CITY OF BURLINGTON, VERMONT
ELECTRIC DEPARTMENT

Basic Financial Statements and
Required Supplementary Information

June 30, 2025 and 2024

(With Independent Auditors’ Report Thereon)

CITY OF BURLINGTON, VERMONT
ELECTRIC DEPARTMENT

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KPMG LLP
Two Financial Center
60 South Street
Boston, MA 02111

Independent Auditors' Report

The Board of Electric Commissioners
City of Burlington, Vermont:

Opinions

We have audited the financial statements of the business-type activities and fiduciary activities of the City of Burlington, Vermont Electric Department (the Department), as of and for the years ended June 30, 2025 and 2024, and the related notes to the financial statements, which collectively comprise the Department's basic financial statements as listed in the table of contents.

In our opinions, the accompanying financial statements referred to above present fairly, in all material respects, the respective financial position of the business-type activities and fiduciary activities of the Department, as of June 30, 2025 and 2024, and the respective changes in financial position and, where applicable, cash flows thereof for the years then ended in accordance with U.S. generally accepted accounting principles.

Basis for Opinions

We conducted our audits in accordance with auditing standards generally accepted in the United States of America (GAAS). Our responsibilities under those standards are further described in the Auditors' Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the Department and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audit. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinions.

Emphasis of Matter

Reporting Entity

As discussed in Note 1, the basic financial statements of the Department are intended to present the financial position, the changes in financial position, and, where applicable, cash flows of only that portion of the business-type activities, each major fund, and the aggregate remaining fund information of the City of Burlington, Vermont that is attributable to the transactions of the Department. They do not purport to, and do not, present fairly the financial position of the City of Burlington, Vermont, as of June 30, 2025 or 2024, the changes in its financial position, or, where applicable, its cash flows for the years then ended in accordance with U.S. generally accepted accounting principles. Our opinions are not modified with respect to this matter.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with U.S. generally accepted accounting principles, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinions. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Department's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control related matters that we identified during the audit.

Required Supplementary Information

U.S. generally accepted accounting principles require that the management's discussion and analysis be presented to supplement the basic financial statements. Such information is the responsibility of management and, although not a part of the basic financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the basic financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with GAAS, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the basic financial statements, and other knowledge we obtained during our audit of the basic financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

KPMG LLP

Boston, Massachusetts
November 10, 2025

This section of the City of Burlington, Vermont Electric Department's (the Department) annual financial report presents a discussion and analysis of the Department's financial performance during the fiscal years ended June 30, 2025 and 2024. Please read it in conjunction with the Department's financial statements, which follow this section.

Overview of the Financial Statements

The financial section of this report consists of three parts: management's discussion and analysis (this section); the financial statements, which provide both long-term and short-term information about the Department's overall financial status; and the notes to the financial statements, which explain some of the information in the financial statements and provide more detailed data.

The Department's financial statements are prepared in conformity with U.S. generally accepted accounting principles (GAAP) as applied to governmental proprietary (enterprise) and fiduciary (custodial) funds and employ the economic resources measurement focus and the accrual basis of accounting. The Department follows GAAP for external financial reporting and is subject, as to rates, accounting, and other matters, to the regulatory authority of the State of Vermont Public Utility Commission (PUC) and the Federal Energy Regulatory Commission (FERC). In accordance with FASB ASC Topic 980, *Regulated Operations*, the Department records certain assets and liabilities in accordance with the economic effects of the rate-making process.

Unless otherwise noted, the remainder of management's discussion and analysis will focus on the Department's proprietary (enterprise) activities.

Financial Highlights

June 30, 2025

- Operating income was $749,504, an increase of $881,657 or 667.1% from operating loss in 2024.
- Sales to ultimate customers were $57,194,765, an increase of $3,178,058 or 5.9% from 2024.
- Other revenues (primarily sales of renewable energy credits) were $10,632,497, an increase of $540,705 or 5.4% from 2024.
- Total operating expenses were $66,935,940, an increase of $3,020,590 or 4.7% from 2024.
- Total net position was $68,462,994, an increase of $2,450,510 or 3.7% compared to 2024.
- Total capital assets (net of depreciation) were $105,134,503, an increase of $5,360,283 or 5.4% above 2024.
- The McNeil Generating Station capacity factor for fiscal year 2025 was 47.2% compared to 41.0% in 2024, supplying 205,765 MWH and 180,046 MWH, respectively, of energy production to the Department.

June 30, 2024 (restated)

- Operating loss was $132,153, a decrease of $1,791,826 or 108.0% from the operating income in 2023.
- Sales to ultimate customers were $54,016,707, an increase of $3,483,600 or 6.9% from 2023.
- Other revenues (primarily sales of renewable energy credits) were $10,091,792, a decrease of $2,312,140 or 18.6% from 2023.

(Continued)

- Total operating expenses were $63,915,350, an increase of $2,758,411 or 4.51% from 2023.
- Total net position was $66,012,484, an increase of $1,252,960 or 1.93% compared to 2023.
- Total capital assets (net of depreciation) were $99,774,220, an increase of $2,976,171 or 3.1% above 2023.
- The McNeil Generating Station capacity factor for fiscal year 2024 was 41.0% compared to 48.9% in 2023, supplying 90,023 MWH and 107,033 MWH, respectively, of energy production to the Department.

Financial Analysis of the Department

Net Position

The following summarizes the Department's overall financial position as of June 30, 2025, 2024, and 2023:

	2025	2024	2023	Percentage change 2024–2025	Percentage change 2023–2024	
Current assets – unrestricted	$ 33,692,403	31,216,267	26,304,063	7.9 %	18.7 %	(A)
Restricted assets	10,681,921	16,134,679	21,166,674	(33.8)	(23.8)	(B)
Capital assets, net	105,134,503	99,774,220	96,798,049	5.4	3.1	
Other noncurrent assets	40,236,114	40,474,260	41,362,349	(0.6)	(2.1)	(C)
Total assets	$ 189,744,941	187,599,426	185,631,135	1.1 %	1.1 %	
Deferred outflows of resources	$ 3,903,885	5,745,652	6,703,141	(32.1)%	(14.3)%	(D)
Current liabilities	$ 11,550,486	11,719,761	10,841,125	(1.4)%	8.1 %	(E)
Current liabilities payable from restricted assets	718,157	759,139	798,539	(5.4)	(4.9)	
Other noncurrent liabilities	2,135,601	2,314,029	2,602,838	(7.7)	(11.1)	
Regulatory liability	821,720	—	—	100.0	—	
Net OPEB liability	743,416	815,159	944,849	(8.8)	(13.7)	
Net pension liability	22,032,125	22,820,338	21,677,516	(3.5)	5.3	(F)
Long-term debt, net	77,118,933	79,760,553	82,746,617	(3.3)	(3.6)	(G)
Total liabilities	$ 115,120,438	118,188,979	119,611,484	(2.6)%	(1.2)%	
Deferred inflows of resources	$ 10,065,394	9,143,615	7,963,268	10.1 %	14.8 %	
Net position:						
Net investment in capital assets	$ 41,480,435	39,964,583	45,408,157	3.8 %	(12.0)%	
Restricted	5,882,225	6,408,333	6,475,757	(8.2)	(1.0)	
Unrestricted	21,100,334	19,639,568	12,875,610	7.4	52.5	
Total net position	$ 68,462,994	66,012,484	64,759,524	3.7 %	1.9 %	

(A) Current assets (unrestricted) at June 30, 2025 were $33,692,403, an increase of $2,476,136 compared to June 30, 2024 primarily due to an increase in cash resulting from grant income, and an increase in inventory for fuels, materials, and environmental credits. Current assets (unrestricted) at June 30, 2024 were $31,216,267, an increase of $4,912,204 compared to June 30, 2023 primarily due to an increase in cash resulting from increased interest and grant income, as well as decreased power production expenses and purchased power expenses, and an increase in Renewable Energy Standard inventory values related to Tier 3 credits.

(B) Restricted assets at June 30, 2025 were $10,681,921, a decrease of $5,452,758 compared to June 30, 2024 primarily due to the drawdown of Electric System Revenue Bond Series 2022A proceeds from the Construction Fund, an investment account where bond proceeds are held until used for the bond's intended purpose. Restricted assets at June 30, 2024 were $16,134,679, a decrease of $5,031,995 compared to June 30, 2023 primarily due to the drawdown of Electric System Revenue Bond Series 2022A proceeds from the Construction Fund, an investment account where bond proceeds are held until used for the bond's intended purpose.

(C) Other noncurrent assets at June 30, 2025 were $40,236,114, a decrease of $238,146 compared to June 30, 2024 in accordance with current regulatory asset amortization schedules, partially offset by an equity investment made in associated companies.

Other noncurrent assets at June 30, 2024 were $40,474,260, a decrease of $888,089 compared to June 30, 2023 in accordance with current regulatory asset amortization schedules.

(D) Deferred outflows at June 30, 2025 were $3,903,885, a decrease of $1,841,767 compared to June 30, 2024 due to a decrease in the deferred pension contribution caused by a decrease in the difference between actual and projected investment earnings and changes in assumptions. Deferred outflows at June 30, 2024 were $5,745,652, a decrease of $957,489 compared to June 30, 2023 due to a decrease in the deferred pension contribution caused by a decrease in the difference between actual and projected investment earnings.

(E) Current liabilities at June 30, 2025 were $11,550,486, a decrease of $169,275 compared to June 30, 2024 due primarily to decreases in the current portion of long-term debt and miscellaneous other current liabilities, partially offset by increases in miscellaneous operating payables. Current liabilities at June 30, 2024 were $11,719,761, an increase of $878,636 compared to June 30, 2023 due primarily to increases in the current portion of long-term debt and in other current liabilities due to increases in accrued interest, taxes, and payroll, as well as increases in miscellaneous operating payables.

(F) The net pension liability at June 30, 2025 was $22,032,125, a decrease of $788,213 compared to 2024 due to decreases in the difference between the projected and actual investment earnings and changes in assumptions, offset by increases in the difference between projected and actual plan experience and pension contributions. See note 8 – Retirement Benefits.

The net pension liability at June 30, 2024 was $22,820,338, an increase of $1,142,822 compared to 2023 due to increases in the difference between projected and actual plan experience and pension expense, decreases in the difference between the projected and actual investment earnings, and changes in assumptions related to inflation and salary increases, offset by pension contributions. See note 8 – Retirement Benefits.

(G) Long-term debt, net at June 30, 2025 was $77,118,933, a decrease of $2,641,620 compared to June 30, 2024 in accordance with current maturities schedules. Long-term debt, net at June 30, 2024 was $79,760,553, a decrease of $2,986,064 compared to June 30, 2023 in accordance with current maturities schedules.

Changes in Net Position

A summary of changes in net position for the fiscal years ended June 30, 2025, 2024, and 2023 follows:

		2025	2024	2023	Percentage change 2024–2025	Percentage change 2023–2024	
Operating revenues:							
Sales to ultimate customers	$	57,194,765	54,016,707	50,533,107	5.9 %	6.9 %	(A)
Other revenues		10,632,497	10,091,792	12,403,932	5.4	(18.6)	(B)
Less provision for uncollectible accounts		(141,818)	(325,302)	(120,427)	(56.4)	170.1	
Total operating revenues, net	$	67,685,444	63,783,197	62,816,612	6.1	1.5	

	2025	2024	2023	Percentage change 2024–2025	Percentage change 2023–2024	
Operating expenses:						
Production	$ 11,274,110	10,725,988	12,170,285	5.1 %	(11.9)%	(C)
Purchased power	18,222,026	16,485,085	12,955,104	10.5	27.2	(D)
Other power supply expenses	2,079,826	1,879,455	2,309,897	10.7	(18.6)	(D)
Transmission	10,462,515	9,653,765	9,337,070	8.4	3.4	(D)
Energy storage	3,500	—	—	100.0	—	
Distribution	3,795,691	3,590,222	3,171,244	5.7	13.2	(E)
Customer accounting and service	6,486,677	6,399,553	7,699,127	1.4	(16.9)	(F)
Administration and general	6,883,334	7,654,127	6,264,764	(10.1)	22.2	(G)
Depreciation and amortization	6,779,263	6,397,556	6,176,061	6.0	3.6	(H)
Taxes	948,998	1,129,599	1,073,387	(16.0)	5.2	
Total operating expenses	66,935,940	63,915,350	61,156,939	4.7	4.5	
Operating (loss) income	749,504	(132,153)	1,659,673	(667.1)%	(108.0)%	
Other income (expense):						
Dividend income	4,504,935	4,532,992	4,399,511	(0.6)%	3.0 %	
Interest income	663,645	811,785	501,766	(18.2)	61.8	
Loss on sale of capital assets	(61,736)	(129,310)	(116,431)	(52.3)	11.1	
Grants and other income	1,917,271	1,147,367	(9,137)	67.1	(12,657.4)	
Total other income	7,024,115	6,362,834	4,775,709	10.4	33.2	
Total finance charges	(3,151,344)	(3,345,010)	(3,450,296)	(5.8)	(3.1)	
Income before transfers and capital contributions	4,622,275	2,885,671	2,985,086	60.2	(3.3)	
Transfers to the City for payment:						
In lieu of taxes	(2,487,854)	(2,265,941)	(2,133,939)	9.8	6.2	
Income before capital contributions	2,134,421	619,730	851,147	244.4	(27.2)	
Capital contributions	316,089	633,230	735,644	(50.1)	(13.9)	
Change in net position	2,450,510	1,252,960	1,586,791	95.6	(21.0)	
Net position at end of year	$ 68,462,994	66,012,484	64,759,524	3.7 %	1.9 %	

(A) Sales to ultimate customers in 2025 of $57,194,765 increased by $3,178,058 compared to 2024. 2025 reflected a 5.5% increase in rates effective September 1, 2024 and a 0.33% increase in kilowatt hour usage. Sales to ultimate customers in 2024 of $54,016,707 increased by $3,483,600 compared to 2023.

(Continued)

2024 reflected a 5.50% increase in rates effective September 1, 2023, and a 1.6% increase in kilowatt hour usage.

(B) Other revenues for 2025 of $10,632,497 increased by $540,705 compared to 2024 due to increased rental price for conduit rentals, as well as increased McNeil Generating Station and wind environmental credit (EC) production, partially offset by decreased hydroelectric EC production and decreased cost reimbursements from the Energy Efficiency Utility (EEU). Other revenues for 2024 of $10,091,792 decreased by $2,312,140 compared to 2023 due to decreased cost reimbursements from the EEU, and decreased McNeil Generating Station and wind EC production, partially offset by increased hydroelectric EC production.

(C) Production expense for 2025 of $11,274,110 increased by $548,122 compared to 2024 due to increased fuel expense at the McNeil Generating Station, partially offset by lower fuel expense at the Gas Turbine. Production expense for 2024 of $10,725,988 decreased by $1,444,297 compared to 2023 due to decreased fuel expense at the McNeil Generating Station, partially offset by higher fuel expense at the Gas Turbine.

(D) Purchased power costs for 2025 of $18,222,026 increased by $1,736,941 compared to 2024 due to increased deliveries under wind contracts and the purchase of ECs during the year, partially offset by decreased energy costs through the Independent System Operator-New England (ISO-NE) exchange.

Purchased power costs for 2024 of $16,485,085 increased by $3,529,981 compared to 2023 due to the prior year deferral of a revenue shortfall due to reduced price of sales of excess winter energy to ISO-NE and the related annual amortization, which is recorded under ISO-NE Exchange. This increase is also due to increased prices under the Hydro-Québec contract and a new ISO-NE winter reliability charge, partially offset by decreased ISO-NE capacity and ancillary charges, and decreased deliveries under the Hancock Wind contract.

Other power supply expenses are based on ISO-NE administration charges, labor costs, and EC compliance expenses for each of the comparative periods.

Transmission costs for 2025 of $10,462,515 increased by $808,750 compared to 2024 primarily due to increased ISO-NE and New York Power Authority transmission charges, partially offset by decreased Vermont Electric Power Company (VELCO) transmission charges. Transmission costs for 2024 of $9,653,765 increased by $316,695 compared to 2023 primarily due to increased ISO-NE and VELCO transmission charges, partially offset by decreased New York Power Authority transmission charges.

(E) Distribution expense for 2025 of $3,795,691 increased by $205,469 compared to 2024 primarily due to increases in salaries, station expenses, meters, overhead lines, and miscellaneous expenses. These increases are partially offset by decreases in street lighting, rents, station equipment and underground lines expenses. Distribution expense for 2024 of $3,590,222 increased by $418,978 compared to 2023 primarily due to increases in maintenance expenses related to station equipment, overhead lines, and street lighting.

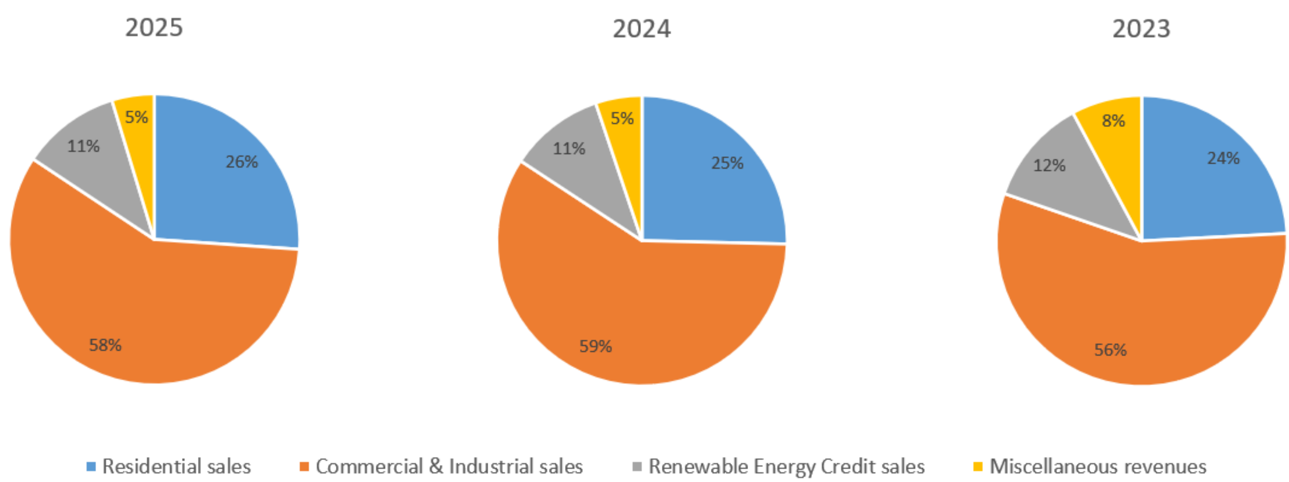
(F) Customer accounting, service, and sales expense for 2025 of $6,486,677 increased by $87,124 compared to 2024 due primarily to an increase in customer assistance expenses and Tier 3 program expenses, partially offset by decrease in EEU program activity expenses and customer record and collection expenses. Customer accounting, service, and sales expense for 2024 of $6,399,553 decreased by $1,299,574 compared to 2023 due primarily to a decrease in EEU program activity expenses, partially offset by increased customer record and collection expenses and Tier 3 program expenses.

(G) Administrative and general (A&G) expense for 2025 of $6,883,334 decreased by $770,793 compared to 2024 primarily due to decrease in pension and benefits, partially offset by increases in salary and office supplies expenses. Administrative and general expense for 2024 of $7,654,127 increased by $1,389,363 compared to 2023 primarily due to increases in salary, pension and benefits, and regulatory commission expenses, partially offset by decreases in office supplies, outside services, and miscellaneous A&G expenses.

(H) Depreciation and amortization, including deferred depreciation expense, for 2025 of $6,779,263 increased by $381,707 compared to 2024 primarily due to an increase in metering equipment depreciation and deferred cost amortization expense, partially offset by a decrease in sinking fund adjustment depreciation expense. Depreciation and amortization, including deferred depreciation expense, for 2024 of $6,397,556 increased by $221,495 compared to 2023 primarily due to an increase in software amortization expense.

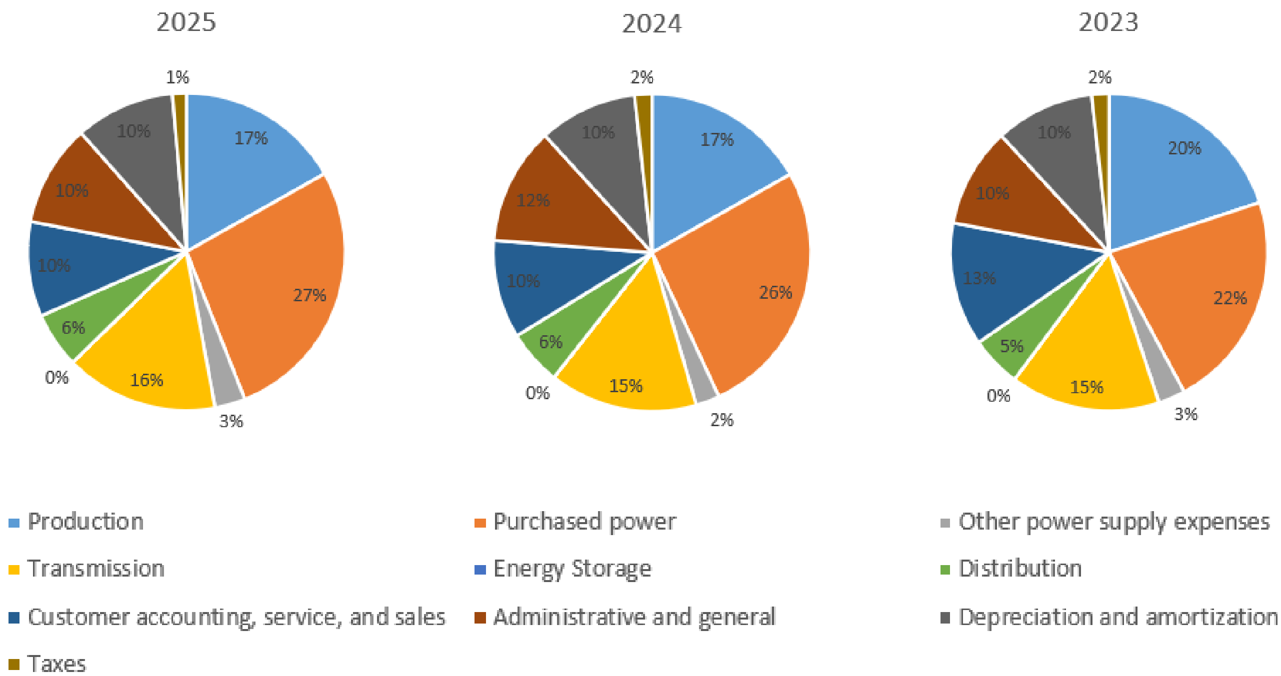
Revenue

The following charts show the major sources of operating revenues for the years ended June 30, 2025, 2024, and 2023:



Operating Expenses

The following charts show the major components of operating expenses for the years ended June 30, 2025, 2024, and 2023:



Long-Term Debt – Revenue and General Obligation Bonds

The following table summarizes long-term debt related to revenue and general obligation bonds for the years ended June 30, 2025, 2024, and 2023:

		2025	2024	2023
Revenue bonds, net of current installments	$	33,171,972	34,571,128	36,574,879
General obligation bonds, net of current installments		43,946,961	45,189,425	46,171,738
Total bonds, net	$	77,118,933	79,760,553	82,746,617

During the fiscal year ended June 30, 2025, the Department, through the City of Burlington, issued $3,000,000 in general obligation bonds, 2024 Series A, with an average coupon rate of 5%.

During the fiscal year ended June 30, 2024, the Department, through the City of Burlington, issued $2,785,000 in general obligation bonds, 2022 BAN Refunding-Electric Department Portion, with an average coupon rate of 5.02%. The Department, through the City of Burlington, also issued $3,000,000 in general obligation bonds, 2023 Series A, with an average coupon rate of 5.02%. These bonds were issued for use during fiscal year 2024 in accordance with the City Charter to cover annual capital improvements to the electric infrastructure of the Department.

Capital Assets

The following chart summarizes capital assets and accumulated depreciation for the years ended June 30, 2025, 2024, and 2023:

		2025	2024	2023
Capital assets	$	227,946,539	217,476,676	209,678,058
Accumulated depreciation/amortization		122,812,036	117,702,456	112,880,009
Net capital assets	$	105,134,503	99,774,220	96,798,049

Capital assets are stated at historical cost and include assets related to land, production plant, transmission plant, distribution plant, general plant, and other plant. Capital assets also include the Department's ownership interest in the following jointly owned facilities:

	2025	2024	2023
McNeil Generating Station	50.0 %	50.0 %	50.0 %

During 2025, net capital assets increased $5,360,283 from 2024. Net capital asset additions amounted to $10,469,863 which included improvements to production and distribution plant and transportation equipment. These capital asset additions were offset by depreciation expense of $4,807,090 and retired plant assets with a net carrying value of $219,420.

During 2024, net capital assets increased $2,976,171 from 2023. Net capital asset additions amounted to $7,798,618 which included improvements to production and distribution plant and transportation equipment. These capital asset additions were offset by depreciation expense of $4,683,965 and retired plant assets with a net carrying value of $370,928.

Requests for Information

This financial report is intended to provide an overview of the finances of the Department for those with an interest in this organization. Questions concerning any information contained in this report may be directed to Emily Stebbins-Wheelock, CFO and Manager of Strategy & Innovation.

CITY OF BURLINGTON, VERMONT
ELECTRIC DEPARTMENT

Statements of Net Position – Proprietary (Enterprise) Fund

June 30, 2025 and 2024

Assets and Deferred Outflows of Resources	2025	2024
Capital assets, net	$ 105,134,503	99,774,220
Current assets:		
Cash and cash equivalents	13,234,262	12,334,880
Restricted investments – deposits with bond trustees and accrued interest receivable	718,157	759,139
Accounts receivable, net of allowance for uncollectible accounts of $302,491 and $217,263, respectively	5,209,077	5,063,177
Unbilled revenues	2,792,386	2,648,674
Fuel and materials inventory, at average cost	7,869,647	7,239,687
Environmental credits inventory	2,787,397	2,307,617
Other	1,799,634	1,622,232
Total current assets	34,410,560	31,975,406
Noncurrent assets:		
Restricted investments – deposits with bond trustees	9,963,764	15,375,540
Regulatory assets	4,357,768	5,172,924
Equity interests in associated companies	35,878,346	35,301,336
Total noncurrent assets	50,199,878	55,849,800
Total assets	189,744,941	187,599,426
Deferred outflows of resources:		
Loss on advanced refunding	205,451	248,155
Pension amounts	3,639,432	5,379,034
Other post-employment benefits amounts	59,002	118,463
Total deferred outflows of resources	3,903,885	5,745,652

(Continued)

CITY OF BURLINGTON, VERMONT
ELECTRIC DEPARTMENT

Statements of Net Position – Proprietary (Enterprise) Fund

June 30, 2025 and 2024

Liabilities and Deferred Inflows of Resources	**2025**	**2024**
Liabilities:		
Current liabilities:		
Current installments of long-term debt:		
Revenue bonds	$ 1,395,000	2,000,000
General obligation debt of the City of Burlington	4,445,000	4,180,000
Accounts payable	3,664,079	3,140,439
Other current liabilities	2,046,407	2,399,322
Liabilities payable from restricted assets – deposits with bond trustees	718,157	759,139
Total current liabilities	12,268,643	12,478,900
Noncurrent liabilities:		
Long-term debt:		
Revenue bonds	33,171,972	34,571,128
General obligation debt of the City of Burlington	43,946,961	45,189,425
Other noncurrent liabilities	2,135,601	2,314,029
Regulatory liability	821,720	—
Net pension liability	22,032,125	22,820,338
Other post-employment benefits	743,416	815,159
Total noncurrent liabilities	102,851,795	105,710,079
Total liabilities	115,120,438	118,188,979
Deferred inflows of resources:		
Pension amounts	1,152,140	698,083
Other post-employment benefits amounts	468,248	551,792
Regulatory deferral	8,445,006	7,893,740
Total deferred inflows of resources	10,065,394	9,143,615
Net position		
Net position:		
Net investment in capital assets	41,480,435	39,964,583
Restricted:		
Deposits with bond trustees	5,882,225	6,408,333
Unrestricted	21,100,334	19,639,568
Total net position	$ 68,462,994	66,012,484

See accompanying notes to financial statements.

CITY OF BURLINGTON, VERMONT
ELECTRIC DEPARTMENT

Statements of Revenues, Expenses, and Changes in Net Position – Proprietary (Enterprise) Fund

Years ended June 30, 2025 and 2024

		2025	2024
Operating revenues:			
Sales to ultimate customers	$	57,194,765	54,016,707
Other revenues		10,632,497	10,091,792
		67,827,262	64,108,499
Less provision for uncollectible accounts		141,818	325,302
Total operating revenues, net		67,685,444	63,783,197
Operating expenses:			
Production		11,274,110	10,725,988
Purchased power		18,222,026	16,485,085
Other power supply expenses		2,079,826	1,879,455
Transmission		10,462,515	9,653,765
Energy Storage		3,500	—
Distribution		3,795,691	3,590,222
Customer accounting, service, and sales		6,486,677	6,399,553
Administrative and general		6,883,334	7,654,127
Depreciation and amortization		6,779,263	6,397,556
Taxes		948,998	1,129,599
Total operating expenses		66,935,940	63,915,350
Operating income (loss)		749,504	(132,153)
Nonoperating revenue (expenses):			
Dividends from associated companies		4,504,935	4,532,992
Interest income		663,645	811,785
Grant income		1,764,030	650,061
Other income, net		58,744	93,934
Unrealized gain on investment		94,497	403,372
Interest and amortization on long-term debt		(3,151,344)	(3,345,010)
Loss on sale of capital assets		(61,736)	(129,310)
Total nonoperating revenue		3,872,771	3,017,824
Income before transfers and capital contributions		4,622,275	2,885,671
Transfers to the City of Burlington for payment in lieu of taxes		(2,487,854)	(2,265,941)
Gain before capital contributions		2,134,421	619,730
Capital contributions		316,089	633,230
Increase in net position		2,450,510	1,252,960
Net position at beginning of year (as restated)		66,012,484	64,759,524
Net position at end of year	$	68,462,994	66,012,484

See accompanying notes to financial statements.

CITY OF BURLINGTON, VERMONT
ELECTRIC DEPARTMENT

Statements of Cash Flows – Proprietary (Enterprise) Fund

Years ended June 30, 2025 and 2024

	2025	2024
Cash flows from operating activities:		
Receipts:		
From ultimate customers	$ 56,827,630	52,984,171
Other revenues	10,624,792	10,030,640
Payments made for:		
Purchased power	(18,049,580)	(15,959,182)
Power production expense	(13,376,871)	(12,230,067)
Transmission expense	(10,462,515)	(9,653,765)
Energy storage expense	(3,500)	—
Distribution expense	(4,435,233)	(3,620,570)
Customer accounts and service expense	(6,995,375)	(7,095,491)
Administration and general expense	(5,300,198)	(5,703,763)
General taxes	(944,324)	(1,105,798)
Net cash provided by operating activities	7,884,826	7,646,175
Cash flows from capital and related financing activities:		
Acquisition and construction of capital assets	(11,650,016)	(8,331,422)
Capital contributions	316,089	633,230
Proceeds from bond premium	625,052	820,963
Principal paid on outstanding debt	(6,180,000)	(5,760,000)
Proceeds from new debt issuance	3,000,000	5,785,000
Refinancing of short-term borrowing	—	(3,000,000)
Interest paid on outstanding debt	(3,390,020)	(3,537,347)
Net cash used in capital and related financing activities	(17,278,895)	(13,389,576)
Cash flows from noncapital financing activities:		
Amounts paid in lieu of taxes	(2,487,854)	(2,265,941)
Regulatory liability	821,720	—
Grant income	1,764,030	650,061
Other income	58,744	93,934
Net cash provided by (used in) noncapital financing activities	156,640	(1,521,946)
Cash flows from investing activities:		
Withdrawals from (deposits with) Bond Trustees	1,739,090	1,538,227
Proceeds from deposits with Bond Trustees	3,808,166	3,897,140
Purchase of equity interest in associated companies	(577,010)	—
Interest and dividends on investments	5,166,565	5,324,626
Net cash provided by investing activities	10,136,811	10,759,993
Net increase in cash and cash equivalents	899,382	3,494,646
Cash and cash equivalents at beginning of year	12,334,880	8,840,234
Cash and cash equivalents at end of year	$ 13,234,262	12,334,880
Reconciliation of cash from operating activities:		
Cash flows from operating activities:		
Operating income (loss)	$ 749,504	(132,153)
Adjustments to reconcile operating income (loss) to net cash provided by operating activities:		
Depreciation	4,729,890	4,562,055
Deferred depreciation expense realized in current year	656,704	1,277,053
Deferred projects amortization	1,392,669	558,448
Debt premium and discount amortization	(235,248)	(230,560)
Changes in assets and liabilities:		
Change in accounts receivable	(145,900)	(703,091)
Change in fuel and materials inventory	(629,960)	150,640
Change in unbilled revenues	(143,712)	(312,594)
Change in other deferred charges	815,156	888,089
Change in other current assets	(175,388)	(71,002)
Change in unbundled environmental credits inventory	(479,780)	(461,360)
Change in loss on advance refunding	42,704	46,499
Change in accounts payable	523,640	124,256
Change in other current liabilities	(346,645)	305,850
Change in net deferred inflow/outflow pension liability	1,405,446	1,990,396
Change in net deferred inflow/outflow OPEB liability	(95,826)	(57,542)
Change in other noncurrent liabilities	(178,428)	(288,809)
Net cash provided by operating activities	$ 7,884,826	7,646,175

See accompanying notes to financial statements.

CITY OF BURLINGTON, VERMONT
ELECTRIC DEPARTMENT

Statements of Net Position – Fiduciary (Custodial) Fund

June 30, 2025 and 2024

		2025	2024
Assets:			
Cash	$	2,324,047	1,625,807
Accounts receivable		459,111	334,458
Total assets		2,783,158	1,960,265
Liabilities:			
Accounts payable		170,363	190,703
Gross revenue taxes payable		8,101	5,692
Fuel taxes payable		1,448	950
Total liabilities		179,912	197,345
Net position restricted for Energy Efficiency Utility programs	$	2,603,246	1,762,920

See accompanying notes to financial statements.

CITY OF BURLINGTON, VERMONT
ELECTRIC DEPARTMENT

Statements of Changes in Net Position – Fiduciary (Custodial) Fund

June 30, 2025 and 2024

		2025	2024
Additions:			
EEC collections from customers	$	2,738,876	2,104,952
Forward capacity market		216,073	194,022
Regional greenhouse gas initiative		596,087	468,968
Weatherization Repayment Assistance Program Administrative Fees			12,000
Total additions		3,551,036	2,779,942
Deductions:			
Payments for programs		2,117,820	2,581,219
Payments for administration		557,554	302,534
EEC uncollectible return		7,263	6,347
Gross revenue taxes		14,379	11,177
Fuel taxes		13,694	10,525
Total deductions		2,710,710	2,911,802
Change in net position		840,326	(131,860)
Net position at beginning of year		1,762,920	1,894,780
Net position at end of year	$	2,603,246	1,762,920

See accompanying notes to financial statements.

(1) Summary of Significant Accounting Policies

(a) Basis of Presentation

The City of Burlington, Vermont Electric Department (the Department) is an enterprise fund of the City of Burlington, Vermont (the City). The City has overall financial accountability for the Department, its Council appoints the Commissioners of the Department who oversee its operations, and the City collateralizes the Department's general obligation debt. The Department is also subject as to rates, accounting, and other matters, to the regulatory authority of the State of Vermont Public Utility Commission (PUC) and the Federal Energy Regulatory Commission (FERC). In accordance with Governmental Accounting Standards Board (GASB) Statement No. 62, *Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30,1989 FASB and AICPA Pronouncements as amended*, the Department records certain assets, liabilities, and deferred inflows of resources in accordance with the economic effects of the rate-making process.

The Department has been offering demand-side management programs since 1989. Effective 1999 the Department became an Energy Efficiency Utility (EEU). The PUC issued an Order of Appointment to the Department to serve as a Vermont EEU within its service territory effective January 1, 2017 through December 31, 2027. The Department is responsible for designing and implementing demand-side services and initiatives to comprehensively address cost-effective opportunities associated with electric and Thermal Energy and Process Fuels (TEPF) efficiency. In addition, effective January 1, 2020 the Department began to function as the Fiscal Agent and fund administrator under 30 V.S.A Section 209(d)(3) for electric efficiency and TEPF activities.

This report includes all of the Department's proprietary fund, which accounts for all activities of the Department. In addition, as discussed in note 1(t), the Department has a custodial relationship with the EEU. As the activities of the custodial fund do not belong to the Department, the net position and related changes in net position related to the custodial fund are reported within the Statements of Net Position – Fiduciary (Custodial) Fund and Statements of Changes in Net Position – Fiduciary (Custodial) Fund.

(b) Capital Assets

Capital assets are stated at historical cost. Provisions for depreciation of general capital assets are reported using the straight-line method at rates based upon the estimated service lives and salvage values of the several classes of property. For revenue bond-funded assets, when those assets have a longer (or shorter) life than the term of the bond funding them, the Department makes two adjustments to depreciation expense (a sinking fund depreciation adjustment and a straight-line depreciation adjustment) to align the timing of rate recovery with the timing of debt principal payments. For assets with a longer life than the term of the bond, the difference between the two adjustments is included in deferred inflows and will be amortized over the remaining life of the asset after the bonds are retired. For certain McNeil assets with a shorter life than the term of the bond, the difference between the two adjustments is included in regulatory assets and will be recovered in future years. See note 4, Regulatory Assets and Regulatory Deferred Inflows of Resources.

Maintenance and repairs of capital assets are charged to maintenance expense. Replacements and betterments are capitalized to capital assets. When assets are retired or otherwise disposed of, the costs are removed from capital assets, and such costs, plus removal costs, net of salvage, are charged to accumulated depreciation.

The Department's capitalization policy considers four factors. Property will be capitalized when:

1. The combined cost to put a unit in service is more than $500 and
2. The unit's estimated life is at least three (3) years.
3. The unit is vital to the Department and must be controlled and tracked, even if it falls under the dollar limit stated in (1) above. Watt-hour meters to record electric usage are the only unit in this category.
4. The PUC rules in a rate-making decision that the Department will capitalize a cost that normally would not be capitalized based on the first three factors above. The Department does not have any assets in this category.

The depreciable lives of utility plant are as follows:

	Depreciable lives
Production plant	10-50 years
Transmission plant	33-50 years
Distribution plant	10-50 years
General plant	5-50 years
Other plant	5 years

(c) Jointly Owned Facility

The Department has recorded its ownership interest in its jointly owned facility as capital assets. The Department's ownership interest in the jointly owned facility is as follows:

	2025	2024
McNeil Generating Station	50.0 %	50.0 %

The Department is responsible for its proportionate share of the operating expenses of the jointly owned facility that are billed to the Department monthly. The associated operating costs allocated to the Department are classified in their respective expense categories in the Statements of Revenues, Expenses, and Changes in Net Position. Separate special-purpose financial statements are available from the Department for this jointly owned facility.

(Continued)

(d) Cash, Cash Equivalents, and Investments

The Department considers unrestricted short-term investments, including money markets and certificates of deposit, that have an original maturity of 90 days or less, to be cash equivalents. The Department considers all restricted money market funds and certificates of deposit that have an original maturity of 90 days or more to be investments. Investments are carried at fair value.

(e) Equity Interests in Associated Companies

The Department follows the cost method of accounting for its 6.38% Class B common stock, 1.97% Class C common stock, and 7.69% Class C preferred stock equity interest in VELCO, and its 5.70% equity interest in Vermont Transco, LLC. Vermont Transco is an affiliated entity of VELCO. VELCO owns and operates a transmission system in the State of Vermont over which bulk power is delivered to all electric utilities in the State of Vermont. Under a Power Transmission Contract with the State of Vermont, VELCO bills all costs, including amortization of its debt and a fixed return on equity, to the State of Vermont and others using the system.

During the year ended June 30, 2025, the Department purchased 25,389 Class A units and 32,312 Class B units in Transco for a cost of $577,010.

During the year ended June 30, 2024, the Department did not make any additional purchases in Transco.

Schedule of carrying value in associated companies

	June 30	
	2025	**2024**
Velco, Class B common stock	$ 1,403,800	1,403,800
Velco, Class C common stock	39,200	39,200
Velco, Class C preferred stock	11,196	11,196
VT Transco, LLC, A Units	15,146,640	14,892,751
VT Transco, LLC, B Units	19,277,510	18,954,389
	$ 35,878,346	35,301,336

(f) Restricted Investments – Deposits with Bond Trustees

The Department has established certain funds required by the General Bond Resolution adopted by the City of Burlington on October 7, 1981 pursuant to which the Electric System Revenue Bonds were issued. The funds include debt service, debt service reserve, construction (capital improvements), and renewal and replacement. Investment securities held in deposits with bond trustees are stated at fair value.

(g) Liabilities Payable from Restricted Assets with Bond Trustees

This balance represents accrued interest expense associated with the Electric System Revenue Bonds. Deposits are made with the Bond Trustees as required by the General Bond Resolution pursuant to which the Electric System Revenue Bonds were issued.

(h) Operating and Nonoperating Revenues and Expenses

Operating revenues are defined as income received from the sale of electricity to retail customers as well as to other entities for the purpose of resale. In addition, it includes rents from electric property; fees for changing, connecting, or disconnecting service; revenues from the transmission of electricity of others over transmission facilities of the utility; revenue from the sale of Environmental Credits (ECs); and revenue received from requesting utilities to run generation facilities when not economically feasible due to normal market conditions.

Operating expenses are defined as the ordinary costs and expenses of the Department for the operation, maintenance, and repair of the electric plant. Operating expenses include the cost of production by the Department’s owned generating facilities, purchased power, system control and load dispatch, maintenance of transmission and distribution systems, customer accounting and service expenses, administrative and general expenses, and depreciation and amortization. Operating expenses do not include the principal and interest on bonds, notes, or other costs of indebtedness.

Nonoperating revenues are defined as income received from sources other than the sale of electricity or from rents and fees from electric property or services. Nonoperating revenues generally include interest and dividend income, services rendered to customers upon their request, sale of parts from inventory to contractors, and rental of nonutility property merchandise.

Revenues from the sale of electricity, including amounts billed to the City of Burlington, are billed monthly based on billing rates authorized by the PUC that are applied to customers’ consumption of electricity.

The fair value of donated capital assets is reported in the accompanying financial statements as capital contributions.

(i) Estimated Unbilled Revenue

The Department records unbilled revenue at the end of each accounting period based on estimates of electric services rendered but not yet billed to customers.

(j) Taxes and Fees

The Department is exempt from Federal income taxes. Although it is also exempt from municipal property taxes, the Department pays an amount in lieu of taxes to the City of Burlington. The Department incurred payments in lieu of taxes totaling $2,505,184 and $2,281,861 for the years ended June 30, 2025 and 2024, respectively, with $17,330 and $15,920, respectively, being allocated to operating expenses.

In addition to the payments in lieu of taxes, the Department paid indirect costs of $412,108 and $403,783 in 2025 and 2024, respectively, for a prorated share of costs associated with general government, human resources, and city attorney services as billed by the City Treasurer's Office.

The City of Burlington requires the Department to charge a franchise fee on its electric bills to its retail customers on behalf of the City. The franchise fee for both 2025 and 2024 was 3.5% of operating revenues and was charged separately to customers on electric bills and is therefore excluded from both operating revenues and expenses. The Department is not required to pay the City for franchise fee amounts billed to customers but not collected.

The Vermont Department of Taxes assesses a 6% sales and use tax on 31% of taxable purchases for the McNeil Generating Station. Due to a manufacturers' exemption clause, purchases of wood chips, oil, gas, and electricity were not subject to sales and use tax for the years ended June 30, 2025 and 2024. The City of Burlington imposed a 1% sales tax upon taxable sales within the City. The McNeil Generating Station is exempt from these sales taxes due to only being subject to use taxes.

(k) Inventories

Inventories consist of fuel, materials, supplies, and purchased Tier 1 ECs and earned Tier 3 Credits eligible for compliance with Vermont's Renewable Energy Standard (RES). Inventories are stated at the lower of cost or market. Cost is determined on a weighted average cost basis. Fuel is reported as inventory until it is used for power production, at which time it is expensed as a component of fuel expense. Wood fuel inventory consists of the cost of woodchips. As wood fuel inventory is used, it is expensed on a weighted average cost basis. Material and supplies inventory consists of items primarily used in the utility business for construction, operation, and maintenance of poles, wires, and conduit. Tier 1 ECs and Tier 3 Credits are reported as inventory until used for annual compliance with Vermont's RES, at which time they are expensed as a component of other power supply expense and customer accounting, service, and sales expense, respectively.

(l) Deferred Loss on Refunded Debt

The Department incurred various losses in prior years in connection with the refinancing of Electric System Revenue Bonds. A deferred loss on reacquired (refunded) debt is amortized over the life of the new debt. Unamortized balances are included as a deferred outflow of resources on the statements of net position.

(m) Unamortized Debt Premiums and Discounts

Premiums and discounts incurred in connection with the sale of bonds are amortized over the terms of the related debt. Unamortized balances are included as a component of long-term debt.

(n) Restricted Net Position

Net position is restricted when constraints are placed on them externally. When both restricted and unrestricted resources are available for use, it is the Department's policy to use restricted assets first with unrestricted resources used as needed.

(Continued)

(o) Use of Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant items subject to such estimates and assumptions include the allowance for doubtful accounts and unbilled revenue and the valuation of the net pension and other post-employment benefits (OPEB) liabilities. Actual results could differ from those estimates.

(p) Accounts Receivable and Allowance

The Department records customer accounts receivable at net realizable value. This value includes an appropriate allowance for estimated uncollectible accounts to reflect any expected loss on the accounts receivable balances and charged to the provision for doubtful accounts. The Department calculate this allowance based on available relevant information, in addition to historical loss information and the level of past-due accounts based on the contractual terms of the receivables. The allowance for doubtful accounts was $302,491 and $217,263 as of June 30, 2025 and 2024, respectively.

(q) Environmental Credits

The Department receives ECs based on the amount of energy produced by its renewable resources in a year. These ECs have value in terms of allowing the holder to demonstrate compliance with the Renewable Portfolio Standard (RPS) requirements of the various New England states. These ECs may be bought and sold, separate from the underlying energy production, and vary in value based on the amount of supply versus the demands created by the RPS, for each particular type of EC. The ability to claim energy renewability is transferred with the EC (either lost in the case of an EC sale or acquired in the case of an EC purchase).

The Department's policy & planning staff monitors output levels from the EC-producing units, EC commitments made, the markets for these ECs, and the state statutes and rules that govern the creation and sale of these ECs. With the advent of Vermont's RES in 2017, the policy & planning staff also monitor the Department's own need for ECs to comply with the RES.

The Department periodically sells ECs either through broker-initiated transactions or through direct placement with entities that need the ECs to comply with various New England statutes. The Department enters into agreements to sell or buy ECs for prior, current, and future years' production and electricity sales. Any revenue related to such sales recognized at the time ECs are actually delivered. Any expenses related to such purchases are recognized at the time the contracts are signed.

In 2008, the McNeil Generating Station (McNeil) installed a Regenerative Selective Catalytic Reduction (RSCR) unit. The RSCR unit significantly reduces McNeil's Nitrous Oxide (NOx) emission levels, which allows the station to qualify to sell Connecticut Class 1 ECs. The McNeil ECs are determined to be qualified for sale based on a review of emissions outputs submitted by McNeil. At the end of every quarter, an affidavit is signed stating whether McNeil's emissions meet the requirements needed to produce Connecticut Class 1 ECs. McNeil receives a certification from the State of Connecticut indicating that it met the standards for the quarter based on the statistics provided by McNeil.

(Continued)

Effective September 1, 2014, the Department became the 100% owner of the Winooski One hydroelectric facility. Winooski One is a Low Impact Hydro Institute (LIHI)–certified generator and is qualified to produce Massachusetts Class 2 ECs (non–waste-to-energy).

The Department receives ECs from the Vermont Wind Project in Sheffield (the Department is entitled to 40% of the output of the 40 MW project), the Georgia Mountain Community Wind Farm (the Department is entitled to the full 10 MW of output from the project), along with ECs from its entitlement to 13.5 MW of the 52 MW Hancock Wind Project. The ECs from all these wind facilities are qualified for participation in most of the high-value New England EC markets.

In February 2015, the Department commissioned a 500 kW AC solar array at the Burlington International Airport (and leases space on the parking garage roof under a long-term agreement between the Department and the Burlington International Airport). Following that, in October 2015, the Department commissioned a 107 kW AC solar array at the Department's offices at 585 Pine Street. The Department owns 100% of these resources. Additionally, Burlington receives ECs from South Forty Solar, a 2.5 MW solar array, as well as ECs (or similar attributes) from several smaller solar arrays totaling 409 kW. One of the solar PPAs discussed in the Commitments and Contingencies Footnote (11.b.7) has elected not to transfer ECs to the Department. All of these systems reside within the City limits. These solar arrays are designed to help reduce the Department's peak demand and energy needs during high-priced periods. Most of these facilities are qualified to produce Massachusetts Class 1 ECs. The Pine Street array and South Forty Solar project are also qualified as Vermont Tier 2 ECs, which can be applied to the Department's Tier 3 obligation under the RES if Tier 3 program activity does not meet or exceed Tier 3 requirements.

In January 2025, the Vermont PUC approved the Department's application to aggregate solar net-metering systems within its service territory for purposes of monitoring and reporting Vermont RES Tier 2 ECs to the New England Power Pool Generation Information System ("NEPOOL GIS"). BED must submit to the PUC quarterly energy production from these systems along with any additions and modifications to its list of aggregated facilities on a quarterly basis. Pursuant to Vermont's RES, BED cannot sell these ECs, they need to be retired in satisfaction of the RES (but they do reduce the need for the Department to purchase ECs to retain renewability in a like amount).

The Department no longer receives ECs from Vermont Standard Offer projects purchased by the Vermont Purchasing Agent. At the end of 2016, the Department's status as a distribution utility that sources 100% of the load it serves from renewable sources exempted it from purchasing energy from these projects in 2017. As of June 30, 2025, the Department expects this exemption will continue through at least 2026.

The Department purchases Vermont Tier 1 ECs to replace the New England Class I ECs that are sold in the market to maintain its ability to claim 100% renewability. The Department will continue to purchase ECs to replace the New England Class I ECs that are sold into the market on a voluntary basis.

Vermont's RES was updated in 2024 to include two additional categories of requirements. As a 100% renewable utility, the Department is exempt from Tier 4, which requires a defined percentage of the renewable energy that electric distribution utilities use to satisfy Tier 1 be from new regional renewable energy. Starting January 1, 2025, the Department must comply with Tier 5, which requires that 100% renewable utilities satisfy a certain percentage of their annual load growth above the baseline load of calendar year 2024 (beginning at 50% and increasing through 2035) with energy from facilities that qualify under Tier 2 (distributed renewable energy) or Tier 4 (new regional renewable energy with an in-service date after January 1, 2010). The Department has solar resources and the above-described net metered ECs that qualify for Tier 2 along with ECs from multiple wind resources that currently qualify for Tier 4; both therefore may be used for Tier 5 compliance. To the extent that the Department does have an obligation pursuant to Tier 5 and needs to retire Tier 4 ECs, that obligation will reduce the ability to sell (and the need to replace) high value ECs.

Proceeds from EC sales are included in other revenue. For the fiscal year ended June 30, 2025, EC revenue for McNeil, wind resources, the Winooski One hydroelectric facility, and the solar arrays were $3,756,750, $2,724,148, $814,697, and $145,830 respectively. For the fiscal year ended June 30, 2024, REC revenue for McNeil, wind resources, the Winooski One hydroelectric facility, and the solar arrays were $3,157,978, $2,437,683, $1,007,220 and $175,383 respectively.

(r) Pollution Remediation Obligations

The City is a potentially responsible party (PRP) as one of several landowners of a hazardous waste superfund site in Burlington, Vermont that is the subject of remediation ordered by the Environmental Protection Agency (EPA). The Department has agreed to share on an equal basis with the City all past and future costs incurred in connection with the remediation of this site. In light of the agreement between the City and the EPA concerning the remediation plan at the site, the Department believes that the likelihood of any liability material to the financial position of the Department is remote and as such no liability has been accrued as of June 30, 2025 and 2024.

The Department faces possible liability with respect to the J. Edward Moran Electric Generation Station (Moran Station). The Moran Station is a decommissioned coal-fired power plant that was controlled and operated by the Department from 1954 until 1990 when the Department entered into a memorandum of understanding (MOU) with the City of Burlington transferring responsibility for the Moran Station to the City. The MOU transferred the Moran Station to the City in “as is” condition and held the Department harmless for any and all future liability and or responsibility for such Moran Station and property, excluding environmental remediation (if any) which shall be required in the future by a state or federal environmental regulatory agency, for conditions existing before the transfer. In 2009 the City conducted an assessment of activities at the Moran Station site and was engaged in a corrective action plan with the Vermont Department of Environmental Conservation. The City and the Department entered into a letter of agreement in December 2009 whereby the Department agreed to make a $100,000 payment to the City as settlement of the Department’s liability for any and all environmental remediation costs associated with known environmental contamination at the Moran Station. In September 2019, the City began the efforts of creating a Site Resolution Plan and in February 2020, the City Council authorized the Mayor to execute a settlement agreement between the City and the Department to compensate the City for the costs of abating/remediating contaminants that had been identified at that time as requiring such abatement. In June 2022, the Department entered into a new MOU with the City of Burlington that calls for the Department to make a contribution of $950,715 toward the abatement and/or remediation of the contaminants. The terms of the MOU also release the Department from any future environmental liability at the Moran site for any known or unknown above-ground contamination and any below-ground contamination that is known or should have been known as of the date of the MOU. The MOU further requires the City to consult with and obtain prior consent from the Department concerning future soil disturbance or the proposed use of the Moran site in a different manner than the current condition. The Department also executed a promissory note with the City that calls for the Department to pay the City the $950,715 in eight equal installments with an interest rate of 1.00% per year on the unpaid principal. This obligation is reported as an other current and other non-current liability.

There have been no legally enforceable liabilities associated with the retirement of a tangible asset and as such no asset retirement obligation has been recorded for the years ending June 30, 2025 and 2024.

(s) Pension Obligations

In accordance with GASB Statement No. 68, *Accounting and Reporting for Pensions,* and GASB No. 71*, Pension Transitions for Contributions Made Subsequent to the Measurement Date – an amendment of GASB Statement No. 68*, employers report a net pension liability and related pension amounts as determined by the plan under the requirements contained in GASB Statement No. 67. Disclosures required under GASB Statement No. 68 apply to the Department for its participation in the City of Burlington Employees Retirement System defined benefit plan.

(t) Postemployment Benefits other than Pensions

In accordance with GASB Statement No. 75, *Accounting and Financial Reporting for Postemployment Benefits other than Pensions*, employers report liabilities, deferred outflows of resources, deferred inflows of resources, and expenses associated with OPEB plans.

(u) Fiduciary Activities

The Department has adopted GASB Statement No. 84, *Fiduciary Activities*. Guidance under GASB Statement No. 84 updates existing guidance regarding the identification of fiduciary activities for accounting and financial reporting purposes and how these activities should be reported. Since January 1, 2020, the Department functions as the Fiscal Agent and fund administrator under 30 V.S.A Section 209(d)(3) for electric efficiency and TEPF.

As a result of the implementation of GASB Statement No. 84, the EEU activities and the Department’s role as a Fiscal Agent are considered a fiduciary activity and as such are reported as custodial assets within the financial statements.

(v) Leases

The Department has adopted GASB Statement No. 87, *Leases*. Guidance under GASB Statement No. 87 updates existing guidance regarding the standards of accounting and financial reporting for leases by lessees and lessors. The Department evaluated its existing leases and determined that the amounts associated do not have a material effect on the Department’s financial statements for the years ending June 30, 2025 and 2024.

(Continued)

(w) Vermont Renewable Energy Standard Compliance

VT RES Tier 1 EC purchases and Tier 3 program activity in excess of that required for compliance in a given period appear as EC inventory assets on the Statement of Net Position. ECs and Tier 3 credits used for annual compliance are expensed as a component of other power supply expense and customer accounting, service, and sales expense, respectively. This accounting policy improves the alignment between the expenses being recorded and the statutory obligation for compliance in each reporting period, aligns the amount recorded as an annual expense more closely with the amount that Vermont regulators will allow to be recoverable in rates, and improves the accuracy and representativeness of the Department's financial reporting by reflecting current inventories of ECs and Tier 3 program credits on its financial statements.

(x) Subscription-Based Information Technology Agreements

During the year ended June 30, 2023, the Department adopted GASB Statement No. 96, *Subscription-Based Information Technology Agreements (SBITAs)*. Guidance under GASB Statement No. 96 establishes uniform guidance for accounting and financial reporting for transactions that meet the SBITA definition. The Department evaluated its existing information technology contracts and determined that none meet the criteria to be considered as SBITAs under GASB Statement No. 96 for the years ending June 30, 2025 and 2024.

(y) Risks and Uncertainties

In June 2025, Connecticut enacted a statutory change (Public Act 25-173) that requires wood energy plants such as McNeil to bid and be awarded a contract through a CT Department of Energy & Environmental Protection (DEEP) procurement process to continue to be eligible for CT Class 1 Renewable Energy Credits after October 1, 2025. McNeil is eligible under the new statute to bid in the procurement process, for which DEEP opened a proceeding on September 2, 2025, and BED plans to submit a response on behalf of McNeil to the request for proposal when issued. McNeil remains eligible for several REC markets for existing renewable energy plants in New England, including Vermont Tier 1 credits. The financial and/or operational impact of this statutory change, if any, remain unknown as of the date of the financial statements.

(z) Adoption of GASB Statements

The Department implemented GASB Statement No. 101, *Compensated Absences*, for the fiscal year ended June 30, 2025. GASB Statement 101 replaces the requirements of Statement No. 16, *Accounting for Compensated Absences*. GASB Statement No. 101 establishes standards of accounting and financial reporting requirements for compensated absences and associated salary-related payments, recognizing liability for leave that is attributable to services already rendered, accumulates, and is more likely than not to be used or paid out. See Note 10 for additional information regarding the Department's Compensated Absences liability.

Implementation of this new reporting standard required that the Department restate its beginning net position as of July 1, 2023, for the cumulative effects of applying this statement, in accordance with GASB Statement No. 100, *Account Changes and Error Corrections*.

(Continued)

Adjustment to the Department's beginning net position as of July 1, 2023, to reflect compensated absences liability:

July 1, 2023 beginning net position (as originally stated)	$	64,811,727
Compensated absences adjustment		(52,203)
Adjusted beginning net position (restated)	$	64,759,524

(aa) Reclassifications

Certain prior year amounts have been reclassified for consistency with the current year presentation. These reclassifications had no effect on the reported results of operations.

Pursuant to a final rule issued effective January 1, 2025 by FERC, the name of Renewable Energy Credit accounts was changed to Environmental Credits. FERC also codified treatment of these credits for utilities as an inventoriable asset and created a designated account for them under the current asset sub-category. Previously, the Department had been treating these inventories as deferred debits, noncurrent assets, as they did not previously have a FERC-defined account. The Department updated the description of these inventories and included them in current assets. A reclassification has been made to the Statements of Net Position as of June 30, 2024 to include $2,307,617 of these EC inventories under the current assets section and removed from the noncurrent assets section.

Pursuant to this same rule, FERC also clarified that these related expenses should be included in Other Power Supply expense sub-function. Previously, the Department had been including these expenses in Purchased Power expense. An adjustment has been made to the Statement of Revenues, Expenses, and Changes in Net Position for fiscal year ended June 30, 2024 to reclassify these EC expenses. A reclassification of $333,178 has been included in Other Power Supply expense and removed from Purchased Power expense. This reclassification does not affect previously reported increase in net position in the Statement of Revenue, Expenses, and Changes in Net Position.

(2) Capital Assets

	Capital assets			
	June 30, 2024	Additions	Disposals and transfers	June 30, 2025
Operating:				
Land – nondepreciable	$ 1,140,532	—	—	1,140,532
Production plant	18,194,555	9,341	—	18,203,896
Transmission plant	2,358,314	—	47,406	2,310,908
Distribution plant	97,493,062	4,129,900	83,047	101,539,915
General plant	14,730,226	865,016	136,953	15,458,289
Other plant	8,229,333	6,102	—	8,235,435
Depreciable operating	141,005,490	5,010,359	267,406	145,748,443
Construction WIP	5,845,965	8,248,005	3,536,013	10,557,957
Total	147,991,987	13,258,364	3,803,419	157,446,932
McNeil 50%:				
Land – nondepreciable	138,299	—	—	138,299
Production plant	56,965,214	1,076,477	—	58,041,691
General equipment	8,461	1,170	—	9,631
Other plant	383,477	—	—	383,477
Depreciable McNeil 50%	57,357,152	1,077,647	—	58,434,799
Total	57,495,451	1,077,647	—	58,573,098
Construction WIP	66,496	1,014,918	1,077,647	3,767
Total capital assets	205,553,934	15,350,929	4,881,066	216,023,797
Electric plant acquisition:				
Adjustment:				
Production plant – Winooski One	11,922,742	—	—	11,922,742
Total capital assets and acquisition adjustment	$ 217,476,676	15,350,929	4,881,066	227,946,539

	Capital assets			
	June 30, 2023	Additions	Disposals and transfers	June 30, 2024
Operating:				
Land – nondepreciable	$ 1,140,532	—	—	1,140,532
Production plant	17,651,567	542,988	—	18,194,555
Transmission plant	2,358,314	—	—	2,358,314
Distribution plant	94,411,728	3,173,757	92,423	97,493,062
General plant	13,768,228	1,171,781	209,783	14,730,226
Other plant	7,702,812	526,521	—	8,229,333
Depreciable operating	135,892,649	5,415,047	302,206	141,005,490
Construction WIP	3,787,402	6,364,085	4,305,522	5,845,965
Total	140,820,583	11,779,132	4,607,728	147,991,987
McNeil 50%:				
Land – nondepreciable	138,299	—	—	138,299
Production plant	56,202,445	762,769	—	56,965,214
General equipment	180,704	19,631	191,874	8,461
Other plant	383,477	—	—	383,477
Depreciable McNeil 50%	56,766,626	782,400	191,874	57,357,152
Total	56,904,925	782,400	191,874	57,495,451
Construction WIP	29,808	819,088	782,400	66,496
Total capital assets	197,755,316	13,380,620	5,582,002	205,553,934
Electric plant acquisition:				
Adjustment:				
Production plant – Winooski One	11,922,742	—	—	11,922,742
Total capital assets and acquisition adjustment	$ 209,678,058	13,380,620	5,582,002	217,476,676

		Accumulated depreciation		
	June 30, 2024	**Depreciation**	**Disposals and transfers**	**June 30, 2025**
Operating:				
Production plant	$ 8,754,352	624,144	—	9,378,496
Transmission plant	953,596	72,359	29,044	996,911
Distribution plant	43,260,949	2,403,323	59,013	45,605,259
General plant	9,580,574	559,721	131,363	10,008,932
Other plant	5,969,161	260,541	—	6,229,702
Total	68,518,632	3,920,088	219,420	72,219,300
McNeil 50%:				
Production plant	44,237,598	882,026	—	45,119,624
General equipment	54,850	4,482	—	59,332
Other plant	382,983	494	—	383,477
Total	44,675,431	887,002	—	45,562,433
Total accumulated depreciation	113,194,063	4,807,090	219,420	117,781,733
Electric plant acquisition Adjustment:				
Accumulated amortization	4,508,393	521,910	—	5,030,303
	$ 117,702,456	5,329,000	219,420	122,812,036
Net capital assets	$ 99,774,220	10,021,929	4,661,646	105,134,503

(Continued)

		Accumulated depreciation			
		June 30, 2023	Depreciation	Disposals and transfers	June 30, 2024
Operating:					
Production plant	$	8,137,814	616,538	—	8,754,352
Transmission plant		880,842	72,754	—	953,596
Distribution plant		41,014,261	2,298,200	51,512	43,260,949
General plant		9,241,749	548,283	209,458	9,580,574
Other plant		5,688,234	280,927	—	5,969,161
Total		64,962,900	3,816,702	260,970	68,518,632
McNeil 50%:					
Production plant		43,380,759	856,839	—	44,237,598
General equipment		154,879	9,929	109,958	54,850
Other plant		382,488	495	—	382,983
Total		43,918,126	867,263	109,958	44,675,431
Total accumulated depreciation		108,881,026	4,683,965	370,928	113,194,063
Electric plant acquisition Adjustment:					
Accumulated amortization		3,998,983	509,410	—	4,508,393
	$	112,880,009	5,193,375	370,928	117,702,456
Net capital assets	$	96,798,049	8,187,245	5,211,075	99,774,220

During fiscal years 2025 and 2024, respectively, the Department allocated $77,201 and $121,910 of depreciation expense to other operating expense captions in the statements of revenues, expenses, and changes in net position in order to allocate depreciation associated with stockroom equipment and vehicles to capital projects.

In August 2014, the Department acquired the Winooski One hydroelectric facility, an existing facility on the Winooski River between the Cities of Burlington and Winooski. The Department recorded the net book value of the station as received. The difference between the fair market value purchase price and the net book value has been recorded in the electric plant acquisition adjustment account and is being amortized over the life of the associated bond financing.

(3) Cash and Cash Equivalents and Investments

(a) Custodial Credit Risk – Deposits

The custodial credit risk for current operating deposits is the risk that in the event of a bank failure, the Department's proprietary fund deposits may not be recovered. The deposits in the bank in excess of the insured amount are uninsured and uncollateralized. Total proprietary fund deposits at June 30, 2025 were $14,028,773 of which $13,277,773 was exposed to custodial credit risk; however, the City of Burlington is insured with the Federal Home Loan Bank (FHLB), Pittsburgh under a letter of credit for $16,000,000 expiring August 21, 2025 which would cover uninsured amounts over the FDIC limit of $250,000. Total proprietary fund deposits at June 30, 2024 were $13,009,048 of which $12,259,048 was exposed to custodial credit risk; however, the City of Burlington is insured with the Federal Home Loan Bank (FHLB), Pittsburgh under a letter of credit for $14,000,000 expiring October 2, 2024, which would cover uninsured amounts over the FDIC limit of $250,000.

Total fiduciary (custodial) fund deposits at June 30, 2025 were $2,324,046, all of which was exposed to custodial credit risk. Total fiduciary (custodial) fund deposits at June 30, 2024 were $1,625,807, all of which was exposed to custodial credit risk.

(b) Fair Value Measurements

GASB Statement No. 72, *Fair Value Measurement and Application*, sets forth the framework for measuring fair value. The framework provides a fair value hierarchy that prioritizes the inputs to valuation techniques used for measuring fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for incidental assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). The three levels of the fair value hierarchy under GASB Statement No. 72 are described as follows:

Level 1 – Inputs to the valuation methodology are unadjusted quoted prices for identical assets or liabilities in active markets that the Department has the ability to access.

Level 2 – Input to valuation methodology include:

- Quoted prices for similar assets or liabilities in active markets;
- Quoted prices for identical or similar assets or liabilities in inactive markets;
- Inputs other than quoted prices that are observable for the asset or liability;
- Inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 3 – Inputs to the valuation methodology are unobservable and significant to the fair value measurement. Unobservable inputs reflect the Department’s own assumptions about the inputs market participants would use in the pricing of the asset or liability (including assumption of risk). Unobservable inputs are developed based on the best information available in circumstances and may include the Department’s own data.

All the Department’s investments, as of June 30, 2025 and 2024 are considered to be Level 1 under the fair value hierarchy.

(c) Investments

The Department has a formal investment policy and is authorized per Article 1, Section 1.1 of the General Bond Resolution to invest in obligations as follows:

(1) Direct obligations of the United States of America or obligations guaranteed by the United States of America.

(2) Bonds, notes or other evidences of indebtedness issued or guaranteed by the CoBank, Federal Intermediate Credit Banks, FHLB, FNMA, GNMA, Export-Import Bank of the United States, Federal Land Banks, United States Postal Service, Federal Financing Bank, or any agency or instrumentality of or corporation wholly owned by the United States of America.

(3) New Housing Authority Bonds issued by public agencies or municipalities and fully secured by a pledge of annual contributions under annual contributions contract with the United States of America, or Project Notes issued by public agencies or municipalities and fully secured by a requisition or payment agreement with the United States of America.

(4) Obligations of any state, commonwealth, or territory of the United States of America, or the District of Columbia, or any political subdivision of the foregoing, with an investment grade rating not lower than the three highest categories by at least one nationally recognized debt rating service.

(5) Certificates of deposit and bankers acceptances issued by banks that are members of the Federal Deposit Insurance Corporation and each of which has a combined capital and surplus of not less than $10,000,000, provided that the time deposits in and acceptances of any bank under the Resolution (a) do not exceed at any time 25% of the combined capital and surplus of the bank or (b) are fully secured by obligations described in items 1, 2, 3, and 4 above.

(6) Repurchase contracts with banks that are described in item 5 of this paragraph, or with recognized primary dealers in government bonds, fully secured by obligations described in items 1, 2, 3, and 4 above.

(d) Concentration of Credit Risk

Concentration of credit risk of investments is the risk of loss attributable to the magnitude of a Department’s investment in a single issuer. The Department invests its current operating cash in money market accounts, which are approximately 21% and 16% of the total investment balance at June 30, 2025 and 2024, respectively. The invested balance of money market funds reported within unrestricted cash and cash equivalents at June 30, 2025 and 2024 was $3,392,707 and $3,300,959, respectively. The Department invests its restricted funds in several cash accounts with its bond trustees. The invested balance of cash funds reported within restricted investments-deposits with bond trustees at June 30, 2025 and 2024 was $3,956,728 and $6,876,548, respectively. The invested balance of U.S. Treasuries reported within restricted investments at June 30, 2025 and 2024 was $6,719,723 and $9,224,736, respectively.

(e) Interest Rate Risk – Investments

Interest rate risk is the risk that changes in interest rates of debt investments will adversely affect the fair value of an investment. The Department has minimized its risk exposure as its investments are limited to government securities and other high-quality investments as outlined in the investment policy.

The money market funds held by the Department are not rated.

The Department's propriety debt investments as of June 30, 2025 and 2024 are (all of which are restricted by bond resolution) presented below by investment type, and debt securities are presented by remaining maturity. The fiduciary fund has no debt investments.

	U.S. Treasury		Total	Investment maturities (in years)				
Year	bills	Cash	fair value	Less than 1	1–2	2–3	3–4	5+
2025	$ 6,719,723	3,956,728	10,676,451	6,719,723	—	—	—	—
2024	$ 9,224,735	6,876,548	16,101,283	9,224,736	—	—	—	—

The Department is required by its bond indenture to make monthly deposits into the renewal and replacement fund equal to 10% of the monthly revenue bond debt service funding requirements. Funds on deposit may be withdrawn from the renewal and replacement fund for expenses allowed by the bond covenant. Amounts in excess of $867,000 at June 30 may be returned to the revenue fund. A summary of deposits with bond trustees is as follows:

	June 30	
	2025	2024
Bond funds:		
Construction fund	$ 4,081,539	8,967,207
Renewal and replacement fund	867,000	867,000
Debt service fund	2,113,157	2,759,139
Debt service reserve fund	3,614,755	3,507,937
	10,676,451	16,101,283
Accrued interest receivable	5,470	33,396
	$ 10,681,921	16,134,679

(4) Regulatory Assets, Regulatory Liabilities, and Regulatory Deferred Inflows of Resources

Regulatory assets, regulatory liabilities, and regulatory deferred inflows of resources at June 30, 2025 and 2024 are composed of the following:

		2025	2024
Deferred depreciation expense to be recovered in future years	$	948,945	1,054,384
COVID-19 capitalized personnel costs		82,469	131,508
IBEW pension back-payment		76,161	152,321
Triennial consulting engineer report		54,600	—
Winter 2022-2023 excess energy revenue shortfall		2,601,396	3,121,675
Moran settlement payment		594,197	713,036
Total regulatory assets	$	4,357,768	5,172,924
McNeil turbine overhaul		821,720	—
Total regulatory liability	$	821,720	—
Deferred depreciation expense – McNeil Plant	$	2,560,373	2,650,951
Deferred depreciation expense – operating		5,884,633	5,242,789
Total regulatory deferred inflows of resources	$	8,445,006	7,893,740

(a) Deferred Depreciation Expense to be Recovered in Future Years

Provisions for depreciation of general capital assets, including the McNeil Generation Station, are reported using the straight-line method at rates based upon the estimated service lives and salvage values of the several classes of property. However, a portion of the current depreciation expense for the McNeil Station is only recoverable through future rates. The difference is included in deferred charges (calculated as the straight-line depreciation expense less the depreciation expense on a sinking fund basis) and will be recovered in future years. The Department recorded straight-line depreciation of $4,807,090 and $4,683,965 for the years ended June 30, 2025 and 2024, respectively. In 2025 and 2024, $641,844 and $1,276,685, respectively, of deferred depreciation expense was realized. Unamortized deferred depreciation of $948,945 and $1,054,384 remained at June 30, 2025 and 2024, respectively.

(b) COVID-19 Capitalized Personnel Costs

On September 9, 2021, the Department filed a request with the PUC for an accounting order, pursuant to 30 V.S.A. §221, that would allow the Department to capitalize certain costs by debiting FERC account 182.3 (other regulatory assets) instead of showing the costs as expenses on its income statements for the year ending June 30, 2021. The Department evaluated its budgeted capitalized labor and benefit expenses to identify which capital projects have been delayed specifically due to the COVID-19 pandemic for the year ending June 30, 2021. The Department proposed to capitalize and record as a regulatory asset $146,721 instead of showing these expenses on its income statement for the year ending June 30, 2021. On October 25, 2021, the PUC issued the accounting order. This regulatory asset is being amortized over a 5-year period beginning on August 1, 2022.

On July 31, 2020, the Department filed a request with the PUC for an accounting order, pursuant to 30 V.S.A. §221, that would allow the Department to capitalize certain costs by debiting FERC account 182.3 (other regulatory assets) instead of showing the costs as expenses on its income statements for the year ending June 30, 2020. The Department evaluated its budgeted capitalized labor and benefit expenses to identify which capital projects have been delayed specifically due to the COVID-19 pandemic for the year ending June 30, 2020. The Department proposed to capitalize and record as a regulatory asset $231,768 instead of showing these expenses on its income statement for the year ending June 30, 2020. On September 17, 2020, the PUC issued the accounting order. On February 25, 2021, the Department notified the PUC that it would reduce the fiscal year 2020 regulatory asset to $98,472 due to the reimbursement of some COVID-19–related expenses. This regulatory asset is being amortized over a 5-year period beginning on August 1, 2021.

(c) International Brotherhood of Electrical Workers (IBEW) Pension Back-Payment

As discussed in note 8, as a result of a March 25, 2021 arbitration decision, the Burlington Employee Retirement Systems (BERS) Plan is required to pay additional benefits to certain IBEW union employees and provide the same additional benefits to up to certain current IBEW employees who may qualify for those benefits if they continue to work for the Department for more than 25 years. The City's actuary calculated a total of $1,234,973 in past benefits owed to the 24 eligible employees who retired after May 4, 2008 through June 30, 2021, and the BERS Plan has paid these back benefits to the individual employees. The City and the Department agreed in October 2021 that the Department's share of the back benefits was 35.24% or $435,204. The Department included this amount, amortized over five years, in its June 17, 2021 rate case, which was approved by the PUC in February 24, 2022. This regulatory asset is being amortized over a 5-year period beginning in fiscal year 2022.

(d) Triennial Consulting Engineer Report

The Department is required to engage a consulting engineer at least once every three fiscal years to examine and report on the properties of the Electric Plant as a covenant of the General Bond Resolution that authorizes the issuance of Electric System Revenue Bonds. The Department included its expenses associated with the fiscal year 2024 report, $81,900, amortized over three years, in its June 14, 2024 rate case, which was approved by the PUC on May 1, 2025.

(e) Winter 2022-2023 Excess Energy Revenue Shortfall

Forward prices for the sale of excess energy for the winter of 2023-2024, which were relied upon to establish the Department's cost of service in its 2022 rate request, were unprecedentedly high. Actual prices for excess energy that the Department received from ISO-NE during that period were significantly lower. The difference between the forward and actual prices for the sale of excess energy from December 2022 to March 2023 for the same volume of energy was $4,162,233 of lost revenues. The Department included this amount, amortized over eight years, in its June 16, 2023 rate case, which was approved by the PUC on February 21, 2024. Amortized expense of $520,279 was recorded in 2025 and 2024.

(f) Moran Settlement Payment

Pursuant to the terms of a June 2022 MOU with the City of Burlington, the Department agreed to make a contribution of $950,715 toward the abatement and/or remediation of environmental contaminants at the site of the former Moran Station. The Department included this amount, amortized over eight years, in its June 16, 2022 rate case, which was approved by the PUC on October 12, 2023.

(g) McNeil Turbine Overhaul

The Department completes a routine maintenance overhaul of turbines used in generating operations at the McNeil plant approximately every seven years, depending on the plant's production. The Department included one seventh of the amount of the overhaul that occurred in fiscal year 2019, $1,150,408, in the cost-of-service calculation submitted with its June 17, 2021 rate case, which was approved by the PUC on February 24, 2022. One seventh of this cost, $164,344, was also included in the cost-of-service calculation submitted with the Department's 2022, 2023, 2024, and 2025 rate cases in order for the Department to collect funds for costs that are expected to be incurred during the next routine turbine overhaul. Amortization expense of $821,720 and $0 was recorded in fiscal years 2025 and 2024, respectively.

(h) Deferred Depreciation Expense to be Paid in Future Years

Beginning in 2011, certain accumulated deferred depreciation balances became negative due to the fact that the financed assets were close to being fully depreciated when compared to the future debt sinking fund requirements. These accumulated amounts are displayed as deferred inflows of resources. Deferred depreciation expense of $8,445,006 and $7,893,740 remained at June 30, 2025 and 2024, respectively.

(Continued)

(5) Long-Term Liabilities

Outstanding debt consists of the following at June 30, 2025 and 2024:

	June 30, 2024	Increases	Payments and reductions	June 30, 2025	Current portion
Outstanding debt:					
Electric System Revenue Bonds:					
3.78% 2014 Series A, due 2035	$ 7,650,000		(570,000)	7,080,000	595,000
3.36% 2014 Series B, due 2025	665,000		(665,000)	—	—
4.85% 2017 Series A, due 2032	3,350,000		(350,000)	3,000,000	370,000
Taxable 3.40% 2017 Series B, due 2032	3,725,000		(415,000)	3,310,000	430,000
5% 2022 Series A, due 2043	18,045,000		—	18,045,000	—
Total revenue bonds	33,435,000	—	(2,000,000)	31,435,000	1,395,000
Adjustments:					
Add unamortized premium	3,557,031		(48,131)	3,508,900	—
Less unamortized discount	(420,903)		43,975	(376,928)	—
Total revenue debt of the department	36,571,128	—	(2,004,156)	34,566,972	1,395,000
General obligation debt, repayable from the Department’s resources:					
3.73%, due 2032:					
CI#2011B	495,000		(55,000)	440,000	55,000
6.00%, due 2032:					
CI#2012B	740,000		(65,000)	675,000	70,000
2.78%, due 2034:					
CI#2014	1,650,000		(150,000)	1,500,000	150,000
4.82%, due 2029:					
CI#2016A	5,230,000		(900,000)	4,330,000	955,000
4.62% due 2037:					
CI#2016B	2,260,000		(130,000)	2,130,000	135,000
4.03% due 2030:					
CI#2016C	4,695,000		(695,000)	4,000,000	725,000

	June 30, 2024	Increases	Payments and reductions	June 30, 2025	Current portion
General obligation debt, repayable from the Department's resources:					
2.76% due 2030:					
CI#2016D	$ 5,535,000		(835,000)	4,700,000	870,000
4.88% due 2038:					
CI#2017C	2,365,000		(120,000)	2,245,000	125,000
5.00% due 2039:					
CI#2018B	2,500,000		(115,000)	2,385,000	120,000
4.39% due 2040:					
CI#2019A	2,610,000		(110,000)	2,500,000	115,000
Taxable 2.59% due 2036:					
CI#2019C	7,055,000		(650,000)	6,405,000	675,000
3.45% due 2041					
CI#2021A	2,455,000		(95,000)	2,360,000	95,000
5.00% due 2042					
CI#2022A	2,570,000		(85,000)	2,485,000	90,000
5.02% due 2043					
CI#2022 BAN Refunding	2,785,000		(85,000)	2,700,000	90,000
5.00% due 2043					
CI#2023A	3,000,000		(90,000)	2,910,000	95,000
5.00% due 2044					
CI#2024A	—	3,000,000	—	3,000,000	80,000
Total general obligation bonds	45,945,000	3,000,000	(4,180,000)	44,765,000	4,445,000
Add unamortized premium	4,219,813	433,628	(331,494)	4,321,947	—
Less unamortized discount	(795,388)		100,402	(694,986)	—
Total general obligation debt	49,369,425	3,433,628	(4,411,092)	48,391,961	4,445,000
Total long-term debt	$ 85,940,553	3,433,628	(6,415,248)	82,958,933	5,840,000

	June 30, 2024 (restated)	Increases	Payments and reductions	June 30, 2025	Less current portion	Net noncurrent liability
Other noncurrent liabilities:						
Accumulated provision for compensated absence	$ 1,232,589		(47,399)	1,185,190		1,185,190
Other post-employment benefit	815,159		(71,743)	743,416		743,416
On-bill revolving loans	465,596			465,596		465,596
Equipment financing note	216,758		(200,009)	16,749	(16,749)	—
Moran Frame promissory note	720,083		(117,048)	603,035	(118,219)	484,816
Net pension liability	22,820,338		(788,213)	22,032,125		22,032,125
Total other noncurrent liabilities	$ 26,270,523	—	(1,224,412)	25,046,111	(134,968)	24,911,143

	June 30, 2023	Increases	Payments and reductions	June 30, 2024	Current portion
Outstanding debt:					
Electric System Revenue Bonds:					
3.78% 2014 Series A, due 2035	$ 8,195,000	—	(545,000)	7,650,000	570,000
3.36% 2014 Series B, due 2025	1,310,000	—	(645,000)	665,000	665,000
4.85% 2017 Series A, due 2032	3,690,000	—	(340,000)	3,350,000	350,000
Taxable 3.40% 2017 Series B, due 2032	4,130,000	—	(405,000)	3,725,000	415,000
5% 2022 Series A, due 2043	18,045,000	—	—	18,045,000	—
Total revenue bonds	35,370,000	—	(1,935,000)	33,435,000	2,000,000
Adjustments:					
Add unamortized premium	3,603,501	—	(46,470)	3,557,031	—
Less unamortized discount	(463,622)	—	42,719	(420,903)	—
Total revenue debt of the department	38,509,879	—	(1,938,751)	36,571,128	2,000,000
General obligation debt, repayable from the Department's resources:					
3.73%, due 2032:					
CI#2011B	545,000	—	(50,000)	495,000	55,000
6.00%, due 2032:					
CI#2012B	800,000	—	(60,000)	740,000	65,000
2.78%, due 2034:					
CI#2014	1,800,000	—	(150,000)	1,650,000	150,000
4.82%, due 2029:					
CI#2016A	6,210,000	—	(980,000)	5,230,000	900,000
4.62% due 2037:					
CI#2016B	2,385,000	—	(125,000)	2,260,000	130,000
4.03% due 2030:					
CI#2016C	5,345,000	—	(650,000)	4,695,000	695,000

		June 30, 2023	Increases	Payments and reductions	June 30, 2024	Current portion
2.76% due 2030:						
CI#2016D	$	6,345,000	—	(810,000)	5,535,000	835,000
4.88% due 2038:						
CI#2017C		2,480,000	—	(115,000)	2,365,000	120,000
5.00% due 2039:						
CI#2018B		2,610,000	—	(110,000)	2,500,000	115,000
4.39% due 2040:						
CI#2019A		2,715,000	—	(105,000)	2,610,000	110,000
Taxable 2.59% due 2036:						
CI#2019C		7,555,000	—	(500,000)	7,055,000	650,000
3.45% due 2041						
CI#2021A		2,545,000	—	(90,000)	2,455,000	95,000
5.00% due 2042						
CI#2022A		2,650,000	—	(80,000)	2,570,000	85,000
2.79% Series 2022 Bond						
Anticipation Note		3,000,000	—	(3,000,000)	—	—
5.02% due 2043						
CI#2022 BAN Refunding		—	2,785,000	—	2,785,000	85,000
5.00% due 2044						
CI#2023A		—	3,000,000	—	3,000,000	90,000
Total general obligation bonds		46,985,000	5,785,000	(6,825,000)	45,945,000	4,180,000
		3,898,348	639,496	(318,031)	4,219,813	—
		(886,611)	—	91,223	(795,388)	—
Total general obligation debt		49,996,737	6,424,496	(7,051,808)	49,369,425	4,180,000
Total long-term debt	$	88,506,616	6,424,496	(8,990,559)	85,940,553	6,180,000

		June 30, 2023	Increases	Payments and reductions	June 30, 2024	Less current portion	Net noncurrent liability
Other noncurrent liabilities:							
Accumulated provision for compensated absence	$	1,218,953	13,636	—	1,232,589	—	1,232,589
Other post-employment benefit		944,849	—	(129,690)	815,159	—	815,159
On-bill revolving loans		463,496	—	(1,840)	461,656	—	461,656
Equipment financing note		398,534	—	(181,776)	216,758	(200,009)	16,749
Moran Frame promissory note		835,973	—	(115,890)	720,083	(117,048)	603,035
Net pension liability		21,677,516	1,142,822	—	22,820,338	—	22,820,338
Total other noncurrent liabilities	$	25,539,321	1,156,458	(429,196)	26,266,583	(317,057)	25,949,526

The Electric System Revenue Bonds have been issued pursuant to the General Bond Resolution and are collateralized by a pledge of the Department's operating revenues. Pursuant to the General Bond Resolution, "revenues" (as defined) means all rates, fees, charges, or other income and includes rentals, proceeds of insurance or condemnation or other disposition of assets, proceeds of bonds or notes, and earnings from the investment of revenues. On an annual basis, revenues must be sufficient after deducting operating expenses (as defined) to meet minimum debt service coverage requirements (as defined). If minimum debt service coverage requirements are not met, the Department must take timely corrective action.

The Department has pledged future revenues, net of specified operating expenses, to repay the principal and interest on its Electric System Revenue Bonds issued in 2014, 2017, and 2022. The bonds are payable solely from revenues as defined and are payable through 2043. Annual principal and interest payments on the bonds are expected to require less than 50% of net revenues. The total principal and interest remaining to be paid on the bonds was $44,188,512 and $47,665,808 at June 30, 2025 and 2024, respectively. During 2025, principal and interest paid, and net revenues available for debt service, were $3,477,296 and $12,919,828, respectively. During 2024, principal and interest paid, and net revenues available for debt service, were $3,492,679 and $12,081,219, respectively.

The general obligation bonds were issued to finance electric system improvements and are collateralized by the general revenue-raising power of the City of Burlington. Pursuant to the terms of the General Bond Resolution, the claim on the revenues of the Department by the holders of revenue bonds under the General Bond Resolution is prior to any claim of the holders of general obligation bonds.

During the fiscal year ended June 30, 2025, the Department, through the City of Burlington, issued $3,000,000 in general obligation bonds, 2024 Series A, with an average coupon rate of 5%.

During the fiscal year ended June 30, 2024, the Department, through the City of Burlington, issued $2,785,000 in general obligation bonds, 2022 BAN Refunding-Electric Department Portion, with an average coupon rate of 5.02%. These bonds were issued in accordance with the City Charter for the purpose of refunding the $3,000,000 Bond Anticipation Note (BAN), Series 2022, issued September 15, 2022. The Department, through the City of Burlington, also issued $3,000,000 in general obligation bonds, 2023 Series A, with an average coupon rate of 5.02%.

Annual debt service requirements exclusive of unamortized premium or discount are as follows:

	Revenue debt		General obligation debt		
	Principal	**Interest**	**Principal**	**Interest**	**Total**
Year ending June 30:					
2026	$ 1,395,000	1,408,176	4,445,000	1,797,827	9,046,003
2027	1,445,000	1,352,969	4,490,000	1,621,633	8,909,602
2028	1,505,000	1,297,039	4,600,000	1,435,244	8,837,283
2029	2,395,000	1,216,854	4,740,000	1,242,964	9,594,818
2030–2034	11,465,000	4,467,149	13,790,000	4,091,138	33,813,287
2035–2039	7,030,000	2,371,825	7,945,000	1,972,142	19,318,967
2040–2044	6,200,000	639,500	4,525,000	556,575	11,921,075
2045–2049	—	—	230,000	5,750	235,750
	$ 31,435,000	12,753,512	44,765,000	12,723,273	101,676,785

(6) Short-Term Debt

In February 2012, the City issued on behalf of the Department a $5,000,000 General Obligation Revenue Anticipation Note (Line of Credit) with a local bank, placing the Line of Credit directly with the Department. On June 30, 2022 the Line of Credit was renewed for a two-year term to June 30, 2024. The Line of Credit was not renewed as of June 30, 2024. In June 2024, the City issued on behalf of the Department a new $10,000,000 General Obligation Revenue Anticipation Note (Line of Credit) with a local bank, placing the Line of Credit directly with the Department. The Department had the entire Line of Credit balance of $10,000,000 available for use during fiscal year 2025, and at the end of fiscal year 2024. The Department had the previous entire Line of Credit balance of $5,000,000 available for use during fiscal year 2024. There was no activity during the past two fiscal years. On June 25, 2025 the Line of Credit was renewed for a two-year term to June 24, 2027.

(Continued)

(7) Production Expenses

Production expenses are comprised of the following:

		Year ended June 30	
		2025	2024
McNeil Generating Station:			
Fuel	$	7,579,169	6,797,760
Operations		2,200,420	1,973,909
Maintenance		855,281	971,898
		10,634,870	9,743,567
Winooski One Hydro station:			
Operations		155,424	244,445
Maintenance		199,184	194,403
		354,608	438,848
Gas turbine			
Fuel		167,358	309,652
Operations		43,178	66,512
Maintenance		54,904	148,291
		265,440	524,455
Solar:			
Operations		19,192	19,118
Total production expenses	$	11,274,110	10,725,988

(8) Retirement Benefits

The City maintains a single employer defined benefit pension plan and a deferred compensation retirement plan. The Department contributes to the defined benefit plan the allocated required contribution as set forth by the City's actuary for its employees, together with a direct employee contribution of 4.340% (nonunion) and 4.340% and 5.340% (IBEW union, depending on choice of plan) of gross base wages. For the years ended June 30, 2025 and 2024, the Department made 100% of its required contributions which totaled $1,843,779 and $1,728,654, respectively. Participation in the deferred compensation plan is strictly voluntary, with no matching contribution from the Department.

(a) Defined Benefit Plan

All full-time employees of the Department participate in the City of Burlington Employees' Retirement System (BERS Plan). The BERS Plan covers substantially all of the City's employees except elected officials, other than the mayor, and the majority of the public school teachers, who are eligible for the Vermont Teachers' Retirement System.

For purposes of measuring the net pension liability, deferred outflows of resources and deferred inflows of resources related to pensions, and pension expense, information about the fiduciary net position of the BERS Plan and additions to/deductions from BERS Plan's fiduciary net position have been determined on the same basis as they are reported by the BERS Plan. For this purpose, benefit payments (including refunds of employee contributions) are recognized when due and payable in accordance with the benefit terms. Investments are reported at fair value.

Unaudited financial information for the BERS Plan is available from the City of Burlington, Burlington Vermont 05401.

(i) Summary of BERS Plan

All eligible Department union and nonunion employees vest 100% after 5 years of creditable service. Department employees who retire at 65 are entitled to a retirement benefit.

For non-union employees hired prior to July 1, 2006 and IBEW union employees hired on or before May 4, 2008: Age 65 and older, the retirement benefit is the greater of (i) 1.6% of average final compensation (AFC) (at age 65) times creditable service not in excess of 25 years plus 0.5% of AFC (at age 65) times creditable service in excess of 25 years or (ii) the actuarial equivalent of the benefit determined at age 65. This benefit will be increased by the Cost of Living Adjustment detailed below.

For non-union employees hired after July 1, 2006 and IBEW union employees hired after May 4, 2008: Age 65 and older, the retirement benefit is the greater of (i) 1.4% of AFC (at age 65) times creditable service not in excess of 25 years plus 0.5% of AFC (at age 65) times creditable service in excess of 25 years or (ii) the actuarial equivalent of the benefit determined at age 65. This benefit will be increased by the Cost of Living Adjustment detailed below.

In lieu of this benefit, at the time of retirement, a non-union employee may choose (i) an accrual rate of 1.9% for all years of service prior to June 30, 2006 for the first 25 years, an accrual rate of 1.8% for all years of service commencing July 1, 2006 for the first 25 years, plus an accrual of 0.5% for creditable service in excess of 25 years, and a Cost of Living Adjustment equal to one-half of the Cost of Living Adjustment detailed below, or (ii) an accrual rate of 2.2% for all years of service prior to June 30, 2006 for the first 25 years, an accrual rate of 2.0% for all years of service commencing July 1, 2006 for the first 25 years, plus an accrual of 0.5% for creditable service in excess of 25 years, with no Cost of Living Adjustment.

As a result of a March 25, 2021 arbitration decision, the BERS Plan is required to pay additional benefits to 24 IBEW employees and provide the same additional benefits to up to 29 current IBEW employees who may qualify for those benefits if they continue to work for BED for more than 25 years. The arbitrator found that these employees who were hired prior to May 4, 2008 who chose a half or no-cost of living adjustment (COLA) benefit should receive the pre-May 4, 2008, higher multiplier for all years of service over 25 for IBEW.

The arbitrator ruled that the employees are to be made whole and are not entitled to interest on any back pension benefits owed. The make-whole remedy has two parts: (1) a payment of back benefits for those eligible employees who retired after May 4, 2008 and (2) an increase in future

 (Continued)

contributions to the BERS Plan for IBEW employees hired before May 4, 2008. The City's actuary calculated a total of $1,234,973 in past benefits owed to the 24 eligible employees who retired after May 4, 2008 through June 30, 2021, and the BERS Plan has paid these back benefits to the individual employees. The City and the Department agreed in October 2021 that the Department's share of the back benefits was 35.24% or $435,204. Further, in its annual valuation report as of June 30, 2021 the City's actuary increased the unfunded accrued liability and the actuarially determined employer contribution (ADEC) by $3,880,000 and $348,000, respectively, to reflect the cost of providing this additional benefit to the approximately 29 current employees who may qualify at retirement. Per City policy, the ADEC is shared 70% by the employer and 30% by employees.

Except for employees detailed below, the above benefit based on AFC and creditable service at retirement is reduced by 2% for each year that retirement is between ages 60 and 64. For IBEW union employees hired before May 1, 2008 who elect an additional contribution rate of 4%, a reduction factor is applied of 2% for each year the retirement precedes age 65. For IBEW union employees hired before May 1, 2008, who elect a contribution rate of 3%, the benefit is reduced by a factor which varies with age: factor of 1 at age 65 and a factor of 0.4 at age 50.

For IBEW employees hired after May 4, 2008, the benefit is reduced by a factor which varies by age: factor of 1 at age 65 and a factor of 0.356 at age 55.

(ii) Cost of Living Adjustment

Benefits increase annually by changes in the Consumer Price Index of more than 1%. For IBEW employees retiring after March 9, 2016 and non-union employees retiring after July 1, 2017, the maximum annual increase is 2.75%. For all other members, the maximum annual increase is 5%. This increase is not applicable to deferred vested benefit prior to commencement, survivor income benefit, disability benefit prior to normal retirement age, or participants who choose to have no cost of living adjustment.

(iii) Pension Liabilities, Pension Expense, and Deferred Outflows of Resources and Deferred Inflows of Resources Related to Pensions

The BERS Plan's net pension liability was measured as of June 30, 2024 (Measurement Date). As of the Measurement Date, BERS Plan reported a net pension liability of $120,022,896. The plan fiduciary net position as a percentage of the total pension liability is 67.11%.

At June 30, 2025 and 2024, the Department reported a liability of $22,032,125 and $22,820,338, respectively, for its proportionate share of the net pension liability. The net pension liability at June 30, 2025 was measured as of June 30, 2024 and the total pension liability used to calculate the net pension liability was determined by an actuarial valuation as of that date. The net pension liability at June 30, 2024 was measured as of June 30, 2023 and the total pension liability used to calculate the net pension liability was determined by an actuarial valuation as of that date. The Department's proportion of the net liability was based on a projection of the Department's long-term share of contributions relative to the projected contributions of all participating departments in the City, actuarially determined. At June 30, 2025, the Department's proportion was 18.36%, which was a decrease of 0.10% from its proportion measured as of June 30, 2024. At June 30, 2024, the

Department's proportion was 18.46%, which was a decrease of 0.16% from its proportion measured as of June 30, 2023.

For the years ended June 30, 2025 and 2024, the Department recognized pension expense of $3,249,225 and $3,719,050, respectively. At June 30, 2025 and 2024, the Department reported its allocated proportionate share of deferred outflows of resources and deferred inflows of resources related to pensions from the following sources:

	2025	
	Deferred outflows of resources	Deferred inflows of resources
Payment after the measurement date	$ 1,843,779	—
Difference between actual and projected experience	1,600,401	—
Net difference between actual and projected investment earnings	—	564,408
Changes in assumptions	195,252	—
Change in proportion	—	587,732
	$ 3,639,432	1,152,140

	2024	
	Deferred outflows of resources	Deferred inflows of resources
Payment after the measurement date	$ 1,728,654	—
Difference between actual and projected experience	1,461,840	—
Net difference between actual and projected investment earnings	1,587,491	—
Changes in assumptions	601,049	—
Change in proportion	—	698,083
	$ 5,379,034	698,083

Deferred outflows of resources for payments made after the measurement date will be recognized as a reduction in the net pension liability in the next fiscal year. Other amounts reported as deferred outflows of resources and deferred inflows of resources will be recognized in pension expense as follows:

Year ended June 30:		
2025	$	360,515
2026		1,453,176
2027		(705,583)
2028		(464,595)
Thereafter		
Total	$	643,513

(iv) Actuarial Assumptions

The actuarial assumptions used in the June 30, 2024 and 2023 valuations were based on results of an actuarial experience study for the period July 1, 2017 to July 1, 2022, with changes in the methodology for amortizing the unfunded accrued liability.

	2025	2024
Valuation dates	June 30, 2024	June 30, 2023
Mortality tables	Pub-2010 public retirement plans amount-weighted general employees mortality tables, scale MP-2021 set forward 2 years (retirees)	Pub-2010 public retirement plans amount-weighted general employees mortality tables, scale MP-2021 set forward 2 years (retirees)
	Pub-2010 public retirement plans amount-weighted general disabled retirees mortality tables, scale MP-2021 set forward 3 years (disabled)	Pub-2010 public retirement plans amount-weighted general disabled retirees mortality tables, scale MP-2021 set forward 3 years (disabled)
	Pub-2010 public retirement plans amount-weighted general contingent survivors mortality tables, scale MP-2021 set forward 3 years (survivors)	Pub-2010 public retirement plans amount-weighted general contingent survivors mortality tables, scale MP-2021 set forward 3 years (survivors)
Inflation	2.7%	2.7%
Salary increases	3.1% average, including inflation	3.1% average, including inflation
Investment rate of return	7.10%	7.10%

The long-term expected rate of return on pension plan investments was selected from a best estimate range determined using the building-block approach. Under this method, an expected future real return range (expected returns, net of pension plan investment expense and inflation) is calculated separately for each asset class. These ranges are combined to produce the long-term expected rate of return by weighting the expected future real rates of return net of investment expenses by the target asset allocation percentage and by adding expected inflation. The target allocation and best estimates of arithmetic real rates of return for each major asset class are summarized in the following table:

	Target allocation	20 Year expected rate of return
Asset class:		
Core Fixed Income	20.00 %	5.90 %
U.S. Bonds – Dynamic	7.00	6.80
U.S. Large Cap Equity	33.00	7.30
U.S. Small Cap Equity	9.50	6.80
International Developed Equity	19.00	8.20
International Emerging Markets Equity	7.00	10.10
Private equity	0.50	10.30
Real estate	4.00	7.80

Discount rate 7.10%

The projection of cash flows used to determine the discount rate for financial reporting purposes assumed that contributions will continue to be made in accordance with the current funding policy. Based on those assumptions, the BERS Plan’s fiduciary net position was projected to be available to make all projected future benefit payments of current active and inactive employees. Therefore, the long-term expected rate of return on pension plan investments was applied to all periods of projected benefit payments to determine the total pension liability.

(v) Sensitivity of the Department’s Proportionate Share of the Net Pension Liability to Changes in the Discount Rate

The following presents the Department’s proportionate share of the net pension liability calculated using a 2025 and 2024 discount rate of 7.10%, for financial reporting purposes, as well as what the Department’s proportionate share of the net pension liability would be if it were calculated using a discount rate that is 1-percentage-point lower or 1-percentage-point higher than those rates:

	2025		
	1% Decrease (6.10%)	Current discount rate 7.10%	1% Increase (8.10%)
Department’s proportionate share of the net pension liability	$ 28,836,638	22,032,125	16,233,584

		2024		
		1% Decrease (6.10%)	**Current discount rate 7.10%**	**1% Increase (8.10%)**
Department's proportionate share of the net pension liability	$	29,423,075	22,820,338	17,195,864

(b) Deferred Compensation Plan

The Department offers its employees a deferred compensation plan administered through the City, in accordance with Section 457 of the Internal Revenue Code. The plan permits employees to defer a portion of their salary until future years. The deferred compensation is not available to the employees until termination, retirement, death, or for "unforeseeable emergency" as defined by IRS guidelines. The assets of the plan are not included in the accompanying financial statements.

(9) Other Post-Employment Benefits (OPEB)

The City maintains a single employer post-retirement benefits other than pension (OPEB) plan (the Plan). Plan costs relate to subsidized health care and life insurance for retirees during the period from retirement to the date of eligibility for social security benefits.

(a) OPEB Plan

Post-employment benefits and Compensated Absences (below) are paid for by the applicable fund where the employee is charged. For the years ended June 30, 2025 and 2024, the Department's contribution was $31,198 and $15,445, respectively, and is determined on a pay as you go basis.

No assets are accumulated in a trust that meets the criteria in paragraph 4 of GASB Statement No. 75.

(i) Summary of OPEB Plan

Department employees' normal retirement age is 65 with 5 years of service; early retirement is age 55 with 5 years of service. All members are eligible where permanently disabled.

Retired employees pay 100% of their post-retirement medical premium costs, which are based on COBRA rates for pre-65 coverage.

The City provides $2,000 in life insurance for retirees, except for members of AFSCME and IBEW unions who receive $10,000 in life insurance. Certain current retirees have $6,000 of life insurance in force.

Retired employees pay 100% of their dental costs. Dental coverage is generally available for up to 18 months. The City does not subsidize this benefit.

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(ii) Total OPEB Liability, OPEB Expense, and Deferred Outflows of Resources and Deferred Inflows of Resources Related to OPEBs

At June 30, 2025 and 2024, the Department reported a liability of $743,416 and $815,159, respectively, for its proportionate share of the total OPEB liability. The total OPEB liability as of June 30, 2025 was determined by an actuarial valuation as of July 1, 2023 increased by service costs and interest and decreased by benefit payments to estimate the total OPEB liability at June 30, 2025. The total OPEB liability as of June 30, 2024 was determined by an actuarial valuation as of July 1, 2023 increased by service costs and interest and decreased by benefit payments to estimate the total OPEB liability at June 30, 2024. The total OPEB liability as of June 30, 2025 and June 30, 2024 was also adjusted to reflect any material plan changes after the valuation. The Department's proportion of the total OPEB liability was based on a projection of the Department's long-term share of contributions to the OPEB plan relative to the projected contributions of all participating departments in the City, actuarially determined. At June 30, 2025 and 2024, the Department's proportion was 16.5%.

For the years ended June 30, 2025 and 2024, the Department recognized OPEB expense of $64,628 and $42,097, respectively. At June 30, 2025 and 2024, the Department reported its allocated proportionate share of deferred outflows of resources and deferred inflows of resources related to OPEB from the following sources:

	2025	
	Deferred outflow of resources	**Deferred inflow of resources**
Difference between actual and projected experience	$ —	226,141
Changes in assumptions	21,058	172,876
Changes in proportion	37,944	69,231
	$ 59,002	468,248

	2024	
	Deferred outflow of resources	**Deferred inflow of resources**
Difference between actual and projected experience	$ —	312,719
Changes in assumptions	65,341	102,832
Changes in proportion	53,122	136,241
	$ 118,463	551,792

(Continued)

Amounts reported as deferred outflows of resources and deferred inflows of resources related to OPEB will be recognized in OPEB expense as follows:

Year ended June 30:		
2026	$	158,380
2027		110,578
2028		55,405
2029		54,055
2030		26,710
Thereafter		4,118
Total	$	409,246

(iii) *Actuarial Assumptions*

The total OPEB liability in the June 30, 2025 and 2024 Measurement Date was determined using the following actuarial assumptions:

	2025	**2024**
Valuation dates	July 1, 2023	July 1, 2023
Mortality tables	Pub-2010 public retirement plans amount-weighted general employees mortality tables, scale MP-2021 set forward 2 years (retirees)	Pub-2010 public retirement plans amount-weighted general employ mortality tables, scale MP-2021 set forward 2 years (retirees)
	Pub-2010 public retirement plans amount-weighted general contingent survivors mortality tables, scale MP-2021 set forward 3 years (survivors)	Pub-2010 public retirement plans amount-weighted general conting survivors mortality tables, scale M set forward 3 years (survivors)
Inflation	2.7%	2.7%
Salary increases	2.7%	2.7%
Discount rate	5.20%	3.93%

Healthcare Cost Trend Rates: 7.00% in 2023, reducing by 0.2% each year to an ultimate rate of 4.70% per year rate for 2035 and later.

Healthcare cost trend rates reflect both the current and long-term outlook for increases in healthcare costs. The short-term rates were based on recent industry surveys, plan experience, and near-term expectations. The long-term trend rate was based on the actuary’s general inflation assumption plus an adjustment to reflect expectations for long-term medical inflation.

Since the Plan is not funded, the selection of the discount rate is consistent with the GASB Statement No. 75 standards linking the discount rate to the 20-year AA municipal bond index for unfunded OPEB plans. The discount rate used for the Plan's valuation is equal to the published Bond Buyer GO 20-Bond Municipal Index effective as of June 30, 2025. At June 30, 2025 and 2024, the discount rate was 5.20% and 3.93%, respectively.

(iv) Sensitivity of the Department's Proportionate Share of the Net OPEB Liability to Changes in the Discount Rate

The following presents the Department's proportionate share of the net OPEB liability calculated using the current discount rate of 5.20%, as well as what the Department's proportionate share of the net OPEB liability would be if it were calculated using a discount rate that is 1-percentage-point lower (4.20%) or 1-percentage-point higher (6.20%) than the current rate:

	2025		
	1% Decrease 4.20%	**Current discount rate 5.20%**	**1% Increase 6.20%**
Department's proportionate share of the net OPEB liability	$ 835,924	743,416	665,023

	2024		
	1% Decrease 2.93%	**Current discount rate 3.93%**	**1% Increase 4.93%**
Department's proportionate share of the net OPEB liability	$ 923,781	815,159	724,037

(v) Sensitivity of the Department's Proportionate Share of the Net OPEB Liability to Changes in Healthcare Cost Trend Rates

The following presents the Department's proportionate share of the net OPEB liability calculated using the current healthcare cost trend rate of 7.0% decreasing to 4.70%, as well as what the Department's proportionate share of the net OPEB liability would be if it were calculated using a healthcare cost trend rate that is 1-percentage-point lower (6.0% decreasing to 3.70%) or 1-percentage-point higher (8.0% decreasing to 5.70%) than the current rate.

		2025		
		1% Decrease (6.0% decreasing to 3.70%)	Current healthcare cost trend rate (7.0% decreasing to 4.70%)	1% Increase (8.0% decreasing to 5.70%)
Department's proportionate share of the net OPEB liability	$	674,607	743,416	826,530

		2024		
		1% Decrease (6.0% decreasing to 3.70%)	Current healthcare cost trend rate (7.0% decreasing to 4.70%)	1% Increase (8.0% decreasing to 5.70%)
Department's proportionate share of the net OPEB liability	$	743,708	815,159	901,502

(10) Compensated Employee Absences

Vested vacation and earned compensatory time are recorded under other noncurrent liabilities. Employees earn vacation leave based upon length of employment up to a maximum of 200 hours per year, but may accumulate no more than a maximum of 360 hours.

Employees also accrue sick leave based upon length of employment up to 144 hours per year. The Department has accrued a liability for a portion of accrued sick leave for eligible employees. At retirement, union employees can convert unused sick leave 2:1 up to 240 hours to 120 hours of pay. This conversion may not bring the sick leave balance below 240 hours. Nonunion employees hired prior to January 1, 2001, upon retirement can convert one-third (1/3) the number of days of accumulated unused sick leave up to a maximum payment of four (4) weeks or, upon resignation, can convert one-fourth (1/4) the number of days of accumulated unused sick leave up to a maximum payment of three (3) weeks.

At June 30, 2025 and 2024, the Department has reported accrued compensated employee absences of $1,185,190 and $1,232,589, respectively, in other noncurrent liabilities.

(11) Commitments and Contingencies

(a) The Department receives output from generation of the McNeil Generating Station, the Burlington Gas Turbine, the Winooski One hydroelectric facility, the Airport Solar array, and the Pine Street Solar array. The Department is responsible for the operation of all these resources. The Department is entitled to 50% of the output of the McNeil Generating Station as 50% owner; The Department owns 100% of the other resources and is entitled to 100% of their output.

(b) In addition to energy provided by its owned generation, the Department purchases a portion of its electricity requirements pursuant to long-term (greater than one year in duration) contracts. During the fiscal years ended June 30, 2025 and 2024, long-term sources of purchased power included:

1. New York Power Authority (NYPA) power from hydro stations on the Niagara and St. Lawrence rivers under contracts through April 30, 2032.

2. Under a contract that was originally scheduled to expire in 2021, but which was extended for five years, the Department receives 16 MW (40%) of Vermont Wind's wind farm in northeast Vermont (Sheffield) through October 18, 2026. The Department's 16 MW entitlement is expected to provide approximately 9% of the Department's annual energy requirements.

3. The Department purchases energy from the Georgia Mountain Community Wind (GMCW) project, which began commercial operation on December 31, 2012. Pursuant to a 25-year contract, the Department receives 10 MW (100%) entitlement from GMCW's wind farm in Milton/Georgia, Vermont. GMCW is expected to provide approximately 8% of the Department's annual energy needs.

4. Deliveries pursuant to a ten-year contract with Hancock Wind began in December 2016. Under the contract, which expires in December 2026, the Department will receive 13.5 MW (26.5%) of Hancock's wind farm. It is expected to provide approximately 10% of the Department's annual energy needs.

5. Prior to 2017, the Department received energy from long-term purchases from small in-state resources under a state-mandated feed-in tariff program (called Standard Offer resources). Effective January 1, 2017, the Department was exempted from purchasing energy from these high-priced resources (in recognition of its 100% renewable energy purchases). No power was received from Standard Offer Resources in either fiscal year 2024 or 2025. The Department expects this exemption to continue through at least December 31, 2026.

6. The Burlington City Council, the Vermont PUC, and the voters of Burlington have approved a 23-year energy-only contract with Hydro-Quebec. Deliveries began (for the Department) in November 2015. Under the contract, the Department received 5 MW of contract energy for the period November 1, 2015 to October 31, 2020 and is now receiving a second (additional) 4 MW of contract energy for the period November 1, 2020 to October 31, 2038 (i.e., 9 MW in total). BED's entitlement is expected to provide approximately 16% of the Department's annual energy requirements at the 9 MW level.

7. In 2013, the Department entered a long-term power agreement to purchase the output of a 2.5 MW solar generating facility located in Burlington (South Forty Solar). This facility came online in January of 2018 and provides the Department with VT Tier 2 ECs as well as energy and reduced capacity and transmission requirements.

8. In addition to South Forty Solar, the Department purchases the output from 7 small, in-city solar projects under long-term agreements that amount to 414 kW.

9. In 2017, the Department signed a two-year contract with Great River Hydro with deliveries beginning January 1, 2019. In 2019, this contract was extended for five additional years from 2020 through 2024. The Department receives 7.5 MW during 16 peak hours of each day, along with the associated ECs (that qualify as VT Tier I). This contract is sourced from one or more hydro facilities in the State of Vermont.

10. In 2024, the Department signed an 18-month contract beginning July 2024 with FirstLight for 35% of the output of the Shepaug Dam.

Energy and Capacity payments under these long-term power supply contracts were $16,423,984 and $14,482,063 for the years ended June 30, 2025 and 2024, respectively, with the increase from 2024 being largely due to the new FirstLight contract and increased wind generation, partially offset by the end of the Great River Hydro contract. Budgeted commitments under these long-term contracts and long-term contracts approved and executed for future delivery periods total $50,991,417 for the 5-year period from July 1, 2025 to June 30, 2028.

Fiscal year		Budgeted commitments
2026	$	14,873,694
2027		10,258,238
2028		8,563,289
2029		8,593,085
2030		8,703,111
	$	50,991,417

The remainder of the Department's energy requirements (if any) are satisfied through short-term purchases including:

- Short-term purchases from market counterparties if necessary.
- Net exchange of energy through the Independent System Operator – New England power markets.

The costs of power purchased under these contracts are accounted for as purchased power expenses in the statements of revenues, expenses, and changes in net assets. The percentages of the Department's total energy sources were provided as follows:

	2025	2024
McNeil Generation and Gas Turbine	30 %	28 %
Winooski One	7	12
New York Power Authority	5	5
Wind Production	27	25
Hydro-Quebec	16	16
Great River Hydro	7	13
FirstLight	7	—
In-City Solar	1	1
	100 %	100 %

Note: the percentages are relative to the Department's total available sources of energy rather than a percentage of requirements. Additionally, the Department sells ECs associated with much of the above generation and the above table should not be considered a representation of the Department's renewability. In both years, the sources of energy shown above exceeded the Department's annual energy requirements.

(12) Subsequent Events

The Department considers events or transactions that occur after the balance sheet date, but before the financial statements are issued to provide additional evidence relative to certain estimates or to identify matters that require additional disclosure. These financial statements were issued on November 10, 2025 and subsequent events have been evaluated through that date.

On June 16, 2025 the Department filed with the PUC a request for a 4.5% rate increase. PUC approval of the rate filing is pending. As permitted under Vermont statue, the Department began charging its customers the 4.5% increase as a tariff adjustment for bills rendered on or after September 1, 2025.

On August 7, 2025 the Department, through the City of Burlington, issued $6,540,000 in Electric Revenue Refunding Bonds, 2025 Series A. This advance refunding relieved the City's callable 2014 Series A Revenue Bonds, and will mature in 2034 with an average coupon rate of 3.236%. The Department is expecting net present value savings on the 2025 Series A financing of $168,755.

On September 17, 2025 the Department purchased 10,109 Class A units and 12,865 Class B units in Transco for a cost of $229,740.