

The United Illuminating Company

Financial Statements (Unaudited)

For the Three Months Ended March 31, 2026 and 2025

The United Illuminating Company

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**The United Illuminating Company
Statements of Income (Unaudited)**

Periods Ended March 31,	2026	2025
(Thousands)		
Operating Revenues	\$ 383,474	\$ 354,334
Operating Expenses		
Electricity purchased	117,507	124,169
Operations and maintenance	140,812	125,712
Depreciation and amortization	31,170	30,328
Taxes other than income taxes, net	29,927	31,760
Total Operating Expenses	319,416	311,969
Operating Income	64,058	42,365
Other income	6,477	6,238
Other deductions	(369)	(2,051)
Earnings from equity method investments	1,337	265
Interest expense, net of capitalization	(15,763)	(12,347)
Income Before Income Tax	55,740	34,470
Income tax expense	12,312	6,860
Net Income	\$ 43,428	\$ 27,610

**The United Illuminating Company
Statements of Comprehensive Income (Unaudited)**

Periods Ended March 31,	2026	2025
(Thousands)		
Net Income	\$ 43,428	\$ 27,610
Other Comprehensive (Loss) Income, Net of Tax		
Amortization of pension cost for non-qualified plans, net of income tax	(2,345)	54
Other Comprehensive (Loss) Income, Net of Tax	(2,345)	54
Comprehensive Income	\$ 41,083	\$ 27,664

The United Illuminating Company
Balance Sheets (Unaudited)

As of	March 31, 2026	December 31, 2025
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	\$ 117,900	\$ 47,512
Accounts receivable and unbilled revenues, net	219,668	202,560
Accounts receivable from affiliates	902	67,338
Notes receivable from affiliates	32,995	7,654
Materials and supplies	18,005	18,083
Derivative assets	51	127
Prepayments and other current assets	47,941	32,012
Income tax receivable	4,667	46,715
Regulatory assets	91,855	72,448
Total Current Assets	533,984	494,449
Utility plant, at original cost	4,334,713	4,255,022
Less accumulated depreciation	(1,337,216)	(1,310,433)
Net Utility Plant in Service	2,997,497	2,944,589
Construction work in progress	300,618	333,858
Total Utility Plant	3,298,115	3,278,447
Operating lease right-of-use assets	10,997	11,150
Equity method investments	70,114	72,147
Other property and investments	22,132	23,564
Regulatory and Other Assets		
Regulatory assets	280,444	282,708
Other	38,631	38,147
Total Regulatory and Other Assets	319,075	320,855
Total Assets	\$ 4,254,417	\$ 4,200,612

The United Illuminating Company
Balance Sheets (Unaudited)

As of	March 31, 2026	December 31, 2025
(Thousands, except share information)		
Liabilities		
Current Liabilities		
Accounts payable and accrued liabilities	\$ 127,564	\$ 144,225
Accounts payable to affiliates	19,543	63,117
Interest accrued	13,473	11,410
Taxes accrued	33,829	33,744
Operating lease liabilities	783	846
Derivative liabilities	64	158
Other current liabilities	74,208	77,185
Regulatory liabilities	173,314	115,450
Total Current Liabilities	442,778	446,135
Regulatory and Other Liabilities		
Regulatory liabilities	336,057	336,684
Other Non-current Liabilities		
Deferred income taxes	511,438	494,435
Pension and other postretirement	45,734	46,205
Operating lease liabilities	14,820	14,945
Environmental remediation costs	11,819	13,887
Other	31,987	29,318
Total Regulatory and Other Liabilities	951,855	935,474
Non-current debt	1,138,469	1,138,771
Total Liabilities	2,533,102	2,520,380
Commitments and Contingencies		
Common Stock Equity		
Common stock (no par value, 30,000,000 shares authorized and 100 shares outstanding at March 31, 2026 and December 31, 2025)	1	1
Additional paid-in capital	906,409	906,409
Retained earnings	824,316	780,888
Accumulated other comprehensive loss	(9,411)	(7,066)
Total Common Stock Equity	1,721,315	1,680,232
Total Liabilities and Equity	\$ 4,254,417	\$ 4,200,612

The United Illuminating Company
Statements of Cash Flows (Unaudited)

Periods Ended March 31,	2026	2025
(Thousands)		
Cash Flow from Operating Activities:		
Net income	\$ 43,428	\$ 27,610
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	31,170	30,328
Regulatory assets/liabilities amortization	17,319	(12,370)
Regulatory assets/liabilities carrying cost	(580)	(2,260)
Amortization of debt issuance costs	(351)	143
Deferred taxes	12,181	6,926
Pension cost	445	1,305
Loss on disposal of assets	50	—
Earnings from equity method investments	(1,334)	(262)
Cash distribution from equity method investments	1,163	226
Other non-cash items	(1,805)	(1,970)
Changes in operating assets and liabilities:		
Accounts receivable, from affiliates, and unbilled revenues	49,328	(1,290)
Inventories	78	370
Accounts payable, to affiliates, and accrued liabilities	(43,813)	(49,001)
Taxes accrued	42,133	10,375
Other assets/liabilities	(15,115)	(20,143)
Regulatory assets/liabilities	17,716	62,125
Net Cash Provided by Operating Activities	152,013	52,112
Cash Flow from Investing Activities:		
Capital expenditures	(59,778)	(84,072)
Contributions in aid of construction	1,016	3,180
Notes receivable from affiliates	(25,200)	23,000
Proceeds from sale of utility plant	133	57
Cash distribution from equity method investments	2,204	1,814
Net Cash Used in Investing Activities	(81,625)	(56,021)
Cash Flow from Financing Activities:		
Repayments of non-current debt	—	(50,000)
Notes payable to affiliates	—	58,800
Net Cash Provided by Financing Activities	—	8,800
Net Increase in Cash and Cash Equivalents	70,388	4,891
Cash and Cash Equivalents, Beginning of Period	47,512	1,202
Cash and Cash Equivalents, End of Period	\$ 117,900	\$ 6,093

**The United Illuminating Company
Statements of Changes in Equity (Unaudited)**

(Thousands, except per share amounts)	Number of shares (*)	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stock Equity
Balance, December 31, 2024	100 \$	1 \$	906,409 \$	652,641 \$	(6,980) \$	1,552,071
Net income	—	—	—	27,610	—	27,610
Other comprehensive income, net of tax	—	—	—	—	54	54
Comprehensive income						27,664
Balance, March 31, 2025	100 \$	1 \$	906,409 \$	680,251 \$	(6,926) \$	1,579,735
Balance, December 31, 2025	100 \$	1 \$	906,409 \$	780,888 \$	(7,066) \$	1,680,232
Net income	—	—	—	43,428	—	43,428
Other comprehensive loss, net of tax	—	—	—	—	(2,345)	(2,345)
Comprehensive income						41,083
Balance, March 31, 2026	100 \$	1 \$	906,409 \$	824,316 \$	(9,411) \$	1,721,315

(*) No par value.

Notes to Financial Statements

Note 1. Significant Accounting Policies

Background and nature of operations: The United Illuminating Company (UI) is a regulated operating electric public utility engaged in the purchase, transmission, distribution, and sale of electricity for residential, commercial and industrial purposes. UI is regulated as an electric distribution company by the Connecticut Public Utilities Regulatory Authority (PURA) and is also subject to regulation by the Federal Energy Regulatory Commission (FERC). UI serves approximately 351,600 customers as of March 31, 2026 in its service territory of approximately 335 square miles in southwestern Connecticut.

UI is a wholly-owned subsidiary of UIL Holdings Corporation (UIL Holdings). UIL Holdings, whose primary business is ownership of its operating regulated utility businesses, is a wholly-owned subsidiary of Avangrid Networks, Inc. (Networks), which is a wholly-owned subsidiary of Avangrid, Inc., which is a wholly-owned subsidiary of Iberdrola, S.A., a corporation organized under the law of the Kingdom of Spain.

UI is also a party to a joint venture with Clearway Energy, Inc., a subsidiary of Global Infrastructure Partners (GIP), pursuant to which UI holds 50% of the membership interests in GCE Holding LLC, whose wholly-owned subsidiary, GenConn Energy LLC, or GenConn, operates peaking generation plants in Devon, Connecticut (GenConn Devon) and Middletown, Connecticut (GenConn Middletown).

Basis of presentation: The accompanying unaudited condensed financial statements for the interim periods have been prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) for interim financial information. Accordingly, the interim condensed financial statements do not include all the information and note disclosures required by U.S. GAAP for complete financial statements.

In the opinion of management, the accompanying condensed financial statements contain all adjustments necessary to present fairly our condensed financial statements for the interim periods described herein. All such adjustments are of a normal and recurring nature, except as otherwise disclosed. The results for the three months ended March 31, 2026, are not necessarily indicative of the results for the entire fiscal year ending December 31, 2026.

Significant Accounting Policies and New Accounting Pronouncements: The new accounting pronouncements we have adopted as of January 1, 2026, and reflected in our condensed financial statements are described below. There have been no other material changes to the significant accounting policies described in our financial statements and FERC Form No.1 for the fiscal year ended December 31, 2025, except for those described below resulting from the adoption of new authoritative accounting guidance issued by Financial Accounting Standards Board (FASB).

Adoption of New Accounting Pronouncements

Although we are not a public business entity, we adopt new accounting standards based on public business entity guidance aside from the effective dates in certain situations where we may follow the effective dates for private entities.

(a) Simplified credit loss guidance

In July 2025, FASB issued guidance to simplify applying ASC 326, Financial instruments – Credit losses, to current accounts receivable and contract assets arising from transactions accounted for under ASC 606, Revenue from contracts with customers, including those assets acquired in a

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business combination or recognized through the consolidation of a variable interest entity that is not a business if those assets arose from transactions that the acquiree or variable interest entity accounted for under ASC 606. The update introduces (1) a practical expedient allowing entities to assume current conditions remain unchanged over the remaining life of these assets, and (2) an accounting policy election for non-public entities, permitting consideration of post-balance sheet cash collections when estimating expected credit losses, provided the practical expedient is also elected. The amendment is effective for all entities in interim and annual periods for fiscal years beginning after December 15, 2025. We do not expect the new guidance to have a material impact on our results of operations, financial position and cash flows.

Accounting Pronouncements Issued But Not Yet Adopted

The following are new accounting pronouncements not yet adopted that we have evaluated or are evaluating to determine their effect on UI's financial statements.

(a) Accounting for internal-use software costs

In September 2025 FASB issued guidance to modernize internal-use software guidance to eliminate the old stage-based capitalization model and to introduce a probable-to-complete threshold, requiring management authorization, funding commitment, and a probable expectation of completion before capitalization begins. It provides enhanced guidance and examples for applying this threshold, including factors for assessing significant development uncertainty such as novel features or ongoing revisions to performance requirements. Existing rules for external-use software, types of costs eligible for capitalization, and the point at which capitalization ceases remain unchanged. The amendment is effective for all entities in interim and annual periods for fiscal years beginning after December 15, 2027. We do not expect the new guidance to have a material impact on our results of operations, financial position and cash flows.

(b) Hedge accounting improvements

In November 2025, the FASB issued guidance, which provides refinements to hedge documentation and easing of certain operational requirements. The amendments primarily affect cash flow hedges, with targeted changes to fair value and net investment hedges. They (1) allow hedging a clearly related variable price component of a forecasted nonfinancial transaction, (2) permit grouping forecasted transactions with similar risk exposure, and (3) introduce a model for cash flow hedging "choose-your-rate" debt that lets borrowers change documented indexes or tenors without automatically ending hedge accounting. The amendment is effective for interim and annual reporting periods in fiscal years beginning after December 15, 2026, for public business entities, and after December 15, 2027, to all other entities. We are evaluating to determine the effect of this amendment on our hedge accounting programs and overall financial statements.

(c) Accounting for government grants

In December 2025, FASB issued amendments to provide comprehensive guidance on recognizing, measuring, and presenting government grants under ASC 832, Accounting for government grants by business entities, which previously only addressed disclosures. The amendment responds to the lack of explicit U.S. GAAP guidance that led to diverse practices and reliance on other GAAP or International Financial Reporting Standards (IFRS) by analogy. It classifies grants into asset-related and income-related categories, offering two approaches for asset-related grants: the cost accumulation approach (reducing the asset's carrying amount) and the deferred income approach (recognizing income systematically over the asset's useful life). Income-related grants, such as operating expense reimbursements, are recognized over the period the related costs occur, while grants for past costs or immediate support are recognized

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when the probable threshold is met. The amendment also includes guidance for business combinations, specifying when deferred income should or should not be recognized by the acquirer. The amendment is effective for public entities in fiscal years beginning after December 15, 2028, and for others after December 15, 2029, with transition options including modified prospective, modified retrospective, or full retrospective approaches. We do not expect the new guidance to have a material impact on our results of operations, financial position and cash flows.

Note 2. Industry Regulation

Rates

Utilities are entitled by Connecticut statutes to charge rates that are sufficient to allow them an opportunity to cover their reasonable operating and capital costs, to attract needed capital, and to maintain their financial integrity, while also protecting relevant public interests.

On September 9, 2022, UI filed a distribution revenue requirement case. UI's filing proposed a three-year rate plan commencing September 1, 2023 through August 31, 2026. PURA issued a Final Decision on August 25, 2023, which approved an annual revenue requirement of \$384.9 million and a 1-year rate plan commencing on September 1, 2023. This represents an increase of \$22.9 million to the Company's currently approved base distribution revenue requirement. PURA established an allowed return on equity of 9.10%, but reduced the allowed ROE by an aggregate 47 basis point reduction (i.e., to 8.63%), and 2 basis points were reversed by PURA on June 13, 2025, bringing the total ROE to 8.65%, subject to certain conditions and timelines. The Final Decision established a capital structure consisting of 50% common equity and 50% debt. The Final Decision resulted in an average increase in base distribution rates of about 6.6% and an average increase in customer bills of about 2% compared to current levels. Given the expiration of the rate plan, UI had been operating under the 2023 approved rate schedules. On September 18, 2023, UI filed an appeal of the PURA's Final Decision in Connecticut Superior Court, because of actual and legal errors related to the treatment of deferred assets, plant in service, and operating expenses. A decision was issued by the Court on March 13, 2025, which largely upheld PURA's Final Decision.

On November 12, 2024, UI filed an application to adjust its rates and charges which proposed to amend UI's existing rate schedules effective November 1, 2025, in order to address a significant deficiency in distribution-related operating revenues. More specifically, the UI application proposed a change in base distribution rates to be implemented in the rate year beginning November 1, 2025, with proposed rates designed to provide incremental operating revenues of approximately \$105 million. UI's application also included several measures to moderate the impact of the proposed rate update for customers, including, a low-income discount rate to provide rate relief to UI's disadvantaged customers, as well as proposing to continue an economic development rate to support continued commercial growth in UI's service territory. In April and May, 2025, UI attended 9 days of evidentiary hearings in support of its application. PURA released a Final Decision on this application on October 28, 2025, approving approximately \$65 million in increased operating revenues, with a return on equity rate of 9.45%, 9.25% after 20 basis point reduction, and a 51% equity ratio. The company filed a motion for reconsideration in November 2025 with a focus on the applied ROE penalties, and the disallowances for inflation protections, Board of Directors expenses, and audit expenses. PURA approved our request for reconsideration, and issued a decision on these issues on March 3, 2026. PURA removed the 20 basis point penalties, raising UI's ROE to 9.45%.

Connecticut Energy Legislation

On June 29, 2023, the Governor of Connecticut signed into law an energy bill titled *An Act Strengthening Protections for Connecticut Consumers*, which, among other things, provided PURA with additional powers to regulate the State's public service companies. More specifically, the Act modified certain ratemaking mechanisms such as revenue decoupling, allows PURA to initiate more frequent rate reviews in between rate cases, modifies electric distribution billing formats, precludes recovery of rate case expenses and appeals from rate proceedings, and mandates various reporting requirements.

On July 1, 2025, the Governor of Connecticut signed into law Public Act 25-173 (formerly Senate Bill 4) *An Act Concerning Energy Affordability, Access and Accountability*. This Act is broad in scope and includes language that provides PURA and the electric distribution companies in Connecticut to modify the process for procuring electric supply, requires any transmission projects to develop project alternatives if certain conditions are met, reduces the Class I Renewable Portfolio Standard percentages for years 2026 – 2030, and specifies the conduct of PURA regarding PURA terms and voting requirements for rate cases and other decisions. We will continue to review the requirements of this Act for the next legislative session.

Power Supply Arrangements

Under Connecticut law, UI's retail electricity customers can choose their electricity supplier while UI remains their electric distribution company. UI purchases power for those of its customers under standard service rates who do not choose an alternative retail electric supplier and have a maximum demand of less than 500 kilowatts, as well as its customers under supplier of last resort service who are not eligible for standard service rates and do not choose to purchase electric generation service from an alternate retail electric supplier. The cost of the purchased power is a "pass-through" to those customers through the General Services Charge (GSC) charge on their bills.

UI must procure the power to serve its standard service load pursuant to a procurement plan approved by PURA. Under the procurement plan, UI procures wholesale power for its standard service customers on a full requirements basis pursuant to contracts with a maximum duration of 12 months, with the delivery of such wholesale power to commence no later than one year from the applicable bid day.

At the conclusion of the period ended March 31, 2026, UI has wholesale power supply agreements in place for 100% of the first half of 2026, 80% for the second half of 2026, and 10% for the first half of 2027. Supplier of last resort service is procured on a quarterly basis and UI has a wholesale power supply agreement in place for the first and second quarters of 2026.

UI determined that its contracts for standard service and supplier of last resort service are derivatives under ASC 815 "Derivatives and Hedging" and elected the "normal purchase, normal sale" exception under ASC 815 "Derivatives and Hedging." UI regularly assesses the accounting treatment for its power supply contracts. These wholesale power supply agreements contain default provisions that include required performance assurance, including certain collateral obligations, in the event that UI's credit rating on senior debt were to fall below investment grade. If such an event had occurred as of March 31, 2026, UI would have had to post collateral of approximately \$19.2 million. We would have been and remain able to provide such collateral.

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New Renewable Source Generation

Under Connecticut Public Act (PA) 11-80, Connecticut electric utilities are required to enter into long-term contracts to purchase Connecticut Class I Renewable Energy Certificates (RECs) from renewable generators located on customer premises. Under this program, UI was initially required to enter into contracts totaling approximately \$200 million in commitments over an approximate 21-year period. The obligations were initially expected to phase in over a six-year solicitation period and peak at an annual commitment level of about \$14 million per year after all selected projects are online. PA 17-144, PA 18-50 and PA 19-35 extended the original six-year solicitation period of the program by adding seventh, eighth, ninth, and tenth years, and increased the original funding level of this program by adding up to \$64 million in additional commitments by UI. Upon purchase, UI accounts for the RECs as inventory. UI expects to partially mitigate the cost of these contracts through the resale of the RECs. PA 11-80 provides that the remaining costs (and any benefits) of these contracts, including any gain or loss resulting from the resale of the RECs, are fully recoverable from (or credited to) customers through electric rates.

In October of 2018, UI entered into five Power Purchase Agreements (PPAs) totaling approximately 50 MW from developers of offshore wind and fuel cell generation pursuant to state law that provides the net costs of the PPAs are recoverable through electric rates. On December 19, 2018, PURA approved the PPAs, and approved UI's use of the non-bypassable federally mandated congestion charges for all customers to recover the net costs of the PPAs.

In 2019, UI entered into PPAs with 11 projects, totaling approximately 12 million MWh, pursuant to state law that provides that the net costs of the PPAs are recoverable through electric rates. UI terminated eight of these contracts in 2022 and 2023, and the remaining three projects with existing contracts from these 2019 procurements are with Millstone Nuclear, Seabrook Nuclear and Revolution Wind.

In 2020, Pursuant to Connecticut Act Concerning the Procurement of Energy Derived From Offshore Wind, UI entered into a PPA with Vineyard Wind, an affiliate of UI, to provide 804 MW of offshore wind through the development of its Park City Wind Project. Similar to the case with the zero carbon PPAs discussed above, the net costs of the PPAs are recoverable through electric rates. On October 13, 2023, PURA approved the termination of this agreement between UI and its affiliate for the development of Park City Wind Project.

Revenues are recorded gross from contracts with customers when UI is a principal if it controls a promised good or service before transferring that good or service to the customer. Revenues are recorded net of expenses and regulatory deferrals from contracts with customers when UI is an agent if it arranges for another entity to provide the goods or services.

Transmission

PURA decisions do not affect the revenue requirements determination for UI's transmission business, including the applicable ROE. UI's transmission rates are determined by a tariff regulated by the FERC and administered by ISO New England, Inc. (ISO-NE). Transmission rates are set annually pursuant to a FERC authorized formula that allows for recovery of direct and allocated transmission operating and maintenance expenses, and for a return of and on investment in assets.

On September 30, 2011, the Massachusetts Attorney General, DPU, PURA, New Hampshire Public Utilities Commission, Rhode Island Division of Public Utilities and Carriers, Vermont Department of Public Service, numerous New England consumer advocate agencies and transmission tariff customers collectively filed a joint complaint (Complaint I) with the FERC

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pursuant to sections 206 and 306 of the Federal Power Act against several New England Transmission Owners (NETOs) claiming that the approved base ROE of 11.14% used by NETOs in calculating formula rates for transmission service under the ISO-New England Open Access Transmission Tariff (OATT) was not just and reasonable and seeking a reduction of the base ROE to 9.2%. UI is a NETO with assets and service rates that are governed by the OATT and will thereby be affected by any FERC order resulting from the filed complaint.

On December 26, 2012, a second related complaint (Complaint II) for a subsequent rate period was filed requesting the ROE be reduced to 8.7%. On July 31, 2014, a third related complaint (Complaint III) was filed for a subsequent rate period requesting the ROE be reduced to 8.84%. On April 29, 2016, a fourth complaint (Complaint IV) was filed for a rate period subsequent to prior complaints requesting the base ROE be 8.61% and ROE cap be 11.24%. On October 16, 2014, the FERC issued its decision in Complaint I, setting the base ROE at 10.57% and a maximum total ROE of 11.74% (base plus incentive ROEs) for the October 2011 – December 2012 period as well as prospectively from October 16, 2014. On March 3, 2015, the FERC upheld its decision and further clarified that the 11.74% ROE cap will be applied on a project specific basis and not on a transmission owner's total average transmission return. Complaints II and III were consolidated and the administrative law judge issued an initial decision on March 22, 2016. The initial decision determined that, (1) for the fifteen month refund period in Complaint II, the base ROE should be 9.59% and that the ROE cap (base ROE plus incentive ROEs) should be 10.42% and (2) for the fifteen month refund period in Complaint III and prospectively, the base ROE should be 10.90% and that the ROE Cap should be 12.19%. The initial decision in Complaints II and III is the administrative law judge's recommendation to the FERC Commissioners.

UI reserved for refunds for Complaints I, II and III consistent with the FERC's March 3, 2015 decision in Complaint I. Refunds were provided to customers for Complaint I. UI's total reserve associated with Complaints II and III is \$10.2 million as of March 31, 2026, which has not changed since December 31, 2025, except for the accrual of carrying costs.

Following various intermediate hearings, orders and appellate decisions, on October 16, 2018, the FERC issued an order directing briefs and proposing a new methodology to calculate the NETOs ROE that is contained in NETOs' transmission formula rate on file at the FERC (the October 2018 Order). Pursuant to the October 2018 Order, the NETOs filed initial briefs on the proposed methodology in all four Complaints on January 11, 2019 and replied to the initial briefs on March 8, 2019.

On November 21, 2019, the FERC issued rulings on two complaints challenging the base return on equity for Midcontinent Independent System Operator, or MISO transmission owners. These rulings established a new zone of reasonableness based on equal weighting of the DCF and capital-asset pricing model for establishing the base return on equity. This resulted in a base return on equity of 9.88% as the midpoint of the zone of reasonableness. Various parties requested rehearing on this decision, which was granted. On May 21, 2020, FERC issued a ruling, which, among other things, adjusted the methodology to determine the MISO transmission owners' ROE, resulting in an increase in ROE from 9.88% to 10.02% by utilizing the risk premium (RP) model in addition to the DCF model and capital-asset pricing model under both prongs of Section 206 of the FPA, and calculated the zone of reasonableness into equal thirds rather than employing the quartile approach. On November 19, 2020, FERC issued an order addressing arguments raised on rehearing of its May 21, 2020 order making minor adjustments to certain typographical errors with regard to some of the case inputs it included in its risk premium model analysis. However, those minor adjustments did not affect the outcome of the case, leaving the 10.02% ROE established by the May 21, 2020 order in place. Parties to these orders affecting the MISO transmission owners' base ROE petitioned for their review at the D.C. Circuit Court of Appeals in January 2021. The NETO's submitted an amici curia brief in support of the MISO

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transmission owners' on March 17, 2021. On August 9, 2022, the D.C. Circuit Court vacated FERC's orders and remanded the matter back to FERC. The D.C. Circuit Court held that FERC failed to offer a reasoned explanation for its decision to reintroduce the RP model after initially, and forcefully, rejecting it and that because FERC adopted that significant portion of its model in an arbitrary and capricious fashion, the new ROE produced by that model cannot stand. On October 17, 2024, FERC issued its order on remand in the MISO ROE complaint proceedings. In this order, FERC reduced the MISO transmission owners' base ROE to 9.98% by eliminating the risk premium model from the ROE calculation, consistent with the DC Circuit's remand, and affirmed the refunds ordered in Opinion 569 (which were not addressed on appeal by the DC Circuit). On November 13, 2024, the NETOs submitted a supplemental brief into the NETO ROE case. The supplemental brief primarily addresses distinctions between the MISO transmission owners' and the NETOs' ROE cases. On March 25, 2025, FERC issued an order on rehearing in the MISO ROE complaint proceeding that sustained the same result as the October 17, 2024, order.

MISO transmission owners affected by the October 17, 2024 order petitioned for review of the ordered refunds at the D.C. Circuit Court of Appeals in February 2025. The NETO's submitted an amici curia brief in support of the MISO transmission owners on August 21, 2025.

On March 19, 2026, the FERC issued its decision on the four Complaints. For Complaint I, FERC set the base ROE at 9.57% and a maximum total ROE of 12.09% (base plus incentive ROEs) for the October 2011 - December 2012 period as well as prospectively from October 16, 2014. The calculation method adopted uses only the DCF and capital-asset pricing models and does not adopt the use of the expected earnings and risk premium models. FERC dismissed Complaints II, III and IV. The company is reviewing the decision, including matters related to effective dates, potential rehearing or appeal. No determination has been made as to the ultimate impact, if any, on the company's financial position, results of operations, or cash flows. We cannot predict the outcome of this proceeding.

On April 15, 2021, the FERC issued a supplemental Notice of Proposed Rulemaking (Supplemental NOPR) that proposes to eliminate the 50 basis-point ROE incentive for utilities who join Regional Transmission Organizations after three years of membership. The NETOs submitted initial comments in opposition to the Supplemental NOPR on June 25, 2021 and reply comments on July 26, 2021. If the elimination of the 50 basis-point ROE incentive adder becomes final, we estimate we would have an approximately \$2 million reduction in earnings per year. We cannot predict the outcome of this proceeding.

Equity Investment in Peaking Generation

UI is a party to a joint venture with Clearway Energy, Inc., a subsidiary of Global Infrastructure Partners (GIP), pursuant to which UI holds 50% of the membership interests in GCE Holding LLC, whose wholly-owned subsidiary, GenConn Energy LLC, or GenConn, operates peaking generation plants in Devon, Connecticut (GenConn Devon) and Middletown, Connecticut (GenConn Middletown). The two peaking generation plants are both participating in the ISO-New England markets.

GenConn and PURA have completed settlement of all previous appeals related to annual revenue requirements for fiscal periods 2020 to 2025 as of June 10, 2025. Per the Settlement agreement and on a forward basis GenConn will utilize fixed debt to equity structure in its annual filings for approval of its revenue requirements. On June 27, 2025, GenConn filed with PURA requesting approval of its 2026 revenue requirements. GenConn received a final decision on December 17, 2025 from PURA approving \$43.9 million revenue requirements for the 2026 operating year.

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Minimum Equity Requirements for Regulated Subsidiaries

Pursuant to agreements with PURA, UI is restricted from paying dividends if paying such dividend would result in a common equity ratio lower than 300 basis points below the equity percentage used to set rates in the most recent distribution rate proceeding as measured using a trailing 13-month average calculated as of the most recent quarter end. In addition, UI is prohibited from paying dividends to their parent if the utility's credit rating, as rated by any of the three major credit rating agencies, falls below investment grade, or if the utility's credit rating, as determined by two of the three major credit rating agencies, falls to the lowest investment grade and there is a negative watch or review downgrade notice.

Note 3. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations we capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric rates. We base our assessment of whether recovery is probable on the existence of regulatory orders that allow for recovery of certain costs over a specific period, or allow for reconciliation or deferral of certain costs. When costs are not treated in a specific order we use regulatory precedent to determine if recovery is probable. We also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs. Of the total regulatory assets net of regulatory liabilities, approximately \$186.5 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

Details of other regulatory assets and other regulatory liabilities are shown in the tables below. They result from various regulatory orders that allow for the deferral and/or reconciliation of specific costs. Regulatory assets and regulatory liabilities are classified as current when recovery or refund in the coming year is allowed or required through a specific order or when the rates related to a specific regulatory asset or regulatory liability are subject to automatic annual adjustment.

Regulatory assets as of March 31, 2026 and December 31, 2025 consisted of:

As of	March 31,	December 31,
	2026	2025
(Thousands)		
Contracts for differences	\$ 13	\$ 32
COVID-19 cost recovery	4,939	5,027
Deferred transmission expense	41,800	34,804
Environmental remediation costs	16,246	17,209
Excess generation service charge	40,930	28,510
Pension and other postretirement benefit plans	63,212	64,197
Pension and other postretirement benefits cost deferrals	16,369	17,014
Storm costs	24,383	25,442
Unamortized losses on reacquired debt	3,333	3,458
Unfunded future income taxes	140,806	139,319
Other	20,268	20,144
Total regulatory assets	372,299	355,156
Less: current portion	91,855	72,448
Total non-current regulatory assets	\$ 280,444	\$ 282,708

Notes to Financial Statements

Contracts for differences represent the deferral of unrealized gains and losses on contracts for differences derivative contracts. The balance fluctuates based upon quarterly market analysis performed on the related derivatives. The amounts, which do not earn a return, are fully offset by a corresponding derivative asset/liability.

COVID-19 cost recovery represents deferred COVID-19-related costs in the state of Connecticut based on the order issued by PURA on April 29, 2020, requiring utilities to track COVID-19-related expenses and lost revenue and create a regulatory asset.

Deferred transmission expense represents deferred transmission income or expense and fluctuates based upon actual revenues and revenue requirements.

Environmental remediation costs includes spending that has occurred and is eligible for future recovery in customer rates. Environmental costs are currently recovered through a reserve mechanism whereby projected spending is included in rates with any variance recorded as a regulatory asset or a regulatory liability. The amortization period will be established in future proceedings and will depend upon the timing of spending for the remediation costs. It also includes the anticipated future rate recovery of costs that are recorded as environmental liabilities since these will be recovered when incurred. Because no funds have yet been expended for the regulatory asset related to future spending, it does not accrue carrying costs and is not included within rate base.

Excess generation service charge represents deferred generation-related costs or revenues for future recovery from or return to customers. The amount fluctuates based upon timing differences between revenues collected from rates and actual costs incurred.

Pension and other postretirement benefit plans represent the actuarial losses on the pension and other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future pension expenses.

Pension and other postretirement benefits cost deferrals include the difference between actual expense for pension and other postretirement benefits and the amount provided for in rates. The recovery of these amounts will be determined in future proceedings.

Storm costs are allowed in rates based on an estimate of the routine costs of service restoration. UI is also allowed to defer unusually high levels of service restoration costs resulting from major storms when they meet certain criteria for severity and duration. A portion of this balance is amortized through current rates, and the remaining portion will be determined through future rate cases.

Unamortized losses on reacquired debt represent deferred losses on debt reacquisitions that will be recovered over the remaining original amortization period of the reacquired debt.

Unfunded future income taxes represent unrecovered federal and state income taxes primarily resulting from regulatory flow through accounting treatment and are the offset to the unfunded future deferred income tax liability recorded. The income tax benefits or charges for certain plant related timing differences, such as removal costs, are immediately flowed through to, or collected from, customers. This amount is being amortized as the amounts related to temporary differences that give rise to the deferrals are recovered in rates.

Other includes items such as deferred loss on sale of non-utility property.

Notes to Financial Statements

Regulatory liabilities as of March 31, 2026 and December 31, 2025 consisted of:

As of	March 31, 2026	December 31, 2025
(Thousands)		
2017 Tax Act	\$ 197,648	\$ 198,578
Accrued removal obligations	79,487	77,817
Accumulated deferred investment tax credits	8,256	8,439
Conservation and load management	6,203	—
Middletown/Norwalk local transmission network service collections	14,379	14,522
Non-bypassable charges	132,436	77,217
Pension and other postretirement benefit plans	25,456	26,374
Pension and other postretirement benefits cost deferrals	929	1,010
Revenue decoupling mechanism	8,088	11,619
Rate refund - FERC ROE proceeding	10,160	9,984
System benefit charge	21,301	21,339
Other	5,028	5,235
Total regulatory liabilities	509,371	452,134
Less: current portion	173,314	115,450
Total non-current regulatory liabilities	\$ 336,057	\$ 336,684

2017 Tax Act represents the impact from remeasurement of deferred income tax balances as a result of the Tax Act enacted by the U.S. federal government on December 22, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates from 35% to 21% under the provisions of the Tax Act will result in amounts previously and currently collected from utility customers for these deferred taxes to be refundable to such customers.

Accrued removal obligations represent the differences between asset removal costs recorded and amounts collected in rates for those costs. The amortization period is dependent upon the asset removal costs of underlying assets and the life of the utility plant.

Accumulated deferred investment tax credits represent investment tax credits related to plant investments that are deferred when earned and amortized over the estimated lives of the related assets.

Conservation and load management represents the difference between UI's costs for customer conservation measures and the amounts collected in rates for those costs.

Middletown/Norwalk local transmission network service collections represents allowance for funds used during construction of the Middletown/Norwalk transmission line, which is being amortized over the useful life of the project.

Non-bypassable charges represent non-bypassable federally mandated congestion costs or revenues for future recovery from or return to customers. The amount fluctuates based upon timing differences between revenues collected from rates and actual costs incurred.

Pension and other postretirement benefit plans represent the actuarial gains on the pension and other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future pension expenses.

Notes to Financial Statements

Pension and other postretirement benefits cost deferrals include the difference between actual expense for pension and other postretirement benefits and the amount provided for in rates. The recovery of these amounts will be determined in future proceedings.

Revenue decoupling mechanism represents the mechanism established to disassociate the utility's profits from its delivery/commodity sales.

Rate refund - FERC ROE proceeding represents the reserve associated with the FERC proceeding around the base return on equity (ROE) reflected in ISO-NE's open access transmission tariff.

System benefits charge represents the mechanism by which UI recovers costs associated with hardship uncollectible customer accounts, arrearage forgiveness programs, and other customer assistance programs. The amount fluctuates based upon timing differences between revenues collected from rates and actual costs incurred.

Other includes items such as deferral of CAM gross earnings tax expense collected in base distribution rates for periods between January 1, 2020 and August 31, 2023.

Note 4. Revenue

We recognize revenue when we have satisfied our obligations under the terms of a contract with a customer, which generally occurs when the control of promised goods or services transfers to the customer. We measure revenue as the amount of consideration we expect to receive in exchange for providing those goods or services. Contracts with customers may include multiple performance obligations. For such contracts, we allocate revenue to each performance obligation based on its relative standalone selling price. We generally determine standalone selling prices based on the prices charged to customers. Certain revenues are not within the scope of ASC 606, such as revenues from leasing, derivatives, other revenues that are not from contracts with customers and other contractual rights or obligations, and we account for such revenues in accordance with the applicable accounting standards. We exclude from revenue amounts collected on behalf of third parties, including any such taxes collected from customers and remitted to governmental authorities. We do not have any material significant payment terms because we receive payment at or shortly after the point of sale.

The following describes the principal activities from which we generate revenue.

UI derives its revenue primarily from tariff-based sales of electricity service to customers in its Connecticut territory with no defined contractual term. For such revenues, we recognize revenues in an amount derived from the electricity delivered to customers. Other major sources of revenue are electricity transmission and wholesale sales of electricity.

Tariff-based sales are subject to PURA regulation, which determines prices and other terms of service through the ratemaking process. Customers have the option to obtain the electricity directly from UI or from another supplier. For customers that receive their electricity from another supplier, UI acts as an agent and delivers the electricity by that supplier. Revenue in those cases is only for providing the service of delivery of the electricity.

Transmission revenue results from others' use of the utility's transmission system to transmit electricity and is subject to FERC regulation, which establishes the prices and other terms of service. Long-term wholesale sales of electricity are based on individual bilateral contracts. Short-term wholesale sales of electricity are generally on a daily basis based on market prices and are administered by an independent entity, ISO-New England, Inc.

Notes to Financial Statements

The performance obligation in all arrangements is satisfied over time because the customer simultaneously receives and consumes the benefits as UI delivers or sells the electricity or provides the transmission service.

UI records revenue from Alternative Revenue Programs (ARPs), which is not ASC 606 revenue. Such programs represent contracts between UI and their regulators. UI ARPs include revenue decoupling mechanisms, other ratemaking mechanisms, and annual revenue requirement reconciliations.

UI also has various other sources of revenue including billing, collection, other administrative charges, sundry billings, rent of utility property, and miscellaneous revenue. It classifies such revenues as other ASC 606 revenues to the extent they are not related to revenue generating activities from leasing, ARPs, or other activities.

Revenues disaggregated by major source for the three months ended March 31, 2026 and 2025, are as follows:

Three Months Ended March 31,	2026	2025
(Thousands)		
Regulated operations – electricity	\$ 369,559	\$ 337,667
Other (a)	2,872	3,053
Revenue from contracts with customers	372,431	340,720
Leasing revenue	1,540	2,703
Alternative revenue programs	6,318	8,996
Other revenue	3,185	1,915
Total operating revenues	\$ 383,474	\$ 354,334

(a) Primarily includes certain intra-month trading activities, billing, collection, administrative charges, sundry billings, and other miscellaneous revenue.

As of March 31, 2026 and December 31, 2025, nearly all of the accounts receivable balances included in “Accounts receivable and unbilled revenues, net” on our condensed balance sheets are related to contracts with customers and include unbilled revenues of \$69.3 million and \$75.4 million, respectively.

Note 5. Income Taxes

The effective tax rate for the three months ended March 31, 2026 was 22.1%, which was higher than the 21% statutory federal income tax rate due predominately to state taxes and permanent tax adjustments, partially offset by excess ADIT amortization and Equity AFUDC flowthrough. The effective tax rate for the three months ended March 31, 2025 was 19.9%, which was lower than the 21% statutory federal income tax rate due predominately to excess ADIT amortization and Equity AFUDC, partially offset by state taxes.

Note 6. Bank Loans and Other Borrowings

UI had no short-term debt outstanding as of both March 31, 2026 and December 31, 2025. UI funds short-term liquidity needs through an agreement among Avangrid’s regulated utility subsidiaries (the Virtual Money Pool Agreement), a bi-lateral intercompany credit agreement with Avangrid (the Bi-Lateral Intercompany Facility), and a bank provided credit facility to which UI is a party (the AGR Credit Facility), each of which are described below.

Notes to Financial Statements

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. UI has a lending/borrowing limit of \$100 million under this agreement. UI had no debt outstanding under this agreement as of both March 31, 2026 and December 31, 2025.

The Bi-Lateral Intercompany Facility provides for borrowing of up to \$500 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. UI had no debt outstanding under this agreement as of both March 31, 2026 and December 31, 2025.

On December 22, 2025, the utilities (New York State Electric and Gas Corporation (“NYSEG”), Rochester Gas and Electric Corporation (“RG&E”), Central Maine Power Company (“CMP”), The United Illuminating Company (“UI”), Connecticut Natural Gas Corporation (“CNG”), The Southern Connecticut Gas Company (“SCG”) and The Berkshire Gas Company (“BGC”)) executed a new credit facility with an aggregate limit of \$1,500 million and a termination date of December 23, 2030. Under the terms of the revolving credit facility, each borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit contained in the agreement. NYSEG has a maximum sublimit of \$1,000 million, RG&E has \$500 million, CMP has \$375 million, UI has a maximum sublimit of \$150 million, SCG has a maximum sublimit of \$75 million, and CNG and BGC have maximum sublimits of \$50 million. The new facility has set minimum sublimits of \$600 million for NYSEG, \$250 million for RG&E, \$150 million for CMP, \$25 million for UI, CNG, SCG, and BGC. The facility fees range from 5 to 25 basis points. UI had no debt outstanding under this agreement as of both March 31, 2026 and December 31, 2025.

In the Avangrid Credit Facility we covenant not to permit, without the consent of the lender, our ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of indebtedness to total capitalization, the facility excludes from net worth the balance of accumulated other comprehensive loss as it appears on the balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness we may maintain. Continued un-remedied failure to comply with those covenants for five business days after written notice of such failure from the lender constitutes an event of default and would result in acceleration of maturity. Our ratio of indebtedness to total capitalization pursuant to the revolving credit facility was 0.40 to 1.00 at March 31, 2026. We are not in default as of March 31, 2026.

Note 7. Preferred Stock

At March 31, 2026, UI had 1,119,612 shares of \$100 par value preferred stock, 2,400,000 shares of \$25 par value preferred stock, and 5,000,000 shares of \$25 par value preference stock authorized but unissued.

Note 8. Environmental Liability

From time to time environmental laws, regulations and compliance programs may require changes in our operations and facilities and may increase the cost of electric service.

English Station

In January 2012, Evergreen Power, LLC (Evergreen Power) and Asnat Realty LLC (Asnat), then owners of a former generation site on the Mill River in New Haven (English Station) that UI sold to Quinnipiac Energy in 2000, filed a lawsuit in federal district court in Connecticut related to environmental remediation at the English Station site. This proceeding was stayed in 2014 pending resolutions of other proceedings before the DEEP concerning the English Station site. In December 2016, the court administratively closed the file without prejudice to reopen upon the filing of a motion to reopen by any party.

On April 8, 2013, DEEP issued an administrative order addressed to UI, Evergreen Power, Asnat and others, ordering the parties to take certain actions related to investigating and remediating the English Station site. This proceeding was stayed while DEEP and UI continue to work through the remediation process pursuant to the consent order described below. Status reports are filed monthly with DEEP.

On August 4, 2016, DEEP issued a partial consent order (the PCO), that requires UI to investigate and remediate certain environmental conditions within the perimeter of the English Station site. Under the PCO, if the cost of this remediation is less than \$30 million, UI will remit to the State the difference between such cost and \$30 million. If the cost of such compliance exceeds \$30 million, UI must comply with the PCO, but may seek to recover costs above \$30 million in consultation with the State.

UI continues its activities to investigate and remediate the environmental conditions at the site. In 2023 and 2024 DEEP sent UI a series of letters requesting details on remediation plans and security, which UI responded to.

On January 25, 2024, DEEP issued a notice of declaratory ruling to determine the “high occupancy standard” necessary “to abate on-site pollution and impacts for industrial/commercial use of the Site...inside the buildings” as referenced in section (B)(1)(e)(4) of the PCO. UI submitted its written comments objecting to the proceedings on March 11, 2024. DEEP issued a Declaratory Ruling on May 28, 2024 declaring that the high occupancy standard is applicable. On July 3, 2024, UI appealed DEEP’s ruling to the Connecticut Superior Court and was granted a request to move the case to the complex litigation docket. On July 31, 2025 the Court issued a decision that sustained UI’s appeal and remanded the matter to DEEP due to alleged ambiguities in the language of the PCO. There is no timetable for DEEP to proceed with further fact-finding. On August 19, 2025, UI appealed the Court’s decision. DEEP filed a cross-appeal on August 25, 2025. The appeal is presently pending before the Connecticut Appellate Court. UI’s opening brief is due July 15, 2026.

On January 29, 2024, DEEP also served UI with a Summons and Complaint seeking injunctive relief and enforcement of the consent order from the Connecticut Superior Court. UI filed its Answer and Special Defenses on May 13, 2024. A procedural schedule was set by the court that establishes a trial date of October 20, 2026. The case is docketed under the Complex Litigation Docket of the Connecticut Superior Court. DEEP filed a motion to strike UI’s amended special defenses on November 21, 2024, and UI responded on December 23, 2024. This Motion was granted in part, however, UI filed Amended Special Defenses on November 6, 2024. DEEP again filed a Motion to Strike. The Court heard this Motion at the aforementioned March 31, 2025 hearing. DEEP also filed a Motion to Dismiss UI’s Counterclaim for a declaratory ruling on the applicable remediation standard under the PCO. UI timely responded to the Motion to Dismiss. The Motion to Dismiss was granted on February 7, 2025. DEEP also filed a motion to strike UI’s amended special defenses, which the Court granted in part and denied in part. UI’s Special

Notes to Financial Statements

Defenses of waiver and estoppel survived the motion while the contract-based defenses were stricken.

On November 5, 2025, the parties entered into settlement discussions presided over by a mediator. Those discussions are ongoing. The parties have sought extensions of time in the two matters so that the litigation is effectively stayed while settlement discussions take place.

As of March 31, 2026 and December 31, 2025, the amount reserved related to English Station was \$20.1 million and \$20.2 million, respectively. We cannot predict the outcome of this matter.

Other

In 2025, UI initiated remedial action at the property referred to as the East Shore Site located in New Haven. Following procurement for the remedial action activities, UI updated its reserve. The amount reserved for this property was \$18.0 million as of March 31, 2026 and \$18.3 million as of December 31, 2025, respectively.

UI also holds a reserve for remediation of 801 Bridgeport Ave, the site of a former operations center. The amount reserved for this site was \$0.3 million as of both March 31, 2026 and December 31, 2025.

Our environmental liability accruals are recorded on an undiscounted basis and are expected to be paid through the year 2084.

Note 9. Accounting for Derivative Instruments and Hedging Activities

Our operating and financing activities are exposed to certain risks, which are managed by using derivative instruments. All derivative instruments are recognized as either assets or liabilities at fair value on our condensed balance sheets in accordance with the accounting requirements concerning derivative instruments and hedging activities.

Derivatives not designated as hedging instruments

Pursuant to Connecticut's 2005 Energy Independence Act, PURA solicited bids to create new or incremental capacity resources in order to reduce federally mandated congestion charges, and selected four new capacity resources. To facilitate the transactions between the selected capacity resources and Connecticut electric customers, and provide the commitment necessary for owners of these resources to obtain necessary financing, PURA required that UI and The Connecticut Light and Power Company (CL&P) execute long-term contracts with the selected resources. In August 2007, PURA approved four CfDs, each of which specifies a capacity quantity and a monthly settlement that reflects the difference between a forward market price and the contract price. UI executed two of the contracts and CL&P executed the other two contracts. The costs or benefits of each contract will be paid by or allocated to customers and will be subject to a cost-sharing agreement between UI and CL&P pursuant to which approximately 20% of the cost or benefit is borne by or allocated to UI customers and approximately 80% is borne by or allocated to CL&P customers.

PURA has determined that costs associated with these CfDs will be fully recoverable by UI and CL&P through electric rates, and in accordance with ASC 980 "Regulated Operations," UI has deferred recognition of costs (a regulatory asset) or obligations (a regulatory liability). The CfDs are marked-to-market in accordance with ASC 815 "Derivatives and Hedging." For those CfDs signed by CL&P, UI records its approximate 20% portion pursuant to the cost-sharing agreement noted above. As of March 31, 2026, UI has recorded a gross derivative asset of \$0.1 million (\$0 of which is related to UI's portion of the CfD signed by CL&P), a regulatory asset of \$0, a gross

Notes to Financial Statements

derivative liability of \$0.1 million (\$0 of which is related to UI's portion of the CfD signed by CL&P), and a regulatory liability of \$0. As of December 31, 2025, UI had recorded a gross derivative asset of \$0.1 million (\$0 of which is related to UI's portion of the CfD signed by CL&P), a regulatory asset of \$0, a gross derivative liability of \$0.2 million (\$0 of which is related to UI's portion of the CfD signed by CL&P), and a regulatory liability of \$0.

The unrealized gains and losses from fair value adjustments to these derivatives, which are recorded in regulatory assets, for the three months ended March 31, 2026 and 2025, respectively, were as follows:

	Three Months Ended March 31,	
	2026	2025
(Thousands)		
Derivative assets	\$ (76)	\$ (97)
Derivative liabilities	\$ 94	\$ 3,902

Note 10. Fair Value of Financial Instruments and Fair Value Measurements

The estimated fair value of debt amounted to \$1,126 million as of March 31, 2026 and \$1,148 million as of December 31, 2025, respectively. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the electricity industry and the credit ratings of the borrowers in each case. The fair value hierarchy for the fair value of debt is considered as Level 2.

Assets and liabilities measured at fair value on a recurring basis

The financial instruments measured at fair value as of March 31, 2026 and December 31, 2025, respectively, consisted of:

As of March 31, 2026	Level 1	Level 2	Level 3	Total
(Thousands)				
Derivative assets				
Contracts for differences	\$ —	\$ —	\$ 51	\$ 51
Equity investments with readily determinable fair values				
Supplemental retirement benefit trust life insurance policies	—	21,857	—	21,857
Total	\$ —	\$ 21,857	\$ 51	\$ 21,908
Derivative liabilities				
Contracts for differences	\$ —	\$ —	\$ (64)	\$ (64)
Total	\$ —	\$ —	\$ (64)	\$ (64)

Notes to Financial Statements

As of December 31, 2025		Level 1		Level 2		Level 3		Total
(Thousands)								
Derivative assets								
Contracts for differences	\$	—	\$	—	\$	127	\$	127
Equity investments with readily determinable fair values								
Supplemental retirement benefit trust life insurance policies		—		23,293		—		23,293
Total	\$	—	\$	23,293	\$	127	\$	23,420
Derivative liabilities								
Contracts for differences	\$	—	\$	—	\$	(158)	\$	(158)
Total	\$	—	\$	—	\$	(158)	\$	(158)

We had no transfers to or from Level 1 and 2 during the periods ended March 31, 2026 and December 31, 2025. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

Valuation techniques: We determine the fair value of our derivative assets and liabilities and non-current equity investments utilizing market approach valuation techniques:

- UI enters into CfDs, which are marked-to-market based on a probability-based expected cash flow analysis that is discounted at risk-free interest rates and an adjustment for non-performance risk using credit default swap rates. We include the fair value measurement for these contracts in Level 3 (Refer to Note 9 for further discussion of CfDs).
- We measure the fair value of the supplemental retirement benefit life insurance trust based on quoted prices in the active markets for the various funds within which the assets are held and include the measurement in Level 2.

The determination of fair value of the CfDs was based on a probability-based expected cash flow analysis that was discounted at risk-free interest rates, as applicable, and an adjustment for non-performance risk using credit default swap rates. Certain management assumptions were required, including development of pricing that extends over the term of the contracts. We believe this methodology provides the most reasonable estimates of the amount of future discounted cash flows associated with the CfDs. Additionally, on a quarterly basis, we perform analytics to ensure that the fair value of the derivatives is consistent with changes, if any, in the various fair value model inputs. Significant isolated changes in the risk of non-performance, the discount rate or the contract term pricing would result in an inverse change in the fair value of the CfDs. Additional quantitative information about Level 3 fair value measurements of the CfDs is as follows:

Unobservable Input	Range at March 31, 2026	Range at December 31, 2025
Risk of non-performance	0.63%	0.48%
Discount rate	3.72%	3.47%
Forward pricing (\$ per MW)	\$2.59	\$2.59

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The reconciliation of changes in the fair value of financial instruments based on Level 3 inputs for the three months ended March 31, 2026 and 2025, respectively, is as follows:

Three Months Ended March 31,	2026	2025
(Thousands)		
Beginning balance	\$ (31)	\$ (14,151)
Unrealized gains, net	18	3,805
Ending balance	\$ (13)	\$ (10,346)

Note 11. Postretirement and Similar Obligations

The components of net periodic benefit cost for pension and postretirement benefits for the three months ended March 31, 2026 and 2025, respectively, consisted of:

Three Months Ended March 31,	Pension Benefits		Postretirement Benefits	
	2026	2025	2026	2025
(Thousands)				
Net periodic benefit cost				
Service cost	\$ —	\$ —	\$ 41	\$ 58
Interest cost	4,428	4,714	375	560
Expected return on plan assets	(4,968)	(4,479)	(695)	(623)
Amortization of prior service cost (credit)	297	297	(525)	—
Amortization of net loss (gain)	688	773	(393)	(407)
Net periodic benefit cost (credit)	\$ 445	\$ 1,305	\$ (1,197)	\$ (412)

Note 12. Equity Method Investments

UI is a party to a 50-50 joint venture with Clearway Energy, Inc. in GenConn, which operates two peaking generation plants in Connecticut. UI's investment in GenConn is being accounted for as an equity investment, the carrying value of which was \$70.1 million and \$72.1 million as of March 31, 2026 and December 31, 2025, respectively.

UI's pre-tax income from its equity investment in GenConn was \$1.3 million and \$0.3 million for the three months ended March 31, 2026 and 2025, respectively.

Cash distributions from GenConn are reflected as either distributions of earnings or as returns of capital in the operating and investing sections, respectively, of the condensed statements of cash flows. UI received cash distributions from GenConn of \$3.4 million and \$2.0 million during the three months ended March 31, 2026 and 2025, respectively.

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Note 13. Other Income and Other Deductions

Other income and deductions for the three months ended March 31, 2026 and 2025, respectively, consisted of:

Three Months Ended March 31,		2026	2025
(Thousands)			
Interest and dividends income	\$	512	\$ 269
Allowance for funds used during construction		4,012	3,170
Carrying costs on regulatory assets		2,739	2,795
Miscellaneous		(786)	4
Total other income	\$	6,477	\$ 6,238
Pension non-service components	\$	623	\$ (949)
Miscellaneous		(992)	(1,102)
Total other deductions	\$	(369)	\$ (2,051)

Note 14. Related Party Transactions

Certain Networks subsidiaries, including UI, borrow from AGR, the parent of Networks, through intercompany revolving credit agreements. For UI, the intercompany revolving credit agreements provide access to supplemental liquidity. See Note 6 for further detail on the credit facility with AGR.

AGR, through its affiliates, provides administrative and management services to Networks operating utilities, including UI, pursuant to service agreements. The cost of those services is allocated in accordance with methodologies set forth in the service agreements. The cost allocation methodologies vary depending on the type of service provided. Management believes such allocations are reasonable. The charge for operating and capital services provided to UI by AGR and its affiliates was \$20.8 million and \$20.2 million for the three months ended March 31, 2026 and 2025, respectively. The charge for services provided by UI to AGR and its subsidiaries was approximately \$4.8 million and \$4.2 million for the three months ended March 31, 2026 and 2025, respectively. All charges for services are at cost.

The balance in accounts payable to affiliates of \$19.5 million at March 31, 2026 and \$63.1 million at December 31, 2025 is primarily due to UIL Holdings. The balance in accounts receivable from affiliates of \$0.9 million at March 31, 2026 is receivable from various companies and \$67.3 million at December 31, 2025 is receivable from Avangrid Service Company.

There were \$33.0 million of notes receivable from affiliates at March 31, 2026, which is receivable from CMP. There were \$7.7 million notes receivable from affiliates at December 31, 2025, which is receivable from BGC and CNG. Notes payable to affiliates and notes receivables from affiliates relate to the Virtual Money Pool Agreement and the Bi-Lateral Intercompany Facility as discussed in Note 6 of these financial statements.