698,149	360,205
14	6622	CIP & Systems Compliance	Total Dir Labor	2,247,524	484,342	1,163,094	600,089
15	6623	Asset Management	Total Dir Labor	392,711	84,629	203,228	104,854
16	6627	IT - Infrastructure Support Request	Total Dir Labor	4,011,958	864,577	2,076,188	1,071,193
17	6630	IT - Infrastructure Operation Enhancement Effort	Total Dir Labor	492,137	106,056	254,681	131,401
18		Total		10,293,521	1,875,345	5,299,051	3,119,125
19							
20		**IT Cyber Security**					
21	6540A	Cyber Security Controls Assessment	Total Dir Labor	3,606	777	1,866	963
22	6540D	Intrusion Monitoring and Response	Total Dir Labor	1,542,910	332,497	798,456	411,957
23	6540E	IT System Compliance, Response and Reporting	Total Dir Labor	13,394	2,886	6,932	3,576
24	6540	Security Compliance and Reporting	Total Dir Labor	1,316,248	283,652	681,159	351,438
25	6543	Critical Infrastructure Protection WG (NERC)	Total Dir Labor	35,548	7,661	18,396	9,491
26	6546	IT Internal Audit Support	Total Dir Labor	10,197	2,197	5,277	2,722
27	6547	Cyber Security Training	Total Dir Labor	52,087	11,225	26,955	13,907
28	6548	CIP Compliance & Monitoring	Total Dir Labor	108,190	23,315	55,988	28,887
29				3,082,180	664,210	1,595,028	822,942
30		**IT Architecture & Analytics**					
31	6571	DBA Support - MOPS	Total Dir Labor	1,586,162	341,818	820,839	423,505
32	6591	Data Architect - MOPS	Total Dir Labor	415,702	89,584	215,126	110,992
33	6594	IT Data Analyst	Total Dir Labor	1,028,863	221,720	532,436	274,706
34	6595	IT WEB Application Support	Total Dir Labor	1,786,522	384,995	924,525	477,001
35	6596	IT Data Governance	Total Dir Labor	415,702	89,584	215,126	110,992
36	6597	IT - BI IT Commitments	Total Dir Labor	171,477	36,953	88,739	45,784
37	21706	Enterprise Software Support	Total Dir Labor	1,509,829	325,368	781,336	403,124
38	21801	Software Support - Settlements	Alloc-Fixed	924,913	-	739,930	184,983
39	21803	Software Support - Finance	Alloc-Fixed	53,141	-	42,512	10,628
40	21804	Software Support - Mitigation	Alloc-Fixed	428,698	-	342,959	85,740
41	21806	Software Support - Enterprise	Total Dir Labor	260,554	56,149	134,837	69,568
42	21810	IT Issue Resolution	Alloc-Fixed	763	-	610	153
43	21811	Single Sign On Support	Alloc-Fixed	11,250	-	9,000	2,250
44	21814	IT - Manual Database Edit	Total Dir Labor	14,496	3,124	7,502	3,870
45	21824	FCTS Support	Alloc-Fixed	411,555	-	-	411,555
46	21832	GDMA/Gateway Support	Alloc-Fixed	28,113	-	22,490	5,623
47	21834	Federated SSO support	Total Dir Labor	4,576	986	2,368	1,222
48		Total		9,052,312	1,550,281	4,880,335	2,621,696
49							
50		**IT Enterprise Applications Development**					
51	21701	IT Settlement Application Support	Alloc-Fixed	1,525	-	1,220	305
52	21702	IT Corporate Application Support	Alloc-Fixed	6,482	-	5,186	1,296
53	21707	Application Analysis and Conceptual Design	Alloc-Fixed	377,785	-	302,228	75,557
54	21708	Application Design Evaluation and Selection	Alloc-Fixed	474,303	-	379,442	94,861
55	21709	Technology Evaluation and Selection	Alloc-Fixed	2,176,561	-	1,741,249	435,312
56	21710	Indirect Supervision and Administration	Alloc-Fixed	1,629,404	-	1,303,523	325,881
57	21711	EWR and CAPA Analysis	Alloc-Fixed	85,432	-	68,346	17,086
58	21712	Automated Testing	Total Dir Labor	94,949	20,462	49,136	25,351
59		Total		4,846,442	20,462	3,850,331	975,650
60							
61		**IT Energy Management Systems**					
62	21600	Indirect Supervision and Administration	Total Dir Labor	98,141	21,149	50,788	26,204
63	21602	Applications Support	Total Dir Labor	386,490	83,289	200,009	103,193
64	21604	Dispatcher Training Simulatory Support	Alloc-Fixed	1,548,987	1,239,190	309,797	-
65	21605	DAM FTR/ARR Support	Alloc-Fixed	2,302,153	460,431	1,381,292	460,431
66	21606	Real-time Market Support	Alloc-Fixed	2,065,535	413,107	1,239,321	413,107
67		Total		6,401,306	2,217,165	3,181,207	1,002,934
68							
69							
70		**IT Power System Modeling Management**					
71	21650	Indirect Supervision and Administration	Total Dir Labor	325,034	70,045	168,205	86,784
72	21654	NX9 Administration	Alloc-Fixed	98,135	39,254	39,254	19,627
73	21651	Power System Modeling	Alloc-Fixed	1,840,535	736,214	736,214	368,107
74	21652	System Application Support	Alloc-Fixed	37,053	14,821	14,821	7,411
75	21655	ICCP Support	Alloc-Fixed	1,199,852	479,941	479,941	239,970
76	21656	Transmission Project Management	Alloc-Fixed	22,229	17,783	4,446	-
77	21657	Model On Demand Admin	Alloc-Fixed	824,811	-	-	824,811
78	21658	PSMM- Model on Demand Case Requests	Alloc-Fixed	48,523	-	-	48,523
79	21659	Synchrophasor Applications	Alloc-Fixed	98,135	14,720	14,720	68,695
80	21661	MAS Software Dev and Support	Alloc-Fixed	97,036	-	-	97,036
81		Total		4,591,344	1,372,779	1,457,602	1,760,964
82							
83		**Total ISO**		$ 189,438,836	$ 46,428,249	$ 87,981,617	$ 55,028,971
				100.0%	24.5%	46.4%	29.0%

(1) From Exhibit 3 (RCL-3), Schedule 5.0.
(2) Provided by ISO-NE.

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER26-___-000
DIRECT LABOR COST ALLOCATIONS TO SCHEDULES BY COST CATEGORY
TEST YEAR 2026

Line No.	Activity Code No. (a)	Activity Code Description (b)	Allocation Factor (1) (c)	Self-Funding Tariff Total (2) (d)	Schedule 1 (e)	Schedule 2 (f)	Schedule 3 (g)
1	**Cost Ctr.**	**Summary Of Departmental Labor Allocation Using "Alloc-Fixed" Allocators**					
2	307	Administration-CEO		$ -	$ -	$ -	$ -
3			Adm Labor	0.00%	0.00%	0.00%	0.00%
4	302	Finance		$ 2,726	$ 1,227	$ 1,227	$ 273
5			Fin Labor	100.00%	45.00%	45.00%	10.00%
6	108	Facilities & Security		$ -	$ -	$ -	$ -
7			Bldg Labor	0.00%	0.00%	0.00%	0.00%
8	703	Strategy, Risk & Operations Compliance		$ 1,643,429	$ 725,895	$ 261,464	$ 656,069
9			SROC Labor	100.00%	44.17%	15.91%	39.92%
10	301	Human Resources		$ -	$ -	$ -	$ -
11			HR Labor	0.00%	0.00%	0.00%	0.00%
12	306	Legal Department		$ 2,707,333	$ 159,255	$ 557,392	$ 1,990,686
13			Legal Labor	100.00%	5.88%	20.59%	73.53%
14	305	Internal Audit		$ 183,433	$ -	$ 183,433	$ -
15			IA Labor	100.00%	0.00%	100.00%	0.00%
16	701	COO-Adm		$ 996,540	$ 267,073	$ 477,841	$ 251,626
17			COO Labor	100.00%	26.80%	47.95%	25.25%
18	310	Market & Credit Risk		$ -	$ -	$ -	$ -
19			MCR Labor	0.00%	0.00%	0.00%	0.00%
20	105	System Operations & Market Administration		$ 970,461	$ 287,405	$ 483,115	$ 199,941
21			SYSOPS Labor	100.00%	29.62%	49.78%	20.60%
22	101	Operations		$ 10,458,798	$ 3,167,404	$ 5,723,034	$ 1,568,360
23			OPS Labor	100.00%	30.28%	54.72%	15.00%
24	110	Operational Performance Trng and Integration		$ 7,292,051	$ 2,575,953	$ 3,339,477	$ 1,376,621
25			OPSPERF Labor	100.00%	35.33%	45.80%	18.88%
26	103	Operations Support Services		$ 6,630,273	$ 3,129,185	$ 1,129,927	$ 2,371,161
27			TSO Labor	100.00%	47.20%	17.04%	35.76%
28	404	Market Monitoring		$ 5,119,788	$ -	$ 3,583,852	$ 1,535,936
29			MMM Labor	100.00%	0.00%	70.00%	30.00%
30	416	Market Administration & Auctions		$ 2,285,185	$ 205,666	$ 2,054,967	$ 24,552
31			MA Labor	100.00%	9.00%	89.93%	1.07%
32	401	Market Analysis & Settlements		$ 2,924,703	$ 298,951	$ 1,214,202	$ 1,411,549
33			STLM Labor	100.00%	10.22%	41.52%	48.26%
34	411	Market Operations Support Services		$ 1,809,366	$ 276,264	$ 1,023,920	$ 509,181
35			MOSS Labor	100.00%	15.27%	56.59%	28.14%
36	406	Participant Support & Solutions		$ 1,631,366	$ 424,155	$ 1,076,702	$ 130,509
37			PSS Labor	100.00%	26.00%	66.00%	8.00%
38	410	Participant Training Services		$ 3,372,763	$ -	$ 2,594,961	$ 777,801
39			PTS Labor	100.00%	0.00%	76.94%	23.06%
40	204	System Planning		$ 1,443,084	$ 34,955	$ 676,114	$ 732,016
41			SP Labor	100.00%	2.42%	46.85%	50.73%
42	203	Planning Services		$ 4,323,635	$ 317,898	$ 677,168	$ 3,328,569
43			PSR Labor	100.00%	7.35%	15.66%	76.99%
44	205	Transmission Planning		$ 10,711,082	$ 10,481,424	$ -	$ 229,658
45			TP Labor	100.00%	97.86%	0.00%	2.14%
46	1	Program Management		$ 511,530	$ -	$ 366,155	$ 145,375
47			PMO Labor	100.00%	0.00%	71.58%	28.42%
48	315	Advanced Technology Solutions		$ 745,092	$ -	$ -	$ 745,092
49			ATS Labor	100.00%	0.00%	0.00%	100.00%
50	408	Market Development & Settlements Admin.		$ 9,410,738	$ -	$ 3,049,640	$ 6,361,098
51			MD Labor	100.00%	0.00%	32.41%	67.59%
52	407	Participant Relations & Services		$ 268,579	$ -	$ 134,289	$ 134,289
53			PRS Labor	100.00%	0.00%	50.00%	50.00%
54	210	IT Management		$ 437,810	$ 149,877	$ 145,592	$ 142,341
55			ITM Labor	100.00%	34.23%	33.25%	32.51%
56	201	IT Infrastructure Services		$ 1,591,224	$ -	$ 795,612	$ 795,612
57			ITS Labor	100.00%	0.00%	50.00%	50.00%
58	211	IT Architecture & Analytics		$ 1,858,431	$ -	$ 1,157,501	$ 700,930
59			ITDG Labor	100.00%	0.00%	62.28%	37.72%
60	222	IT Cyber Security		$ -	$ -	$ -	$ -
61			ITCS	0.00%	0.00%	0.00%	0.00%
62	102	IT Energy Management Systems		$ 5,916,675	$ 2,112,727	$ 2,930,410	$ 873,538
63			EMS Labor	100.00%	35.71%	49.53%	14.76%
64	213	IT Enterprise Applications Development		$ 4,751,493	$ -	$ 3,801,194	$ 950,299
65			ESD	100.00%	0.00%	80.00%	20.00%
66	216	IT Power System Modeling Management		$ 4,266,310	$ 1,302,734	$ 1,289,396	$ 1,674,180
67			ITPSM	100.00%	30.54%	30.22%	39.24%
68		Total Direct Labor		$ 94,263,898	$ 25,918,050	$ 38,728,586	$ 29,617,262
69				100.00%	27.50%	41.09%	31.42%
70							
71		**Summary Of Allocations Of Labor Based On Fixed Allocators and Allocated Departmental Labor**					
72		Total Direct Labor		$ 94,263,898	$ 25,918,050	$ 38,728,586	$ 29,617,262
73			Dir Labor	100.00%	27.50%	41.09%	31.42%
74		Total Indirect Labor		$ 95,174,938	$ 20,510,199	$ 49,253,031	$ 25,411,708
75			InDir Labor	100.00%	21.55%	51.75%	26.70%
76		Total Labor Expense		$ 189,438,836	$ 46,428,249	$ 87,981,617	$ 55,028,971
77			Total Dir Labor	100.00%	24.51%	46.44%	29.05%

(1) From Exhibit 3 (RCL-3), Schedule 5.0.
(2) Provided by ISO-NE.

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER26-___-000
ALLOCATION FACTORS BY COST CATEGORY
TEST YEAR 2026

Line No.	Activity Code No.	Activity Code Description	Allocation Factor	Self-Funding Tariff Total	Schedule 1	Schedule 2	Schedule 3	Reference
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1		Administration-CEO						
2	12651	Indirect Administrative Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
3	12652	NEPOOL Committee Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
4	12653	Adm/Finance/HR - Regional Committee Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
5	12654	National Committee Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
6	12657	Indirect Administrative Support for BCC	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
7								
8		Finance						
9	11601	Payroll Administration	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
10	11701	Accounts Payable	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
11	11702	Procurement	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
12	11901	Settle for Power Transactions	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
13	12001	Budgeting and Forecasting	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
14	12005	Credit Administration	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
15	12101	Ledger Closing, Financial Statements and Tax Reporting	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
16	12201	Treasury and Cash Management	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
17	25554	Generation Information System	Alloc-Fixed	100.00%	45.00%	45.00%	10.00%	Per ISO-NE Staff
18	92004	Depreciation Expense 2004 Assets	Alloc-Fixed	100.00%	20.83%	52.21%	26.96%	Per ISO-NE Staff
19	92005	Depreciation Expense 2005 Assets	Alloc-Fixed	100.00%	21.14%	52.01%	26.85%	Per ISO-NE Staff
20	92006	Depreciation Expense 2006 Assets	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
21	92007	Depreciation Expense 2007 Assets	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
22	92008	Depreciation Expense 2008 Assets	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
23	92009	Depreciation Expense 2009 Assets	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
24	92010	Depreciation Expense 2010 Assets	Total Dir Labor	100.00%	0.00%	0.00%	0.00%	Per ISO-NE Staff
25	92012	Depreciation Expense 2012 Assets	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
26	92013	Depreciation Expense 2013 Assets	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
27	92014	Depreciation Expense 2014 Assets	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
28	92015	Depreciation Expense 2015 Assets	Total Dir Labor	100.00%	0.00%	0.00%	0.00%	Per ISO-NE Staff
29	92016	Depreciation Expense 2016 Assets	Alloc-Fixed	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
30	92017	Depreciation Expense 2017 Assets	Alloc-Fixed	100.00%	6.46%	85.54%	8.00%	Per ISO-NE Staff
31	92018	Depreciation Expense 2018 Assets	Alloc-Fixed	100.00%	0.24%	99.46%	0.30%	Per ISO-NE Staff
32	92019	Depreciation Expense 2019 Assets	Alloc-Fixed	100.00%	1.52%	96.59%	1.89%	Per ISO-NE Staff
33	92020	Depreciation Expense 2020 Assets	Alloc-Fixed	100.00%	5.42%	92.92%	1.66%	Per ISO-NE Staff
34	92021	Depreciation Expense 2021 Assets	Alloc-Fixed	100.00%	7.77%	82.28%	9.95%	Per ISO-NE Staff
35	92022	Depreciation Expense 2022 Assets	Alloc-Fixed	100.00%	11.91%	57.17%	30.92%	Per ISO-NE Staff
36	92023	Depreciation Expense 2023 Assets	Alloc-Fixed	100.00%	13.44%	51.98%	34.59%	Per ISO-NE Staff
37	92024	Depreciation Expense 2024 Assets	Alloc-Fixed	100.00%	12.66%	54.38%	32.95%	Per ISO-NE Staff
38	92025	Depreciation Expense 2025 Assets	Alloc-Fixed	100.00%	12.53%	62.50%	24.96%	Per ISO-NE Staff
39	92026	Depreciation Expense 2026 Assets	Alloc-Fixed	100.00%	15.36%	60.22%	24.41%	Per ISO-NE Staff
40	99707	Amortization of Land Recovery	Alloc-Fixed	100.00%	6.26%	61.50%	32.24%	Per ISO-NE Staff
41	99995	NPCC/NERC Dues	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
42	99996	Operating Contingency	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
43	99998	Payroll & Other Accruals	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
44								
45		Facilities & Security						
46	12664	Building Maintenance	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
47								
48		Strategy, Risk & Operations Compliance						
49	14809	ROC - Tariff Compliance	Alloc-Fixed	100.00%	30.00%	60.00%	10.00%	Per ISO-NE Staff
50	22704	Record Retention Services	Alloc-Fixed	100.00%	33.30%	33.30%	33.40%	Per ISO-NE Staff
51	22705	Corporate Scorecard	Alloc-Fixed	100.00%	33.30%	33.30%	33.40%	Per ISO-NE Staff
52	22706	Document Management Services	Alloc-Fixed	100.00%	40.00%	30.00%	30.00%	Per ISO-NE Staff
53	22719	Human Performance Improvement	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
54	22721	Corp Strategic Risk	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
55	23006	Business Continuity Planning	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
56	25011	Corrective Action/Preventive Action	Alloc-Fixed	100.00%	33.30%	33.30%	33.40%	Per ISO-NE Staff
57								
58		Market & Credit Risk						
59	22714	FAP Analysis	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
60								
61		Human Resources						
62	12661	Employee Affairs (Recreation Committee)	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
63	12701	Recruiting/Interviewing	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
64	12702	Intern Expense	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
65	12801	Employee Relations	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
66	12901	Benefit Administration	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
67	12951	Compensation	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
68	12961	HR - General	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
69	12962	HR - Training	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
70	13410	Power Training & Development	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
71	13411	Markets Training & Development	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
72	13412	People Training & Development	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
73	13413	Business Skills Training & Development	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
74	13414	Technology Training & Development	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
75	13602	Enterprise Learning - Cyber Security Training & Documentation Work	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
76	22311	Employee Development	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1		Internal Audit						
2	15001	Indirect Management Duties	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
3	15002	Personnel Management	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
4	15003	Budget & Forecasting	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
5	15004	Audit Follow-up Activities	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
6	15005	Audit & Finance Committee	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
7	15006	Internal Audit Business Process Update	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
8	15007	Annual Audit Work Plan	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
9	15011	Internal Audit Meetings	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
10	15013	Indirect Adminstrative Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
11	15014	GRC Tool Admin and Development	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
12	15020	Audit- Internal Audit-Finance	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
13	15021	Performance Measurements	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
14	15022	Vendor Contracts	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
15	15023	Wire Transfers	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
16	15028	Audit - Executive Compensation and Expense Reporting	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
17	15029	Audit - Payroll	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
18	15040	Audit-Operations	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
19	15085	Audit - Information Technology	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
20	15133	Satellite Operations Reviews	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
21	15150	Audit - Internal Audit Other	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
22	15161	External Audit- Pension Audit	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
23	15162	External Audit- Financial Audit	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
24	15165	External Audit - Operations	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
25	15166	External Audit -Pricing Module Certification	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
26	15176	External Audit - ISO Internet Vulnerability Assessment	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
27	15186	External Audit - SSAE 18 Direct Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
28	25702	External Audit - SSAE 18 Direct Management	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
29	28005	Fraud, Waste & Abuse Program	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
30	28007	Contractor/Consultant Review	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
31								
32		Legal Department						
33	12422	Interconnection Queue	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
34	12502	Board of Directors	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
35	12508	Energy Markets / Complaints / Rule Changes	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
36	12513	Miscellaneous Labor Matters	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
37	12514	NEPOOL Participants Committee	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
38	12517	Administrative and Clerical Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
39	12543	Independent Market Advisor	Alloc-Fixed	100.00%	0.00%	70.00%	30.00%	Per ISO-NE Staff
40	12559	General Corporate	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
41	12587	Capacity Market Development	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
42	12588	GC- Web Content Management	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
43	12606	GC - NERC	Alloc-Fixed	100.00%	45.00%	10.00%	45.00%	Per ISO-NE Staff
44	12611	GC - Ancillary Services Markets	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
45	12617	GC - IRC Activities	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
46	12619	Compliance	Alloc-Fixed	100.00%	40.00%	40.00%	20.00%	Per ISO-NE Staff
47	12627	GC - State Relations/Programs/Task Force Comm	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
48	12622	Open Access Transmission Tariff	Alloc-Fixed	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
49	12631	GC - FERC Order 1000 (Legal Only)	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
50	12663	Public Information	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
51	12669	Government Affairs	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
52								
53		COO-Adm						
54	19001	NEPOOL Committee Support	Total OPS Labor	100.00%	26.80%	47.95%	25.25%	Per ISO-NE Staff
55	19003	National Committee Support	Total OPS Labor	100.00%	26.80%	47.95%	25.25%	Per ISO-NE Staff
56	19005	Indirect Supervision/Clerical Support	Total OPS Labor	100.00%	26.80%	47.95%	25.25%	Per ISO-NE Staff
57	19009	Renewable Resource Integration	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
58								
59		System Operations & Market Administration						
60	14404	NEPOOL Committee Support	SOA Labor	100.00%	34.54%	46.42%	19.04%	Per ISO-NE Staff
61	14405	Indirect Supervision/Clerical Support	SOA Labor	100.00%	34.54%	46.42%	19.04%	Per ISO-NE Staff
62	14407	Regional Committee Support	SOA Labor	100.00%	34.54%	46.42%	19.04%	Per ISO-NE Staff
63	14408	National Committee Support	SOA Labor	100.00%	34.54%	46.42%	19.04%	Per ISO-NE Staff
64	19101	NEPOOL Committee Support	MOA Labor	100.00%	0.00%	70.00%	30.00%	Per ISO-NE Staff

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Line No.	Activity Code No.	Activity Code Description	Allocation Factor	Self-Funding Tariff Total	Schedule 1	Schedule 2	Schedule 3	Reference
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1		Operations						
2	14001	Generation Dispatch	Alloc-Fixed	100.00%	0.00%	84.00%	16.00%	Per ISO-NE Staff
3	14002	Transmission Operations	Alloc-Fixed	100.00%	80.00%	5.00%	15.00%	Per ISO-NE Staff
4	14304	Advanced Scheduling and Forecasting	Alloc-Fixed	100.00%	5.00%	79.00%	16.00%	Per ISO-NE Staff
5	14402	Operations Training	Alloc-Fixed	100.00%	40.00%	40.00%	20.00%	Per ISO-NE Staff
6	14562	Ops - Regional Committee Support	OPS Labor	100.00%	27.96%	55.36%	16.68%	Per ISO-NE Staff
7	14563	National Committee Support	OPS Labor	100.00%	27.96%	55.36%	16.68%	Per ISO-NE Staff
8	14565	Employee Development	OPS Labor	100.00%	27.96%	55.36%	16.68%	Per ISO-NE Staff
9	14582	Ops - Recurring Analysis and Reporting	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
10	14586	Ops - Other External Support Meetings	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
11	14589	Ops - OPTI Control Performance Monitor	Alloc-Fixed	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
12								
13		Operational Performance Trng and Integration						
14	14402	Operations Training	Alloc-Fixed	100.00%	40.00%	40.00%	20.00%	Per ISO-NE Staff
15	14462	OSS - General Systems Operations Support	TSO Labor	100.00%	32.37%	47.81%	19.82%	Per ISO-NE Staff
16	14564	Indirect Supervision/Clerical Support	OPS Labor	100.00%	27.96%	55.36%	16.68%	Per ISO-NE Staff
17	14574	OPTI Continuing Training	Alloc-Fixed	100.00%	40.00%	40.00%	20.00%	Per ISO-NE Staff
18	14575	Ops - OPTI System Operator Initial Training	Alloc-Fixed	100.00%	40.00%	40.00%	20.00%	Per ISO-NE Staff
19	14576	Ops - OPTI Internal/External Operations Training	Alloc-Fixed	100.00%	40.00%	40.00%	20.00%	Per ISO-NE Staff
20	14577	Ops - OPTI Training Program Administration	Alloc-Fixed	100.00%	40.00%	40.00%	20.00%	Per ISO-NE Staff
21	14579	Ops - OPTI TTSE Maintenance	Alloc-Fixed	100.00%	40.00%	40.00%	20.00%	Per ISO-NE Staff
22	14583	Ops - Ad Hoc Analysis and Reporting	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
23								
24								
25		Operations Support Services						
26	14477	Participant project and outage coordination support	Alloc-Fixed	100.00%	50.00%	0.00%	50.00%	Per ISO-NE Staff
27	14453	National Committee Support	TSO Labor	100.00%	32.37%	47.81%	19.82%	Per ISO-NE Staff
28	14454	Indirect Supervision/Clerical Support	TSO Labor	100.00%	32.37%	47.81%	19.82%	Per ISO-NE Staff
29	14467	OSS - Nuclear Plant Liaison	TSO Labor	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
30	14756	OSS - Human Performance Improvement Program	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
31	18361	Transmission Studies, Operations, OASIS Support	Alloc-Fixed	100.00%	80.00%	5.00%	15.00%	Per ISO-NE Staff
32	18381	Transmission Outage Application - Short Term	Alloc-Fixed	100.00%	80.00%	5.00%	15.00%	Per ISO-NE Staff
33	18382	Transmission Outage Application - Long Term	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
34								
35		Market Monitoring						
36	16101	Market Power Monitoring and Mitigation	Alloc-Fixed	100.00%	0.00%	70.00%	30.00%	Per ISO-NE Staff
37	16102	Regulatory Activities	Alloc-Fixed	100.00%	0.00%	70.00%	30.00%	Per ISO-NE Staff
38	16121	FCM Market Monitoring	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
39								
40		Market Administration & Auctions						
41	21901	Day Ahead Price Monitoring	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
42	21902	Real Time Price Verification	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
43	21904	MA - NEPOOL Committee Support	Alloc-Fixed	100.00%	0.00%	96.84%	3.16%	Per ISO-NE Staff
44	21907	Indirect Supervision/Clerical Support	MA Labor	100.00%	0.00%	96.84%	3.16%	Per ISO-NE Staff
45	21908	Employee Development	MA Labor	100.00%	0.00%	96.84%	3.16%	Per ISO-NE Staff
46	21909	Customer Support	Alloc-Fixed	100.00%	0.00%	96.84%	3.16%	Per ISO-NE Staff
47	21915	FTR/Auction Administration	Alloc-Fixed	100.00%	50.00%	50.00%	0.00%	Per ISO-NE Staff
48	21917	Real Time Price Finalization	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
49	21951	FCM Annual Reconfiguration Auction Administration	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
50	21953	FCM Monthly Administration	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
51								
52		Market Analysis & Settlements						
53	1701	Billing Statements - Energy	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
54	1702	Billing Statements - Transmission	Alloc-Fixed	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
55	1713	Billing Statements - ISO Tariff	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
56	1717	Inventoried Energy Program	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
57	1718	Mystic COS	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
58	1719	FCM Daily	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
59	2005	Customer Service	STLM Labor	100.00%	14.79%	48.71%	36.50%	Per ISO-NE Staff
60	2007	Admin support - NEPOOL Committees	STLM Labor	100.00%	14.79%	48.71%	36.50%	Per ISO-NE Staff
61	2009	Indirect Supervision/Clerical Support	STLM Labor	100.00%	14.79%	48.71%	36.50%	Per ISO-NE Staff
62	2010	Employee Development	STLM Labor	100.00%	14.79%	48.71%	36.50%	Per ISO-NE Staff
63	2013	FTR Administration	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
64	2014	Billing Statements - NCPC	Alloc-Fixed	100.00%	0.00%	50.00%	50.00%	Per ISO-NE Staff
65	2020	Billing Disputes	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
66	2021	Analysis & Reporting	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
67	2024	ASM Regulation	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
68	2025	ASM Locational Forward Reserve	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
69	2026	Batch Processing	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
70	2032	Billing	STLM Labor	100.00%	14.79%	48.71%	36.50%	Per ISO-NE Staff
71	2033	Market Analysis	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
72	2047	Score Card	STLM Labor	100.00%	14.79%	48.71%	36.50%	Per ISO-NE Staff
73	2048	FCM	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
74	2049	Product Testing	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
75	2051	Legal Support	Alloc-Fixed	100.00%	0.00%	50.00%	50.00%	Per ISO-NE Staff

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1		Market Operations Support Services						
2	3000	Hourly Settlements Support	Alloc-Fixed	100.00%	0.00%	50.00%	50.00%	Per ISO-NE Staff
3	3002	Monthly Settlements Support	Alloc-Fixed	100.00%	50.00%	0.00%	50.00%	Per ISO-NE Staff
4	3003	MOSS - Market Analysis Support	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
5	3004	MOSS - Asset Registration and Auditing Support	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
6	3006	Customer Service	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
7	3008	Admin Support	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
8	3009	Indirect Supervision (Principal Analysts only)	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
9	3010	Employee Development	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
10	3017	Project MAS (Market Analysis & Settlements)	Alloc-Fixed	100.00%	25.00%	25.00%	50.00%	Per ISO-NE Staff
11								
12		Participant Support & Solutions						
13	16001	Participant/membership support	Alloc-Fixed	100.00%	0.00%	50.00%	50.00%	Per ISO-NE Staff
14	16006	Call Support (Ask ISO)	Alloc-Fixed	100.00%	26.00%	66.00%	8.00%	Per ISO-NE Staff
15	16024	Training Delivery	Alloc-Fixed	100.00%	0.00%	50.00%	50.00%	Per ISO-NE Staff
16	16414	Direct Customer Contact	MS Labor	100.00%	0.00%	90.00%	10.00%	Per ISO-NE Staff
17	16419	Asset Registration Implemented	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
18	16420	Asset Registration Review	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
19	16422	Claimed Capability Audits	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
20	16432	New Generation Coordination and Registration	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
21	16434	QMS/CAPA Process and Procedure Updates	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
22	16436	Mkt Trng/Cus Serv Indirect Supervision	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
23								
24		Participant Training Services						
25	16021	Training Development	Alloc-Fixed	100.00%	0.00%	50.00%	50.00%	Per ISO-NE Staff
26								
27		System Planning						
28	18402	Transmission Planning/Economic Studies Initiative	Alloc-Fixed	100.00%	0.00%	50.00%	50.00%	Per ISO-NE Staff
29	18531	SP - Indirect Supervision/Clerical Support	Alloc-Fixed	100.00%	24.83%	17.73%	57.44%	Per ISO-NE Staff
30								
31		Planning Services						
32	18101	Develop Load Forecast	Alloc-Fixed	100.00%	20.00%	20.00%	60.00%	Per ISO-NE Staff
33	18121	Operations Forecast Support	Alloc-Fixed	100.00%	20.00%	20.00%	60.00%	Per ISO-NE Staff
34	17101	Analysis	Alloc-Fixed	100.00%	0.00%	70.00%	30.00%	Per ISO-NE Staff
35	17131	Calculate Objective Capability	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
36	17403	TCA Application Review	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
37	17409	Environmental/Emissions Supp	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
38	17503	FCA - New Resource Qualification Support	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
39	17504	FCA - Perform Transmission / Topology Assessments	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
40	17507	FCA - Auctions & Filings	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
41	17508	FCA - Annual Reconfiguration Auction Support/Reliability Reviews	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
42	18131	Other Load Forecasting Activities	Alloc-Fixed	100.00%	20.00%	20.00%	60.00%	Per ISO-NE Staff
43	18133	Solar Load Forecast Development	Alloc-Fixed	100.00%	20.00%	20.00%	60.00%	Per ISO-NE Staff
44	18134	Electrification Forecasts	Alloc-Fixed	100.00%	20.00%	20.00%	60.00%	Per ISO-NE Staff
45	18135	CELT Rep-Res Outage Analysis	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
46								
47		Transmission Planning						
48	21660	Stability Case Building	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
49	14715	Non DOE Funded/Unallowable	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
50	18201	Transmission System Assessment	Alloc-Fixed	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
51	18301	NEPOOL Administrative Support - Schedule 1 Tariff	Alloc-Fixed	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
52	18333	General SIS/FS	Alloc-Fixed	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
53	18334	Indirect Supervision/Clerical Support	Alloc-Fixed	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
54	18335	Regulatory Activities - NPCC	Alloc-Fixed	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
55	18336	National Activities	Alloc-Fixed	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
56	18337	TR - Regulatory Activities	Alloc-Fixed	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
57	18346	OATT and Oper. Agreement Dev., Adm. and Support	Alloc-Fixed	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
58	18349	TR - Process CEII Requests	Alloc-Fixed	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
59	18351	Resource Integration	Alloc-Fixed	100.00%	100.00%	0.00%	0.00%	Per ISO-NE Staff
60								
61		Program Management						
62	801	Program Management - Administration	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
63	1661	ISO Program Management	Alloc-Fixed	100.00%	0.00%	70.00%	30.00%	Per ISO-NE Staff
64	1665	Product and Test Mgmt.	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
65	25003	Emerging Work Initiatives	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
66	26125	Real-time Market Clearing Engine Phase I	Alloc-Fixed	100.00%	0.00%	100.00%	0.00%	Per ISO-NE Staff
67	26133	Day Ahead Ancillary Services	Alloc-Fixed	100.00%	0.00%	30.00%	70.00%	Per ISO-NE Staff
68	26153	CAMS Tech Upgrade	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
69	26187	Distributed Energy Resources (DER)	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
70								
71		Advanced Technology Solutions						
72	21201	Advanced Technology Solutions	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
73	21203	Employee Development	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
74	21207	ATS - Capacity Auction Reforms	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER26-___-000
ALLOCATION FACTORS BY COST CATEGORY
TEST YEAR 2026

Line No.	Activity Code No.	Activity Code Description	Allocation Factor	Self-Funding Tariff Total	Schedule 1	Schedule 2	Schedule 3	Reference
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1		Market Development & Settlements Admin.						
2	16607	National Committee Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
3	19104	Indirect Supervision/Clerical Support	MOA Labor	100.00%	0.00%	70.00%	30.00%	Per ISO-NE Staff
4	21001	Market Development	Alloc-Fixed	100.00%	0.00%	50.00%	50.00%	Per ISO-NE Staff
5	21002	Administration	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
6	21003	Employee Development	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
7	21007	Budget/Forecast Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
8	21010	MD - Day-Ahead Reserve Market	Alloc-Fixed	100.00%	0.00%	95.00%	5.00%	Per ISO-NE Staff
9	21011	Capacity Market	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
10	22602	NEPOOL Committee Meetings & Support	Alloc-Fixed	100.00%	0.00%	50.00%	50.00%	Per ISO-NE Staff
11	22656	Energy, Reserve, and Regulation Markets	Alloc-Fixed	100.00%	0.00%	75.00%	25.00%	Per ISO-NE Staff
12	22661	Project: DER Participation	Alloc-Fixed	100.00%	0.00%	50.00%	50.00%	Per ISO-NE Staff
13	22662	Flexible Response Services	Alloc-Fixed	100.00%	0.00%	50.00%	50.00%	Per ISO-NE Staff
14	22663	Energy Shortage Pricing	Alloc-Fixed	100.00%	0.00%	75.00%	25.00%	Per ISO-NE Staff
15	22664	Capacity Auction Reforms	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
16								
17		Participant Relations & Services						
18	22607	NEPOOL Committee Administration	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
19	22613	PR&S Indirect Supervision	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
20	22614	PR&S Project Development	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
21								
22		IT Management						
23	6517	Employee Development - Hardware/Software	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
24	6519	Indirect Supervision and Clerical Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
25	6556	Budget Preparation, Tracking & Forecast	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
26	6557	Information Technology Committee	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
27	22501	Change Management Support	Alloc-Fixed	100.00%	45.00%	45.00%	10.00%	Per ISO-NE Staff
28	22505	Administrative	Alloc-Fixed	100.00%	34.00%	33.00%	33.00%	Per ISO-NE Staff
29								
30		IT Infrastructure Services						
31	6510	Desktop Support - Hardware	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
32	6511	Desktop Support - Software	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
33	6512	Host Computer - Hardware	Alloc-Fixed	100.00%	0.00%	75.00%	25.00%	Per ISO-NE Staff
34	6513	Host Computer - Software	Alloc-Fixed	100.00%	0.00%	75.00%	25.00%	Per ISO-NE Staff
35	6514	Networking - Hardware	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
36	6516	Communications	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
37	6602	Help Desk Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
38	6615	Host Computer Monitoring	Alloc-Fixed	100.00%	0.00%	50.00%	50.00%	Per ISO-NE Staff
39	6616	Desktop Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
40	6622	CIP & Systems Compliance	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
41	6623	Asset Management	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
42	6627	IT - Infrastructure Support Request	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
43	6630	IT - Infrastructure Operation Enhancement Effort	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
44								
45		IT Cyber Security						
46	6539	IT Policy/Procedures Program	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
47	6540	Security Compliance and Reporting	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
48	6540A	Cyber Security Controls Assessment	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
49	6540D	Intrusion Monitoring and Response	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
50	6540E	IT System Compliance, Response and Reporting	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
51	6541	Security SW Tools Program	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
52	6543	Critical Infrastructure Protection WG (NERC)	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
53	6546	IT Internal Audit Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
54	6547	Cyber Security Training	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
55	6548	CIP Compliance & Monitoring	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER26-___-000
ALLOCATION FACTORS BY COST CATEGORY
TEST YEAR 2026

Line No.	Activity Code No.	Activity Code Description	Allocation Factor	Self-Funding Tariff Total	Schedule 1	Schedule 2	Schedule 3	Reference
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1		IT Architecture & Analytics						
2	21706	Enterprise Software Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
3	21801	Software Support - Settlements	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
4	21802	Software Support - Publishing	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
5	21803	Software Support - Finance	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
6	21804	Software Support - Mitigation	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
7	21805	Software Support - TSO	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
8	21806	Software Support - Enterprise	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
9	21807	Software Support - Planning	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
10	21808	Training Delivery to NON-IT	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
11	21810	IT Issue Resolution	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
12	21811	Single Sign On Support	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
13	21812	GADS Support	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
14	21814	IT - Manual Database Edit	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
15	21816	CMS Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
16	21818	Discoverer Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
17	21824	FCTS Support	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
18	21825	eTariff Support	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
19	21830	Annual Software Maintenance for Enterpirse Wide Software	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
20	21832	GDMA/Gateway Support	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
21	21834	Federated SSO support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
22	6571	DBA Support - MOPS	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
23	6581	IT Bridge Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
24	6591	Data Architect - MOPS	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
25	6594	IT Data Analyst	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
26	6595	IT WEB Application Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
27	6596	IT Data Governance	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
28	6597	IT - BI IT Commitments	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
29								
30		IT Energy Management Systems						
31	21600	Indirect Supervision and Administration	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
32	21601	Power System Modeling	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
33	21602	Applications Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
34	21603	EMS Power System Applications Support	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
35	21604	Dispatcher Training Simulatory Support	Alloc-Fixed	100.00%	80.00%	20.00%	0.00%	Per ISO-NE Staff
36	21605	DAM FTR/ARR Support	Alloc-Fixed	100.00%	20.00%	60.00%	20.00%	Per ISO-NE Staff
37	21606	Real-time Market Support	Alloc-Fixed	100.00%	20.00%	60.00%	20.00%	Per ISO-NE Staff
38	21607	Forecast Support	Alloc-Fixed	100.00%	20.00%	60.00%	20.00%	Per ISO-NE Staff
39								
40		IT Enterprise Applications Development						
41	21701	IT Settlement Application Support	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
42	21702	IT Corporate Application Support	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
43	21707	Application Analysis and Conceptual Design	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
44	21708	Application Design Evaluation and Selection	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
45	21709	Technology Evaluation and Selection	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
46	21710	Indirect Supervision and Administration	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
47	21711	EWR and CAPA Analysis	Alloc-Fixed	100.00%	0.00%	80.00%	20.00%	Per ISO-NE Staff
48	21712	Automated Testing	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
49	6518	Employee Development - Software	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
50								
51		IT Power System Modeling Management						
52	21650	Indirect Supervision and Administration	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff
53	21651	Power System Modeling	Alloc-Fixed	100.00%	40.00%	40.00%	20.00%	Per ISO-NE Staff
54	21652	System Application Support	Alloc-Fixed	100.00%	40.00%	40.00%	20.00%	Per ISO-NE Staff
55	21653	PSMM-TTSE Support	Alloc-Fixed	100.00%	80.00%	20.00%	0.00%	Per ISO-NE Staff
56	21654	NX9 Administration	Alloc-Fixed	100.00%	40.00%	40.00%	20.00%	Per ISO-NE Staff
57	21655	ICCP Support	Alloc-Fixed	100.00%	40.00%	40.00%	20.00%	Per ISO-NE Staff
58	21656	Transmission Project Management	Alloc-Fixed	100.00%	80.00%	20.00%	0.00%	Per ISO-NE Staff
59	21657	Model On Demand Admin	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
60	21658	PSMM- Model on Demand Case Requests	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
61	21659	Synchrophasor Applications	Alloc-Fixed	100.00%	15.00%	15.00%	70.00%	Per ISO-NE Staff
62	21661	MAS Software Dev and Support	Alloc-Fixed	100.00%	0.00%	0.00%	100.00%	Per ISO-NE Staff
63								
64		Strategy, Risk & Operations Compliance						
65	14806	Employee Development	Alloc-Fixed	100.00%	55.55%	19.33%	25.12%	Per ISO-NE Staff
66	14807	NERC RSAW Update and Audit Prep	Alloc-Fixed	100.00%	50.00%	0.00%	50.00%	Per ISO-NE Staff
67	14816	Support NE Compliance Groups	Total Dir Labor	100.00%	21.55%	51.75%	26.70%	Per ISO-NE Staff

ISO NEW ENGLAND INC.

FERC COMPLIANCE FILING

ALLOCATION ON 2026 Budgeted Depreciation

Line No.	Description	Unrecovered Basis				Self-Funding Tariff			
		Total	Adjustments	Adj. Total		Total	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**2026 Items:**								
2	Building Improvements	$ -	$ -	$ -		$ -	$ -	$ -	$ -
3	Back-up Control Center	-	-	-		-	-	-	-
4	Furniture, Fixtures, and Equipment	23,810	-	23,810		23,810	5,131	12,321	6,357
5	Non-Project Capital Spending (Hardware and Software)	222,222	-	222,222		222,222	47,889	115,000	59,333
6	Market Systems and Enhancement Projects	1,784,678	-	1,784,678		1,784,678	213,336	1,158,116	413,226
7	Non-Market Systems and Enhancement Projects	736,817	-	736,817		736,817	158,784	381,303	196,730
8	Total 2026 Items - $	$ 2,767,527	$ -	$ 2,767,527		$ 2,767,527	$ 425,140	$ 1,666,741	$ 675,646
9	Total 2026 Items - %					100.00%	15.36%	60.22%	24.41%
10									
11	**2025 Items:**								
12	Building Improvements	$ 342,327	$ -	$ 342,327		$ 342,327	$ 73,771.39	$ 177,154.04	$ 91,401.22
13	Back-up Control Center	-	$ -	-		-	-	-	-
14	Furniture, Fixtures, and Equipment	95,263	-	95,263		95,263	20,529	49,299	25,435
15	Non-Project Capital Spending (Hardware and Software)	627,381	-	627,381		627,381	135,201	324,670	167,511
16	Market Systems and Enhancement Projects	5,161,909	-	5,161,909		5,161,909	251,117	3,672,920	1,237,873
17	Non-Market Systems and Enhancement Projects	2,856,955	-	2,856,955		2,856,955	657,963	1,453,563	745,429
18	Total 2025 Items - $	$ 9,083,835	$ -	$ 9,083,835		$ 9,083,835	$ 1,138,581	$ 5,677,606	$ 2,267,648
19	Total 2025 Items - %					100.00%	12.53%	62.50%	24.96%
20									
21	**2024 Items:**								
22	Building Improvements	$ 38,887	$ -	$ 38,887		$ 38,887	$ 8,380.22	$ 20,124.20	$ 10,382.92
23	Back-up Control Center	-	-	-		-	-	-	-
24	Furniture, Fixtures, and Equipment	1,709	-	1,709		1,709	368	885	456
25	Non-Project Capital Spending (Hardware and Software)	1,166,221	-	1,166,221		1,166,221	251,321	603,520	311,381
26	Market Systems and Enhancement Projects	4,859,009	-	4,859,009		4,859,009	380,740	2,650,174	1,828,095
27	Non-Market Systems and Enhancement Projects	2,185,467	-	2,185,467		2,185,467	404,110	1,212,759	568,598
28	Total 2024 Items - $	$ 8,251,294	$ -	$ 8,251,294		$ 8,251,294	$ 1,044,920	$ 4,487,461	$ 2,718,913
29	Total 2024 Items - %					100.00%	12.66%	54.38%	32.95%
30									
31	**2023 Items:**								
32	Building Improvements	$ 27,747	$ -	$ 27,747		$ 27,747	$ 5,979.47	$ 14,359.05	$ 7,408.44
33	Back-up Control Center	-	-	-		-	-	-	-
34	Furniture, Fixtures, and Equipment	4,421	-	4,421		4,421	953	2,288	1,180
35	Non-Project Capital Spending (Hardware and Software)	409,496	-	409,496		409,496	88,246	211,914	109,336
36	Market Systems and Enhancement Projects	5,243,792	-	5,243,792		5,243,792	477,957	2,696,171	2,069,664
37	Non-Market Systems and Enhancement Projects	2,700,649	-	2,700,649		2,700,649	553,637	1,434,078	712,933
38	Total 2023 Items - $	$ 8,386,105	$ -	$ 8,386,105		$ 8,386,105	$ 1,126,773	$ 4,358,811	$ 2,900,522
39	Total 2023 Items - %					100.00%	13.44%	51.98%	34.59%
40									
41	**2022 Items:**								
42	Building Improvements	$ 5,053	$ -	$ 5,053		$ 5,053	$ 1,089	$ 2,615	$ 1,349
43	Back-up Control Center	-	-	-		-	-	-	-
44	Furniture, Fixtures, and Equipment	31,283	-	31,283		31,283	6,741	16,189	8,353
45	Non-Project Capital Spending (Hardware and Software)	192,060	-	192,060		192,060	41,389	99,391	51,280
46	Market Systems and Enhancement Projects	3,122,660	-	3,122,660		3,122,660	304,321	1,820,419	997,920
47	Non-Market Systems and Enhancement Projects	529,232	-	529,232		529,232	108,748	279,598	140,887
48	Total 2022 Items - $	$ 3,880,288	$ -	$ 3,880,288		$ 3,880,288	$ 462,288	$ 2,218,212	$ 1,199,788
49	Total 2022 Items - %					100.00%	11.91%	57.17%	30.92%
50									
51	**2021 Items:**								
52	Building Improvements	$ 57,744	$ -	$ 57,744		$ 57,744	$ 12,444	$ 29,882	$ 15,418
53	Back-up Control Center	-	-	-		-	-	-	-
54	Furniture, Fixtures, and Equipment	286	-	286		286	62	148	76
55	Non-Project Capital Spending (Hardware and Software)	3,484	-	3,484		3,484	751	1,803	930

ISO NEW ENGLAND INC.

FERC COMPLIANCE FILING

ALLOCATION ON 2026 Budgeted Depreciation

Line No.	Description	Unrecovered Basis				Self-Funding Tariff			
		Total	Adjustments	Adj. Total		Total	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
56	Market Systems and Enhancement Projects	1,627,986	-	1,627,986		1,627,986	108,830	1,378,665	140,490
57	Non-Market Systems and Enhancement Projects	66,567	-	66,567		66,567	14,345	34,449	17,773
58	Total 2021 Items - $	$ 1,756,067	$ -	$ 1,756,067		$ 1,756,067	$ 136,432	$ 1,444,947	$ 174,688
59	Total 2021 Items - %					100.00%	7.77%	82.28%	9.95%
60									
61	**2020 Items:**								
62	Building Improvements	$ 50,523	$ -	$ 50,523		$ 50,523	$ 10,888	$ 26,146	$ 13,490
63	Back-up Control Center	-	-	-		-	-	-	-
64	Furniture, Fixtures, and Equipment	1,259	-	1,259		1,259	271	652	336
65	Non-Project Capital Spending (Hardware and Software)	304	-	304		304	66	158	81
66	Market Systems and Enhancement Projects	785,848	-	785,848		785,848	34,164	751,684	-
67	Non-Market Systems and Enhancement Projects	-	-	-		-	-	-	-
68	Total 2020 Items - $	$ 837,935	$ -	$ 837,935		$ 837,935	$ 45,388	$ 778,639	$ 13,907
69	Total 2020 Items - %					100.00%	5.42%	92.92%	1.66%
70									
71	**2019 Items:**								
72	Building Improvements	$ 12,292	$ -	$ 12,292		$ 12,292	$ 2,649	$ 6,361	$ 3,282
73	Back-up Control Center	-	-	-		-	-	-	-
74	Furniture, Fixtures, and Equipment	-	-	-		-	-	-	-
75	Non-Project Capital Spending (Hardware and Software)	5,280	-	5,280		5,280	1,138	2,732	1,410
76	Market Systems and Enhancement Projects	231,255	-	231,255		231,255	-	231,255	-
77	Non-Market Systems and Enhancement Projects	-	-	-		-	-	-	-
78	Total 2019 Items - $	$ 248,828	$ -	$ 248,828		$ 248,828	$ 3,787	$ 240,349	$ 4,692
79	Total 2019 Items - %					100.00%	1.52%	96.59%	1.89%
80									
81	**2018 Items:**								
82	Building Improvements	$ 2,106	$ -	$ 2,106		$ 2,106	$ 454	$ 1,090	$ 562
83	Back-up Control Center	-	-	-		-	-	-	-
84	Furniture, Fixtures, and Equipment	-	-	-		-	-	-	-
85	Non-Project Capital Spending (Hardware and Software)	-	-	-		-	-	-	-
86	Market Systems and Enhancement Projects	185,097	-	185,097		185,097	-	185,097	-
87	Non-Market Systems and Enhancement Projects	-	-	-		-	-	-	-
88	Total 2018 Items - $	$ 187,203	$ -	$ 187,203		$ 187,203	$ 454	$ 186,187	$ 562
89	Total 2018 Items - %					100.00%	0.24%	99.46%	0.30%
90									
91	**2017 Items:**								
92	Building Improvements	$ 61,353	$ -	$ 61,353		$ 61,353	$ 13,222	$ 31,750	$ 16,381
93	Back-up Control Center	-	-	-		-	-	-	-
94	Furniture, Fixtures, and Equipment	-	-	-		-	-	-	-
95	Non-Project Capital Spending (Hardware and Software)	-	-	-		-	-	-	-
96	Market Systems and Enhancement Projects	143,439	-	143,439		143,439	-	143,439	-
97	Non-Market Systems and Enhancement Projects	-	-	-		-	-	-	-
98	Total 2017 Items - $	$ 204,793	$ -	$ 204,793		$ 204,793	$ 13,222	$ 175,190	$ 16,381
99	Total 2017 Items - %					100.00%	6.46%	85.54%	8.00%
100									
101	**2016 Items:**								
102	Building Improvements	$ 24,556	$ -	$ 24,556		$ 24,556	$ 5,292	$ 12,708	$ 6,556
103	Back-up Control Center	-	-	-		-	-	-	-
104	Furniture, Fixtures, and Equipment	-	-	-		-	-	-	-
105	Non-Project Capital Spending (Hardware and Software)	66	-	66		66	14	34	18
106	Market Systems and Enhancement Projects	-	-	-		-	-	-	-
107	Non-Market Systems and Enhancement Projects	-	-	-		-	-	-	-
108	Total 2016 Items - $	$ 24,623	$ -	$ 24,623		$ 24,623	$ 5,306	$ 12,742	$ 6,574
109	Total 2016 Items - %					100.00%	21.55%	51.75%	26.70%
110									

ISO NEW ENGLAND INC.

FERC COMPLIANCE FILING

ALLOCATION ON 2026 Budgeted Depreciation

Line No.	Description	Unrecovered Basis				Self-Funding Tariff			
		Total	Adjustments	Adj. Total		Total	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
111	**2015 Items:**								
112	Building Improvements	$ -	$ -	$ -		$ -	$ -	$ -	$ -
113	Back-up Control Center	-	-	-		-	-	-	-
114	Furniture, Fixtures, and Equipment	-	-	-		-	-	-	-
115	Non-Project Capital Spending (Hardware and Software)	-	-	-		-	-	-	-
116	Market Systems and Enhancement Projects	-	-	-		-	-	-	-
117	Non-Market Systems and Enhancement Projects	-	-	-		-	-	-	-
118	Total 2015 Items - $	$ -	$ -	$ -		$ -	$ -	$ -	$ -
119	Total 2015 Items - %					0.00%	0.00%	0.00%	0.00%
120									
121	**2014 Items:**								
122	Building Improvements	$ 73,004	$ -	$ 73,004		$ 73,004	$ 15,732	$ 37,780	$ 19,492
123	Back-up Control Center	-	-	-		-	-	-	-
124	Furniture, Fixtures, and Equipment	-	-	-		-	-	-	-
125	Non-Project Capital Spending (Hardware and Software)	-	-	-		-	-	-	-
126	Market Systems and Enhancement Projects	-	-	-		-	-	-	-
127	Non-Market Systems and Enhancement Projects								
128	Total 2014 Items - $	$ 73,004	$ -	$ 73,004		$ 73,004	$ 15,732	$ 37,780	$ 19,492
129	Total 2014 Items - %					100.00%	21.55%	51.75%	26.70%
130									
131	**2013 Items:**								
132	Building Improvements	$ -	$ -	$ -		$ -	$ -	$ -	$ -
133	Back-up Control Center	827,131	-	827,131		827,131	178,247	428,040	220,844
134	Furniture, Fixtures, and Equipment	-	-	-		-	-	-	-
135	Non-Project Capital Spending (Hardware and Software)	-	-	-		-	-	-	-
136	Market Systems and Enhancement Projects	-	-	-		-	-	-	-
137	Non-Market Systems and Enhancement Projects	-	-	-		-	-	-	-
138	Total 2013 Items - $	$ 827,131	$ -	$ 827,131		$ 827,131	$ 178,247	$ 428,040	$ 220,844
139	Total 2013 Items - %					100.00%	21.55%	51.75%	26.70%
140									
141	**2012 Items:**								
142	Building Improvements	$ 2,825	$ -	$ 2,825		$ 2,825	$ 609	$ 1,462	$ 754
143	Back-up Control Center	77,606	-	77,606		77,606	16,724	40,161	20,721
144	Furniture, Fixtures, and Equipment	-	-	-		-	-	-	-
145	Non-Project Capital Spending (Hardware and Software)	-	-	-		-	-	-	-
146	Market Systems and Enhancement Projects	-	-	-		-	-	-	-
147	Non-Market Systems and Enhancement Projects	-	-	-		-	-	-	-
148	Total 2012 Items - $	$ 80,431	$ -	$ 80,431		$ 80,431	$ 17,333	$ 41,623	$ 21,475
149	Total 2012 Items - %					100.00%	21.55%	51.75%	26.70%
150									
151	**2011 Items:**								
152	Facilities Project	$ -	$ -	$ -		$ -	$ -	$ -	$ -
153	Furniture, Fixtures, and Equipment	-	-	-		-	-	-	-
154	Non-Project Capital Spending (Hardware and Software)	-	-	-		-	-	-	-
155	Market Systems and Enhancement Projects	-	-	-		-	-	-	-
156	Non-Market Systems and Enhancement Projects	-	-	-		-	-	-	-
157	Total 2011 Items - $	$ -	$ -	$ -		$ -	$ -	$ -	$ -
158	Total 2011 Items - %					0.00%	0.00%	0.00%	0.00%
159									

ISO NEW ENGLAND INC.

FERC COMPLIANCE FILING

ALLOCATION ON 2026 Budgeted Depreciation

Line No.	Description	Unrecovered Basis				Self-Funding Tariff			
		Total	Adjustments	Adj. Total		Total	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
160	**2010 Items:**								
161	Facilities Project	$ -	$ -	$ -		$ -	$ -	$ -	$ -
162	Furniture, Fixtures, and Equipment	-	-	-		-	-	-	-
163	Non-Project Capital Spending (Hardware and Software)	-	-	-		-	-	-	-
164	Market Systems and Enhancement Projects	-	-	-		-	-	-	-
165	Non-Market Systems and Enhancement Projects	-	-	-		-	-	-	-
166	Total 2010 Items - $	$ -	$ -	$ -		$ -	$ -	$ -	$ -
167	Total 2010 Items - %					0.00%	0.00%	0.00%	0.00%
168									
169	**2009 Items:**								
170	Facilities Project	$ 1,230	$ -	$ 1,230		$ 1,230	$ 265	$ 637	$ 328
171	Furniture, Fixtures, and Equipment	-	-	-		-	-	-	-
172	Non-Project Capital Spending (Hardware and Software)	-	-	-		-	-	-	-
173	Market Systems and Enhancement Projects	-	-	-		-	-	-	-
174	Non-Market Systems and Enhancement Projects	-	-	-		-	-	-	-
175	Total 2009 Items - $	$ 1,230	$ -	$ 1,230		$ 1,230	$ 265	$ 637	$ 328
176	Total 2009 Items - %					100.00%	21.55%	51.75%	26.70%
177									
178	**2008 Items:**								
179	Facilities Project	$ 548	$ -	$ 548		$ 548	$ 118	$ 284	$ 146
180	Furniture, Fixtures, and Equipment	-	-	-		-	-	-	-
181	Non-Project Capital Spending (Hardware and Software)	-	-	-		-	-	-	-
182	Market Systems and Enhancement Projects	-	-	-		-	-	-	-
183	Non-Market Systems and Enhancement Projects	-	-	-		-	-	-	-
184	Total 2008 Items - $	$ 548	$ -	$ 548		$ 548	$ 118	$ 284	$ 146
185	Total 2008 Items - %					100.00%	21.55%	51.75%	26.70%
186									
187	**2007 Items:**								
188	Facilities Project	$ 156,427	$ -	$ 156,427		$ 156,427	$ 33,710	$ 80,951	$ 41,766
189	Furniture, Fixtures, and Equipment		-	-		-	-	-	-
190	Non-Project Capital Spending (Hardware and Software)		-	-		-	-	-	-
191	Market Systems and Enhancement Projects		-	-		-	-	-	-
192	Non-Market Systems and Enhancement Projects		-	-		-	-	-	-
193	Non-Market Systems and Enhancement Projects	-	-	-		-	-	-	-
194	Total 2007 Items - $	$ 156,427	$ -	$ 156,427		$ 156,427	$ 33,710	$ 80,951	$ 41,766
195	Total 2007 Items - %					100.00%	21.55%	51.75%	26.70%
196									
197	**2006 Items:**								
198	Facilities Project	$ 568,947	$ -	$ 568,947		$ 568,947	$ 122,608	$ 294,430	$ 151,909
199	Furniture, Fixtures, and Equipment		-	-		-	-	-	-
200	Non-Project Capital Spending (Hardware and Software)		-	-		-	-	-	-
201	Market Systems and Enhancement Projects		-	-		-	-	-	-
202	Non-Market Systems and Enhancement Projects		-	-		-	-	-	-
203	Total 2006 Items - $	$ 568,947	$ -	$ 568,947		$ 568,947	$ 122,608	$ 294,430	$ 151,909
204	Total 2006 Items - %					100.00%	21.55%	51.75%	26.70%
205									
206	**2005 Items:**								
207	Building/property improv. (Renov. workspace, network & voice rewiring)	$ 758,548	$ -	$ 758,548		$ 758,548	$ 163,467	$ 392,548	$ 202,532
208	Capital Interest/Fees	14,622	-	14,622		14,622	-	9,577	5,044
209	Total 2005 Items - $	$ 773,169	$ -	$ 773,169		$ 773,169	$ 163,467	$ 402,126	$ 207,577
210	Total 2005 Items - %					100.00%	21.14%	52.01%	26.85%

ISO NEW ENGLAND INC.

FERC COMPLIANCE FILING

ALLOCATION ON 2026 Budgeted Depreciation

Line No.	Description	Unrecovered Basis Total	Adjustments	Adj. Total		Self-Funding Tariff Total	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
211									
212	**2004 Items:**								
213	Building/property improv. (Renov. workspace, network & voice rewiring)	$ 41,709	$ -	$ 41,709		$ 41,709	$ 8,988	$ 21,585	$ 11,136
214	Capital Interest/Fees	1,451	-	1,451		1,451	-	950	501
215	Total 2004 Items - $	$ 43,160	$ -	$ 43,160		$ 43,160	$ 8,988	$ 22,535	$ 11,637
216	Total 2004 Items - %					100.00%	20.83%	52.21%	26.96%
217									
218	**Total Unrecovered Plant in Service - $**	$ 38,152,545	$ -	$ 38,152,545		$ 38,152,545	$ 4,942,759	$ 22,555,289	$ 10,654,497
219	**- %**					100.00%	12.96%	59.12%	27.93%

ISO NEW ENGLAND INC.
2026 Operating Expense Budget

Line No.	Cost Category		Amount
	(a)		(b)
1	**Revenues and Other Income**	$	(1,691,344)
2	**Salaries and Overhead**		191,175,656
3	**Professional Fees & Consultants**		28,468,012
4	**Building Services**		3,869,430
5	**Rents/Leases**		2,372,099
6	**Network Operations**		4,287,379
7	**Computer Services**		36,024,464
8	**Data Services and Office Expenses**		2,499,052
9	**Insurance Expense**		3,831,097
10	**Meetings & Related Expenses**		1,785,946
11	**Education & Training**		1,409,632
12	**Fees, Taxes, and Licenses**		285,190
13	**CEO Emerging Work Allowance**		3,000,000
14	**Operating Contingency**		700,000
15	**Net Expense before Depreciation and Debt Service**		**278,016,613**
16			
17	**Depreciation**		38,251,846
18	**NPCC/NERC Dues**		9,955,133
19	**Interest Expense**		3,767,898
20	**Depreciation, Interest Expense and Regulatory Fees**		**51,974,877**
21			
22	**Total Operating Expense Budget**	**$**	**329,991,490**

ISO New England Inc.
2026 Operating Expense Budget

Line No.			
	Revenues and Other Income		
1		Interest income	(1,300,064)
2		Fees for Participant training seminars and materials	(166,800)
3		Fees to transmission owners for scheduling services (OATI)	(114,480)
4		Purchase Discounts	(110,000)
5			**$ (1,691,344)**
6	**Salaries and Overhead**		
7		Salaries	146,440,553
8		Payroll Taxes and Employee Benefits	43,008,603
9		Board Fees and Expenses	1,726,500
10			**191,175,656**
11	**Professional Fees and Consultants**		
12	Consulting		
13		Information Technology (GE Vernova based support, support for resource adequacy and capacity market modeling, SMS/SAS/EMS/CAMS Support, Energy Management System Support, Software License Management & Reporting Support, Website Support, Cyber Security and Vulnerability Testing, Desktop and Database Services Support, and other Temp Help)	10,486,004
14		Market Advisor, Market Development support of Capacity Auction Reforms and Full Net CONE (Cost of New Entry) recalculation, Advanced Technology Solutions funding for Gas Modeling and various other technological enhancement research.	5,178,419
15		Funding for Asset Condition Review Work, Long-Term Transmission Planning RFPs, NERC and NPCC requirements for energy assessments and planning, long-term forecasting, power system modeling advancements, and Transmission Planning for increased effort to support system assessments with increased penetration of inverter-based resources	2,715,384
16	Human Resource Consulting and Recruiting Services		3,379,377
17	Legal fees		2,377,000

ISO New England Inc.
2026 Operating Expense Budget

18		Includes legal fees for OATT, regulatory filings, energy markets, market rules and proceedings, Market Monitoring Support, Siting costs, billing disputes, new initiatives/emerging issues funding, tariff and corporate matters, and miscellaneous labor matters.	
19		Auditors fees - SSAE Type 18 Audit, Network and IT Systems, Operations, Financial, Pension	1,489,800
20		External Affairs	469,894
21		Finance Support and Payroll Services, Implement Security Best Practices, Misc Other	955,320
22		Market Monitoring	636,000
23		Market and Credit Risk	350,000
24		Strategy, Risk & Operational Compliance	208,814
25		Corporate Communications Support	222,000
26			**28,468,012**
27	**Building Services**		
28		Repairs and maintenance	651,819
29		Utilities	1,680,647
30		Miscellaneous (grounds keeping, supplies, building security)	1,536,964
31			**3,869,430**
32	**Rents/Leases**		
33		Various office and computer service equipment leases	2,148,331
34		Leasing of land adjacent to Holyoke facility	181,008
34		Auto leases and Auto Maintenance	42,760
35			**2,372,099**
36	**Network Operations**		
37		Shared microwave	141,624
38		Network circuits and Internet circuits	1,916,307
39		Telephone and long distance lines	2,166,151
40		Miscellaneous maintenance and service items	63,297
41			**4,287,379**
42	**Computer Services**		
43		Software and licensing costs	3,238,961
44		Maintenance contracts	24,395,111
44		Computer supplies	368,544
45		SaaS Applications and Cloud Computing	8,021,848

ISO New England Inc.
2026 Operating Expense Budget

46			**36,024,464**
47	**Data Services and Office expenses**		
48		Office supplies	108,574
49		Postage and courier	42,250
50		Printing Expense	51,350
51		Data Services, Dues, and subscriptions	2,270,878
52		Office equipment maintenance	14,000
53		Other Miscellaneous	12,000
54			**2,499,052**
55			
56	**Insurance Expense**		
57		Property and liability (including Cyber Security)	3,429,697
58		Directors and officers	401,400
59			**3,831,097**
60			
61	**Meetings & Related Expenses**		**1,785,946**
62		Includes travel and related expenses for stakeholder meetings throughout the region, for regulatory meetings and support including FERC, NERC, NPCC, and state agencies, for Industry and Other Conference attendance, in addition to other miscellaneous travel reimbursement and employee service recognition	
63			
64	**Education & Training**		**1,409,632**
65		Includes funding for Enterprise wide training including Leadership and Management Development, Technical and NERC Certification Training, Communications and Presentation Training, Management and General Training, and Education Reimbursement	
66			
67	**Fees, Taxes and Licenses**		
68		Real estate tax	170,171
69		Business license and Bank Fees	115,019
70			**285,190**

ISO New England Inc.
2026 Operating Expense Budget

CEO Emerging Work Allowance		
	New activities and initiatives that occur during the year.	**3,000,000**
Operating Contingency		
	Funding of last resort to cover unknown expenses (Board Approved).	**700,000**
Depreciation, Debt Service of Capitalized Costs and Regulatory Fees		
	Depreciation and Amortization expense and Disposal	38,251,846
	NPCC/NERC Dues	9,955,133
	Interest expense	3,767,898
		51,974,877
Total Operating Expense Budget		**$ 329,991,490**

Exhibit 3
RCL-5
Schedule 3

ISO New England Inc.
Operating Expense Budget
Variance Summary
Proposed Year 2026 Budget vs 2025 Budget
(amounts in thousands)

Line No.	DESCRIPTION	Proposed Annual Budget 2026	Original 2025 Budget	Variance 2026 Budget vs 2025 Budget Inc/(Decrease)
1	**Revenues and Other Income**	$ (1,691.3)	$ (1,783.0)	$ 91.7
2	**Salaries and Overhead**	191,175.7	175,597.1	15,578.6
3	**Professional Fees & Consultants**	28,468.0	27,776.9	691.1
4	**Building Services**	3,869.4	3,492.5	377.0
5	**Rents/Leases**	2,372.1	2,123.3	248.8
6	**Network Operations**	4,287.4	3,935.8	351.6
7	**Computer Services**	36,024.5	31,336.4	4,688.1
8	**Data Services and Office Expenses**	2,499.1	2,191.6	307.5
9	**Insurance Expense**	3,831.1	3,887.2	(56.1)
10	**Meetings & Related Expenses**	1,785.9	1,637.2	148.7
11	**Education & Training**	1,409.6	1,433.1	(23.5)
12	**Fees, Taxes, and Licenses**	285.2	277.1	8.1
13	**CEO Emerging Work Allowance**	3,000.0	3,000.0	-
14	**Operating Contingency**	700.0	700.0	-
15	**Net Expense before Depreciation and Debt Service**	**278,016.6**	**255,605.1**	**22,411.5**
16				
17	**Depreciation**	38,251.8	36,975.3	1,276.5
18	**NPCC/NERC Dues**	9,955.1	9,253.5	701.7
19	**Interest Expense**	3,767.9	4,571.0	(803.1)
20	**Depreciation, Interest Expense and Regulatory Fees**	**51,974.9**	**50,799.8**	**1,175.1**
21	**Total Operating Expense Budget**	**$ 329,991.5**	**$ 306,404.9**	**$ 23,586.6**

ISO NEW ENGLAND INC.
Change in Operating Expense Budgets
Proposed Year 2026 Budget vs. 2025 Budget
(Amounts in thousands)

Line No.				
1	**Revenues and Other Income**			
2		Lower forecasted Interest Income due to projecting lower operating cash balance from expected withdrawals under FERC Order 2023 partially offset by higher miscellaneous revenue	161.3	
3		Participant Market Training Fees	(69.6)	
4	**Total change in Revenues and Other Income**			**$ 91.7**
5				
6	**Salaries and Overhead**			
7		Increase includes funding of 18.5 out of 25 new positions approved for 2026 and carry over of 16 positions from 2025 (that were deferred during that time)	7,948.5	
8		Merit and Promotion	6,038.7	
9		Employee Benefit and Tax Cost Changes	1,543.4	
10		Conversion of six former consultants to full-time employees	1,194.3	
11		Change for Decrease in Vacancy from 6% to 5%	1,558.3	
12		Salary Rate Changes	(2,545.4)	
13		Other minor changes	(159.2)	
14	**Total change in Salaries and Overhead**			**15,578.6**
15				
16	**Professional Fees and Consultants**			
17				
18		Increase in funding for Asset Condition Reviewer Work	1,000.0	
19		Transmission Services & Resource Qualification - reductions due to completion of regional study work with PJM and NYISO for 1,200MW single source contingency limit appropriateness and to determine upgrades required to support 2,000MW single source limit, transmission planning system assessment under NERC Transmission Planning Standard TPL-001, and Wind, Solar, and Generation dataset information that will be obtained via other sources. Reductions were partially offset with increases for consulting support for Long-Term Transmission Planning (LTTP) proposals and other Transmission Planning work.	(2,071.6)	
20		Market Monitoring support for technology assessment and Artificial Intelligence development for use in detection and mitigation of energy market activity	190.0	
21		System Operations & Market Administration - Reduction in funding to support transmission planning and analysis studies to establish facility out transfer capability for Northern New England and NECEC which was completed in 2025.	(273.0)	
22		Legal Department - Increase in regulatory counsel fees for FERC Order filings and responses to supplement ISO-NE Legal staff	500.0	
23		Reduction in Advanced Technology Solutions outside Research & Development support	(452.5)	
24		Human Resources - Increase in Board of Director search fees to recruit for position scheduled for turnover and consulting services, data, and research to support critical HR initiatives	223.0	
25		Information and Cyber Security Services addition of professional fees for GE Vernova based support, an IT Services Analyst to support the Enterprise Application Support Team, and a Lead Microsoft Cloud Engineer to support IT Infrastructure Team. Increases were partially offset by reductions for five consultant positions being converted to full time employees	716.7	
26		Internal Audit - Increases for Consultant funds to perform audits or assist with various engagements including systems and cyber security related work	174.5	
27		Consulting support to provide research, recommendations, and implementation of enhanced security best practices for ISO workforce (including senior management)	500.0	
28		Other minor changes	184.0	

ISO NEW ENGLAND INC.
Change in Operating Expense Budgets
Proposed Year 2026 Budget vs. 2025 Budget
(Amounts in thousands)

Line No.				
29	**Total change in Professional Fees and Consultants**			**691.1**
30	**Building Services**	Increases in Building Service costs due to cyclical maintenance items that are due for completion in 2026, higher utility expense largely for delivery service fees at Windsor facility, and inflationary and other small increases across line items		**377.0**
31				
32	**Rents/Leases**	Increase for leasing tranche of blade servers for data center replacements that is more favorable than buying and is part of a multi-year data center refresh		**248.8**
33				
34	**Network Operations**	Network Operations increases for transition of communication lines to new technologies, for data redundancy, and for inflationary and communication line increases		**351.6**
35				
36	**Computer Services**	Increases for: cyber security (security log management, network detection and response tool, zero trust access and protection, and cloud monitoring); network collaboration software; computing and storage capacity application; licensing for System Planning and Operations applications; for nGEM vendor support with the Real-Time Market Clearing Engine application that is higher cost than the legacy Real-Time application; costs under NERC CIP Synchrophasor compliance adoption; and inflationary and vendor increases across our portfolio of computer service products		**4,688.1**
37				
38	**Data Services and Office Expenses**	Data Services & Office Expense increases including data services subscriptions for Market Monitoring fuel price and forecast utilization, for vendor third party risk assessment, and participant credit rating services		**307.5**
39				
40	**Insurance Expense**	Carryover into 2026 of decrease due to actual 2025 premium renewals coming in lower than budget		**(56.1)**
41				
42	**Meetings & Related Expenses**	Meetings & related expense increase due to higher travel costs, travel for offsite training of additional staff, and to attend participant and industry meetings and conferences		**148.7**
43				
44	**Education & Training**	Training of additional staff and for education of new platforms and tools.		**(23.5)**
45				
46	**Regulatory Fees, Taxes, and Licenses**	Increases due to higher estimated real estate taxes.		**8.1**
47				
48				
49	**Total Change in Net Expense before Depreciation and Debt Service**			**$ 22,411.5**
50				
51	**Depreciation and Debt Service**	Depreciation expense increases primarily driven by 2025 or 2026 project implementations including nGEM Real-Time Market Clearing Engine, Enterprise Resource Planning System Replacement, CIP Electronic Security Perimeter Redesign Phase II, and FERC Order 841; partially offsetting increases in this line item are projects that will be fully depreciated in 2025 or 2026 including nGEM Market Clearing Engine Implementation, nGEM Software Development Parts I and II, nGEM Hardware Phase II, and Security Information & Event Management Log Monitoring Replacement	**1,276.5**	
52	**NPCC/NERC Dues**	Increases for both Northeast Power Coordinating Council and North American Electric Reliability Corporation dues assessed to the ISO	**701.7**	
53	**Interest Expense**	Reduction for no expected borrowing on working capital funds based on projections for 2026	**(803.1)**	
54	**Total Depreciation, Interest Expense and Regulatory Fees**			**1,175.0**
55				
56	**Total Change in Operating Expense Budget**			**$ 23,586.6**

ISO NEW ENGLAND INC.
Staffing Projections

Line No.	Department	2025 Budget Staff Level	2026 Budget Staff Level
1	**COO - Administration**	**8.0**	**8.0**
2			
3	System Operations & Market Administration	5.0	5.0
4	Operations	44.0	47.0
5	Operations Support Services	30.0	32.0
6	Operational Performance Trng and Integration	29.0	30.0
7	Market Administration & Auctions	25.0	24.0
8	**System Operations & Market Administration**	**133.0**	**138.0**
9			
10	Planning Services	24.0	32.0
11	Transmission Planning	25.0	29.0
12	Transmission Services & Resource Qualification	32.0	30.0
13	System Planning	4.0	4.0
14	**System Planning**	**85.0**	**95.0**
15			
16	Participant Relations & Services	10.0	12.0
17	Participant Support & Solutions	17.0	17.0
18	**Participant Relations & Services**	**27.0**	**29.0**
19			
20	Market Development & Settlements Admin	5.0	4.0
21	Market Analysis & Settlements	16.0	16.0
22	Market Operations Support Services	16.0	16.0
23	Market Development	14.0	14.0
24	Market Assessment	13.0	15.0
25	**Market Development & Settlements**	**64.0**	**65.0**
26			
27	Energy Management Systems	21.0	22.0
28	Enterprise Applications Development	23.0	25.0
29	Cyber Security	22.0	23.0
30	Enterprise Applications Support	18.0	18.0
31	IT Infrastructure Services	22.0	27.0
32	IT Management	6.0	6.0
33	Power System Modeling Management	22.0	24.0
34	Database & Enterprise Support Services Admin	20.0	22.0
35	Architecture & Data Governance	12.0	11.0
36	Software Development & Power System Supp Admin	3.0	3.0
37	Infrastructure & Enterprise Support Services Admin	5.0	5.0
38	IT Change & Asset License Management	4.0	4.0
39	IT Service Delivery	19.0	21.0
40	IT Arch & Ent Appl Admin	5.0	6.0

ISO NEW ENGLAND INC.
Staffing Projections

Line No.	Department	2025 Budget Staff Level	2026 Budget Staff Level
41	**Information Technology**	**202.0**	**217.0**
42			
43	**Advanced Technology Solutions**	**19.0**	**22.0**
44	**Program Management**	**16.0**	**18.0**
45			
46	**Total COO**	**554.0**	**592.0**
47			
48	**Chief Executive Officer - Administration**	**9.0**	**9.0**
49			
50	Market & Credit Risk	6.0	6.0
51	Facilities & Security	4.0	4.0
52	Strategy, Risk & Operations Compliance	12.0	12.0
53	Finance	22.0	23.0
54	**Finance and Compliance**	**44.0**	**45.0**
55			
56	Legal Department	17.0	18.0
57	Corporate Communications & External Affairs	21.0	22.0
58	**Legal and Public Affairs**	**38.0**	**40.0**
59			
60	**Human Resources**	**19.0**	**21.0**
61			
62	**Market Monitoring and Mitigation**	**18.0**	**20.0**
63			
64	**Internal Audits**	**6.0**	**6.0**
65			
66	**Total Administration**	**134.0**	**141.0**
67			
68	**Total FTE's**	**688.0**	**733.0**
69			
70	**Total Part-timers (X @ 0.5)**	**0.5**	**0.5**
71			
72	**Total Number of Employees**	**688.5**	**733.5**

ISO New England Inc.
2026 Capital Budget

Line No.	Description	2026
1	***Capital Projects - Approved Charters***	
2	**. nGEM Real-Time Market Clearing Engine Implementation**	$ 3,203,600
3	**. Distributed Energy Resources - Order 2222**	2,642,700
4	**. Oracle Platform Replacement**	2,157,400
5	**. Managing Transmission Line Ratings**	1,000,000
6	**. Adoption of NERC CIP Compliance of Synchrophasor Systems**	994,600
7	**. IMM Datamart Improvement Project**	387,000
8	**. CIP Electronic Security Perimeter Redesign Phase III**	293,600
9	**. Voltage Ampere Reactive (VAR) Capability Testing**	144,500
10	**. EMS CFE Refresh**	108,200
11	**. Enterprise Core Network Refresh**	48,000
12	**. Centralized Application Security**	38,700
13	**Sub Total Projects with Approved Charters**	11,018,300
14	***Planning/Conceptual Design [2]***	
15	**. Single Interval MCE Improvements (SIMI)**	5,000,000
16	**. EMP 3.5 Upgrade - GridOS**	3,500,000
17	**. MW Dependent Fuel Price Adjustment**	2,500,000
18	**. Advanced Technology Initiatives**	2,000,000
19	**. Order 2023 Interconnection Reforms**	2,000,000
20	**. Atlassian Cloud Migration**	2,000,000
21	**. Day-Ahead Market Simulator (DAMKTSIM)**	1,800,000
22	**. GridOS Connect**	1,500,000
23	**. Storage as Transmission Only Asset (SATOA)**	500,000
24	**. Replace Employee & Pager Application**	500,000
25	**. Circuit Inventory Management Platform Phase 2**	500,000
26	**. Tie Line Telemetry Replacement**	500,000
27	**. Solar Do Not Exceed Dispatch Phase III**	500,000
28	**. Operations Document Management System MS 365 Conversion**	250,000
29	**. Other Emerging Work Projects**	1,731,700
30	**Subtotal Conceptual Design**	24,781,700
31	***. Non-Project Capital Expenditures***	5,500,000
32	***. Capitalized Interest and Loan Fees***	1,200,000
33	**TOTAL Capital Projects (including Capitalized Interest)**	$ 42,500,000

Exhibit 3
RCL-7
Schedule 1

ISO New England Inc.
FERC DOCKET NO. ER26 -000
Development of Escalation Factors

Line No.	Month	From CELT Report (As Published) Monthly Peak Load (MW)	Monthly Net Energy (GWH)	Data Source	From Monthly Market Reports Monthly Peak Load (MW)	Monthly Net Energy (GWH)	Data Source
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Jan-16	19,451	11,015	Actual	19,451	11,015	Actual
2	Feb-16	19,561	10,126	Actual	19,562	10,126	Actual
3	Mar-16	17,341	9,819	Actual	17,341	9,819	Actual
4	Apr-16	16,963	9,020	Actual	16,963	9,020	Actual
5	May-16	19,029	9,433	Actual	19,029	9,433	Actual
6	Jun-16	19,966	10,176	Actual	19,966	10,176	Actual
7	Jul-16	24,416	12,387	Actual	24,416	12,387	Actual
8	Aug-16	25,596	12,642	Actual	25,596	12,642	Actual
9	Sep-16	23,142	10,164	Actual	23,142	10,164	Actual
10	Oct-16	16,298	9,356	Actual	16,298	9,356	Actual
11	Nov-16	17,517	9,403	Actual	17,517	9,403	Actual
12	Dec-16	19,581	10,840	Actual	19,647	10,884	Actual
13	Jan-17	19,592	10,724	Actual	19,592	10,724	Actual
14	Feb-17	18,165	9,440	Actual	18,165	9,440	Actual
15	Mar-17	17,502	10,425	Actual	17,502	10,425	Actual
16	Apr-17	15,843	8,856	Actual	15,843	8,809	Actual
17	May-17	19,712	9,211	Actual	20,250	9,211	Actual
18	Jun-17	23,868	10,291	Actual	23,968	10,291	Actual
19	Jul-17	23,372	11,413	Actual	23,579	11,412	Actual
20	Aug-17	22,769	11,109	Actual	22,769	11,109	Actual
21	Sep-17	20,999	9,849	Actual	20,999	9,849	Actual
22	Oct-17	17,255	9,283	Actual	17,255	9,283	Actual
23	Nov-17	17,079	9,498	Actual	17,079	9,498	Actual
24	Dec-17	20,476	11,082	Actual	20,524	11,117	Actual
25	Jan-18	20,669	11,538	Actual	20,662	11,536	Actual
26	Feb-18	18,320	9,379	Actual	18,308	9,379	Actual
27	Mar-18	16,943	9,956	Actual	16,943	9,956	Actual
28	Apr-18	15,778	8,996	Actual	15,778	8,996	Actual
29	May-18	17,534	9,151	Actual	17,518	9,150	Actual
30	Jun-18	21,076	9,767	Actual	21,075	9,767	Actual
31	Jul-18	24,512	12,324	Actual	24,511	12,324	Actual
32	Aug-18	26,024	12,605	Actual	26,024	12,606	Actual
33	Sep-18	24,475	10,059	Actual	24,475	10,059	Actual
34	Oct-18	17,479	9,436	Actual	17,479	9,436	Actual
35	Nov-18	17,591	9,723	Actual	17,590	9,724	Actual
36	Dec-18	18,408	10,496	Actual	18,466	10,539	Actual
37	Jan-19	20,773	11,077	Actual	20,773	11,077	Actual
38	Feb-19	18,585	9,659	Actual	18,585	9,659	Actual
39	Mar-19	17,876	9,898	Actual	17,876	9,887	Actual
40	Apr-19	15,034	8,641	Actual	15,034	8,641	Actual
41	May-19	15,748	8,749	Actual	15,748	8,749	Actual
42	Jun-19	19,913	9,414	Actual	19,913	9,414	Actual

Line No.	Month	From CELT Report (As Published)			From Monthly Market Reports		
		Monthly Peak Load (MW)	Monthly Net Energy (GWH)	Data Source	Monthly Peak Load (MW)	Monthly Net Energy (GWH)	Data Source
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
43	Jul-19	24,361	12,393	Actual	24,361	12,393	Actual
44	Aug-19	23,365	11,235	Actual	23,365	11,235	Actual
45	Sep-19	19,106	9,082	Actual	19,162	9,119	Actual
46	Oct-19	16,122	8,897	Actual	16,136	8,920	Actual
47	Nov-19	17,514	9,424	Actual	17,548	9,461	Actual
48	Dec-19	19,033	10,652	Actual	19,065	10,679	Actual
49	Jan-20	18,097	10,417	Actual	18,097	10,417	Actual
50	Feb-20	16,991	9,495	Actual	16,991	9,495	Actual
51	Mar-20	15,812	9,199	Actual	15,888	9,188	Actual
52	Apr-20	14,254	8,271	Actual	14,254	8,271	Actual
53	May-20	16,593	8,247	Actual	16,593	8,247	Actual
54	Jun-20	21,518	9,879	Actual	21,518	9,879	Actual
55	Jul-20	24,776	12,305	Actual	25,121	12,305	Actual
56	Aug-20	24,335	11,485	Actual	24,335	11,485	Actual
57	Sep-20	19,151	9,233	Actual	19,260	9,233	Actual
58	Oct-20	15,584	8,888	Actual	15,616	8,845	Actual
59	Nov-20	17,105	8,980	Actual	17,157	9,020	Actual
60	Dec-20	18,887	10,463	Actual	18,922	10,487	Actual
61	Jan-21	18,839	10,680	Actual	18,839	10,679	Actual
62	Feb-21	18,185	9,747	Actual	18,181	9,746	Actual
63	Mar-21	17,767	9,502	Actual	17,767	9,490	Actual
64	Apr-21	14,684	8,347	Actual	14,684	8,347	Actual
65	May-21	18,882	8,655	Actual	18,882	8,655	Actual
66	Jun-21	25,801	10,722	Actual	25,801	10,722	Actual
67	Jul-21	22,937	11,025	Actual	22,937	11,025	Actual
68	Aug-21	25,128	12,099	Actual	25,241	12,099	Actual
69	Sep-21	20,032	9,648	Actual	20,032	9,648	Actual
70	Oct-21	15,218	8,881	Actual	15,218	8,881	Actual
71	Nov-21	17,003	9,104	Actual	17,039	9,151	Actual
72	Dec-21	17,943	10,296	Actual	17,970	10,315	Actual
73	Jan-22	19,756	11,313	Actual	19,756	11,313	Actual
74	Feb-22	18,500	9,654	Actual	18,500	9,654	Actual
75	Mar-22	16,932	9,615	Actual	16,932	9,603	Actual
76	Apr-22	14,438	8,307	Actual	14,438	8,307	Actual
77	May-22	18,939	8,962	Actual	18,939	8,962	Actual
78	Jun-22	19,972	9,505	Actual	19,972	9,505	Actual
79	Jul-22	24,644	12,140	Actual	24,644	12,140	Actual
80	Aug-22	24,780	12,245	Actual	24,780	12,245	Actual
81	Sep-22	17,749	9,140	Actual	17,749	9,140	Actual
82	Oct-22	14,688	8,659	Actual	14,688	8,659	Actual
83	Nov-22	16,904	8,935	Actual	16,827	8,994	Actual
84	Dec-22	17,949	10,403	Actual	17,956	10,405	Actual
85	Jan-23	17,304	10,233	Actual	17,304	10,233	Actual
86	Feb-23	19,662	9,327	Actual	19,662	9,327	Actual
87	Mar-23	16,202	9,445	Actual	16,202	9,434	Actual
88	Apr-23	14,604	8,131	Actual	14,604	8,131	Actual
89	May-23	14,798	8,217	Actual	14,798	8,217	Actual
90	Jun-23	18,684	9,222	Actual	18,684	9,222	Actual
91	Jul-23	22,999	12,032	Actual	22,999	12,032	Actual
92	Aug-23	19,705	10,533	Actual	19,705	10,533	Actual
93	Sep-23	24,043	9,674	Actual	24,043	9,674	Actual

Line No.	Month	From CELT Report (As Published)			From Monthly Market Reports		
		Monthly Peak Load (MW)	Monthly Net Energy (GWH)	Data Source	Monthly Peak Load (MW)	Monthly Net Energy (GWH)	Data Source
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
94	Oct-23	16,511	8,712	Actual	16,511	8,712	Actual
95	Nov-23	17,260	9,174	Actual	17,277	9,187	Actual
96	Dec-23	17,702	10,023	Actual	17,697	10,022	Actual
97	Jan-24	18,433	10,881	Actual	18,433	10,881	Actual
98	Feb-24	17,207	9,498	Actual	17,207	9,498	Actual
99	Mar-24	15,694	9,257	Actual	15,694	9,257	Actual
100	Apr-24	15,654	8,296	Actual	15,654	8,296	Actual
101	May-24	17,346	8,633	Actual	17,346	8,633	Actual
102	Jun-24	24,166	10,117	Actual	24,166	10,117	Actual
103	Jul-24	24,871	12,307	Actual	24,871	12,307	Actual
104	Aug-24	23,791	10,874	Actual	23,791	10,874	Actual
105	Sep-24	17,055	8,813	Actual	17,055	8,813	Actual
106	Oct-24	14,773	8,566	Actual	14,773	8,566	Actual
107	Nov-24	15,816	8,851	Actual	15,837	8,851	Actual
108	Dec-24	19,030	10,722	Actual	19,038	10,714	Actual
109	Jan-25	19,639	11,382	Actual	19,631	11,389	Actual
110	Feb-25	18,750	9,948	Actual	18,773	9,960	Actual
111	Mar-25	17,292	9,517	Forecast	17,346	9,330	Actual
112	Apr-25	15,407	8,209	Forecast	15,309	8,252	Actual
113	May-25	17,518	8,443	Forecast	14,633	8,386	Actual
114	Jun-25	22,810	9,818	Forecast	26,551	9,972	Actual
115	Jul-25	24,803	11,793	Forecast	25,295	12,176	Actual
116	Aug-25	22,889	11,230	Forecast	22,889	11,230	Forecast
117	Sep-25	20,371	9,368	Forecast	20,371	9,368	Forecast
118	Oct-25	16,205	8,741	Forecast	16,205	8,741	Forecast
119	Nov-25	17,037	8,867	Forecast	17,037	8,867	Forecast
120	Dec-25	19,283	10,591	Forecast	19,283	10,591	Forecast
121	Jan-26	20,056	11,132	Forecast	20,056	11,132	Forecast
122	Feb-26	19,299	9,797	Forecast	19,299	9,797	Forecast
123	Mar-26	17,433	9,591	Forecast	17,433	9,591	Forecast
124	Apr-26	15,511	8,234	Forecast	15,511	8,234	Forecast
125	May-26	17,566	8,424	Forecast	17,566	8,424	Forecast
126	Jun-26	22,877	9,801	Forecast	22,877	9,801	Forecast
127	Jul-26	24,877	11,794	Forecast	24,877	11,794	Forecast
128	Aug-26	22,955	11,233	Forecast	22,955	11,233	Forecast
129	Sep-26	20,444	9,374	Forecast	20,444	9,374	Forecast
130	Oct-26	16,289	8,779	Forecast	16,289	8,779	Forecast
131	Nov-26	17,171	8,946	Forecast	17,171	8,946	Forecast
132	Dec-26	19,452	10,723	Forecast	19,452	10,723	Forecast

Line No.	Month	From CELT Report (As Published) Monthly Peak Load (MW)	Monthly Net Energy (GWH)	Data Source	From Monthly Market Reports Monthly Peak Load (MW)	Monthly Net Energy (GWH)	Data Source
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1			**Annualized Figures**				
2		Average	Total		Average	Total	Month
3	**2016**	19,905	124,382		19,911	124,425	
4	**2017**	19,719	121,181		19,794	121,168	
5	**2018**	19,901	123,431		19,902	123,472	
6	**2019**	18,952	119,122		18,964	119,234	
7	**2020**	18,592	116,862		18,646	116,872	
8	**2021**	19,368	118,706		19,383	118,758	
9	**2022**	18,771	118,878		18,765	118,927	
10	**2023**	18,290	114,723		18,291	114,724	
11	**2024**	18,653	116,815		18,655	116,807	
12	**2025**	19,334	117,907		19,444	118,262	
13	**2026**	19,494	117,828		19,494	117,828	
14			**Annual Escalation**				
15	**2016**	0.9907	0.9743		0.9941	0.9738	
16	**2017**	1.0092	1.0186		1.0055	1.0190	
17	**2018**	0.9524	0.9651		0.9528	0.9657	
18	**2019**	0.9810	0.9810		0.9832	0.9802	
19	**2020**	1.0418	1.0158		1.0395	1.0161	
20	**2021**	0.9692	1.0014		0.9681	1.0014	
21	**2022**	0.9744	0.9650		0.9747	0.9647	
22	**2023**	1.0199	1.0182		1.0200	1.0182	
23	**2024**	1.0365	1.0093		1.0422	1.0125	
24	**2025**	1.0083	0.9993		1.0026	0.9963	
25					**0.998**	**0.995**	**NOT USED**
26			**Last Five Months of Calendar Year**				
27		Average	Total		Average	Total	
28	Dec-16	20,427	52,406		20,440	52,449	Actual
29	Dec-17	19,716	50,821		19,725	50,856	Actual
30	Dec-18	20,795	52,320		20,807	52,364	Actual
31	Dec-19	19,028	49,290		19,055	49,414	Actual
32	Dec-20	19,012	49,049		19,058	49,070	Actual
33	Dec-21	19,065	50,028		19,100	50,094	Actual
34	Dec-22	18,414	49,382		18,400	49,443	Actual
35	Dec-23	19,044	48,116		19,047	48,128	Actual
36	Dec-24	18,093	47,826		18,099	47,818	Forecast
37	Dec-25	19,157	48,797		19,157	48,797	Forecast
38			**Escalation Used for Last Five Months of Calendar Year**				
39	Dec-17				0.9650	0.9696	Actual
40	Dec-18				1.0548	1.0297	Actual
41	Dec-19				0.9158	0.9437	Actual
42	Dec-20				1.0001	0.9930	Actual
43	Dec-21				1.0022	1.0209	Actual
44	Dec-22				0.9634	0.9870	Actual
45	Dec-23				1.0351	0.9734	Actual
46	Dec-24				0.9502	0.9936	Actual
47	Dec-25				1.0585	1.0205	Forecast
48					**0.994**	**0.992**	**NOT USED**

ISO New England Inc.
FERC DOCKET NO. ER26 -000
Billing Determinants for Calendar Year 2025 and Test Year 2026
TEST YEAR 2026

Line No.	Month	Data Source	Schedule 1 Network Load (kW)	Schedule 2 Transaction Units (TUs) Energy TUs	Submitted Virtual Energy	Cleared Virtual Energy	Financial Transmission Rights (FTRs) Submitted FTR Bids	Cleared FTR Bids	Volumes (GWH)	Schedule 3 Peak Volumes Electrical Load (kW)	Export Volumes (MWh)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
						CALENDAR YEAR 2025					
1	Jan-25	Actual	19,191,391	2,128,373	332,711	133,202	33,031	10,581	22,233,285	21,483,313	106,078
2	Feb-25	Actual	18,193,724	1,918,518	353,683	145,799	14,376	4,603	19,237,123	20,757,790	69,868
3	Mar-25	Actual	17,065,943	2,037,822 e	391,898	166,723	15,952	4,755	18,934,308	19,107,866	328,919
4	Apr-25	Actual	14,954,216	1,925,070 e	425,114	178,844	17,224	4,588	16,595,738	16,865,088	202,568
5	May-25	Actual	14,277,648	1,992,063 e	419,753	201,677	19,165	5,171	16,633,351	16,650,875	48,082
6	Jun-25	Actual	25,970,330	2,038,570 e	383,895	196,699	20,128	5,599	20,464,537	28,758,123	215,122
7	Jul-25	Actual	24,582,747	2,123,633 e	377,175	168,166	20,879	4,912	24,902,450	27,719,935	272,194
8	Aug-25	Est.	23,062,000 a	2,115,769 a	313,714 a	145,286 a	22,159 a	6,687 a	22,661,616 a	25,699,003 a	469,492 a
9	Sep-25	Est.	16,664,241 a	1,996,903 a	301,705 a	134,860 a	23,177 a	5,796 a	18,363,077 a	18,926,995 a	445,495 a
10	Oct-25	Est.	14,420,169 a	1,989,574 a	328,421 a	151,347 a	25,561 a	5,944 a	17,709,504 a	16,687,474 a	373,098 a
11	Nov-25	Est.	15,188,773 a	1,971,347 a	331,543 a	141,520 a	25,958 a	6,128 a	18,581,463 a	17,835,718 a	709,055 a
12	Dec-25	Est.	18,484,128 a	2,111,275 a	287,491 a	110,085 a	25,434 a	5,877 a	20,815,789 a	21,514,269 a	136,098 a
13	Totals		222,055,310	24,348,917	4,247,103	1,874,208	263,044	70,641	237,132,241	252,006,449	3,376,066
14											
15						**TEST YEAR 2026**					
16	Jan-26	Est.	19,287,348 b	2,302,721 c d	332,711 a	133,202 a	33,031 a	10,581 a	22,344,451 b	21,590,730 b	106,078 a
17	Feb-26	Est.	18,284,693 b	2,086,780 c d	353,683 a	145,799 a	14,376 a	4,603 a	19,333,309 b	20,861,579 b	69,868 a
18	Mar-26	Est.	17,151,273 b	2,209,544 c d	391,898 a	166,723 a	15,952 a	4,755 a	19,028,979 b	19,203,405 b	328,919 a
19	Apr-26	Est.	15,028,987 b	2,093,522 c d	425,114 a	178,844 a	17,224 a	4,588 a	16,678,716 b	16,949,413 b	202,568 a
20	May-26	Est.	14,349,036 b	2,162,458 c d	419,753 a	201,677 a	19,165 a	5,171 a	16,716,518 b	16,734,129 b	48,082 a
21	Jun-26	Est.	26,100,182 b	2,210,314 c d	383,895 a	196,699 a	20,128 a	5,599 a	20,566,859 b	28,901,914 b	215,122 a
22	Jul-26	Est.	24,705,661 b	2,297,843 c d	377,175 a	168,166 a	20,879 a	4,912 a	25,026,962 b	27,858,535 b	272,194 a
23	Aug-26	Est.	23,177,310 b	2,289,751 c d	313,714 a	145,286 a	22,159 a	6,687 a	22,774,924 b	25,827,498 b	469,492 a
24	Sep-26	Est.	16,747,562 b	2,167,438 c d	301,705 a	134,860 a	23,177 a	5,796 a	18,454,893 b	19,021,630 b	445,495 a
25	Oct-26	Est.	14,492,270 b	2,159,897 c d	328,421 a	151,347 a	25,561 a	5,944 a	17,798,051 b	16,770,911 b	373,098 a
26	Nov-26	Est.	15,264,717 b	2,141,141 c d	331,543 a	141,520 a	25,958 a	6,128 a	18,674,370 b	17,924,897 b	709,055 a
27	Dec-26	Est.	18,576,549 b	2,285,127 c d	287,491 a	110,085 a	25,434 a	5,877 a	20,919,868 b	21,621,840 b	136,098 a
28	Total		223,165,587	26,406,536	4,247,103	1,874,208	263,044	70,641	238,317,902	253,266,481	3,376,066

Escalation factors:	
a	1.000
b	1.005
c	1.029
d	Additionally escalated (above footnote c amount of 1.029) for estimated Day-Ahead Ancillary Services offers in the amount of 112,625 per month
e	March through July 2025 represents actual Energy TUs excluding Day-Ahead Ancillary Services offers

Exhibit 3
RCL-7
Schedule 3

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER256 -000
Rate Design Summary
TEST YEAR 2026

Line No.	Tariff Schedule	Revenue Requirement for Test Year 2026	Billing Units			Proposed Rates		Calculated Revenue
			Blocks		Total			
	(a)	(b)	(c)		(d)	(e)	(f)	(g) (d) x (e)
1	**Schedule 1**	**$ 65,569,804**						
2	Network		Total		223,165,587	$ 0.29382	/kW-mo.	**$ 65,569,804**
3	Through or Out Service					**$ 0.00040**	/kW-hour	
4								
5	**Schedule 2**	**$ 154,761,763**						
6	Transaction Units	$ 23,214,264	15.00%					
7	INC Offers/DEC Bids	$ 133,688						
8	Submitted				4,247,103	$ 0.00500	/Offer or Bid	$ 21,236
9	Cleared				1,874,208	$ 0.06000	/Offer or Bid	$ 112,452
10			Total		6,121,311			$ 133,688
11	Financial Transmission Rights	$ 1,454,345						
12	Submitted FTR Bids	$ 1,018,042	70%		263,044	$ 3.87023	/Bid	$ 1,018,042
13	Cleared FTR Bids	$ 436,304	30%		70,641	$ 6.17635	/Bid	$ 436,304
14			Total		333,685			$ 1,454,345
15								
16	Energy TUs	$ 21,626,231						
17	Block 1		First	12,500	16,650,370	$ 0.86039	/TU-hour	$ 14,325,813
18	Block 2		Next	27,000	5,529,624	$ 0.78217	/TU-hour	$ 4,325,122
19	Block 3		Over	39,500	4,226,541	$ 0.70396	/TU-hour	$ 2,975,297
20			Total		26,406,536			$ 21,626,231
21								
22	Volumetric Measures	$ 131,547,499	85.00%					
23	Block 1		First	250,000	124,510,777	$ 0.58201	/mWh	$ 72,466,011
24	Block 2		Next	1,250,000	92,384,896	$ 0.52910	/mWh	$ 48,880,507
25	Block 3		Over	1,500,000	21,422,229	$ 0.47619	/mWh	$ 10,200,980
26			Total		238,317,902			$ 131,547,499
27								
28			Total					**$ 154,761,763**
29								
30	**Schedule 3**	**$ 94,058,203**						
31	RT NCP Load Obligation	$ 91,357,350	Total		253,266,481	$ 0.36072	/kW-mo.	$ 91,357,350
32	Exports	$ 2,700,853	Total		3,376,066	$ 0.80000	/mWh	$ 2,700,853
33								**$ 94,058,203**
34								
35	Totals	**$ 314,389,770**						**$ 314,389,770**

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER26 -000
Annual Revenue Comparison at Present and Proposed Rates
TEST YEAR 2026

Line No.	Tariff Schedule	2026 Billing Units			Annual Revenue Analysis						Change	
					2025 Approved Rates			2026 Proposed Rates				
		Blocks		Total	Effective Rates		Calculated Revenue	Proposed Rates		Total Revenue (1)	$	%
	(a)	(b)		(c)	(d)	(e)	(f) (c) x (d)	(g)	(h)	(i)	(j) (i) - (f)	(k) (j) / (f)
1	**Schedule 1**											
2	Network	Total		223,165,587	$0.29582	/kW-mo.	**$ 66,016,844**	$ 0.29382	/kW-mo.	**$ 65,569,804**	**$ (447,040)**	**-0.68%**
3												
4	**Schedule 2**											
5	Transaction Units											
6	INC Offers/DEC Bids											
7	Submitted			4,247,103	$0.00500	/Offer or Bid	$ 21,236	$ 0.00500	/Offer or Bid	$ 21,236		
8	Cleared			1,874,208	$0.06000	/Offer or Bid	$ 112,452	$ 0.06000	/Offer or Bid	$ 112,452		
9		Total		6,121,311			$ 133,688			$ 133,688		
10	Financial Transmission Rights											
11	Submitted FTR Bids			263,044	$3.26750	/Bid	$ 859,496	$ 3.87023	/Bid	$ 1,018,042		
12	Cleared FTR Bids			70,641	$5.32383	/Bid	$ 376,081	$ 6.17635	/Bid	$ 436,304		
13		Total		333,685			$ 1,235,577			$ 1,454,345		
14												
15	Energy Transaction Units											
16	Block 1	First	12,500	16,650,370	$0.81457	/TU-hour	$ 13,562,892	$ 0.86039	/TU-hour	$ 14,325,813		
17	Block 2	Next	27,000	5,529,624	$0.74051	/TU-hour	$ 4,094,742	$ 0.78217	/TU-hour	$ 4,325,122		
18	Block 3	Over	39,500	4,226,541	$0.66646	/TU-hour	$ 2,816,821	$ 0.70396	/TU-hour	$ 2,975,297		
19		Total		26,406,536			$ 20,474,455			$ 21,626,231		
20	Volumetric Measures											
21	Block 1	First	250,000	124,510,777	$0.56227	/mWh	$ 70,008,674	$ 0.58201	/mWh	$ 72,466,011		
22	Block 2	Next	1,250,000	92,384,896	$0.51116	/mWh	$ 47,223,463	$ 0.52910	/mWh	$ 48,880,507		
23	Block 3	Over	1,500,000	21,422,229	$0.46004	/mWh	$ 9,855,082	$ 0.47619	/mWh	$ 10,200,980		
24		Total		238,317,902			$ 127,087,220			$ 131,547,499		
25												
26		Total					**$ 148,930,940**			**$ 154,761,763**	**$ 5,830,823**	**3.92%**
27	**Schedule 3**											
28	RT NCP Load Obligation	Total		253,266,481	$0.37690	/kW-mo.	$ 95,456,137	$ 0.36072	/kW-mo.	$ 91,357,350		
29	Exports	Total		3,376,066	$0.82000	/mWh	$ 2,768,374	$ 0.80000	/mWh	$ 2,700,853		
30							**$ 98,224,511**			**$ 94,058,203**	**$ (4,166,308)**	**-4.24%**
31												
32	Totals						**$ 313,172,295**			**$ 314,389,770**	**$ 1,217,475**	**0.39%**

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER26 -000
Comparison of Schedule 2 Revenues from Transaction Units (TUs) for 2024
TEST YEAR 2026

Line No.	Month	Source For TY 2024	TUs Per ISO Tariff Filing for TY 2024 Total TUs	First 12,500	Next 27,000	Over 39,500	Source For TY 2026	TUs Per ISO Tariff Filing for CY 2024 Total TUs	First 12,500	Next 27,000	Over 39,500
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
			Comparison Of Monthly TU Data For CY 2024								
			Billing Determinants - Energy TUs								
1	Jan-24	Jan-23	1,976,778	1,267,078	398,738	310,962	Actual	2,069,826	1,298,554	425,819	345,453
2	Feb-24	Feb-23	1,795,168	1,150,669	362,105	282,394	Actual	1,934,741	1,237,745	393,383	303,613
3	Mar-24	Mar-23	1,976,133	1,266,664	398,608	310,861	Actual	2,042,988	1,292,363	419,581	331,044
4	Apr-24	Apr-23	1,836,797	1,177,352	370,502	288,942	Actual	1,897,572	1,218,595	392,282	286,695
5	May-24	May-23	1,950,569	1,250,278	393,451	306,840	Actual	1,999,318	1,264,876	409,417	325,025
6	Jun-24	Jun-23	1,969,081	1,262,144	397,185	309,752	Actual	2,006,519	1,278,199	416,251	312,069
7	Jul-24	Jul-23	2,071,618	1,327,868	417,868	325,881	Actual	2,104,449	1,314,184	445,012	345,253
8	Aug-24	Aug-22	1,992,560	1,277,193	401,921	313,445	Actual	2,115,769	1,316,387	446,952	352,430
9	Sep-24	Sep-22	1,891,665	1,212,522	381,570	297,574	Actual	1,996,903	1,267,927	420,651	308,325
10	Oct-24	Oct-22	1,870,643	1,199,047	377,329	294,267	Actual	1,989,574	1,267,918	414,017	307,639
11	Nov-24	Nov-22	1,875,634	1,202,246	378,336	295,052	Actual	1,971,347	1,264,745	406,970	299,632
12	Dec-24	Dec-22	1,969,884	1,262,659	397,347	309,878	Actual	2,111,275	1,317,653	433,415	360,207
13	Totals		23,176,532	14,855,723	4,674,962	3,645,847		24,240,281	15,339,146	5,023,750	3,877,385
14											
15	**Totals**		**23,176,532**					**24,240,281**			
16											
17	2024 Approved Rates for Schedule 2			$0.82494	$0.74994	$0.67495			$0.82494	$0.74994	$0.67495
18											
19			Initial Estimate of Revenue From Energy TUs								
20	Jan-24	Jan-23	$ 1,554,177	$ 1,045,263	$ 299,030	$ 209,884	Actual	$ 1,623,731	$ 1,071,229	$ 319,339	$ 233,164
21	Feb-24	Feb-23	$ 1,411,392	$ 949,233	$ 271,557	$ 190,602	Actual	$ 1,521,003	$ 1,021,065	$ 295,014	$ 204,924
22	Mar-24	Mar-23	$ 1,553,669	$ 1,044,922	$ 298,932	$ 209,816	Actual	$ 1,604,221	$ 1,066,122	$ 314,661	$ 223,438
23	Apr-24	Apr-23	$ 1,444,121	$ 971,245	$ 277,854	$ 195,022	Actual	$ 1,492,961	$ 1,005,268	$ 294,188	$ 193,505
24	May-24	May-23	$ 1,533,571	$ 1,031,405	$ 295,065	$ 207,101	Actual	$ 1,569,861	$ 1,043,447	$ 307,038	$ 219,376
25	Jun-24	Jun-23	$ 1,548,125	$ 1,041,193	$ 297,865	$ 209,067	Actual	$ 1,577,232	$ 1,054,437	$ 312,163	$ 210,631
26	Jul-24	Jul-23	$ 1,628,741	$ 1,095,412	$ 313,376	$ 219,954	Actual	$ 1,650,884	$ 1,084,123	$ 333,732	$ 233,029
27	Aug-24	Aug-22	$ 1,566,585	$ 1,053,608	$ 301,417	$ 211,560	Actual	$ 1,659,000	$ 1,085,940	$ 335,187	$ 237,873
28	Sep-24	Sep-22	$ 1,487,260	$ 1,000,258	$ 286,154	$ 200,847	Actual	$ 1,569,531	$ 1,045,964	$ 315,463	$ 208,104
29	Oct-24	Oct-22	$ 1,470,732	$ 989,142	$ 282,974	$ 198,615	Actual	$ 1,564,085	$ 1,045,956	$ 310,488	$ 207,641
30	Nov-24	Nov-22	$ 1,474,656	$ 991,781	$ 283,729	$ 199,145	Actual	$ 1,550,778	$ 1,043,339	$ 305,203	$ 202,237
31	Dec-24	Dec-22	$ 1,548,757	$ 1,041,618	$ 297,987	$ 209,152	Actual	$ 1,655,142	$ 1,086,985	$ 325,035	$ 243,122
32	Totals		18,221,785	12,255,080	3,505,941	2,460,764		19,038,427	12,653,875	3,767,511	2,617,041
33											
34	**Total Energy TU- Revenue**		**$ 18,221,785**					**$ 19,038,427**			
35				**Total**	**Rate**	**($)**			**Total**	**Rate**	**($)**
36	Submitted Virtual Energy Bids/Offers TUs			3,611,175	$0.00500	18,056			3,653,126	$0.00500	18,266
37	Cleared Virtual Energy Bids/Offers TUs			1,758,670	$0.06000	105,520			1,653,847	$0.06000	99,231
38						**$ 123,576**					**$ 117,496**
39				**Total**	**Rate**	**($)**			**Total**	**Rate**	**($)**
40	Submitted FTR Bid TUs			266,091	$2.77242	737,716			250,664	$2.77242	694,946
41	Cleared FTR Bid TUs			70,569	$4.48021	316,164			70,746	$4.48021	316,957
42						**$ 1,053,880**					**$ 1,011,903**
43											
44	**Total Schedule 2 TU- Revenue**		**$ 19,399,241**					**$ 20,167,826**			
45	**Initial True-Up Estimate - Over (Under) Recovery For Jan - Dec**							**$ 768,585**			

Exhibit 3
RCL-7
Schedule 6

ISO NEW ENGLAND INC.
FERC DOCKET NO. ER26- -000
Schedule 2 TU True-Up Summary
TEST YEAR 2026

Line No.		Total Schedule 2 TU Revenues	% TU Difference	
1				
2	**Final 2024 True-Up**			
3	2024 Final TU Collections	$ 20,167,826		
4	Projected TU Collections in TY 2024 Filing	$ 19,399,241		
5	Final Schedule 2 TU Over/(Under) Collection	$ 768,585	3.96%	
6				
7				
8	**Initial Allocation to Volumetric 50%**	**N/A - Over Collected**		
9	**2024 Final True-Up (as calculated above)**			
10	**Total Projected Undercollection to Vol. Meas.**	0.00%		
11				
12			**Allocated to**	
13		**Total**	**TUs**	**VMs**
14	Schedule 2 Allocation before True-up	$ 154,761,763	$ 23,214,264	$ 131,547,499
15	Allocated TU Under-recovery		$ -	$ -
16	Total Revenue Requirement After True-Up	**$ 154,761,763**	**$ 23,214,264**	**$ 131,547,499**
17	% Allocation	100.00%	15.00%	85.00%

NEW ENGLAND POWER POOL
PARTICIPANTS COMMITTEE MEETING

October 9, 2025

RESOLUTION REGARDING THE ISO 2026 BUDGET

RESOLVED, that the Participants Committee supports the Year 2026 operating budget and capital budget proposed by the ISO, as presented at this meeting.

EXHIBIT 4

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.	**)**	**Docket No. ER26-___-000**

TESTIMONY

OF

KATHLEEN DECASTRO

Filed on: October 15, 2025

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO NEW ENGLAND INC.) Docket No. ER26-___-000

Testimony of Kathleen deCastro

Q: PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Kathleen deCastro. I am the Vice President, Human Resources and Chief People Officer at ISO New England Inc. (the "ISO" or "ISO-NE"). My business address is One Sullivan Road, Holyoke, Massachusetts 01040.

Q: PLEASE DESCRIBE, BRIEFLY, YOUR EDUCATIONAL AND EMPLOYMENT BACKGROUND AND THE SCOPE OF YOUR CURRENT POSITION AT ISO NEW ENGLAND.

A. I joined the ISO in June 2022. In my role as Vice President, Human Resources and Chief People Officer, my department and I provide leadership, expertise, programs, and processes to attract, hire, lead, develop, engage, and retain talent for the ISO. I also support the Compensation and Human Resources Committee of the Board of Directors as well as the Joint Nominating Committee, which is responsible for nominating directors to the Board of Directors.

I hold an M.A. in Industrial and Organizational Psychology from the University of New Haven and a B.A. in Psychology from the University of Saint Joseph. I have held a variety of senior human resources leadership roles, including Chief Talent Officer at The Hartford Financial Services Company, US Head of Human Resources at Sun Life Financial, Chief Human Resources Officer at Hanover Insurance Group, and Vice President of Human Resources at Travelers Insurance Company. In all of those positions, I was accountable for building and executing human resources strategies and plans to enable business outcomes and delivering functional excellence in talent acquisition, talent management and development, HR information systems, compensation, and employee wellbeing through large, diverse, geographically dispersed teams.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony discusses the components of the proposed 2026 administrative expenses related to compensation and funding to support the ISO's strategic goal to attract, develop, and retain talent.

Q: HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

- objective of compensation program
- components of compensation
- budget for merit and promotional/adjustment salary increases

- health insurance program
- framework for determining executive compensation
- conclusion

OBJECTIVE OF COMPENSATION PROGRAM

Q. WHAT IS THE OBJECTIVE OF THE ISO'S COMPENSATION PROGRAM?

A. The objective of the compensation program is to offer competitive compensation, coupled with a robust total rewards offering, that enables the ISO to attract and retain the highly-skilled employees needed to lead the ISO and meet its business goals for the New England region. We believe that meeting this objective is vital, particularly in the face of higher demand for technical and seasoned talent as the ISO's workload increases in volume and complexity. Retention of our present staff is ultimately less expensive than high levels of turnover, considering the costs of recruiting, relocation, development time, and the disruption of workflow. We also believe that meeting this objective improves our attractiveness to potential candidates to minimize disruptions to the ISO's critical operations that may be caused by extended time-to-fill rates for open, critical roles.

Q. WHAT ARE THE CHALLENGES TO MEETING THE OBJECTIVE OF THE ISO'S COMPENSATION PROGRAM?

A. Workforce trends with respect to both the energy industry, and specifically in the context of the New England region's evolving resource mix and changing

customer use patterns, have exacerbated an already competitive labor market with exceptionally high demand for qualified individuals in the roles we seek to hire. This presents multiple challenges. First, there is a shortage of critical talent in the utility industry, an industry that is undergoing a fundamental transformation as an industry-wide shift in energy resources and customer use patterns is underway. Second, the most critical functions within our organization, information technology and engineering, are also the most difficult to recruit for and retain. Near full employment of these professionals, the highly competitive labor market, and the popularity of 100% remote work arrangements offered by many organizations (as compared to the ISO's hybrid environment) have combined to make sourcing of replacements for open positions more challenging, particularly in engineering, software development, and cyber security, resulting in longer times-to-fill. Third, the ISO's past compensation practices, were not benchmarked in a manner that enabled current market intelligence on some of the ISO's most unique, critical roles, thus impacting our ability to meet the objectives of our compensation program.

In 2022, as these challenges continued to manifest, and retention and turnover challenges increased, we engaged Mercer, a compensation consulting firm, to conduct one-for-one matches of our specific roles across the organization. This work has helped close competitive compensation gaps for our most sought after talent, though the market continues to move and we must continually keep pace

with prevailing competitive wages to attract and retain the highly sought after talent we seek to employ. I explain this Mercer benchmarking study in more detail below.

Q. PLEASE DESCRIBE THE WORKFORCE CHALLENGES RELATED TO THE ENERGY INDUSTRY TRANSITION.

A. As more fully explained in Mr. Ludlow's testimony, the ISO is at a critical juncture as it works to support the region's grid transition while ensuring power grid operations remain efficient and reliable. Changes in energy resources and customer use patterns are driving substantial changes to the New England power system and, as a result, the ISO's workload is expanding and operations are becoming increasingly complex. Similar transitions in the energy industry are underway nationwide, affecting all aspects of the industry beyond the New England region, leading to a tight labor market and inflation on new and existing employees' compensation expectations. For example, the significant increase in demand for System Planning Engineers as a result of continued high levels of regional and interregional transmission expansion planning, large volumes of new generation and data center interconnection activity, and overall resource adequacy concerns, has influenced salary requirements for these roles requiring higher pay to attract and retain this talent. This transition, alongside the effects of inflation, is compounding the already competitive labor market, particularly in fields related to energy efficiency, renewable energy, and smart grid design. The U.S.

Department of Energy's 2025 U.S. Energy and Employment Report (USEER) shows that the energy sector employed 8,500,000 workers in 2025, which is 5.4% of all jobs in the United States. The Report also shows that the energy sector's median wages are 18.8% higher than the United States median wage. The median wage for the Transmission, Distribution and Storage subsector is 20.9% higher than the United States median wage. Additionally, 59% of respondents in this subsector reported that hiring in the professional and business services area was at least "somewhat difficult."

ISO New England's hiring plans align with this trend. As noted in Mr. Ludlow's testimony, a main driver of the 2026 Core Operating Budget increase is the personnel additions to address the complex work to facilitate the electric grid transition. As the ISO's operations step-up in complexity and we recruit (from a talent pool in high demand) for the positions to support such complexity, the ISO's compensation program needs to be able to respond to the changing industry landscape and secure its place as an employer of choice in this growing field.

Q. PLEASE DESCRIBE THE SHORTAGE OF CRITICAL TALENT IN THE UTILITY INDUSTRY, NATIONALLY AND REGIONALLY FOR ISO NEW ENGLAND.

A. While demand for talent is growing, so, too, are the number of retirements experienced or expected within the energy fields, further contributing to the gap for qualified workers. Over the past two decades, numerous studies have

documented the aging of electric industry workforce members. This has caused unprecedented disruption as the energy industry, as a whole, has undergone significant transformation resulting in the need to replace many retiring workers with talent skilled predominately in data analytics and cyber security, and who are facile with leading edge technologies.

Job growth in these fields and other STEM-related fields has continually outpaced that of other occupations. The U.S. Bureau of Labor Statistics projects the growth in STEM occupations to be significantly higher than the growth seen in all other occupations over the next ten years. Specific areas of projected growth include Data Scientists (34%), Information Security Analysts (29%), and Software Developers (15%). This, coupled with the overall growth in energy sectors noted above, results in highly sought after talent in these growing fields.

America's talent shortage has a clear impact on worker availability generally. Specific to New England, according to the U.S. Chamber of Commerce Workforce Shortage Index, four of the six New England states have "more to most severe" labor shortages. Specifically, Connecticut, where the ISO's Windsor facility (Backup Control Center) is located has a "severe" labor shortage. This complicates the search for and retention of talent, even more so in the specialized fields from which we tend to recruit. Because many of the ISO's critical roles cannot be performed fully remote and we believe that onsite collaboration is critical to our mission, we are required to search for candidates that are either

located, or willing to relocate, within commutable distance of our two offices. With tight overall competition for all talent, the ISO is compelled to ensure our salaries are attractive and competitive with compensation offered by other companies who would seek to employ our talent (current employees and potential hires).

Q. PLEASE DESCRIBE THE CHALLENGE IN RECRUITING FOR THE MOST CRITICAL FUNCTIONS WITHIN THE ORGANIZATION (INFORMATION TECHNOLOGY AND ENGINEERING).

A. As noted earlier, workers with the skill sets to perform the ISO's most critical functions are in high demand. One-third of the ISO is comprised of information technology professionals. According to the Bureau of Labor Statistics ("BLS"), U.S. Department of Labor's Occupational Outlook Handbook, employment of computer and information technology occupations is projected to grow much faster than the average for all occupations from 2024 to 2034, "due to employment growth and the need to replace workers who leave their occupations permanently." The median annual wage for this group in May 2024, was 114% of the median annual wage for all occupations reported in that same month. Finally, with the heightened awareness of cyber security threats (which is of particular importance for electric grid infrastructure), companies are struggling to fill cyber security positions. The BLS reports employment of information security analysts is projected to grow 29% from 2024 to 2034.

Engineering staff also represents a critical talent need for the ISO, with many global corporations also competing for these sought after hires. Boston Consulting Group's December 2023 People Strategy publication, *The US Needs More Engineers. What's the Solution?* notes, "[e]very year, the US will need about 400,000 new engineers. Yet the next-generation skill sets that those engineers will require are sorely lacking, presenting the alarming possibility that nearly one in three engineering roles will remain unfilled each year through at least 2030."

An additional hiring challenge is the pressure of high salaries for information technology and engineering professionals that the ISO seeks to employ, as highlighted in the BLS data noted above. As a result, the ISO has been judicious (through the use of the benchmarking study described below) to ensure that salaries for these critical roles are adjusted to remain competitive.

Q. HOW ARE THESE CHALLENGES MANIFESTING THEMSELVES?

A. These challenges are manifested predominantly in the time it takes to fill open positions, the need to keep pace with the salaries of those organizations with whom we compete for talent, and in our ability to retain talent with in-demand skills (reflected in turnover trends in our most critical in-demand positions such as Market Development, System Planning, and Advanced Technology Solutions). Although, we are seeing a positive increase in activity in the candidate pool for many open positions, the high demand for specialized skills required for many ISO roles continues to affect our ability to attract qualified candidates.

While the ISO's turnover has historically been relatively low, with the exception of the COVID-19 pandemic related decrease in turnover in 2020, the ISO experienced an increase over several years followed by sustained higher turnover rates (2017 - 5.1%; 2018 - 7.1%; 2019 - 7.3%; 2020 - 5.5%; 2021 - 10.5%; 2022 – 9.1%; 2023 – 5.9%; 2024 – 6.9%). However, the 2025 annualized turnover is 3.5%. The lower 2025 trend in part, indicates that our compensation adjustment work, targeting, as a priority, the subset of employees with the greatest turnover risk (as explained in more detail below), is producing meaningful results. Although the 2025 annualized turnover rate is lower than the recent peaks in 2021 and 2022, 2024's relatively high turnover rate (and an increase from the 2023 rate) reminds us that this issue still requires our focus, as a significant portion of the turnover is in critical positions.

Within the past few years, a large portion of individuals departing were, and continue to be, information technology, PhD-level research & development electrical engineers and analysts, and engineering professionals from departments that are most critical to operating and planning the grid, as well as designing and running the New England Markets; they also represent those positions that are amongst the hardest to fill. In addition, approximately 19% of the ISO's workforce is currently retirement-eligible. To enable the ISO to transition to and operate under a future grid that takes into account state energy policies, the

Company expects these positions to be replaced predominately with individuals possessing critical in-demand skills.

Traditionally, the ISO's salaries for these positions have been equal to, or in many cases, lower than the going market rate, making it even more challenging to fill these roles and this discrepancy has a greater impact in competitive labor markets where employers are willing to pay above market rates for in-demand talent. A similar dynamic occurs for positions that require more experienced staff whose competencies command higher salaries. The skills we seek are largely not present in the local marketplace, requiring candidates to relocate which adds to the difficulty of hiring. Our offer acceptance rate was 95% in the year 2020. It steadily declined to a low of 78% in 2023 and, although it has improved to 84% as a result of more competitive offers being extended, it still remains an area of focus to ensure that we are timely filling open positions with high quality candidates. As of August 2025, 57% of our declines – when reasons were shared – were based on acceptance of a competing job offer. Although, not all of our offer declines have been a result of compensation, it is a prevailing factor in many of our offer declines (*i.e.*, where the candidate took a higher paying position). This trend is also an indication that the job-specific salary benchmarking has helped and we must remain focused on delivering competitive compensation offers to candidates.

Finally, while the ISO currently offers the opportunity for much of the workforce to use hybrid work arrangements, certain positions cannot be performed on a hybrid schedule and require full-time office work (*e.g.*, control room operators and certain cyber security positions). For other positions, particularly in the information technology department, the hybrid options do not offer as much flexibility as other information technology organizations that offer fully remote work. This has affected our ability to attract information technology talent. The ISO continues to balance the need to offer many employees flexible work arrangements to aid in recruitment and retention, with the need for in person collaboration to meet the challenges of the region during the significant grid transition. The ISO's geographical location and our hybrid work posture have combined to further limit our candidate pool as many candidates reaching the offer phase have declined opportunities with us as they reconsider their plans to relocate, a necessity given our hybrid work environment. This is an additional contributing factor to our offer declinations for some of our most critical roles.

Q. GIVEN THE TURNOVER TREND DESCRIBED ABOVE, HAS THE ISO MADE ANY ADJUSTMENTS TO THE VACANCY ASSUMPTIONS IN THE 2026 BUDGET?

A. Yes, the 2026 Core Operating Budget (as defined in the filing letter) includes a reduced vacancy rate from 6% to 5%. As explained in more detail in the filing letter and Mr. Ludlow's testimony, the grid transition and the impact of such

transition on the ISO's work flow will result in increased variability in the ISO's budgeting assumptions, including, but not limited to assumptions regarding turnover rates and headcount needs. Because of higher fluctuations in the vacancy rate in 2024, the 2025 Core Operating Budget included an increased vacancy rate (increased from 5% to 6%). In 2025, however, we have seen an improvement in turnover positively impacting our vacancy rate. This improvement combined with the modest improvement in acceptance rates due to more competitive compensation offers, influenced our vacancy rate assumptions. The 2026 Core Operating Budget includes a forecasted vacancy rate of 5%.

Q. GIVEN THE CHALLENGES YOU DESCRIBE ABOVE PLEASE DESCRIBE THE FUNDING INCLUDED IN THE 2026 BUDGET RELATED TO SUPPORT STRATEGIC GOAL 5 TO ATTRACT, DEVELOP, AND RETAIN TALENT.

A. As explained in Mr. Ludlow's testimony, the 2026 Core Operating Budget includes an $10 million funding increase in support of the Attract, Develop, and Retain Talent Strategic Goal (Strategic Goal 5). As I explain in greater detail later in my testimony, the primary driver of the $10 million funding increase related to this goal is funding to maintain competitive compensation ($6.0 million). Strategic Goal 5 funding also includes amounts related to the relocation of approximately 90 employees to the Windsor campus ($400,000); consulting services, data, and research to support critical Human Resources initiatives

($200,000); an increase in Board of Director retainer fees ($100,000); and Board of Director search fees to recruit for a new director for an upcoming vacancy ($200,000).

As explained below, the 2026 Core Operating Budget also includes increased funding to reflect increased costs related to employee benefits, primarily for medical insurance costs (as a result of ISO claims history and industry trends); and increased number of employees in the Defined Contribution Benefit Plan.[1] (collectively, $1.5 million). Additional detail regarding the ISO's retirement plan offerings, participation numbers, and impact on the budget can be found at Slides 81 and 101-103 of the Budget Presentation (as defined in the filing letter).

Q. HOW DOES THE ISO SEEK TO MAINTAIN THE COMPETITIVENESS OF ITS COMPENSATION?

A. The ISO, in partnership with our third party compensation consulting firm, identifies the industries with which it competes for talent – in other words, the industries from which the ISO recruits, and to which the ISO loses employees. These are other energy companies (including market participants) or for-profit utility companies, other independent system operators and regional transmission organizations, energy-related consulting firms, and the broader industry (for positions not specific to utilities).

[1] *See* Budget Presentation, Slide 103 (explaining that in 2014 the pension plan became closed to new participants; as a result, all new hires in the organization are eligible under the Defined Contribution Benefit Plan).

Next, target ranges of compensation are created as result of market data provided by third party consulting firms who collect average pay information from participating companies. We target our positions, on average, to be paid at the 50th percentile of the market, with variation due to experience, performance, and market availability. Organizations such as World at Work and Aon suggest that around 75% of companies target the 50th percentile. Individual salaries may exceed the 50th percentiles depending on (1) the market value for that position, often driven by key factors such as skill demand, skill complexity, and skill scarcity, and/or (2) individual factors of the position incumbent such as performance, experience, and additional position scope.

Specifically, in 2022, because of the challenges I have described we engaged Mercer, a consulting firm that provides strategic compensation and salary planning solutions, to provide a job specific, one-for-one benchmarking analysis. The first phase of the study, completed in late 2022, assessed compensation levels for our most technical engineering and IT roles, approximately 1/3 of our organization. During 2023, we assessed another 1/3 of the organization, with a continued focus on IT and other roles requiring significant technical expertise (Phase 2). We continued the study in 2024, expanding to other functions in the ISO where compensation was below market medians. In 2025 we are concluding the one for one benchmarking analysis with a final set of positions across the organization. As challenges to meeting our compensation objectives will continue

to impact our organizational goals if not addressed, we have found that this study and partnership with Mercer has been worth the effort and time spent, as it has provided us with critical market information and updated methodology to absorb into our current market competitive analysis and pay practices.

Although we have made progress, our work to realize our compensation philosophy to attract and retain the highest caliber talent is not complete. We are continuing to track the compensation competitiveness of the positions assessed in earlier phases, which continue to move with the market at a faster rate than some other roles. We also need to complete the remaining phase of the benchmarking study. This ongoing work is vital to achieve our compensation goals in furtherance of the ISO's strategic objectives.

COMPONENTS OF COMPENSATION

Q. WHAT ARE THE COMPONENTS OF THE ISO'S COMPENSATION?

A. The ISO has a "pay for performance" compensation program composed of two components for all employees, and an additional deferred performance component for officers.

The first component is annual base salary, which reflects external competitiveness, the employee's productivity and performance, the qualifications for the position, and internal equity. An employee's annual base salary evolves based on their job performance, following the annual performance review process.

(These are the merit and promotional increases that will be discussed below.) These changes are necessary for the ISO to meet its compensation philosophy of providing competitive pay, to ensure the ISO is able to meet its critical responsibilities.

The second component of compensation is annual incentive compensation. This program is intended to motivate employees to achieve superior performance on annual business and customer service objectives critical to carrying out the organization's mission and achieving its strategic goals. Subject to eligibility criteria, employees may receive an annual award based on a formula that includes company performance, individual performance, annual base salary, and a grade-related salary percentage. Company performance is determined using goals that are set in advance by the Board of Directors. These goals are objective and measurable using various operational and performance metrics. And, in addition to incenting timely and on-budget delivery of critical projects, these goals include measures important to supporting organizational goals, including operational excellence; stakeholder engagement; responsive market designs; attracting, developing, and retaining talent; and progress and innovation. Performance against these goals is measured using a corporate scorecard that is regularly published to all employees, and the calculation of which is verified by the ISO's internal auditors. The Board of Directors then assigns a final score to the achievement of annual goals.

Periodically, each of these components may need adjustment to maintain competitive compensation. In other words, as illustrated by the ISO's salary benchmarking study, if salaries for specific positions within the ISO are no longer competitive, then adjustments outside of the annual compensation cycle may be required. If such adjustments are required, the ISO will work within its approved budget and utilize funds available from the CEO Emerging Work Allowance (budget risks and contingencies are explained in Mr. Ludlow's testimony) if needed.

For officers, the third and final component of compensation is a deferred performance incentive plan that is designed to encourage retention by deferring payments for two and one-half years after they are declared. This program is intended to provide compensation in lieu of the market prevalent stock programs provided by for-profit competitors. These awards are determined using a formula of company performance against specific corporate goals, individual performance, executive-level related salary percentage, and annual base salary. Again, the goals and their performance are determined by the Board of Directors. Additionally, before the payout, the Board of Directors conducts a retrospective review of the quality and impact of the goal achievement supporting the award.

Employees are not eligible for either type of award in a year in which they receive a performance rating of "Clearly Below Expectations;" and in the event of a major collapse of the bulk electric power system the Board of Directors will

determine appropriate steps, including the elimination of awards. Similarly, if the ISO underperforms in the management of the bulk electric power system or in its other functions in a manner that is not captured in the goal performance score, the Board of Directors can reduce or eliminate the payment of the awards. The Board of Directors has taken this step in the past.

BUDGET FOR MERIT AND PROMOTIONAL/ADJUSTMENT SALARY INCREASES

Q: PLEASE EXPLAIN THE MERIT AND PROMOTIONAL/ADJUSTMENT INCREASE BUDGET.

A. This is a budget that establishes annually the amount that management and the Board of Directors can distribute to the entire employee base for salary increases following the annual performance review process that occurs in the first quarter of each year, changes as a result of promotion, and other targeted equity increases (including, as a result of the Mercer study) that are required to maintain salary competitiveness and pay equity. This salary increase process is a critical component of our ability to maintain competitive salaries, which supports our ability to retain our employees in a very competitive marketplace for their talent.

Q. HOW IS THIS BUDGET DETERMINED?

A. The Compensation and Human Resources Committee of the Board of Directors determines this budget annually with the input of several data points. Annually we rely on nationally recognized salary surveys, such as Willis Towers Watson,

KornFerry, and Mercer. These surveys provide information on all industries nationwide, and some provide specific utility, technology, and engineering/science industry data separately. In addition, the ISO relies on a Mercer conducted salary survey amongst the other regional independent system operators and regional transmission organizations which is useful given some of the unique positions employed by independent system operators and regional transmission organizations. And, as noted earlier in my testimony, the ISO has incorporated the results of the Mercer benchmarking study into its compensation budgeting process. In summary, the ISO uses all of the data and insight from these multiple sources in establishing the compensation budget, with particular emphasis on the more detailed one for one Mercer benchmarking analysis.

Q. WHAT WERE THE SURVEY RESULTS REGARDING PROJECTED INCREASES FOR 2026?

A. Data received from general, all industry surveys show an average merit increase of 3.5% - 3.6%. Data from the utility industry (such as the North American Electric Reliability Corporation, other independent system operators and regional transmission organizations, and Korn Ferry) show an average merit increase of 3.5% - 4.0%. Promotional and equity (or adjustment) funds are not detailed in all surveys, and the details that are included vary based on how survey respondents budget for promotional or adjustment amounts. However, the generally accepted standard for promotional spending is 0.5% - 1.0%, with industry specific

datapoints (such as the North American Electric Reliability Corporation and other independent system operators and regional transmission organizations) showing a range of promotional increases of 1.5% - 2.0%. While the ISO has improved its competitive position, we are still below competitive ranges for many critical positions and as a result, use this survey data in conjunction with the ISO specific Mercer benchmarking results.

Q. WHAT DID THE COMPENSATION CONSULTANT BENCHMARKING RESULTS INDICATE REGARDING THE ISO'S SALARIES?

A. As noted above, we engaged Mercer to perform a multi-year competitive compensation benchmarking study to examine salary competitiveness across the organization.

The first roles studied in 2022 included many of our most technical engineering, analyst, and information technology roles. We discovered that our base salaries were below market, and requested a higher salary adjustment budget for 2023 than in prior years so that we could begin to address deficits. The 2024 budget also included funding for further adjustments needed to align the salaries of these critical roles with market. Phase 1 of our efforts with Mercer included our most technical and sought after positions, including those where the most turnover was being observed. As we expected, the assessment of those positions showed that our aim to be within the median range for those jobs required that we provide compensation increases. Using contingency funding in the 2023 budget, we made

certain critical adjustments but were not able to fully address the identified deficiencies.

In 2023, we completed Phase 2 of the analysis, covering an additional 200+ employees, with the results we were anticipating: Phase 2 showed less of a competitive gap than the Phase 1 roles, while still requiring some significant adjustments (as reflected in the 2024 and, to a lesser extent, the 2025 budget). This correlation is to be expected as the phases of the Mercer analysis were designed to start with those positions most in demand and include in later phases those jobs more easily filled and that we expect will already be closer to the current market median. The 2025 compensation budget enabled additional adjustments for positions that were not prioritized in the first two phases but were under competitive as compared their market benchmarks as provided by Mercer. Phase 3, with a final set of positions across the organization, is currently being finalized. The prior phase adjustments have closed many of the critical compensation gaps, but funding is needed, and allocated in the 2026 budget to maintain our competitive stance and adjust to the market as it changes in real time.

In summary, as reflected in ISO New England's 2024 salary budget, increases were higher than typical due in large part to the need to make up ground on salary median targets for our most critical positions through promotional and equity adjustments, but the budgeted 2025 and 2026 increases have begun to normalize,

primarily because of the ISO's significant work in 2024 to adjust salaries to more competitive levels. Our 2026 salary increases seek to maintain the improved competitive posture overall, while budgeting for targeted promotional and adjustment increases to track with market movement identified by our latest Mercer work.

Q. WHAT ARE THE ISO'S MERIT AND PROMOTIONAL/ADJUSTMENT INCREASE BUDGETS FOR 2026?

A. After reviewing the data described above, the Compensation and Human Resources Committee approved a merit increase budget of 4.0% (which is consistent with the energy industry data) and a promotional/adjustment increase budget of 1.5% (which is also consistent with energy industry data and less than the 2025 promotional/adjustment increases). The overall increase (5.5%) is necessary to fund typical market-driven salary increases (particularly within the energy industry), and to make the appropriate adjustments to base salaries, as informed by the Mercer benchmarking study, to address the competitive shortfalls explained above.

As noted above, although we have made progress addressing the discrepancies identified in the Mercer study, we still have targeted adjustments to make to close the identified competitive gap. The 5.5% budgeted salary increase is based on the amounts needed to address the results of the benchmarking study while

recognizing that the market continually moves and evolves and requires the ISO to make strategic adjustments to maintain competitiveness.

HEALTH INSURANCE PROGRAM

Q. DOES THE BUDGET INCLUDE ANY INCREASES IN HEALTH INSURANCE COSTS?

A. Yes, for the 2026 plan year the ISO's medical plan was renewed with a 9.2% increase to the plan premiums.[2] The medical plan increase is based on several factors including industry trends and ISO-specific historical claim experience. Our third party broker reviewed the plan increase and confirmed that this increase is consistent with (and in some cases less than) market increases.

Q. DO ISO-NE EMPLOYEES PAY THEIR FAIR SHARE OF HEALTH INSURANCE COSTS?

A. Yes. As part of maintaining a competitive compensation program the ISO has established and administers competitive benefit programs, including the selection, design, and administration of all health and welfare benefits (*e.g.*, medical, life insurance, etc.). The Human Resources Department benchmarks all benefits on an ongoing basis. In engaging such analysis, the Human Resources Department has found that the amount of employee contributions are in line with similarly situated companies. As a result, the plan increases noted above impacted not only

[2] The 2026 budget assumed a slightly higher medical plan increase (based on initial quotes available during the formation of the budget). The resulting reduction will result in approximately $540,000 being returned to the CEO Emerging Work Allowance.

the ISO's 2026 budget, but will also require increased employee contributions although the ratio of employee to employer paid benefit cost will stay the same.

FRAMEWORK FOR DETERMINING EXECUTIVE COMPENSATION

Q. WHAT IS THE FRAMEWORK FOR THE ISO'S DETERMINATION OF EXECUTIVE COMPENSATION?

A. The ISO is a not-for-profit company under Section 501(c)(3) of the Internal Revenue Code. The Internal Revenue Code and related Treasury regulations require that the compensation paid to executive officers meet a standard of "reasonableness." Specifically, compensation must fall within a range of competitive practices for total compensation paid by similarly-situated organizations, both taxable and tax-exempt, for functionally comparable positions.

The Internal Revenue Code allows a tax-exempt organization to establish a "rebuttable presumption" of reasonableness. This places the onus on the Internal Revenue Service to show that compensation is unreasonable. The rebuttable presumption requires that the compensation arrangement be approved in advance by independent individuals (*e.g.*, the Board of Directors), that the Board of Directors has obtained and relied upon appropriate data as to comparability (*i.e.*, compensation paid by similarly-situated entities – taxable and tax-exempt – for positions with a similar scope of responsibility), and that the Board of Directors adequately documents the basis for its determination.

Q. HOW HAS THE ISO ATTEMPTED TO SECURE THE BENEFIT OF THE PRESUMPTION OF REASONABLENESS?

A. The ISO's Board of Directors approves all executive compensation, and documents the basis for its determination. In order to ensure that the Board of Directors has obtained and relied upon appropriate data as to comparability, the ISO retains an outside compensation advisor, Mercer. Mercer prepares an opinion annually on the reasonableness of the ISO's executive compensation, using as comparators other independent system operators and regional transmission organizations, as well as for-profit utilities and other companies, based on their organizational character/complexity, geographic location, role of the incumbent, and labor market for the executive team. The data for these groups is then blended to create a composite market reference as an overall benchmark. This composite reflects the fact that the ISO competes for executive talent in the energy industry, as well as in the broader general industry for positions in areas like Legal, Finance, and Human Resources.

Q. WHAT IS THE BOARD OF DIRECTORS' PROCESS FOR DETERMINING EXECUTIVE COMPENSATION?

A. This process occurs in the first quarter of each year. In determining executive compensation, the Board of Directors first asks the Compensation and Human Resources Committee to consider appropriate compensation. Both the Compensation and Human Resources Committee, and then the Board of

Directors, consider the CEO's appraisal of each executive's experience, responsibilities, performance, specific skill set, and contribution to strategic goal achievement (and, for the CEO, the Chair's appraisal of the same factors as related to the CEO), and the ISO's financial and operational achievement. The Board of Directors then provides its compensation recommendations to Mercer for an opinion on reasonableness, prior to implementation.

Q. WHAT WAS THE CONCLUSION OF MERCER'S MOST RECENT REASONABLENESS OPINION?

A. Mercer's most recent reasonableness opinion concluded that the proposed 2025 total compensation for executives was reasonable.

Q. HOW WILL 2026 EXECUTIVE COMPENSATION BE DETERMINED?

A. The Board of Directors will use the same process described above, involving the Compensation and Human Resources Committee's review and approval followed by full Board of Directors approval of executive compensation. Likewise, the Board of Directors will employ Mercer to ensure the reasonableness of 2026 compensation. While 2026 compensation has not yet been determined, 2025 executive compensation will be the base for 2026 compensation and the Board has not authorized any wholesale changes to the compensation programs described above. Preliminary information provided by Mercer, suggests that it is reasonable to presume that the 2026 executive compensation will be similar to the 2025 compensation, with minimal changes necessary to maintain competitiveness.

Q. IS THE ISO'S EXECUTIVE COMPENSATION PUBLICLY DISCLOSED?

A. Yes. The ISO discloses the total compensation for each executive in its Internal Revenue Service Form 990, a copy of which the ISO is required to provide to anyone who requests it. The ISO also includes information regarding base salary for each officer on page 104 of its annual FERC Form 1.

Q. IS DIRECTOR COMPENSATION REVIEWED FOR REASONABLENESS?

A. Yes, similar to the reasonableness analysis for executive compensation, the ISO engages Mercer to provide a reasonableness opinion for director compensation. Mercer's most recent reasonableness opinion concluded that the ISO's director compensation, including the increases to the retainer amounts included in the proposed 2026 operating budget, was reasonable. The retainer adjustments were made after a market competitiveness review of the ISO's director compensation.

CONCLUSION

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

I declare under penalty of perjury that the foregoing is true and correct.

Executed as of October 15, 2025.

Kathleen deCastro

EXHIBIT 5

Exhibit 5

ISO New England Inc.
2026 Capital Projects Schedule

($000's)	Project-To-Date	Current Year (2025) Cost to Complete [1]	2026 Cost to Complete	Future Cost to Complete	Total Project Costs	Estimated Complete Date
Capital Projects - Approved Charters						
. nGEM Real-Time Market Clearing Engine Implementation	$ 10,193.0	$ 1,355.6	$ 3,203.6	$ -	$ 14,752.2	05/26
. Distributed Energy Resources - Order 2222	281.7	2,427.2	2,642.7	-	5,351.6	11/26
. Oracle Platform Replacement	25.8	612.4	2,157.4	-	2,795.6	11/26
. Managing Transmission Line Ratings	7,332.8	369.1	1,000.0	-	8,701.9	12/26
. Adoption of NERC CIP Compliance of Synchrophasor Systems	734.3	345.2	994.6	-	2,074.1	08/26
. IMM Datamart Improvement Project	2.1	172.9	387.0	-	562.0	10/26
. CIP Electronic Security Perimeter Redesign Phase III	36.2	775.7	293.6	-	1,105.5	06/26
. Voltage Ampere Reactive (VAR) Capability Testing	3.1	252.4	144.5	-	400.0	03/26
. EMS CFE Refresh	264.4	381.8	108.2	-	754.4	06/26
. Enterprise Core Network Refresh	154.4	1,593.5	48.0	-	1,795.9	08/26
. Centralized Application Security	30.0	113.9	38.7	-	182.6	02/26
Sub Total Projects with Approved Charters	19,057.7	8,399.8	11,018.3	-	38,475.9	
Planning/Conceptual Design [2]						
. Single Interval MCE Improvements (SIMI)	187.7	12.3	5,000.0	8,000.0	13,200.0	06/28
. EMP 3.5 Upgrade - GridOS	-	400.0	3,500.0	3,000.0	6,900.0	09/27
. MW Dependent Fuel Price Adjustment	27.1	72.9	2,500.0	-	2,600.0	12/26
. Advanced Technology Initiatives	-	-	2,000.0	2,000.0	4,000.0	12/27
. Atlassian Cloud Migration	338.4	41.6	2,000.0	-	2,380.0	12/26
. Order 2023 Interconnection Reforms	129.3	11.7	2,000.0	-	2,141.0	09/26
. Day-Ahead Market Simulator (DAMKTSIM)	55.9	44.1	1,800.0	-	1,900.0	12/26
. GridOS Connect	339.4	159.3	1,500.0	-	1,998.7	12/26
. Storage as Transmission Only Asset (SATOA)	1.5	498.5	500.0	-	1,000.0	10/26
. Tie Line Telemetry Replacement	99.2	50.8	500.0	-	650.0	10/26
. Replace Employee & Pager Application	49.0	1.0	500.0	-	550.0	12/26
. Circuit Inventory Management Platform Phase II	-	-	500.0	-	500.0	10/26
. Solar Do Not Exceed Dispatch Phase III	-	-	500.0	-	500.0	12/26
. Operations Document Management System MS 365 Conversion	30.1	9.9	250.0	-	290.0	10/26
. Long-term FTRs [3]	907.5	-	-	-	907.5 [3]	TBD
. Other Emerging Work	-	-	1,731.7	-	1,731.7	
. Sub-Total Conceptual Design	2,165.1	1,302.1	24,781.7	13,000.0	41,248.9	
. Non-Project Capital Expenditures	2,985.2	3,214.8	5,500.0	-	11,700.0	
. Capitalized Interest and Loan Fees	578.7	521.3	1,200.0	-	2,300.0	
Total Capital Projects (Including Capitalized Interest)	**$ 24,786.8**	**$ 13,437.9**	**$ 42,500.0**	**$ 13,000.0**	**$ 93,724.7**	

[1] The amounts under the "Current Year (2025) Cost to Complete" list only includes those projects with budgeted costs in 2026 and beyond.

[2] The 2026 Budget for Projects in Planning and Conceptual Design is not final. Once the project scope and timeline have been determined the budget will be finalized.

[3] The Long-term FTRs project has been indefinitely deferred pending the development of appropriate credit requirements.

EXHIBIT 6

CROSS-REFERENCE TABLE
(showing location in the ISO's filing of applicable items from
Statements AA - BM in Section 35.13(h))

Statement AA	Balance sheets: See balance sheets from ISO's 2024 Form 1 (Exhibit 7).
Statement AB	Income statements: See income statements from ISO's 2024 Form 1 (Exhibit 7 hereto). A comparison of budgeted net operating expenses for 2026 with budgeted 2025 operating expenses is contained in Exhibit 3, RCL-5, Schedules 3 and 4.
Statement AC	Retained earnings statement: Not applicable.
Statement AD	Cost of plant: The ISO's "plant" consists of office furniture and equipment (Account 391). The ISO does not own generation, transmission or distribution equipment. See 2024 ISO Form 1 balance sheet (Exhibit 7) at page 110, lines 2 and 4. The three "functions" of the ISO (and reflected in Section IV.A. of the ISO New England Inc. Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3 (the "Tariff")) are the three Services[1] provided by the ISO.
Statement AE	Accumulated depreciation and amortization: See 2024 ISO Form 1 balance sheet (Exhibit 7) at page 110, line 5.
Statement AF	Specified deferred credits: Not applicable.
Statement AG	Specified plant accounts (other than plant in service): Not applicable, because the ISO is not seeking a return on rate base.
Statement AH	Operation and maintenance expenses: These are functionalized among the Services in Exhibit 3. See ISO's 2024 Form 1 pages 320-323 Electric Operation & Maintenance Expenses (Exhibit 7).
Statement AI	Wages and salaries: These are functionalized among the Services in Exhibit 3, RCL-3, Schedules 2.0 and 4.0. A comparison of staffing levels for 2025 and 2026 is contained in Exhibit 3, RCL-5, Schedule 5.
Statement AJ	Depreciation and amortization (lease and sublease) expenses: These are functionalized among the Services in Exhibit 3, RCL-3, Schedule 3.0. Depreciation and amortization rates are discussed in

[1] Capitalized terms not otherwise defined in this Exhibit have the meanings ascribed thereto in the Tariff.

	Section I.C.2 of the transmittal letter and in Mr. Ludlow's testimony (Exhibit 3).
Statement AK	Taxes other than income taxes: See Exhibit 3, RCL-5, Schedules 1 and 2.
Statement AL	Working capital: The Commission has authorized a revolving line of credit of $20 million for the ISO's working capital needs. *See* 186 FERC ¶ 62,024 (2024). Due to the nature of the limited plant owned by the ISO, the concepts of supplies, fuel supplies, plant materials and operating supplies are not applicable to the ISO. Prepaid expenses for the ISO consist mainly of insurance costs.
Statement AM	Construction work in process. See ISO's 2024 Form 1 page 216 Construction Work in Progress – Electric (Exhibit 7).
Statement AN	Notes payable: see description of notes authorized in 109 FERC ¶ 62,194 (2004); 140 FERC ¶ 62,172 (2012); 140 FERC ¶ 62,173 (2012); 144 FERC ¶ 62,087 (2013); 188 FERC ¶ 62,038 (2024). See ISO's 2024 Form 1 pages 256-257 Long-Term Debt (Exhibit 7).
Statement AO	Rate for allowance for funds used during construction: not applicable
Statement AP	Federal income tax deductions - interest: The ISO is exempt from federal income taxation.
Statement AQ	Federal income tax deductions - other than interest: The ISO is exempt from federal income taxation.
Statement AR	Federal tax adjustments: The ISO is exempt from federal income taxation.
Statement AS	Additional state income tax deductions: The ISO pays no state income taxes.
Statement AT	State tax adjustments: The ISO pays no state income taxes.
Statement AU	Revenue credits: Not applicable with respect to generation or transmission. The 2026 Revenue Requirement reflects a decrease from the 2024 true-up, as described in Section I.C.3 of the filing letter, and Exhibit 3, RCL-2.
Statement AV	Rate of return: Not applicable because the ISO seeks no rate of return.

Statement AW	Cost of short-term debt: No short-term debt.
Statement AX	Other recent and pending rate changes: The ISO has no operating revenues that are currently subject to refund.
Statement AY	Income and revenue tax rate data: Not applicable because the ISO pays no federal or state income tax, and no revenue taxes.
Statement BA	Wholesale customer rate groups: For each Service (i.e., each Rate Schedule), the cost of service equals the revenues from the customer group, as ensured by the true-up mechanism contained in Section IV.A.2.2 of the Tariff. For Rate Schedule 1, all transmission customers under the Open Access Transmission Tariff (Section II of the Tariff); for Rate Schedule 2, all Market Participants that participate in the New England Markets for energy; for Rate Schedule 3, all Market Participants that have load, and non-Participant Point-to-Point Transmission Service customers.
Statement BB	Allocation demand and capability data: Not applicable because the ISO's revenue requirement is not based on generation or transmission expenses. The denominators used in the rate design for each Service are explained in Section I.E of the transmittal letter.
Statement BC	Reliability data: Not applicable because the ISO's revenue requirement is not based on generation or transmission expenses. The denominators used in the rate design for each Service are explained in Section I.E of the filing letter.
Statement BD	Allocation energy and supporting data: Not applicable because the ISO's revenue requirement is not based on generation expenses. The denominators used in the rate design for each Service are explained in Section I.E of the transmittal letter.
Statement BE	Specific assignment data: See Exhibit 3 for direct allocations to the three rate schedules in Section IV.A of the Tariff.
Statement BF	Exclusive-use commitments of major power supply facilities: Not applicable.
Statement BG	Revenue data to reflect changed rates: See Sections I.C and I.E of the transmittal letter. The entire projected revenue requirement for

	a Service (discussed in Exhibit 3) is paid for by the corresponding customer group described in the Statement BA discussion, above. The billing determinants for each Service are discussed in Section I.E of the filing letter. The ISO has no fuel clause.
Statement BH	Revenue data to reflect present rate: See Sections I.C. and I.E of the filing letter.
Statement BI	Fuel cost adjustment factors: not applicable.
Statement BJ	Summary cost tables: See Exhibit 3.
Statement BK	Electric utility department cost of service: See Exhibit 3.
Statement BL	Rate design information: See Section I.E of the filing letter.
Statement BM	Construction program statement: Not applicable.

EXHIBIT 7

Name of Respondent: ISO New England Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200	473,090,681	467,311,699
3	Construction Work in Progress (107)	200	43,059,366	26,745,647
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		516,150,047	494,057,346
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	401,238,829	383,475,437
6	Net Utility Plant (Enter Total of line 4 less 5)		114,911,218	110,581,909
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202		
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)			
9	Nuclear Fuel Assemblies in Reactor (120.3)			
10	Spent Nuclear Fuel (120.4)			
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202		
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)			
14	Net Utility Plant (Enter Total of lines 6 and 13)		114,911,218	110,581,909
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)			
19	(Less) Accum. Prov. for Depr. and Amort. (122)			
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224		
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)		4,266,142	3,266,557
25	Sinking Funds (125)			
26	Depreciation Fund (126)			

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)				
Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)			
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)			
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		4,266,142	3,266,557
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		231,268,888	70,011,288
36	Special Deposits (132-134)		30,733,515	27,622,047
37	Working Fund (135)		500	500
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		130,238,775	37,303,880
41	Other Accounts Receivable (143)			
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)			
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)			
45	Fuel Stock (151)	227		
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227		
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228		
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227		

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)				
Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		6,909,067	6,170,359
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)			
61	Accrued Utility Revenues (173)			
62	Miscellaneous Current and Accrued Assets (174)		253,479,396	234,322,946
63	Derivative Instrument Assets (175)			
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)			
65	Derivative Instrument Assets - Hedges (176)		0	850
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		652,630,141	375,431,870
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		855,108	452,183
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	4,843,571	21,385,433
73	Prelim. Survey and Investigation Charges (Electric) (183)			
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)			
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	6,309,293	599,374
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)				
Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
81	Unamortized Loss on Reaquired Debt (189)			
82	Accumulated Deferred Income Taxes (190)	234		
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		12,007,972	22,436,990
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		783,815,473	511,717,326

Name of Respondent: ISO New England Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250		
3	Preferred Stock Issued (204)	250		
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)			
7	Other Paid-In Capital (208-211)	253		
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b		
11	Retained Earnings (215, 215.1, 216)	118		
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118		
13	(Less) Reacquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	0	850
16	Total Proprietary Capital (lines 2 through 15)		0	850
17	LONG-TERM DEBT			
18	Bonds (221)	256	33,565,000	36,745,000
19	(Less) Reacquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256	75,000,000	50,000,000
22	Unamortized Premium on Long-Term Debt (225)			
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)			
24	Total Long-Term Debt (lines 18 through 23)		108,565,000	86,745,000
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		2,666,086	676,772

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)				
Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)			
29	Accumulated Provision for Pensions and Benefits (228.3)		0	16,541,860
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)			
32	Long-Term Portion of Derivative Instrument Liabilities			
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)			
35	Total Other Noncurrent Liabilities (lines 26 through 34)		2,666,086	17,218,632
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)			
38	Accounts Payable (232)		283,037,506	63,847,953
39	Notes Payable to Associated Companies (233)			
40	Accounts Payable to Associated Companies (234)			
41	Customer Deposits (235)		329,763,273	308,851,997
42	Taxes Accrued (236)	262		
43	Interest Accrued (237)		1,054,306	539,183
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)			
48	Miscellaneous Current and Accrued Liabilities (242)		36,073,227	30,994,696
49	Obligations Under Capital Leases-Current (243)		1,305,895	512,851
50	Derivative Instrument Liabilities (244)			
51	(Less) Long-Term Portion of Derivative Instrument Liabilities			
52	Derivative Instrument Liabilities - Hedges (245)			

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)				
Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		651,234,207	404,746,680
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)			
57	Accumulated Deferred Investment Tax Credits (255)	266		
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	21,350,180	3,006,164
60	Other Regulatory Liabilities (254)	278		
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort. (281)	272		
63	Accum. Deferred Income Taxes-Other Property (282)			
64	Accum. Deferred Income Taxes-Other (283)			
65	Total Deferred Credits (lines 56 through 64)		21,350,180	3,006,164
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		783,815,473	511,717,326

Name of Respondent: ISO New England Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

STATEMENT OF INCOME

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)
1	UTILITY OPERATING INCOME							
2	Operating Revenues (400)	300	262,503,596	233,806,867			262,503,596	233,806,867
3	Operating Expenses							
4	Operation Expenses (401)	320	164,037,825	148,159,353			164,037,825	148,159,353
5	Maintenance Expenses (402)	320	65,007,009	54,537,214			65,007,009	54,537,214
6	Depreciation Expense (403)	336	31,543,935	29,994,926			31,543,935	29,994,926
7	Depreciation Expense for Asset Retirement Costs (403.1)	336						
8	Amort. & Depl. of Utility Plant (404-405)	336	39,303	39,303			39,303	39,303
9	Amort. of Utility Plant Acq. Adj. (406)	336						
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)							
11	Amort. of Conversion Expenses (407.2)							
12	Regulatory Debits (407.3)							
13	(Less) Regulatory Credits (407.4)							
14	Taxes Other Than Income Taxes (408.1)	262						
15	Income Taxes - Federal (409.1)	262						
16	Income Taxes - Other (409.1)	262						
17	Provision for Deferred Income Taxes (410.1)	234, 272						

STATEMENT OF INCOME								
Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272						
19	Investment Tax Credit Adj. - Net (411.4)	266						
20	(Less) Gains from Disp. of Utility Plant (411.6)		3,458	0			3,458	
21	Losses from Disp. of Utility Plant (411.7)		374,934	21,520			374,934	21,520
22	(Less) Gains from Disposition of Allowances (411.8)							
23	Losses from Disposition of Allowances (411.9)							
24	Accretion Expense (411.10)							
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		260,999,548	232,752,316			260,999,548	232,752,316
27	Net Util Oper Inc (Enter Tot line 2 less 25)		1,504,048	1,054,551			1,504,048	1,054,551
28	Other Income and Deductions							
29	Other Income							
30	Nonutilty Operating Income							
31	Revenues From Merchandising, Jobbing and Contract Work (415)							
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)							
33	Revenues From Nonutility Operations (417)							

STATEMENT OF INCOME								
Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)
34	(Less) Expenses of Nonutility Operations (417.1)							
35	Nonoperating Rental Income (418)							
36	Equity in Earnings of Subsidiary Companies (418.1)	119						
37	Interest and Dividend Income (419)		2,087,136	1,793,190				
38	Allowance for Other Funds Used During Construction (419.1)							
39	Miscellaneous Nonoperating Income (421)							
40	Gain on Disposition of Property (421.1)							
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		2,087,136	1,793,190				
42	Other Income Deductions							
43	Loss on Disposition of Property (421.2)							
44	Miscellaneous Amortization (425)							
45	Donations (426.1)		14,725	13,550				
46	Life Insurance (426.2)							
47	Penalties (426.3)							
48	Exp. for Certain Civic, Political & Related Activities (426.4)							
49	Other Deductions (426.5)							
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		14,725	13,550				

STATEMENT OF INCOME								
Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)
51	Taxes Applic. to Other Income and Deductions							
52	Taxes Other Than Income Taxes (408.2)	262						
53	Income Taxes-Federal (409.2)	262						
54	Income Taxes-Other (409.2)	262						
55	Provision for Deferred Inc. Taxes (410.2)	234, 272						
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272						
57	Investment Tax Credit Adj.-Net (411.5)							
58	(Less) Investment Tax Credits (420)							
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)							
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		2,072,411	1,779,640				
61	Interest Charges							
62	Interest on Long-Term Debt (427)		3,207,588	2,761,425				
63	Amort. of Debt Disc. and Expense (428)		65,068	57,558				
64	Amortization of Loss on Reaquired Debt (428.1)							
65	(Less) Amort. of Premium on Debt-Credit (429)							
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)							
67	Interest on Debt to Assoc. Companies (430)							

STATEMENT OF INCOME								
Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)
68	Other Interest Expense (431)		303,803	15,208				
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)							
70	Net Interest Charges (Total of lines 62 thru 69)		3,576,459	2,834,191				
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		0	0				
72	Extraordinary Items							
73	Extraordinary Income (434)							
74	(Less) Extraordinary Deductions (435)							
75	Net Extraordinary Items (Total of line 73 less line 74)							
76	Income Taxes-Federal and Other (409.3)	262						
77	Extraordinary Items After Taxes (line 75 less line 76)							
78	Net Income (Total of line 71 and 77)		0	0				

Name of Respondent: ISO New England Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

STATEMENT OF CASH FLOWS

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 117)	0	0
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	31,543,935	29,994,926
5	Amortization of (Specify) (footnote details)		
8	Deferred Income Taxes (Net)		
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	(123,053,950)	111,806,381
11	Net (Increase) Decrease in Inventory		
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	250,278,997	(216,980,738)
14	Net (Increase) Decrease in Other Regulatory Assets	16,541,861	3,281,476
15	Net Increase (Decrease) in Other Regulatory Liabilities		
16	(Less) Allowance for Other Funds Used During Construction		
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
18.1	Net (increase) / Decrease in Derivative Asset Instruments	850	19,851
18.2	Net Increase / (Decrease) in Accumulated Other Comprehensive Income	(850)	50,749
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	175,310,843	(71,827,355)
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(35,873,243)	(33,297,268)
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		

STATEMENT OF CASH FLOWS			
Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
30	(Less) Allowance for Other Funds Used During Construction		
31	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(35,873,243)	(33,297,268)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(35,873,243)	(33,297,268)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	75,000,000	
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		

STATEMENT OF CASH FLOWS			
Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
70	Cash Provided by Outside Sources (Total 61 thru 69)	75,000,000	
72	Payments for Retirement of:		
73	Long-term Debt (b)	(53,180,000)	(3,180,000)
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock		
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	21,820,000	(3,180,000)
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	161,257,600	(108,304,623)
88	Cash and Cash Equivalents at Beginning of Period	70,011,288	178,315,911
90	Cash and Cash Equivalents at End of Period	231,268,888	70,011,288

Name of Respondent: ISO New England Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

ISO New England Inc.
Statements of Financial Position
As of December 31, 2024 and 2023

The accompanying financial statements on pages 110 through 121 (excluding pages 118 and 119) of this Form 1 Report of ISO New England Inc. were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission ("FERC") as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than U.S. generally accepted accounting principles ("GAAP").

The primary differences between the Company's FERC financial statements and GAAP financial statements are:

(1)The gross presentation of accounts receivable and accounts payable;

(2)The presentation of regulatory assets and regulatory liabilities in the balance sheet under GAAP requirements differs from FERC requirements, although no differences exist for the reporting periods;

(3)The segregation of unamortized debt expenses from property and equipment;

(4)The inclusion of debt issuance costs directly attributable to issuing a debt instrument as part of unamortized debt expenses and bonds on the FERC balance sheet;

(5)The presentation of an interest rate cap agreement as a Derivative Asset-Hedge on the Form 1 balance sheet instead of Deferred charges and Other Assets for the unamortized balance and fair market value, respectively.

(6)Restricted cash on deposit, reported as Special Deposits, includes no distinction in classification between current and long-term;

(7)Accrued compensation, reported as Miscellaneous Current and Accrued Liabilities, includes no distinction in classification between current and long-term;

(8)There is no current liability classification of the current portion of long-term debt in the FERC balance sheet;

(9)The presentation of the difference between book value and fair market value of an interest rate cap agreement as Accumulated Other Comprehensive Income on the Form 1 Balance Sheet instead of Deferred Income;

(10)Combined Deposit payable and Restricted cash on deposit payable into Customer Deposits on the Form 1, with no distinction in classification between current and long-term;

(11)The presentation of term loan fees as Other Interest Expense on the Form 1 Statement of Income instead of Administrative and other expense;

(12)The presentation of the change in Special Deposits, Customer Deposits, and Other Assets on the statements of cash flows as an operating activity instead of a financing activity as required by US GAAP;

(13) The inclusion of Right-of-use asset, both current and non-current, as Property and Equipment on the Form 1 balance sheet.

The notes below are excerpts from the Company's GAAP basis financial statements as of and for the years ended December 31, 2024 and 2023. The following disclosures contain information in accordance with GAAP reporting requirements. As such, due to the differences between FERC and GAAP reporting requirements, certain amounts disclosed in the following notes may not agree to balances in the FERC financial statements.

1. Summary of Significant Accounting Policies Description of Business

ISO New England Inc. (the "Company" or "ISO") is the Regional Transmission Organization ("RTO") for New England in compliance with the requirements of the Federal Energy Regulatory Commission ("FERC"). On January 1, 2013, the ISO became the central counterparty to market transactions that flow through the ISO. The change to central counterparty was the result of a FERC rulemaking designed to afford the ISO and market participants ("Participants") more protection in bankruptcy. The ISO's assumption of the central counterparty role did not have a material effect on the ISO's settlement of the markets or on business operations.

The ISO's mission, in collaboration with its stakeholders, is to ensure that New England has reliable, competitively priced wholesale electricity through three interconnected responsibilities: managing the operation of the region's high-voltage power grid; administering the region's billion-dollar competitive markets for buying and selling wholesale electricity; and engaging in planning, studies, and analysis to make sure New England's electricity needs will be met over the next ten years and beyond.

The ISO is governed by an independent board of directors and is regulated by FERC. FERC's mandated or approved rules are detailed in the ISO New England Inc. Transmission, Markets, and Services Tariff (the "Tariff" or "ISO Tariff").

On January 13, 2014, the ISO, along with several Reliability Coordinators (as that term is defined by the North American Electric Reliability Corporation ("NERC")), became a member of EIDSN, Inc. ("EIDSN"). EIDSN is a 501(c)(6), nonstock, nonprofit corporation that was established to, among other things, facilitate the secure, consistent, effective, and efficient sharing of important electric transmission and operational data among its members and/or other applicable parties to help improve electric industry operations and promote the reliable and efficient operation of the bulk power system.

Basis of Accounting and Presentation

The accompanying financial statements have been prepared on an accrual basis of accounting in accordance with U.S. generally accepted accounting principles and Financial Accounting Standards Board Accounting Standards Codification (FASB ASC) Topic 980,*Regulated Operations,*and FASB ASC 958,*Not-for-Profit Entities*.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant items subject to such estimates and assumptions include the useful lives of fixed assets; and assumptions utilized in the accounting for employee benefit obligations such as discount rates, return on assets, fair value of investments and other contingencies.

Regulatory Accounting

The Company's financial statements are prepared in accordance with generally accepted accounting principles for rate-regulated entities. As such, regulators may permit specific incurred costs, typically treated as expenses by unregulated entities, to be deferred and expensed in future periods when it is probable that such costs will be recovered in customer rates. Incurred costs are deferred as regulatory assets when the ISO concludes that it is probable future revenues will be provided to permit recovery of the previously incurred cost. A regulatory liability is recorded when amounts that have been recorded by the ISO are likely to be refunded to customers through the rate-setting process.

Cash and Cash Equivalents

The Company considers cash on hand and short-term marketable securities with original maturities of three months or less to be cash equivalents. The cash equivalents at December 31, 2024 and 2023 were held in overnight repurchase agreements, money market accounts as well as in direct and indirect obligations of the United States, with original maturities of three months or less.

Restricted Cash on Deposit

The balance of approximately $32,058,000 and $29,441,000 at December 31, 2024 and 2023, respectively, recorded as restricted cash on deposit, represents the Forward Capacity Market Forfeited Funds, the Congestion Revenue Fund, the FERC Order Funds, and Cluster Study Funds. The balance has a corresponding liability on the accompanying Statements of Financial Position. The restricted cash on deposit at December 31, 2024 and 2023 was held in overnight repurchase agreements and in direct and indirect obligations of the United States of America, with original maturities of three months or less.

The following table provides a reconciliation of cash, cash equivalents, and restricted cash reported within the Statements of Financial Position that sum to the total of the same such amounts shown in the Statements of Cash Flows.

	December 31, 2024	2023
Cash and cash equivalents	$ 231,269,000	$ 70,012,000
Restricted cash on deposit	12,654,000	10,224,000
Restricted cash on deposit, net of current portion	19,404,000	19,217,000
Total	$ 263,327,000	$ 99,453,000

The cash and cash equivalents and restricted cash on deposit are recorded at fair market value and are classified as Level 1.

Accounts Receivable and Accounts Payable

In the course of bulk power transactions administered by the Company on behalf Participants, amounts for energy purchased and sold among Participants become payable to and receivable from such Participants. The Company summarizes and prices the energy transactions and provides an invoice or remittance advice to each Participant that summarizes the amount either receivable from or payable to each Participant twice per week.

Accounts payable on the accompanying Statements of Financial Position are segregated between (i) the amounts owed for energy transactions and transmission, for which the ISO functions as paying agent, and are included in Accounts payable as "Settlement, net," and (ii) the administrative expenses incurred by the Company in the course of operations. The reference to "Settlement, net" is used due to the nature of billing and payment for the amounts owed for energy transactions and transmission markets, and represents the Participants' net amount due, less any amounts that may have been owed to them.

The net unbilled receivables, the majority of which have been determined from the settlement process, include those amounts that will be billed and included in the invoice or remittance advice to Participants on subsequent invoices issued twice per week. The balance at the end of the year primarily represents ISO Tariff revenues. The net payables and receivables for these energy transactions are settled with the Participants in the same week.

Property and Equipment in Service and Work in Process

Property and equipment in service is stated at cost, net of accumulated depreciation and amortization. The Company capitalizes the interest and fees associated with borrowings that the Company has entered into for the acquisition of assets related to a project that has a material effect on the Company's financial position as required by FASB ASC Topic 980,*Regulated Operations.*

The Company capitalizes the cost of payroll, payroll-related costs and third-party consulting fees incurred in the direct development or enhancement of solutions as internal-use software. Development costs incurred during the preliminary project stage or costs incurred for requirements gathering, data conversion activities, training, maintenance and minor enhancements are expensed as incurred. Development costs incurred for the coding, configuration, interfacing, automation and testing of new functionality after the preliminary project stage is complete are capitalized. Capitalized software costs are amortized on a straight-line basis over three to five years based on the nature and estimated useful life of the applicable solution. Amortization of capitalized software costs is included in depreciation and amortization expense within the Statements of Activities.

Depreciation and Amortization

Depreciation is generally computed using the straight-line method over an estimated useful life ranging from three years to twenty-five years (e.g., computer hardware, software and accessories - three to five years; software development costs - three to five years; vehicles - three to seven years; furniture and fixtures and machinery and equipment - seven years; building and building improvements - one to twenty-five years or remaining life of the building improvement; and building - twenty-five years). Capitalized interest and fees are amortized over the same useful life of the asset to which it pertains, principally software development costs and building. No depreciation is recorded for assets classified as work in process until the assets are placed into service (Note 3).

Leases

The Company determines whether an arrangement is a lease at the inception of the arrangement based on the terms and conditions in the contract. A contract contains a lease if there is an identified asset and the Company has the right to control the asset.

Right-of-use ("ROU") assets represent the Company's right to use an underlying asset for the lease term and lease liabilities represent the Company's obligation to make lease payments arising from the lease. Operating lease ROU assets and liabilities are recognized at the commencement date based on the present value of lease payments over the lease term. Most of the Company's leases do not provide the lessor's implicit rate; the Company uses its incremental borrowing rate at the commencement date in determining the present value of lease payments. Lease terms include options to extend the lease when it is reasonably certain those options will be exercised. The Company has not entered into any leases that contain a residual value guarantee or a variable lease payment. Leases with an initial term of 12 months or less are not recorded on the Statements of Financial Position, and lease expense is recognized on a straight-line basis over the lease term.

The Company has lease agreements with lease and non-lease components, which are accounted for as a single lease component for all asset classes. Additionally, for equipment leases, the portfolio approach is applied to account for the operating lease ROU assets and lease liabilities. In the Statements of Activities, lease expense for operating lease payments is recognized on a straight-line basis over the lease term.

Deferred Charges and Regulatory Assets and Liabilities

As a regulated entity, the Company, in appropriate circumstances, establishes regulatory assets or liabilities, and thereby defers the Statements of Activities impact of certain charges or revenues because it is probable to be collected or refunded through future customer billings.

The Company incurred costs with the purchase of land located at Helmsford Way for which the costs were deferred and amortized. The current year amortization is included in the current year's filing pursuant to Section IV.A, Recovery of ISO Administrative Expenses, of the ISO Tariff. The remaining cost for the land located at Helmsford Way will be collected in future filings.

The following table is a detail of the deferred charges, regulatory assets and liabilities balances as presented in the accompanying Statements of Financial Position at December 31:

Deferred charges	2024	2023
Land located on Helmsford Way	$ 560,000	$ 599,000
	$ 560,000	$ 599,000

Regulatory assets - current	2024	2023
Actual 2023 under collection	$ 4,843,000	$ -
	$ 4,843,000	$ -

Regulatory assets, net of current portion	2024	2023
Actual 2023 under collection	$ -	$ 4,843,000
Asset related to pension and postretirement benefit liabilities (Note 5)	-	16,542,000
	$ -	$ 21,385,000

Regulatory liability - current	2024	2023
Actual 2022 over collection	$ -	$ 3,006,000
Market to Market Interest Rate Cap	-	1,000
	$ -	$ 3,007,000

Regulatory liability, net of current portion	2024	2023
Actual 2024 over collection	$ 15,601,000	$ -
Pension and postretirement benefit liabilities (Note 5)	5,749,000	-
	$ 21,350,000	$ -

Income Taxes

The Company is an entity organized as a non-stock corporation under the General Corporation Law, as amended, of the State of Delaware. The Company has been recognized by the Internal Revenue Service as an organization described in Internal Revenue Code (IRC) 501(c)(3) and is generally exempt from income taxes under IRC Section 501(a). The Company has determined prior to recording any benefit in the financial statements that it is more likely than not that the tax position will be sustained upon examination by the appropriate taxing authorities, as required by the Accounting for Uncertainty within Income Taxes in FASB ASC Topic 740,*Income Taxes*. A tax position is measured at the largest amount of benefit that is greater than fifty percent likely of being realized upon settlement.

Pension and Other Postretirement Plans

The Company has two noncontributory defined benefit pension plans (one for union and the other for non-union employees). The benefits are based on age, years of service, and average compensation. The Company also sponsors a defined postretirement benefit health, dental, and life insurance plan.

The Company records annual amounts relating to its pension and other postretirement plans based on calculations that incorporate various actuarial and other assumptions, including discount rates, mortality, assumed rates of return, compensation increases, turnover rates, and healthcare cost trend rates. The Company reviews its assumptions on an annual basis and makes modifications to the assumptions based on current rates and trends when it is appropriate to do so. The Company believes the assumptions utilized in recording its obligations under its plans are reasonable based on its experience and market conditions.

Security Deposits and Deposit Payable

The Participants are required to comply with the Financial Assurance Policy under the ISO's Tariff. Under the Financial Assurance Policy, most Participants are required to provide financial assurance due to their market activity or if they do not qualify for a credit limit. Participants must provide such financial assurance in an acceptable form which may be cash collateral. Any Participant utilizing the cash collateral option must sign a security agreement with the ISO granting the ISO a continued security interest in the collateral. The balance at December 31, 2024 and 2023 were $253,479,000 and $234,322,000, respectively, and recorded as an asset on the accompanying Statements of Financial Position.

The following table provides a reconciliation of Deposit Payable as reported within the Statements of Financial Position.

	December 31,	
	2024	2023
Security deposit payable	$ 253,479,000	$ 234,322,000
System Impact Studies deposit	41,076,000	42,292,000
Forward Capacity Market deposit	1,999,000	2,364,000
Other deposit payable	506,000	279,000
Total	$ 297,060,000	$ 279,257,000

Revenue Recognition

The Company recovers its operating and debt service costs pursuant to Section IV of the ISO's Tariff, which provides for recovery of expenses through three schedules to Section IV.A. Scheduling, System Control and Dispatch Service (Schedule 1), Energy Administration Service (Schedule 2), and Reliability Administration Service (Schedule 3) recover related costs through a pre-approved rate applied to each month's activity. Schedules 1, 2, and 3 are subject to true-up through subsequent years' rates, and any over or under collection are recorded as regulatory assets or regulatory liabilities and will be recovered under future filings to recover the ISO's expenses.

In addition to the recovery of these operating and debt service costs, the Company acts as a billing agent for a number of different pass-through expenditures on behalf of Participants and other regulatory bodies, including system impact study expenses, the FERC's Annual Electric Charges, and amounts related to the annual budget of the New England States' Committee on Electricity, each as required by the Tariff.

Concentrations

The Company's top 10 Participants represented approximately 52% or $142,811,000 and 51% or $109,397,000 in Tariff revenues for the years ended December 31, 2024 and 2023, respectively. The Company's top 10 Participants with unbilled receivable balances represented approximately 51% or $22,920,000 and 51% or $17,852,000 as of December 31, 2024 and 2023, respectively.

Liquidity Information

In order to provide additional information about liquidity, assets have been sequenced according to their nearness to conversion to cash, and liabilities have been sequenced according to the nearness of their resulting use of cash. Financial assets available for general expenditures without donor or other restrictions limiting their use, within one year of the respective Statements of Financial Position date, comprise the following:

	December 31, 2024	2023
Cash and cash equivalents	$ 231,269,000	$ 70,012,000
Unbilled receivables, net	45,627,000	37,057,000
Total	$ 276,896,000	$ 107,069,000

The Company's recovery of operating and debt service cost, as described in the Revenue Recognition and Accounts Receivable and Accounts Payable disclosure within this footnote, are collected in arrears, and as a result, the Company's working capital and cash flows may vary throughout the year. To manage unanticipated liquidity needs, the Company has in place a revolving credit agreement, as described within Credit Facilities (Note 4), to be used as needed to cover expenses as a result of the timing of cash flows.

Fair Value of Financial Instruments

In determining fair value of financial assets and liabilities, the Company uses various valuation techniques. The availability of inputs observable in the market varies from instrument to instrument and depends on a variety of factors including the type of instrument, whether the instrument is actively traded, and other characteristics particular to the transaction. For many financial instruments where pricing inputs are readily observable in the market, the used valuation methodology is widely accepted and does not require significant management discretion. For other financial instruments, pricing inputs are less observable in the market and may require management's judgment. The level in the fair value hierarchy within which a fair value measurement in its entirety falls is based on the lowest-level input that is available for that particular financial instrument.

We assess the inputs used to measure fair value using the following three-tier hierarchy, which indicates the extent to which inputs used are observable in the market.

Level 1 Valuation is based upon unadjusted quoted prices for identical instruments traded in active markets.

Level 2 Valuation is pricing inputs other than Level 1 that are observable, either directly or indirectly, such as quoted prices for similar assets; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the same term of the assets. Inputs are obtained from various sources including investors and dealers.

Level 3 Valuation is generated from model-based techniques that use at least one significant assumption not observable in the market. These unobservable assumptions may include management's own judgments about the assumptions investors would use in pricing the asset or liability. Valuation techniques include use of option pricing models, discounted cash flow models and similar techniques.

2. Commitments and Contingencies

Capital and Administrative Funding Tariff

FERC accepted the ISO's capital and administrative funding filings to recover administrative expenses for 2024 and 2023. These filings, made pursuant to Section IV of the Tariff, support the ISO's loan arrangements with various banks and note holders to fund the capital and working capital requirements of the Company.

Legal Proceedings

The Company is involved in various claims and legal proceedings of a nature considered normal to its business. The claims are in various stages and some may ultimately be brought to trial. While it is not feasible to predict or determine the outcome of these claims, it is the opinion of management that the final outcome of these claims will not materially impact the operating results of the Company.

3. Property and Equipment In-Service, Net and Work in Process

	December 31, 2024	2023
Computer hardware, software and accessories	$ 275,701,000	$ 275,256,000
Software development costs	111,228,000	109,044,000
Furniture and fixtures	4,442,000	4,439,000
Machinery and equipment	392,000	382,000
Building and building improvements	57,899,000	57,693,000
Capitalized interest and fees	10,514,000	10,043,000
Vehicles	19,000	19,000
	470,195,000	466,876,000
Less: accumulated depreciation and amortization	(401,747,000)	(383,963,000)
Property and equipment in-service, net	**$ 68,448,000**	**$ 82,913,000**
Work in process ("WIP")	**$ 43,059,000**	**$ 26,746,000**

Costs within WIP primarily include the following projects: Day-ahead Ancillary Services Improvements, nGEM Real-Time Market Clearing Engine Implementation,CIP Electronic Security Perimeter Redesign Phase II, Managing Transmission Line Ratings, Enterprise Resource Planning System Replacement, nGEM Software Development Part III, EMS Short-term Load Forecast Replacement, and Day-ahead Ancillary Services Benchmark Levelswhich all began in 2022 and2023, andcontinued into 2024. Additionally, a number of new projects began in 2024such as Integrated Market Stimulator nGEM Compatibility Enhancement, Windows Server Replacement Phase II and various other market enhancement projects that have not been placed in service as of December 31, 2024.

Depreciation and amortization expense was $31,583,000 and $30,034,000 for the years ended December 31, 2024and 2023, respectively.

4. Credit Facilities

Revolving Credit Arrangement

In March 2024, the Company entered into a $40,000,000 revolving credit arrangement that expires on March 1, 2028, and any outstanding balance must be paid by this date. In November 2023, the Company filed under Federal Power Act Section 204 with FERC to increase the previously approved $20,000,000 line of credit to $40,000,0000; the filing was approved in January 2024. Additionally, at the same time the Company entered into a $4,000,000 revolving credit agreement with the same terms as noted above. For both revolving credit agreements, interest accrues on both revolving credits at either Base Rate, LIBOR or a Benchmark replacement such as SOFR, of which the Company has the option of selecting the Overnight, Weekly, 30, 60, 90, or 180-day rate. Interest is paid at the earlier of the selected term or 30 days.

The $40,000,000 revolving credit agreement has an outstanding balance for each of the years ended December 31, 2024 and 2023 was $0 and the weighted average interest for each of the years ended December 31, 2024 and 2023 was $419,000 and $0 respectively.

The $4,000,000 revolving credit agreement has an outstanding balance and weighted average interest for each of the years ended December 31, 2024 and 2023 was $0 in both fiscal years.

Long Term Debt

At December 31, 2024, the following amounts were outstanding on long-term debt:

	Tax-exempt Bonds (iii)	Tax-exempt CT Bonds (iv)	Private Placement (v)	Total
Total outstanding:				
Maturities	$ 13,195,000	20,370,000	75,000,000	108,565,000
Less unamortized debt issuance costs	(32,000)	(138,000)	(120,000)	(290,000)
Total debt, net	13,163,000	20,232,000	74,880,000	108,275,000
Current portion:				
Maturities	$ 1,820,000	1,360,000	-	3,180,000
Less unamortized debt issuance costs	-	-	-	-
Total current portion	1,820,000	1,360,000	-	3,180,000
Long term portion:				
Maturities	$ 11,375,000	19,010,000	75,000,000	105,385,000
Less unamortized debt issuance costs	(32,000)	(138,000)	(120,000)	(290,000)
Total long term portion	11,343,000	18,872,000	74,880,000	105,095,000
Fair market value at year-end			$ 76,193,000	
Incremental borrowing rate (for FMV)			5.06%	
Weighted average SIFMA interest	3.32%	3.34%		
Weighted average floating interest rate	3.29%	3.30%		

At December 31, 2023, the following amounts were outstanding on long-term debt:

	Private Placement (i)	Private Placement (ii)	Tax-exempt Bonds (iii)	Tax-exempt CT Bonds (iv)	Total
Total outstanding:					
Maturities	$ 11,000,000	39,000,000	15,015,000	21,730,000	36,745,000
Less unamortized debt issuance costs	-	(2,000)	(37,000)	(147,000)	(186,000)
Total debt, net	$ 11,000,000	38,998,000	14,978,000	21,583,000	86,559,000
Current portion:					
Maturities	$ 11,000,000	39,000,000	1,820,000	1,360,000	53,180,000
Less unamortized debt issuance costs	-	(2,000)	-	-	(2,000)
Total current portion	11,000,000	38,998,000	1,820,000	1,360,000	53,178,000
Long term portion:					
Maturities	$ -	-	13,195,000	20,370,000	33,565,000
Less unamortized debt issuance costs	-	-	(37,000)	(147,000)	(184,000)
Total long term portion	$ -	-	13,158,000	20,223,000	33,381,000
Fair market value at year-end	$ 10,802,000	$ 38,726,000			
Incremental borrowing rate (for FMV)	5.34%	5.34%			
Weighted average SIFMA interest			3.30%	3.31%	
Weighted average floating interest rate			3.24%	3.25%	

(i & ii) Private Placement Debt

Both the $11,000,000 and $39,000,000 private placement loans were paid in full on the maturity date of November 8, 2024.

(iii) Tax-Exempt Bonds

In February 2005, the Company entered into tax-exempt financing of $45,500,000 in the form of Multi-Mode Variable Rate Civic Facility Revenue Bonds ("Bonds"), which were issued by the Massachusetts Development Finance Agency. The proceeds of the Bonds were loaned to the Company to assist in financing and refinancing a construction project located at the Main Control Center. Principal payments of $455,000, paid quarterly, began in May 2007 with the final repayment due on February 1, 2032. The tax-exempt financing is backed by a letter of credit that the Company originally entered into in February 2005. The letter of credit with an original expiration date of August 2024 contains an evergreen clause that will automatically renew annually with the beneficiaries. The par value of the Bonds approximates the fair value and the Bonds are classified as Level 2.

Interest accrues quarterly on the Bonds at a weekly variable rate based upon the Securities Industry and Financial Markets Association "SIFMA" Swap Index. The Company is charged an annual fee of 0.38% paid quarterly based on the maximum amount available to be drawn under the letter of credit including principal and interest commitments.

(iv) Tax-Exempt CT Bonds

In December 2012, the Company entered into tax-exempt financing of $36,000,000 in the form of Multi-Mode Variable Rate Civic Facility Revenue Bonds ("CT Bonds"), which were issued by Connecticut Innovations Incorporated. The proceeds of the CT Bonds were loaned to the Company to assist in financing a project located in Windsor, Connecticut to acquire real property and construct an office building with data center and control center, including miscellaneous property and equipment to serve as a Back-up Control Center. Principal payments of $340,000 are paid quarterly, with the final repayment due in November 2039. The tax-exempt financing is backed by a letter of credit that the Company originally entered into in December 2012. The letter of credit with an original expiration date of December 2024 and contains an evergreen clause that will automatically renew annually with the beneficiaries. The par value of the Bonds approximates the fair value and the Bonds are classified as Level 2.

Interest accrues quarterly on the $36,000,000 tax-exempt bonds, at a weekly variable rate based upon the SIFMA. The Company is charged an annual fee of 0.38% paid quarterly based on the maximum amount available to be drawn under the letter of credit including principal and interest commitments.

(v) Private Placement Debt

In August 2024, the Company entered into an $75,000,000 private placement loan, which is made up of a ten-year 5.27% senior note. Payment is due in full on August 27, 2034, with mandatory prepayments upon certain contingent events occurring and interest is accrued and paid semi-annually. Funding of $25,000,000 for this loan was received in August 2024 and the remaining balance of $50,000,000 in November 2024. This loan is included in long-term debt on the accompanying Statements of Financial Position.

Principal payments on the private placement debt and tax-exempt bonds, excluding debt issuance costs, are due annually as follows:

2025	$ 3,180,000
2026	3,180,000
2027	3,180,000
2028	3,180,000
2029	3,180,000
Thereafter	92,665,000
	$ 108,565,000

Interest incurred on the revolving credit arrangement, private placement debt, and tax-exempt bonds for the years ended December 31, 2024 and 2023 was approximately $4,263,000 and
$3,357,000, respectively.

Interest Rate Cap

The Company purchased an interest rate cap on October 31, 2013 for $706,000 for a predetermined notional amount to lock into a derivative arrangement whereby the Company will receive a payment whenever 74% of the one-month SOFR exceeds 2.48%. The purchase of the interest rate cap was to mitigate the interest rate risks associated with the tax-exempt debt. The derivative arrangement was amended and restated effective May 1, 2022 to February 1, 2024 with the notional amount of $5,225,000, which was amortized to zero as the floating rate debt is repaid. The interest rate cap expired in February of 2024 and not renewed. The fair market value of the interest rate cap as of December 31, 2024 and 2023 was $0 and $1,000, respectively. The fair market values were recorded as an other asset and regulatory liability in 2024 and 2023 on the accompanying Statements of Financial Position. The fair market values are derived from third-party financial institutions and the interest rate cap is classified as Level 2.

5. Pension and Other Postretirement Benefits

The Company sponsors two defined benefit pension plans (one for union and the other for non- union employees), also referred to herein as the non-contract and contract plans, each of which is funded solely by Company contributions. Benefits are determined based on years of service and average compensation. Effective January 1, 2014, the defined benefit pension plans were closed to all employees hired or rehired on or after January 1, 2014.

The Company sponsors a postretirement benefit plan that provides medical, dental, and life insurance benefits for eligible employees and their beneficiaries. The medical benefits are contributory with participants' contributions adjusted annually, and participants are responsible for deductible and coinsurance amounts. Dental benefits are non-contributory but participants are responsible for deductible and coinsurance amounts. The life insurance benefits are non- contributory. Effective January 1, 2016, the postretirement benefit plan was closed to employees hired or rehired on or after January 1, 2016.

The Company accounts for the plans as required in FASB ASC Topic 715,*Compensation - Retirement Benefits*. The measurement date used to determine pension and other postretirement benefit obligations is December 31. Additionally, the Company discloses net periodic benefit cost for the defined benefit pension and other postretirement benefit plan for each annual period for which a Statements of Activities is presented as required by the employers' disclosures. As required in Topic 980,*Regulated Operations*, the Company has disclosed the difference in the timing of
recognition of net periodic benefit cost as an expense and as such records the difference as an asset or a liability created by the actions of the regulator under rate making regulations and rules.

Under the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act (collectively, the "Health Care Acts") there are several provisions that may affect a company's postretirement benefit plans, including eliminating lifetime and annual coverage limits, reducing subsidies to Medicare Advantage plans, extending coverage for adult children until age 26, and material benefit cost sharing changes in 2025, including the implementation of a $2,000 member out-of-pocket maximum on Medicare prescription drug plans. For the provisions that are not already reflected in the determination of the underlying health costs, the Company has evaluated the effects of the provisions of the Health Care Acts and concluded that as of December 31, 2024, none of the provisions have a material impact on its postretirement benefit plan. The Company does not provide benefits that are actuarially equivalent to the Medicare prescription drug benefit in its postretirement benefit plan.

The following table sets forth the plans' benefit obligations, fair value of the plans' assets, and the plans' funded status:

	Pension Benefits Years Ended December 31,		Other Postretirement Benefits Years Ended December 31,	
	2024	2023	2024	2023
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 178,789,000	$ 219,161,000	$ 27,545,000	$ 26,940,000
Service cost	7,258,000	5,757,000	1,099,000	1,159,000
Interest cost	3,574,000	10,466,000	1,287,000	1,296,000
Benefits paid	(3,012,000)	(5,741,000)	(1,635,000)	(1,655,000)
Curtailments, settlements and/or special/contractual termination	-	(56,574,000)	-	-
Plan participants' contributions	-	-	516,000	531,000
Actuarial (gain)/loss	(16,697,000)	4,720,000	(1,829,000)	(726,000)
Benefit obligation at end of year	174,912,000	178,789,000	26,983,000	27,545,000
Change in plan assets:				
Fair value of plan assets at beginning of year	163,484,000	197,748,000	26,309,000	23,686,000
Actual return on plan assets	3,617,000	17,847,000	2,565,000	2,922,000
Employer contributions	10,126,000	10,203,000	574,000	325,000
Plan participants' contributions	-	-	516,000	531,000
Benefits paid	(3,012,000)	(5,741,000)	(1,635,000)	(1,655,000)
Curtailments, settlements and/or special/contractual termination	-	(56,574,000)	-	-
Fair value of plan assets at end of year	179,215,000	163,483,000	28,429,000	26,309,000
Funded status at end of the year	4,303,000	(15,306,000)	1,446,000	(1,236,000)
Net amount recognized as non-current assets (liabilities)	$ 4,303,000	$ (15,306,000)	$ 1,446,000	$ (1,236,000)

The following table presents the amounts in Accumulated Other Comprehensive Income (AOCI) that have not yet been recognized in net periodic benefit costs in fiscal year ending December 31, 2024:

	Pension Benefits Years ended December 31,		Other Postretirement Benefits Years ended December 31,	
	2024	2023	2024	2023
Transition obligation/(asset)	$ -	$ -	$ -	$ -
Net actuarial loss/(gain)	360,000	20,928,000	(3,276,000)	(485,000)
Prior service cost/(credit)	-	-	-	(40,000)

The Company has determined that the pension liability is probable of recovery through Section IV.A. of the Tariff and has recorded a regulatory asset as of December 31, 2024 and 2023 in the accompanying Statements of Financial Position.

	Pension Benefits Years ended December 31,		Other Postretirement Benefits Years ended December 31,	
	2024	2023	2024	2023
Components of net periodic benefit cost:				
Service cost	$ 7,258,000	$ 5,757,000	$ 1,099,000	$ 1,159,000
Interest cost (1)	3,574,000	10,466,000	1,287,000	1,296,000
Expected return on plan assets (1)	(10,134,000)	(11,604,000)	(1,604,000)	(1,445,000)
Recognition due to settlement, curtailment, and/or special/contractual termination benefits(1)	-	1,659,000	-	-
Amortization of net actuarial loss (1)	317,000	240,000	-	-
Amortization of unrecognized prior service credit (1)	-	-	(40,000)	(41,000)
Net periodic benefit cost	5,015,000	7,518,000	742,000	969,000
Amount deferred due to actions of the regulator	3,618,000	2,043,000	(164,000)	(255,000)
Net periodic benefit cost recognized	$ 8,633,000	$ 9,561,000	$ 578,000	$ 714,000

(1) The components of net periodic pension cost other than service cost component are included in the line item "Other expense (income)" in the Statement of Activities.

The Company's accumulated benefit obligation for the pension benefit plans (non-contract and contract) was $136,431,000 and $130,934,000 at December 31, 2024 and 2023, respectively.

The following are gains/loss transactions reflected in the measurement of the benefit obligation for the pension benefit plans (non-contracts and contract) as of December 31, 2024:

For the non-contract pension plan, the total actuarial gain during 2024 was $20,816,000. The main source of this gain was due to the discount rate increasing from 4.84% to 5.55%, which caused a gain of approximately $20,997,000. For the contract plan, the total actuarial gain during 2024 was $952,000. The discount rate for the contract plan changed from 4.83% to 5.55%, which caused a gain of approximately $459,000. The other main source of actuarial gain for the contract plan was the annual data update, which caused a gain of $474,000.

The following are gains/loss transactions reflected in the measurement of the benefit obligation for the other postretirement plan, as of December 31, 2024:

For the other postretirement plan, the total actuarial gain during 2024 was $1,829,000. The main source of this gain was due to the discount rate increasing from 4.73% to 5.39%, which caused a gain approximately $1,843,000.

The primary economic assumptions, based on prevailing economic conditions, used to value these liabilities are summarized in the following table.

Weighted-average assumptions used to determine net periodic benefit cost for the following years ended:

	Pension Benefits December 31,		Other Postretirement Benefits December 31,	
	2024	2023	2024	2023
Discount rate	See Below	See Below	4.73%	4.92%
Expected long-term rate of return on plan assets	6.25%	6.25%	6.25%	6.25%
Rate of compensation increase prior to age 40	6.25%	6.25%	6.25%	6.25%
Rate of compensation increase for ages 40-59	4.25%	4.25%	4.25%	4.25%
Rate of compensation increase for ages 60 and after	3.25%	3.25%	3.25%	3.25%

Separate discount rates are used in the pension expense calculations for the non-contract and the contract plans.The discount rates for the non-contract plan of 5.01% as of January 1, 2023 and 6.01% as of November 1, 2023 were used to calculate the pension expense for the 2023 fiscal year, reflecting the October 31, 2023 settlement remeasurement. The discount rates of 4.84% as of January 1, 2024 was used to calculate the non-contract pension expense for the 2024 fiscal year expense calculation. The discount rates for the contract plan of 5.03% as of January 1, 2023 and 4.83% as of January 1, 2024 are used to calculate pension expense for the 2023 and 2024 fiscal years, respectively.

Weighted-average assumptions used to determine benefit obligation for the following years ended:

	Pension Benefits December 31,		Other Postretirement Benefits December 31,	
	2024	2023	2024	2023
Discount rate	See Below	See Below	5.39%	4.73%
Rate of compensation increase prior to age 40	6.25%	6.25%	6.25%	6.25%
Rate of compensation increase for ages 40-59	4.25%	4.25%	4.25%	4.25%
Rate of compensation increase for ages 60 and after	3.25%	3.25%	3.25%	3.25%
Health Care cost trend rates - initial	-	-	6.75%	6.75%
Dental Care cost trend rates - initial	-	-	4.00%	4.00%
Health Care cost trend rates - ultimate	-	-	4.50%	4.50%
Ultimate year	-	-	2034	2033

Separate discount rates are used in the pension calculations for the non-contract and the contract plans. The discount rate for the non-contract plan of 4.84% as of December 31, 2023 was used for the 2023 fiscal year-end benefit obligation calculation. The discount rate for the non-contract plan of 5.55% as of December 31, 2024 was used for the 2024 fiscal year-end benefit obligation calculation. The discount rate for the contract plan of 4.83% as of December 31, 2023 was used for the 2023 fiscal year-end benefit obligation calculation. The discount rate for the contract plan of 5.55% as of December 31, 2024 was used for the 2024 fiscal year-end benefit obligation calculation.

The ISO's pension plan and postretirement benefit plan weighted-average asset allocations and expected returns by asset category are as follows:

Pension and Postretirement Plan Assets

	Target Allocation 2025	Percentage of Plan Assets at December 31 2024	2023	Weighted Average Expected Long-Term Rate of Return - 2025
Equity Securities	19%	45%	46%	1.53%
Debt Securities	75%	44%	42%	4.14%
Other	6%	11%	12%	0.32%
Total	100%	100%	100%	6.00%

The forward-looking estimates of total return were developed based on assumptions for each underlying component, reflecting observable inflation and interest rate information available in the fixed income markets as well as consensus economics forecasts. Long-term assumptions for other asset classes (i.e., equities) are based on historical results, current market characteristics, and professional judgment. In setting this assumption, the ISO relied upon capital market assumptions developed by a market-leading provider of investment services to corporate pension plans.

The respective plan's investment portfolio is to be invested to provide benefits for qualified employees of the ISO. Investments are to be compatible with the liquidity requirements determined by the plan's actuary. An optimal target allocation of 60/40 between equities and fixed income investments is to be kept with an allowance of fifteen percent (15%) over/under deviation from the optimal allocation target. The plan's investment policy provides for gradually reducing the amount of risk, relative to liability measurement, being taken in the portfolio as funding improves. After a funding threshold is achieved, the portfolio targets will remain at that allocation to liability hedging assets even if funding deteriorates due to unfavorable market conditions unless the ISO elects to re-risk the portfolio.

The fair values of the pension plan assets at December 31, 2024 and 2023 by asset category are as follows:

	Market Value at 12/31/24	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Long-term investment strategies:				
Fixed income:				
Long Duration Corporate Bonds	$ 94,610,000	$ -	$ 94,610,000	$ -
Long Duration Government Bonds	$ 36,417,000	-	36,417,000	-
Total	131,027,000	-	131,027,000	-
Collective Investment Trust:				
DB Growth Portfolio	43,872,000	-	43,872,000	-
Total	43,872,000	-	43,872,000	-
Cash and cash equivalents	4,316,000	4,316,000	-	-
Total long-term investments	$ 179,215,000	$ 4,316,000	$ 174,899,000	$ -

	Market Value at 12/31/23	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Long-term investment strategies:				
Fixed income:				
Long Duration Corporate Bonds	$ 39,205,000	$ -	$ 39,205,000	$ -
Long Duration Government Bonds	20,813,000	-	20,813,000	-
Total	60,018,000	-	60,018,000	-
Collective Investment Trust:				
DB Growth Portfolio	100,342,000	-	100,342,000	-
Total	100,342,000	-	100,342,000	-
Cash and cash equivalents	3,123,000	3,123,000	-	-
Total long-term investments	$ 163,483,000	$ 3,123,000	$ 160,360,000	$ -

The fair values of the other postretirement benefit plan assets at December are as follows:

	Market Value at 12/31/24	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Long-term investment strategies:				
Fixed income:				
U.S. and global core fixed income funds	$ 10,789,000	$ 10,789,000	$ -	$ -
U.S. real estate investment trust funds	324,000	324,000	-	-
Total	11,113,000	11,113,000	-	-
US Large Cap	9,699,000	9,699,000	-	-
US Small Cap	1,341,000	1,341,000	-	-
Total	11,040,000	11,040,000	-	-
Global (ex-U.S.) equities:				
Developed markets	5,062,000	5,062,000	-	-
Total	5,062,000	5,062,000	-	-
Hedged equity funds of funds:				
Multiple strategies	901,000	901,000	-	-
Total	901,000	901,000	-	-
Cash and cash equivalents	313,000	313,000	-	-
Total long-term investments	$ 28,429,000	$ 28,429,000	$ -	$ -

	Market Value at 12/31/23	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Long-term investment strategies:				
Fixed income:				
U.S. and global core fixed income funds	$ 11,371,000	$ 11,371,000	$ -	$ -
U.S. real estate investment trust funds	347,000	347,000	-	-
U.S. High Yield Bond Funds	341,000	341,000	-	-
Total	12,059,000	12,059,000	-	-
US Large Cap	8,297,000	8,297,000	-	-
US Small Cap	769,000	769,000	-	-
Total	9,066,000	9,066,000	-	-
Global (ex-U.S.) equities:				
Developed markets	3,884,000	3,884,000	-	-
Total	3,884,000	3,884,000	-	-
Hedged equity funds of funds:				
Multiple strategies	906,000	906,000	-	-
Total	906,000	906,000	-	-
Cash and cash equivalents	394,000	394,000	-	-
Total long-term investments	$ 26,309,000	$ 26,309,000	$ -	$ -

The Company expects to contribute approximately $10,000,000 to its pension plans and $743,000 to its postretirement benefit plan in 2025.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

	Pension Benefits	Other Postretirement Benefits
2025	$ 7,164,000	$ 1,916,000
2026	3,088,000	1,918,000
2027	3,320,000	1,925,000
2028	9,659,000	1,986,000
2029	11,147,000	2,108,000
Years 2030-2034	68,550,000	11,476,000
Total	$ 112,928,000	$ 21,329,000

6. Other BenefitPlans

The Company has a 401(k) Retirement and Savings Plan (the "401(k) Plan") open to substantially all employees. This savings plan provides for employee contributions up to specified limits. The Company matches employee contributions up to 3% of eligible compensation and provides a 50% match on the next 2% of eligible compensation. The matching contributions for the Company were $3,937,000 and $3,798,000, for the years ended December 31, 2024 and 2023, respectively.

In 2014, the Company amended the 401(k) Plan to provide for a special contribution for new employees hired after January 1, 2014. The Company funds the contribution into the 401(k) Plan based on a formula of employee's age, service, and compensation. The contributions paid by the Company were $2,793,000 and $2,188,000 for the years ended December 31, 2024 and 2023, respectively.

The Company maintains a 457(b) Plan that provides for certain members of senior management to defer a portion of their current compensation and have it credited under a supplemental unfunded savings program. The 457(b) Plan is intended to satisfy the requirements of an eligible deferred compensation plan maintained by the ISO as a nongovernment tax-exempt entity under Code section 457(e)(1)(B). The plan participants may direct that these funds be invested in the same investments offered by the ISO 401(k) plan at their discretion. The investment balance was $4,266,000 and $3,267,000 as of December 31, 2024 and 2023, respectively and recorded within other assets and the corresponding deferred compensation liability is recorded in long-term portion of Accrued compensation in the accompanying Statements of Financial Position. The investments are recorded at fair value and are classified as Level 1.

7. Leases

The Company has operating leases for property, office equipment, computer hardware, and motor vehicles. The Company's leases have remaining lease terms of 1 year to 5 years. For purposes of calculating operating lease liabilities, lease terms may be deemed to include options to extend the lease when it is reasonably certain that the Company will exercise those options. The Company's lease arrangements do not contain any material restrictive covenants. The Company's incremental borrowing rate is 2.20%, which is reviewed each time the Company enters into a new lease.
The components of lease cost for operating leases for the years ended December 31, 2024 and 2023 were as follows:

	Years ended December 31,	
	2024	2023
Operating lease cost	$ 992,000	$ 694,000
Short-term lease cost	-	-
Total Lease Cost	$ 992,000	$ 694,000

The operating lease cost is equal to the cash paid from operating cash flows.

Maturity of Lease Liabilities at December 31, 2024

	Operating Leases
2025	$ 1,384,000
2026	1,272,000
2027	1,006,000
2028	460,000
2029	-
Total future undiscounted lease payments	4,122,000
Less: Interest	(150,000)
Present value of lease liabilites	$ 3,972,000

The Company calculates the weighted-average remaining lease term based on the remaining lease term and the lease liability balance for each lease at the reporting date. For the years ended December 31, 2024 and 2023, the Company discloses a weighted-average remaining lease term of 3.18 and 2.71 years respectively, for its operating leases.

The Company calculates the weighted-average discount rate based on the remaining lease payments and discount rate for each lease at the reporting date. For the years ended December 31, 2024 and 2023, the Company discloses a weighted-average discount rate 2.40% and 2.33%, respectively for its operating leases.

8. Functional Classification of Expenses

Operating expenses presented by natural and function classification are as follows:

	December 31, 2024		
	Program Service Expenses	Management & General Expenses	Total
Salaries and benefits	$ 133,453,000	$ 18,811,000	$ 152,264,000
Depreciation and amortization expense	31,428,000	155,000	31,583,000
Professional fees and consultants	21,774,000	3,099,000	24,873,000
Computer Services	22,517,000	1,598,000	24,115,000
All other expenses	28,867,000	2,889,000	31,756,000
Total expenses	$ 238,039,000	$ 26,552,000	$ 264,591,000

	December 31, 2023		
	Program Service Expenses	Management & General Expenses	Total
Salaries and benefits	$ 117,940,000	$ 17,019,000	$ 134,959,000
Depreciation and amortization expense	29,852,000	182,000	30,034,000
Professional fees and consultants	19,365,000	2,835,000	22,200,000
Computer Services	19,322,000	1,147,000	20,469,000
All other expenses	25,311,000	2,628,000	27,939,000
Total expenses	$ 211,790,000	$ 23,811,000	$ 235,601,000

One of the Company's primary responsibilities is to ensure the reliability of the power system for the New England area and as such, our departments are specifically designed to support that function. Those departmental costs are deemed directly identifiable to program services as summarized in the above tables. Other departments that are solely for supporting the Company, such as human resources, are categorized as management and general expenses as summarized in the above tables. For any department that is providing both program and management and general services, an analysis was performed to allocate the costs based on the time spent supporting program services or management and general, and categorized accordingly.

All expenses summarized above, except for depreciation and amortization expense are allocated in the method described above. Depreciation is allocated based on estimated useful life of an asset. Assets with 3-5 year life are primarily computer hardware and software designed for power system and are classified as program service expenses. Any asset with a life of 7 years or greater is related to equipment and building and therefore is allocated under the method described above.

9. Subsequent Events

The Company has evaluated subsequent events from the Statements of Financial Position date through April 10, 2025, the date at which the financial statements were available to be issued, and determined that there are no items to disclose that occurred in the subsequent period.

Name of Respondent: ISO New England Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Day-Ahead Ancillary Services Improvements	8,065,304
2	nGEM Real-Time Market Clearing Engine Implementation	6,823,022
3	CIP Electronic Security Perimeter Redesign Phase II	4,646,330
4	Managing Transmission Line Ratings	4,641,832
5	Enterprise Resource Planning System Replacement	2,370,260
6	2024 System Enhancements	2,285,545
7	Operating System Server Upgrade Phase I	1,866,366
8	nGEM Software Development Part III	1,493,124
9	EMS Short-term Load Forecast Replacement	1,449,203
10	Long Term Transmission Rights (LTTR)	1,379,196
11	Day-ahead Ancillary Services Benchmark Levels	1,146,588
12	Other minor projects (less than 5% and $1,000,000)	6,892,596
43	Total	43,059,366

Name of Respondent: ISO New England Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)
1	Bonds (Account 221)						
2	Tax Exempt Bond Financing		45,500,000		375,242		
3	Tax Exempt Bond Financing		36,000,000		555,436		
4	Subtotal		81,500,000		930,678		
5	Reacquired Bonds (Account 222)						
6							
7							
8							
9	Subtotal						
10	Advances from Associated Companies (Account 223)						
11							
12							
13							
14	Subtotal						
15	Other Long Term Debt (Account 224)						
16	Private Placement Debt		39,000,000		180,254		
17	Private Placement Debt		11,000,000		94,067		
18	Private Placement Debt		75,000,000		430,068		
19	Subtotal		125,000,000		704,389		
33	TOTAL		206,500,000				

LONG-TERM DEBT (Account 221, 222, 223 and 224)						
Line No.	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1						
2	02/01/2005	02/01/2032	06/01/2006	06/01/2031	13,195,000	615,868
3	12/13/2012	11/13/2039	12/13/2012	12/13/2027	20,370,000	808,079
4					33,565,000	1,423,947
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16	05/22/2014	11/08/2024	06/01/2014	06/01/2024	0	1,007,041
17	11/08/2012	11/08/2024	11/30/2012	11/30/2022	0	197,340
18	08/27/2024	08/27/2034	08/27/2024	08/27/2034	75,000,000	579,260
19					75,000,000	1,783,641
33					108,565,000	3,207,588

Name of Respondent: ISO New England Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering		
5	(501) Fuel		
6	(502) Steam Expenses		
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses		
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)		
14	Maintenance		
15	(510) Maintenance Supervision and Engineering		
16	(511) Maintenance of Structures		
17	(512) Maintenance of Boiler Plant		
18	(513) Maintenance of Electric Plant		
19	(514) Maintenance of Miscellaneous Steam Plant		
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)		
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)		
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)		
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses		
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of Lines 62 thru 67)		
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant		
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)		
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)		
75	E. Other Power Supply Expenses		
76	(555) Purchased Power		
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching		
78	(557) Other Expenses		
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)		
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)		
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	6,570,684	5,965,438
85	(561.1) Load Dispatch-Reliability	4,338,733	3,921,278

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	9,735,972	9,019,403
87	(561.3) Load Dispatch-Transmission Service and Scheduling	9,944,115	8,694,392
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	21,573,849	16,703,210
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies	1,463,237	1,590,408
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses		
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses		
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others		
97	(566) Miscellaneous Transmission Expenses		
98	(567) Rents		
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	53,626,590	45,894,129
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	3,834,009	3,145,150
104	(569.2) Maintenance of Computer Software	22,065,983	19,334,377
105	(569.3) Maintenance of Communication Equipment	4,991	128,585
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment		
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines		
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of Lines 101 thru 110)	25,904,983	22,608,112

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	79,531,573	68,502,241
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision	3,958,608	3,607,004
116	(575.2) Day-Ahead and Real-Time Market Facilitation	10,888,885	9,908,577
117	(575.3) Transmission Rights Market Facilitation	416,067	321,838
118	(575.4) Capacity Market Facilitation	8,166,079	8,951,625
119	(575.5) Ancillary Services Market Facilitation	727,852	975,789
120	(575.6) Market Monitoring and Compliance	6,947,653	6,424,895
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents	606,864	384,952
123	Total Operation (Lines 115 thru 122)	31,712,008	30,574,680
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements	617,772	603,150
126	(576.2) Maintenance of Computer Hardware	2,698,006	2,213,254
127	(576.3) Maintenance of Computer Software	33,089,468	26,392,688
128	(576.4) Maintenance of Communication Equipment	3,512	90,486
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)	36,408,758	29,299,578
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)	68,120,766	59,874,258
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering		
135	(581) Load Dispatching		
136	(582) Station Expenses		
137	(583) Overhead Line Expenses		
138	(584) Underground Line Expenses		
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses		

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
140	(586) Meter Expenses		
141	(587) Customer Installations Expenses		
142	(588) Miscellaneous Expenses		
143	(589) Rents		
144	TOTAL Operation (Enter Total of Lines 134 thru 143)		
145	Maintenance		
146	(590) Maintenance Supervision and Engineering		
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment		
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines		
150	(594) Maintenance of Underground Lines		
151	(595) Maintenance of Line Transformers		
152	(596) Maintenance of Street Lighting and Signal Systems		
153	(597) Maintenance of Meters		
154	(598) Maintenance of Miscellaneous Distribution Plant		
155	TOTAL Maintenance (Total of Lines 146 thru 154)		
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)		
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	605,479	611,109
160	(902) Meter Reading Expenses		
161	(903) Customer Records and Collection Expenses	5,969,531	4,989,029
162	(904) Uncollectible Accounts		
163	(905) Miscellaneous Customer Accounts Expenses		
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	6,575,010	5,600,138
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
168	(908) Customer Assistance Expenses	3,641,525	3,309,742
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	3,641,525	3,309,742
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)		
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	26,125,662	23,110,112
182	(921) Office Supplies and Expenses	701,163	633,134
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	5,076,540	5,444,355
185	(924) Property Insurance	2,889,718	2,553,084
186	(925) Injuries and Damages	372,173	373,941
187	(926) Employee Pensions and Benefits	21,261,042	20,416,033
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses		
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses		
192	(930.2) Miscellaneous General Expenses	11,518,734	9,915,705
193	(931) Rents	537,660	334,300
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	68,482,692	62,780,664
195	Maintenance		
196	(935) Maintenance of General Plant	2,693,268	2,629,524

EXHIBIT 8

New England Governors, State Utility Regulators and Related Agencies*

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New England Governors, State Utility Regulators and Related Agencies*

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New England Governors, Utility Regulatory and Related Agencies
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EXHIBIT 9

September 8, 2025

Cheryl LaFleur
Chair
Board of Directors
ISO New England
One Sullivan Road
Holyoke, MA 01040

RE: Comments on Proposed 2026 ISO New England Operating & Capital Budgets

Dear Chair LaFleur:

On behalf of the undersigned New England state agencies, we submit our comments regarding the ISO New England (ISO-NE) proposed 2026 Operating and Capital Budgets.

We reiterate our appreciation for ISO-NE's commitment to the budget review process that has been in place since 2013, and which offers the New England state agencies an opportunity to ask questions and provide input on the proposed budgets for ISO-NE. We strongly believe that budgetary review from the state agencies provides an important perspective and balance to the budgeting process, including by helping ensure that cost concerns are factored into the process. We stress, as we did in last year's comments, that ISO-NE's budgetary growth needs to be accompanied by heightened diligence by ISO-NE and those who oversee it to ensure that budgeted amounts are appropriate for the responsibilities involved and the work required, and that the amounts are efficiently and effectively spent.

After three years of double-digit increases to ISO-NE's operating budget (before depreciation and regulatory fees), this year's proposal represents a smaller increase, though still sizable at 8.3%. Indeed, the budget has gone from $182.6 million for 2022 to $281.8 million proposed for 2026, a cumulative increase of 54% in 4 years. The level of budgeted FTEs has also significantly increased over this period, from 593 to 733.5, for a cumulative increase of 24%, and payroll has gone from $124.6 million in 2022 to

a proposed budgeted amount of $189.4 million in 2026, a cumulative increase of 52%. These are significant increases, which, while generally consistent in our view with the additional demands placed on ISO-NE and the need for it to be able to effectively guide, assist, and manage the transition to a cleaner energy system, are noteworthy and underscore our overarching imperative that all budgeted amounts need to be effectively and efficiently used. In particular, the increase in FTEs and in payroll needs to be accompanied with increased oversight/scrutiny to ensure that employee levels, salary increases, and incentive compensation do not rise above that strictly necessary to ensure that the required work gets done and that the necessary talent and skill sets are acquired and retained. We especially note this need for enhanced scrutiny with regard to executive compensation which tends to become untethered from the discipline of the labor market. The review process for such compensation must be rigorous and exhaustive, particularly during this transition time among ISO-NE's senior leadership. We continue to stress that a well-run, well-designed market needs to be in place throughout the transition, and the importance of ISO-NE anticipating and resolving problems that may arise in its ability to manage reliability, and to ensure efficient and competitive markets.

Regarding this year's proposal, we note that the proposal as of August 2025 is $300,000 less than what was proposed back in June 2025 when presented to NECPUC, for an overall $21.6 million or 8.3% increase from the 2025 operating budget (before depreciation and regulatory fees). ISO-NE is proposing to keep its capital budget level with last year's amount of $42.5 million. For the proposed 2026 operating budget, the increase is primarily driven by increases to payroll and computer services and leasing, including IT support. The other significant driver of the increase is inflationary pressure on operating costs. Considering the challenges facing ISO-NE, these increases are understandable.

One area on which ISO-NE could focus more attention is the incorporation of artificial intelligence (AI) and automation. While we understand that use of these tools involves some risk and should be pursued with caution, and that there are costs associated with implementing them, we suggest that when incorporating such tools, ISO-NE consider their potential to produce efficiency gains beyond the costs, including streamlining staffing needs.

In our comments on last year's proposed budget, we noted the lack of a proactive and ongoing assessment of transmission system costs and procedures, including ISO-NE's insufficient role in the process by which asset condition projects are identified, vetted and priced. We also noted that many of the mechanisms necessary to ensure an efficient wholesale electricity market, such as independent monitoring and competitive processes, should also be utilized to ensure an efficient transmission system. We are therefore heartened and appreciate that ISO-NE's proposed 2026 budget includes a $1 million "placeholder" for Asset Condition Review work but continue to stress that we see the transmission system and its transition and expansion as an area requiring greater ISO-NE engagement.

CONCLUSION

We find the proposed 2026 budget proposal appropriate given the increased amount and complexity of the tasks required of ISO-NE as the New England power system transitions to clean energy. We ask that the Board rigorously oversee ISO-NE employee levels, payroll, and executive compensation to ensure that they are no more than necessary and appropriate, and that it encourage ISO-NE to focus on the cost-benefit of incorporating AI and automation where such adoption is appropriate. We continue to ask that the Board carefully consider how ISO-NE can be more proactive and instrumental in planning, guiding, and improving the transmission system expansion.

Respectfully submitted,

Connecticut Public Utilities Regulatory Authority	Massachusetts Department of Public Utilities
Marissa P. Gillett, Chairman	James M. Van Nostrand, Chair
Ten Franklin Square	Cecile M. Fraser, Commissioner
New Britain, CT 06051	Staci Rubin, Commissioner
	1 South Station, 3rd Floor
Connecticut Office of Consumer Counsel	Boston, MA 02110
Claire E. Coleman, Consumer Counsel	
Ten Franklin Square	
New Britain, CT 06051	

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Office of the Public Advocate
112 State House Station, Augusta, Maine 04333-0112
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Heather Sanborn
PUBLIC ADVOCATE

September 8, 2025

Cheryl LaFleur
Chair, Board of Directors
ISO New England
One Sullivan Road
Holyoke, MA 01040

RE: Comments on Proposed 2026 ISO New England Operating & Capital Budgets

Dear Chair LaFleur:

Thank you for the opportunity to comment on ISO New England's 2026 Operating and Capital Budgets proposed. The Maine Office of the Public Advocate (OPA) offers the following comments.

In general, the OPA is disappointed that the increase in this year's proposed operating budget of 8.3% again substantially exceeds inflation. Our concern is that this increase places additional burden on ratepayers already struggling with rising transmission, distribution, and commodity costs.

We recognize that the increase is smaller than in recent years. Further, the proposed 2026 capital budget is flat compared to 2025. Both of these trends may reflect an increased attention to cost management. We urge the Board to redouble its efforts in this regard.

Finally, the OPA understands the complex nature of the tasks that the ISO must undertake to ensure the reliability of the regional electric grid, and the efficiency of regional electricity markets. We particularly appreciate the ISO's ongoing efforts with respect to capacity auction reform and the development of an asset condition reviewer. We are hopeful, though, that in the future such new initiatives can be more fully staffed and funded within existing resources.

Sincerely,

Heather Sanborn
Public Advocate

Andrew Landry
Deputy Public Advocate

EXHIBIT 10

September 22, 2025

Via Electronic Mail

Marissa P. Gillett, Chairman, Connecticut Public Utilities Regulatory Authority
Claire E. Coleman, Consumer Counsel, Connecticut Office of Consumer Counsel
James M. Van Nostrand, Chair, Massachusetts Department of Public Utilities

Dear State Officials:

Thank you for your letter dated September 8, 2025 outlining your comments on ISO New England's proposed 2026 operating and capital budgets. We appreciate your support for the budgets, and agree that the states' role in reviewing and commenting on the budgets contributes to an efficient and effective process.

We note your request that the Board increase its oversight in light of the growth in ISO-NE's workload and, correspondingly, the budgets. Please be assured that the Board rigorously reviews the budgets and the ISO's compliance with them, as well as the continuing prudency of underlying expenditures. Specifically, the Audit and Finance Committee undertakes an in-depth review of the budgets as they are formulated each year. This year, our bottom-up approach to budgeting, which is intended to meet our organizational goals and only occurs after we engage with stakeholders and the states to identify priorities, allowed us to significantly reduce the preliminary top-down budget that was presented in June.[1] After the budgets are adopted, the Committee reviews budget performance and related financial statements quarterly.

At the same time, the individual committees of the Board review the use of budget dollars within their purviews. For example, the Compensation and Human Resources Committee discusses employee attraction and retention, with an eye on keeping compensation and benefits at levels that are competitive – but do not exceed – what is necessary to develop a workforce that can meet the significant challenges facing us. The Committee also works with outside compensation consultants to ensure that executive compensation meets the same criteria. The Board Markets Committee, meanwhile, is tracking significant work on projects like the Capacity Auction Reforms initiative, and the Information Technology and Cyber Security Committee regularly reviews expenditures on IT-related projects, such as the transition to the cloud.

On the topic of information technology, I want to assure you that ISO-NE is carefully assessing and implementing artificial intelligence. We agree that it has the potential to produce net efficiency gains, and have adopted a process for assessing its use. This process includes risk assessments of

[1] This reduction was in the amount of $900,000, not $300,000 as cited in your letter.

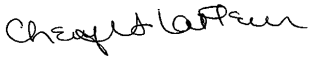
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413-535-4000

data privacy and security, as well as a legal review of intellectual property and licensing terms. Notably, the review also includes cost center management review of budget impact. To date, we have implemented a number of tools that incorporate artificial intelligence. For example, we are currently considering how best to enhance load forecasting using artificial intelligence.

Finally, we appreciate your recognition of our commitment to take on the asset condition reviewer role. We look forward to working with you on this project, along with the many other challenges that face us as a region.

Thank you again for your input and collaboration.

Sincerely,



Cheryl A. LaFleur
Chair, ISO New England Board of Directors

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September 22, 2025

Via Electronic Mail

Heather Sanborn, Public Advocate, Maine Office of the Public Advocate
Andrew Landry, Deputy Public Advocate, Maine Office of the Public Advocate

Dear Ms. Sanborn and Mr. Landry:

Thank you for your letter dated September 8, 2025 outlining your comments on ISO New England's proposed 2026 operating and capital budgets.

We acknowledge your observation that our budget increase exceeds inflation. Please be assured that the Board carefully scrutinizes budget increases, and has determined in this case that they are warranted. Our assessment requires us to balance competing considerations, including ratepayer costs and the increasing scope of our responsibilities, many of which reflect requests of the states and stakeholders.

We appreciate your acknowledgment of our attention to cost management and assure you that the Board will continue to rigorously review the ISO's budgets and the continuing prudency of underlying expenditures. For example, this year, our bottom-up approach to budgeting, which is intended to meet our organizational goals and only occurs after we engage with stakeholders and the states to identify priorities, allowed us to significantly reduce the preliminary top-down budget that was presented in June.[1]

Finally, we thank you for your recognition of our commitment to take on the asset condition reviewer role. We look forward to working with you on this project, along with the many other challenges that face us as a region.

Thank you again for your input and collaboration.

Sincerely,

Cheryl A. LaFleur
Chair, ISO New England Board of Directors

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