STATE OF NEW HAMPSHIRE
BEFORE THE PUBLIC UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
d/b/a EVERSOURCE ENERGY

REQUEST FOR TRANSMISSION COST ADJUSTMENT MECHANISM RATE CHANGE

Docket No. DE 24-090

DIRECT JOINT TESTIMONY OF YI-AN CHEN AND JAMES E. MATHEWS

August 6, 2024

Q. Please state your names, business addresses and your present positions.

A. My name is Yi-An Chen. My business address is 780 North Commercial Street, Manchester, New Hampshire. I am employed by Eversource Energy Service Company as the Director of Revenue Requirements for New Hampshire and in that position, I support Public Service Company of New Hampshire d/b/a Eversource Energy ("PSNH", "Eversource," or the "Company") regarding revenue and rate-related matters.

My name is James E. Mathews. My business address is 107 Selden Street, Berlin, Connecticut. I am employed by Eversource Energy Service Company as the Manager of Rates and Revenue Requirements, Transmission and, in that position, I

provide service to the operating affiliates in Connecticut, Massachusetts, and New Hampshire, including PSNH.

Q. Have you previously testified before the Commission?

A. Ms. Chen: Yes, I have.

A. Mr. Mathews: Yes, I have.

Q. What are your current responsibilities?

A. Ms. Chen: I am currently responsible for the coordination and implementation of revenue requirement calculations and regulatory filings for the Company, as well as the filings associated with PSNH's default Energy Service ("ES"), Stranded Cost Recovery Charge ("SCRC"), Transmission Cost Adjustment Mechanism ("TCAM"), System Benefits Charge ("SBC"), Regulatory Reconciliation Adjustment ("RRA") mechanism, Pole Plant Adjustment Mechanism ("PPAM"), and Base Distribution Rates.

Mr. Mathews: I am currently responsible for coordination and implementation of transmission rate and revenue requirement calculations for the operating affiliates. I also have responsibility related to transmission rate filings before three state utility commissions in the operating companies' service territories, as well as the Federal Energy Regulatory Commission ("FERC").

Q. What is the purpose of your joint testimony?

A. Ms. Chen: My testimony supports PSNH's TCAM filing for proposed rates to take effect October 1, 2024. The testimony and supporting attachments present the reconciliation with actual data through June 30, 2024 and forecast data for the period from July 1, 2024 to September 30, 2025 for transmission costs resulting in the total TCAM rate to take effect on October 1, 2024.

Mr. Mathews: My testimony is to support and describe the year-to-year change in RNS and LNS rates.

Q. What is Eversource requesting in this filing?

A. The TCAM is comprised of a couple of components. One component is the approval of the calculated forecasted average retail transmission rate for the period from October 1, 2024 to September 30, 2025. The second component includes approval of the prior period's over- or under-recovery resulting from the reconciliation of actual transmission costs and revenues against the costs that were forecasted in the previous rate filing. These component parts of the TCAM rate are consistent with the Commission-approved settlement in Docket No. DE 06-028, which created the TCAM, and would be collected over 12 months beginning October 1, 2024.

Q. Will anyone else be providing testimony in support of this filing?

A. Yes. Scott R. Anderson and Steven Allen are each filing testimony in support of the proposed TCAM updated rate. Mr. Anderson will detail the rates applicable to each individual rate class. Mr. Allen will be providing a description of projects developed by the Company and included in RNS and/or LNS rates, as well as describing the planning process at ISO New England ("ISO-NE").

Q. What is Eversource proposing as its annual TCAM rate in this filing?

A. As shown in Attachment YC-1, pages 1 and 2, Eversource is proposing a forecasted average TCAM rate of 3.398 cents per kilowatt-hour (kWh), as compared to the current average rate of 2.701 cents per kWh. The increase in the proposed average TCAM rate effective October 1, 2024 is driven primarily by the following:

- Line 1, an increase in RNS costs of approximately $32.2 million; and
- Line 3, an increase in LNS costs of approximately $13.3 million.

Q. Please provide a five-year historical TCAM rate table.

A. Please refer to the table below for the five-year historical TCAM rate data:

Transmission Cost Adjustment Mechanism (TCAM) Forecast and Average Rate					
($ in 000s, except for the rate per kWh)	**Docket No. DE 20-085 Approved per Order No. 26,386 (July 31, 2020)**	**Docket No. DE 21-109 Approved per Order No. 26,501 (July 29, 2021)**	**Docket No. DE 22-034 Approved per Order No. 26,651 (July 22, 2022)**	**Docket No. DE 23-070 Approved per Order No. 26,888 (September 20, 2023)**	**Docket No. DE 24-090 Proposed**
TCAM Costs	**$213,418**	**$213,755**	**$166,361**	**$209,102**	**$260,416**
Retail Sales (MWh)	7,737,205	7,673,863	7,633,526	7,741,834	7,664,782
TCAM Rate ($/kWh)	**$0.02758**	**$0.02785**	**$0.02179**	**$0.02701**	**$0.03398**

Q. Describe the types of costs included in this TCAM filing.

A. There are two different groups of costs recovered through the TCAM. The first group of costs consists of four cost categories of "wholesale transmission" costs. The second group consists of two cost categories of "other transmission" costs. The "wholesale transmission" costs are as follows:

1. Regional Network Service (RNS) costs
2. Scheduling and Dispatch (S&D) costs
3. Local Network Service (LNS) costs
4. Reliability costs

All transmission costs are regulated and authorized by the FERC. These costs are discussed below in more detail.

1. RNS costs reflect the cost for the provision of regional transmission service across all of New England and recovers the cost of specific facilities referred to as Pooled Transmission Facilities ("PTF"). RNS costs are billed to all entities in the region that have RNS load responsibility, such as PSNH. PSNH's monthly RNS expense bill is based on the annual RNS rate divided by 12, multiplied by PSNH's monthly regional network load. The RNS rate is set annually on January 1 and is calculated under a FERC-approved formula rate included as Attachment F to the ISO-NE Open Access Transmission Tariff ("OATT"). The RNS rate and supporting

calculations are publicly posted on ISO-NE's website[1] 45 days in advance of the annual informational filing submission to FERC on July 31

2. S&D costs are associated with services provided by ISO-NE related to scheduling, system control, and dispatch services. These costs are billed by ISO-NE to all entities in the region that have RNS load responsibility, such as PSNH, based on their monthly peak load, in accordance with the applicable FERC tariff. The S&D rate is set annually on June 1. The S&D rate and supporting calculations are publicly posted on ISO-NE's website[2] 45 days in advance of the annual informational filing submission to FERC on July 31.

3. LNS costs reflect the cost for provision of local transmission service. LNS costs are based on FERC-approved formula rates included as Schedule 21-ES of the ISO-NE OATT. On a monthly basis, Eversource Service Company bills LNS expenses to the Company based on the Schedule 21-ES Local Network Service rate multiplied by PSNH's monthly Local Service load coincident with the local network peak load. Each of Eversource operating company's wholesale LNS costs are billed to its LNS customers on a state-by-state basis; for example, PSNH's LNS costs are

[1] https://www.iso-ne.com/markets-operations/settlements/rate-development - 2024/2025 OATT Schedule 1 & 9 Rate Development Worksheets and Supporting Documents (Schedule 9), posted on June 14, 2024.

[2] https://www.iso-ne.com/markets-operations/settlements/rate-development - 2024/2025 OATT Schedule 1 & 9 Rate Development Worksheets and Supporting Documents (Schedule 1), posted on June 14, 2024.

billed only to PSNH's LNS customers in New Hampshire. The LNS rate is set annually on January 1. The LNS rate and supporting calculations under Schedule 21-ES are publicly posted on ISO-NE's website[3] 45 days in advance of the annual informational filing submission to FERC on July 31.

4. Reliability costs include costs, such as black start and volt-ampere reactive ("VAR") support, that are related to electric system reliability. These reliability costs are billed to all entities in the region that have RNS load responsibility, such as PSNH, based on their monthly peak load.

The "other transmission" costs and credits/revenues are as follows:

5. Hydro-Québec (HQ) Interconnection Capacity Credits;
6. HQ Phase I/II support costs and related revenues; and
7. TCAM working capital allowance return.

Other transmission costs and revenues (numbers 6 and 7) were previously recovered through Eversource's distribution rates, but were transferred in total or in part to the TCAM for recovery, effective July 1, 2010, as part of a negotiated "Settlement Agreement on Permanent Distribution Service Rates" ("Settlement Agreement") between Eversource, Commission Staff ("Staff"), and the Office of Consumer Advocate ("OCA") in Docket No. DE 09-035, that was approved by the

[3] https://www.iso-ne.com/markets-operations/settlements/rate-development - 2024/2025 OATT Schedule 1 & 9 Rate Development Worksheets and Supporting Documents (Schedule ES-2 (Part A), Appendix A), posted on June 14, 2024.

Commission in Order No. 25,123. These costs and revenues are discussed below in more detail.

5. HQ Interconnection Capacity Credits ("HQICCs")[4] were historically included in the Capacity Expense/Credit portion of the ES rate. With the transition from the Eversource-owned generation energy service rates to the new market solicitation rates effective April 1, 2018, it was appropriate to start including these credits in the TCAM, as that is where HQ Phase I/II Support Costs and Revenue Credits are included.

6. HQ Phase I/II support costs are costs associated with FERC-approved contractual agreements between PSNH and other New England utilities to provide support for, and receive rights related to, transmission and terminal facilities that are used to import electricity from Canada. Under the amended, extended and restated agreements,[5] PSNH is charged its proportionate share of O&M and capital costs for a twenty-year term that ends on October 31, 2040.

[4] HQICCs represent a monthly value defined in the ISO-NE Transmission, Markets, and Services Tariff reflecting the annual installed capacity benefits of the Phase I/II high-voltage direct current transmission interface between Hydro-Québec and New England, as determined by ISO-NE, using a standard methodology on file with FERC in conjunction with setting the region's annual Installed Capacity Requirement.

[5] On December 18, 2020 in Docket No. ER21-712-000, the Asset Owners and the IRH Management Committee ("Filing Parties") submitted to FERC for approval an Offer of Settlement ("Settlement") that amended and restated the four Support Agreements and the Use Agreement as part of a comprehensive package that will provide for ongoing financial support of, and related rights and obligations with respect to, the Phase I/II HVDC-TF. The Settlement reflected the exercise by certain IRH of rights under the existing Support Agreements to extend the term of those Support Agreements another twenty years until October 31, 2040. Further, because the Use Agreement by its own terms will remain in effect through expiration of the term of the last Support Agreement, the term of Use Agreement was also extended to October 31, 2040. The Filing Parties asserted that the Phase I/II HVDC-TF are vitally important to both the New England and

Prior to July 1, 2010, Eversource's share of any revenue associated with HQ Phase I/II was returned to customers through the ES rate. Effective July 1, 2010, consistent with the requirements of Order No. 25,122, in the 2010 TCAM docket, Docket No. DE 10-158, PSNH began returning its share of any HQ Phase I/II revenues to customers as a revenue credit in the TCAM. [6] The shift in the collection of the revenue credit from the default ES rate to the TCAM rate was based on the fact that all customers, not just those on default supply, pay the HQ support costs, and therefore all customers should receive the benefit of the revenue credit, which is possible through the non-bypassable TCAM rate.[7] The decrease in the proceeds from the revenue credits as a result of the most recent Use Rights RFP for the 12-month period ending May 2024, as compared to the same period last year, was the result of the decrease in the forward energy markets.

Québec regions and provide a variety of benefits to consumers in New England. In an order issued on May 20, 2021, FERC accepted the Settlement, finding that it appears to be fair and reasonable and in the public interest. See 175 FERC ¶ 61,140 (2020). Materials pertaining to the extension were shared with the Commission, Staff, and OCA in January 2021, and notice of FERC's acceptance of the Settlement was provided to the Commission, Staff, and OCA on May 24, 2021.

[6] PSNH and its affiliates, The Connecticut Light and Power Company ("CL&P") and NSTAR Electric Company ("NSTAR" and together with PSNH and CL&P, "Eversource"), have issued Requests for Proposals for the Reassignment of their Use Rights on the Phase I/II HVDC-TF. Proposals were requested for 100% of the Eversource Use Rights or for tranches of their combined Use Rights in bid blocks of 25%, and a fixed dollar proposal was requested. Based on the recent proposals received, Eversource signed agreements to reassign all of its Use Rights to H.Q. Energy Services (U.S.) Inc. for a one-year term commencing June 1, 2024. All proceeds from the reassignment of Eversource's Use Rights will be credited back on a pro rata basis (by IRH Participant Share percentage) to the retail customers of PSNH, CL&P and NSTAR. The proceeds as a result of the most recent RFP for the period June 2024 to May 2025 are shown in Attachment YC-1, pages 3 and 4, line 10.

[7] Order No. 25,122 at 7.

7. When the TCAM was initially approved in Docket No. DE 06-028, there was no provision for a working capital allowance. The TCAM working capital allowance continued to be included with the distribution working capital allowance. Working capital allowance accounts for the cash working capital needs of the Company, i.e., the amount of money needed to fund operations in the time period between when expenditures are incurred to provide service to customers and when payment is actually received from customers for that service. As part of the Commission-approved Settlement Agreement in Docket No. DE 09-035 (see Order No. 25,123), the distribution revenue requirement calculation excluded working capital on transmission costs. Therefore, the TCAM now includes a working capital allowance based on a lead/lag study as directed by the Commission in Docket No. DE 16-566 (see Order No. 25,912). An updated lead/lag analysis has been completed based on calendar year 2023 for rates effective October 1, 2024 and is discussed later in this testimony.

Q. Please describe the overall mechanics of the TCAM as they are presented in this filing.

A. The TCAM is a mechanism that allows Eversource to fully recover defined FERC and FERC-approved transmission costs. The proposed TCAM updated rate, as mentioned previously, is based on both reconciliations of historic transmission

costs and forecasted future transmission costs using the latest FERC-approved transmission rates.

There are two premises that form the basis of the TCAM. First, the TCAM sets transmission rates for a defined future billing period based on transmission cost estimates using current budget and forecast data supported by the latest known FERC-approved transmission rates. This future billing period is referred to as the "forecast period." Second, the TCAM provides all available actual cost and revenue (recovery) data referred to as the "reconciliation period." Any over- or under-recoveries that are incurred in the reconciliation period are rolled into the subsequent billing period as part of the next TCAM rate.

Q. What is the forecast period used in this filing, and what is the reconciliation period?

A. The forecast period used in this filing is the 12-month period from October 1, 2024 to September 30, 2025.[8] The reconciliation period in this filing is the 12-month period from October 1, 2023 to September 30, 2024, and includes actual results for October 2023 through June 2024 and estimated results for July 2024 through September 2024. The Settled Formula Rate[9] became effective as of January 1,

[8] Docket No. DE 22-034, Order No. 26,735 (November 28, 2022).

[9] The wholesale Transmission rate transparency settlement was filed at FERC on June 15, 2020 and was approved by FERC on December 28, 2020 in Docket No. ER20-2054-000.

2022. Therefore, actual costs during the reconciliation period will reflect activity under the settlement tariff.

Q. Do the RNS and LNS expense forecasts contained in this filing reflect the most current FERC-approved rates that are effective during the forecast period?

A. Yes. Please see the table below for the FERC-approved rates that will be in effect on October 1, 2024 and January 1, 2025, as well as the prior year's FERC-approved rates that were utilized in the RNS and LNS expense forecasts approved in Docket No. DE 23-070:

		(A)	(B)	(C)	(D)	(E) = (A) - (C)	(F) = (B) - (D)
		DE 24-090		DE 23-070		Change	
FERC-approved Rates	Description	Oct 24 - Dec 24	Jan 25 - Sep 25	Oct 23 - Dec 23	Jan 24 - Sep 24		
RNS Rate	$/kW-year	$ 154.35	$ 185.28	$ 141.64	$ 154.35	$ 12.71	$ 30.92
	$/MWh	$ 32.16	$ 38.61	$ 29.51	$ 32.16	$ 2.65	$ 6.44
LNS Rate	$/kW-year	$ 22.96	$ 35.51	$ 20.72	$ 22.96	$ 2.24	$ 12.54
	$/MWh	$ 4.78	$ 7.40	$ 4.32	$ 4.78	$ 0.47	$ 2.61

Q. Please explain how the change in the RNS rate impacts the Company's proposed revenue requirement.

A. The Table above provides the RNS rates that are reflected in the TCAM rate proposed for the period from October 1, 2024 to September 30, 2025 and the RNS rates previously approved for the TCAM period from October 1, 2023 to September 30, 2024. As reflected in Attachment YC-1, page 2, line 1, the Company is projecting an increase in the estimated RNS expenses for the forecast period from October 1, 2024 to September 30, 2025, as compared to the prior year's forecasted RNS expenses. The increase is primarily due to the projected increase in the January

1, 2025 RNS rate. The primary driver of the higher RNS rate as of January 1, 2025 is lower 2023 actual 12-month Coincident Peak (12CP) Regional Network Load as compared to 2021 and 2022. The year-over-year peak load decrease contributes to a higher January 1, 2025 RNS rate in two principal ways. First, the lower 2023 RNS load drove a shortfall in 2023 RNS revenues, and that 2023 RNS under-recovery is incorporated into the subsequent RNS rate. The lower 2023 load further increases the RNS rate because, in accordance with Attachment F of the ISO-NE OATT, it is the divisor used in the development of the January 1, 2025 RNS rate. That is, forecasted 2025 RNS revenue requirements are divided by the two-year prior (in this case 2023) actual loads to derive the January 1, 2025 RNS rate. The lower divisor using 2023 load as compared to 2022 load (used for setting the 2024 RNS rate) mathematically results in a higher RNS rate. Also contributing to the RNS rate increase are incremental forecasted RNS revenue requirements associated with forecasted PTF investments. The TCAM thus reflects higher RNS costs attributable to the Company in accordance with applicable FERC-approved tariffs.

Q. Please explain how the change in the LNS rate impacts the Company's proposed revenue requirement.

A. The Table above provides the LNS rates that are reflected in the TCAM rate proposed for the period from October 1, 2024 to September 30, 2025, and the LNS rates previously approved for the TCAM period from October 1, 2023 to September 30, 2024. As reflected in Attachment YC-1, page 2, line 3, the Company is projecting an increase in the estimated LNS expenses for the forecast period from

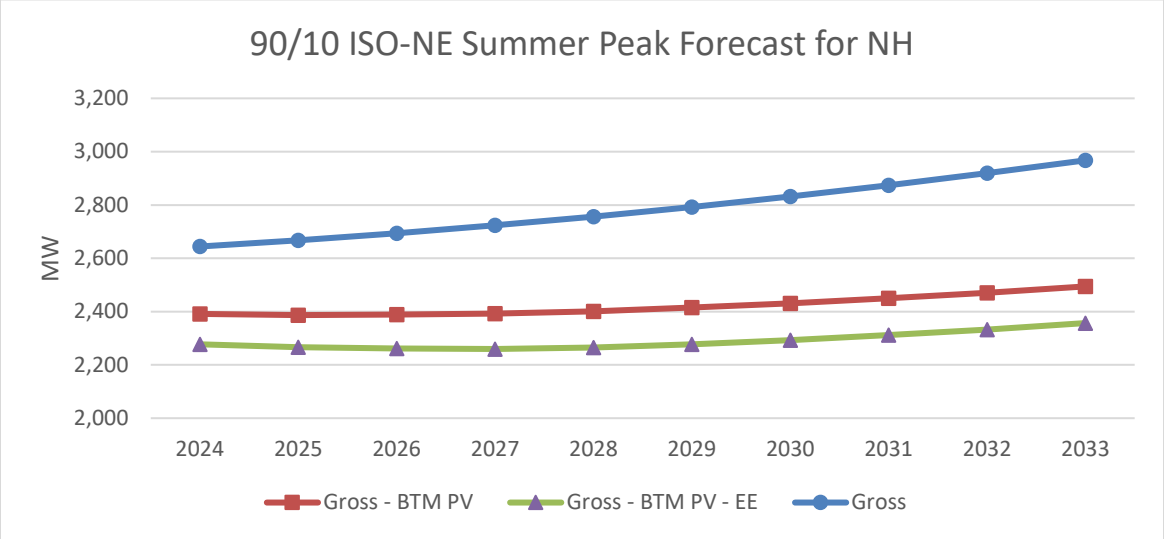
October 1, 2024 to September 30, 2025, as compared to the prior year's forecasted LNS expenses. The increase is primarily due to the projected increase in the January 1, 2025 LNS rate. The primary driver of the higher LNS rate as of January 1, 2025 is increased local service investments placed into service in 2023 and incremental revenue requirements associated with forecasted local service additions for 2024 and 2025.

Q. In Order No. 26,031 (June 28, 2017) in Docket No. DE 17-081, the Commission noted that there have been changes in the RNS rates as a result of changes in peak demand throughout New England. In that order, the Commission noted that as other states in the region reduce their share of peak load relative to the total, New Hampshire's share of the peak, and allocation of costs, increases. The Commission stated that it expected the Company to explain its efforts to reduce peak demand in New Hampshire in future TCAM filings. What efforts has Eversource made to address peak demand in New Hampshire?

A. As the Company described during the hearing in Docket No. DE 17-081, energy efficiency programs reduce consumption of energy (kWh), and related costs, for customers across New Hampshire. The efficiency measures that reduce kWh often also reduce electric demand (measured in kW) at the ISO-NE, distribution, and customer levels during peak periods. Per the end-of-year energy efficiency filing in Docket Nos. DE 14-216, DE 17-136, DE 20-092, and IR 22-042, the efficiency measures installed in the 2017 to 2023 time period were estimated to achieve 74.7 MW in summer peak demand reduction and 78.1 MW in winter peak demand reduction. The 2024-2026 Triennial NHSaves Energy Efficiency Plan, filed in Docket No. DE 23-068 and approved by the Commission in Order No. 26,908

(November 30, 2023), established goals for the time period 2024 to 2026. The plan included estimates of kW demand savings. The efficiency measures proposed for the 2024 to 2026 time period are estimated to achieve 33.9 MW in summer peak demand reduction and 35.2 MW in winter peak demand reduction. As with the kWh savings, the demand savings will persist over the lifetime of the measures installed.

ISO-NE has recognized the impact of these energy efficiency measures on its peak demand forecast for New Hampshire, as shown in the chart below:[10]



[10] Graphical representation of the 90/10 data contained in the Final 2023 CELT Report published May 1, 2024, using data from the 6.2 Forecasts for Transmission tab.
CELT Reports (iso-ne.com)

As is the case in New Hampshire, the majority of demand savings from energy efficiency programs in the region are achieved as a secondary benefit of the measures designed to generate kWh savings. However, New Hampshire efficiency programs have been monitoring demand management demonstrations and programs taking place in other states to advance tailored methodologies for adoption in New Hampshire. During the 2018-2020 triennium, the Company launched Active Demand Reduction ("ADR") pilot programs for (i) Commercial and Industrial load curtailment, (ii) Residential Battery Storage, and (iii) Wi-Fi thermostat direct load control. These pilot programs were continued into the 2021-2023 triennium, where results indicated that the 2023 ADR initiative achieved 6.5 MW in summer peak demand reduction. Building upon those efforts, the approved 2024-2026 Triennial NHSaves Energy Efficiency Plan transitions the ADR pilots into full program offerings. The active demand measures planned for 2024-2026 are estimated to provide incremental reduction to summer peak demand each year of 12-17 MW.

Q. Has Eversource taken any other direct efforts to reduce peak demand in New Hampshire?

A. Yes, Eversource has developed a Commercial and Industrial Demand Reduction Initiative as part of its energy efficiency offerings. This initiative was approved as part of the 2019 Update plan in Docket No. DE 17-136. Under an ADR approach, customers agree to respond to an event call targeting conditions that typically

result in peak reductions through curtailment service providers ("CSPs"), i.e., vendors who identify curtailable load, enroll customers, manage curtailment events, and calculate payments. The participating customers are incentivized to respond to event calls using performance-based incentives. This approach is technology-agnostic and can utilize single end-use control strategies or a multitude of approaches that can reduce demand when an event is called. This typically entails customers using lighting with both manual and automated controls, HVAC with both manual and automated controls, process loads, scheduling changes, excess Combined Heat & Power ("CHP") capacity, and energy storage to reduce demand. The residential ADR initiative consists of two main bring-your-own-device offerings: Battery Storage and Wi-Fi thermostats. Due to the success and popularity of the ADR offerings, the pilots have been expanded to full programs for the 2024-2026 triennium in Docket No. DE 23-068.

In addition to the Energy Efficiency efforts noted above, the Company has proposed as part of its Performance Based Ratemaking ("PBR") plan filed in its recent base distribution rate case, currently pending in Docket No. DE 24-070, the implementation of a reporting metric designed with the specific intention of yielding information and insight into the Company's activities and progress covering ADR as a specific area of interest. The Company is proposing a baseline and target ADR metric to report its progress over the four-year PBR Plan term, for consideration by the Commission.

Q. Did Eversource conduct a lead/lag study for the TCAM, as required in Order No. 25,912, dated June 28, 2016, in Docket No. DE 16-566?

A. Yes, Eversource conducted a lead/lag study for the TCAM and provides that analysis as Attachment YC-2. The results of the lead/lag analysis will be applied effective October 1, 2024. This lead/lag study methodology is substantially the same as that used for the similar studies provided in Docket Nos. DE 20-085, DE 21-109, DE 22-034, and DE 23-070.

Q. How is cash working capital estimated through a lead-lag study?

A. A lead/lag study identifies the amount of time it typically takes for the Company to collect revenue from customers, as well as the amount of time the Company takes to make payment for applicable operating costs. The difference between those two numbers is used as the basis to estimate cash working capital requirements.

Q. Please describe the lead/lag study completed for the TCAM provided as Attachment YC-2.

A. The Lead/Lag Study consists of 13 pages of calculations and supporting schedules to calculate working capital allowances by month for RNS, S&D, LNS, Reliability, HQ support components, and HQICCs. Revenue lag days are the same for all components; however, expense lead days vary by component. Each component has a separate expense lead days schedule.

Q. Please define the terms "revenue lag days" and "expense lead days."

A. Revenue lag is the time, measured in days, between delivery of a service to Eversource customers and the receipt by Eversource of the payment for such service from customers. Similarly, expense lead is the time, again measured in days, between the performance of a service on behalf of Eversource by a vendor or employee and payment for such service by Eversource to a vendor or employee. Since base rates are based on revenue and expenses booked on an accrual basis, the revenue lag results in a need for capital while the expense lead offsets this need to the extent the Company is typically not required to reimburse its vendors until after a service is provided by those vendors.

Q. How is the retail revenue lag computed?

A. The retail revenue lag consists of a

- Meter Reading or Service lag,
- Collection lag, and
- Billing lag.

The sum of the days associated with these three lag components is the total retail revenue lag experienced by Eversource. See Attachment YC-2, page 5.

Q. What lag does the Lead/Lag Study reveal for the component "Meter Reading or Service lag?"

A. The Lead/Lag Study reveals a lag of 15.21 days. This lag was obtained by dividing the number of billing days in the test year by 12 months and then in half to arrive at the midpoint of the monthly service periods.

Q. How was the "Collection Lag" calculated and what was the result?

A. The "Collection Lag" for TCAM totaled 23.04 days. This lag reflects the time delay between the mailing of customer bills and the receipt of the billed revenues from customers. The 23.04 day lag was arrived at by a thorough examination of TCAM accounts receivable balances using the accounts receivable turnover method. End-of-month balances were utilized as the measure of customer accounts receivable. Attachment YC-2, page 6 details monthly balances for the TCAM accounts receivable. Attachment YC-2, page 5 calculated the average daily revenue amount (line 3) by dividing annual transmission retail revenues by 365 days. The resulting Collection Lag is derived by dividing the average accounts receivable balance by the average daily revenue amount to arrive at the Collection Lag of 23.04 days.

Q. How did you arrive at the 1.52 day "Billing Lag"?

A. Nearly all customers are billed the evening after the meters are read. However, if a meter is read on a Friday or prior to a scheduled holiday, there is additional lag over

the weekend or holiday. Consistent with prior year filings, the Company's Billing Lag calculation accounts for this additional lag. The updated lead/lag study uses a 1.52-day Billing Lag as shown in Attachment YC-2, page 7. An exception for large customers, which may require additional time to process, has not been made in this calculation.

Q. Is the total retail revenue lag computed from these separate lag calculations?

A. Yes. The total retail revenue lag of 39.76 days is computed by adding the number of days associated with each of the three retail revenue lag components. See Attachment YC-2, page 5. This total number of lag days represents the amount of time between the recorded delivery of service to retail customers and the receipt of the related revenues from retail customers.

Q. Please explain how the RNS, S&D, LNS, Reliability, HQ expenses, and HQICC lead/lag period is determined.

A. The monthly payments were reviewed and the expense lead days were calculated based on the actual payment date of the payments. Once the lead days for each category were determined, they were summarized and dollar-weighted according to 2023 actual annual amounts to arrive at the lead days. These calculations are shown in Attachment YC-2, pages 8 through 13.

Q. Please explain how the Eversource Energy Service Company (EESC) due date

is determined related to LNS billings.

A. Per the terms of the service contract between the Company and EESC, bills are rendered for each calendar month on or before the twentieth day of the succeeding month and are payable upon presentation and not later than the last day of that month.

Q. Would you summarize the Company's proposal regarding Cash Working Capital?

A. Yes, the results of Eversource's TCAM Cash Working Capital lead/lag analysis is summarized in the table below:

Components	Revenue Lag Days	Lead/(Lag) Days	Net (Lead)/ Lag Days	Net (Lead)/ Lag %
RNS	39.8	61.4	(21.7)	-5.94%
S&D	39.8	61.3	(21.5)	-5.90%
LNS	39.8	37.7	2.1	0.57%
Reliability	39.8	61.5	(21.7)	-5.95%
HQ Expense	39.8	67.8	(28.0)	-7.68%
HQICC	39.8	(31.0)	70.8	19.39%
Total/Average	39.8	60.7	(21.0)	-5.75%

Application of these values results in a total forecast cash working capital allowance of ($15.176) million and a forecast return on working capital of ($1.328) million for the period from October 1, 2024 to September 30, 2025, as shown in Attachment YC-2, page 1, lines 19 and 21, respectively.

Q. Does Eversource require Commission approval of this rate by a specific date?

A. Yes, Eversource is requesting final approval of the proposed TCAM rate update by September 20, 2024 to allow for the implementation of an October 1, 2024 updated TCAM rate.

Q. Will the proposed update to the TCAM rate result in just and reasonable rates?

A. Yes, it will.

Q. Does this conclude your testimony?

A. Yes, it does.