UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Quarterly Period Ended June 30, 2024

or

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission File Number	Name of Registrant; State or Other Jurisdiction of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
001-41137	CONSTELLATION ENERGY CORPORATION (a Pennsylvania corporation) 1310 Point Street Baltimore, Maryland 21231-3380 (833) 883-0162	87-1210716
333-85496	CONSTELLATION ENERGY GENERATION, LLC (a Pennsylvania limited liability company) 200 Energy Way Kennett Square, Pennsylvania 19348-2473 (833) 883-0162	23-3064219

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
CONSTELLATION ENERGY CORPORATION:		
Common Stock, without par value	CEG	The Nasdaq Stock Market LLC

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Constellation Energy Corporation	Yes ☒	No ☐
Constellation Energy Generation, LLC	Yes ☒	No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Constellation Energy Corporation	Large Accelerated Filer ☒	Accelerated Filer ☐	Non-accelerated Filer ☐	Smaller Reporting Company ☐	Emerging Growth Company ☐
Constellation Energy Generation, LLC	Large Accelerated Filer ☐	Accelerated Filer ☐	Non-accelerated Filer ☒	Smaller Reporting Company ☐	Emerging Growth Company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

The number of shares outstanding of each registrant's common stock as of July 31, 2024 was as follows:

Constellation Energy Corporation Common Stock, without par value	312,689,080
Constellation Energy Generation, LLC	Not applicable

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GLOSSARY OF TERMS AND ABBREVIATIONS

Constellation Energy Corporation and Related Entities

CEG Parent	Constellation Energy Corporation
Constellation	Constellation Energy Generation, LLC (formerly Exelon Generation Company, LLC)
Registrants	CEG Parent and Constellation, collectively
Antelope Valley	Antelope Valley Solar Ranch One
Continental Wind	Continental Wind LLC
CRP	Constellation Renewables Partners, LLC (formerly ExGen Renewables Partners, LLC)
NER	NewEnergy Receivables LLC
RPG	Renewable Power Generation, LLC
STP	South Texas Project nuclear generating station
TMI	Three Mile Island nuclear facility
West Medway II	West Medway Generating Station II

Former Related Entities

Exelon	Exelon Corporation
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

AEP Texas	American Electric Power Texas
AESO	Alberta Electric Systems Operator
AOCI	Accumulated Other Comprehensive Income (Loss)
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ASR	Accelerated Share Repurchase
CAISO	California ISO
CenterPoint	CenterPoint Energy Houston Electric, LLC
Clean Air Act	Clean Air Act of 1963, as amended
CMC	Carbon Mitigation Credit
CODM	Chief Operating Decision Maker
DOE	United States Department of Energy
DPP	Deferred Purchase Price
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
ERP	Enterprise Resource Planning
Exchange Act	Securities Exchange Act of 1934, as amended
FERC	Federal Energy Regulatory Commission
Former PECO Units	Limerick, Peach Bottom, and Salem nuclear generating units
Former ComEd Units	Braidwood, Byron, Dresden, LaSalle and Quad Cities nuclear generating units
FRCC	Florida Reliability Coordinating Council
GAAP	Generally Accepted Accounting Principles in the United States
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GWh	Gigawatt hour
ICE	Intercontinental Exchange
IPA	Illinois Power Agency
IRA	Inflation Reduction Act of 2022
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ITC	Investment Tax Credit
MISO	Midcontinent Independent System Operator, Inc.
MW	Megawatt
MWh	Megawatt hour
Mystic COS	Mystic Cost of Service Agreement
NAV	Net Asset Value
NASDAQ	Nasdaq Stock Market, LLC
NDT	Nuclear Decommissioning Trust
NERC	North American Electric Reliability Corporation
NGX	Natural Gas Exchange, Inc.
Non-Regulatory Agreement Units	Nuclear generating units or portions thereof whose decommissioning-related activities are not subject to contractual elimination under regulatory accounting

NPNS	Normal Purchase Normal Sale scope exception
NRC	Nuclear Regulatory Commission
NYISO	New York ISO
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
OIESO	Ontario Independent Electricity System Operator
OPEB	Other Postretirement Employee Benefits
Pension Protection Act (the Act)	Pension Protection Act of 2006
PG&E	Pacific Gas and Electric Company
PJM	PJM Interconnection, LLC
PPA	Power Purchase Agreement
PSDAR	Post-shutdown Decommissioning Activities Report
PSEG	Public Service Enterprise Group Incorporated
PTC	Production Tax Credit
Regulatory Agreement Units	Nuclear generating units or portions thereof whose decommissioning-related activities are subject to contractual elimination under regulatory accounting (includes the Former ComEd units, the Former PECO units and STP)
RNF	Operating Revenues Net of Purchased Power and Fuel Expense
ROU	Right-of-use
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Services
SEC	United States Securities and Exchange Commission
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SNF	Spent Nuclear Fuel
SOFR	Secured Overnight Financing Rate
SPP	Southwest Power Pool
STPNOC	STP Nuclear Operating Company
TMA	Tax Matters Agreement
TSA	Transition Services Agreement
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council
ZEC	Zero Emission Credit

FILING FORMAT

This combined Form 10-Q is being filed separately by Constellation Energy Corporation and Constellation Energy Generation, LLC, (the Registrants). Information contained herein relating to any individual Registrant is filed by the Registrant on its own behalf. Neither Registrant makes any representation as to information relating to the other Registrant.

CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING INFORMATION

This Report contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties. Words such as “could,” “may,” “expects,” “anticipates,” “will,” “targets,” “goals,” “projects,” “intends,” “plans,” “believes,” “seeks,” “estimates,” “predicts,” and variations on such words, and similar expressions that reflect our current views with respect to future events and operational, economic, and financial performance, are intended to identify such forward-looking statements.

The factors that could cause actual results to differ materially from the forward-looking statements made by us include those factors discussed herein, as well as the items discussed in (1) the Registrants' combined 2023 Annual Report on Form 10-K in (a) Part I, ITEM 1A. Risk Factors, (b) Part II, ITEM 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations, and (c) Part II, ITEM 8. Financial Statements and Supplementary Data: Note 19, Commitments and Contingencies; (2) this Quarterly Report on Form 10-Q in (a) Part II, ITEM 1A. Risk Factors, (b) Part I, ITEM 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations, and (c) Part I, ITEM 1. Financial Statements: Note 13, Commitments and Contingencies; and (3) other factors discussed in filings with the SEC by the Registrants.

Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. Neither Registrant undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

WHERE TO FIND MORE INFORMATION

The SEC maintains an Internet site at www.sec.gov that contains reports, proxy and information statements, and other information that we file electronically with the SEC. These documents are also available to the public from commercial document retrieval services and our website at www.ConstellationEnergy.com. Information contained on our website shall not be deemed incorporated into, or to be a part of, this Report.

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

Constellation Energy Corporation and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income
(Unaudited)

(In millions, except per share data)	Three Months Ended June 30, 2024	Three Months Ended June 30, 2023	Six Months Ended June 30, 2024	Six Months Ended June 30, 2023
Operating revenues	$ 5,475	$ 5,446	$ 11,637	$ 13,011
Operating expenses				
Purchased power and fuel	2,292	2,887	5,709	8,616
Operating and maintenance	1,645	1,477	3,131	2,908
Depreciation and amortization	296	274	602	542
Taxes other than income taxes	142	139	282	271
Total operating expenses	4,375	4,777	9,724	12,337
Gain (loss) on sales of assets and businesses	—	—	—	26
Operating income (loss)	1,100	669	1,913	700
Other income and (deductions)				
Interest expense, net	(142)	(103)	(269)	(210)
Other, net	6	605	368	919
Total other income and (deductions)	(136)	502	99	709
Income (loss) before income taxes	964	1,171	2,012	1,409
Income tax (benefit) expense	154	342	318	472
Equity in income (losses) of unconsolidated affiliates	(1)	(5)	(2)	(11)
Net income (loss)	809	824	1,692	926
Net income (loss) attributable to noncontrolling interests	(5)	(9)	(5)	(3)
Net income (loss) attributable to common shareholders	$ 814	$ 833	$ 1,697	$ 929
Comprehensive income (loss), net of income taxes				
Net income (loss)	$ 809	$ 824	$ 1,692	$ 926
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	(1)	(3)	(2)	(3)
Actuarial loss reclassified to periodic cost	21	8	39	13
Pension and non-pension postretirement benefit plan valuation adjustment	(2)	—	(5)	(53)
Unrealized gain (loss) on cash flow hedges	2	—	2	—
Unrealized gain (loss) on foreign currency translation	(1)	3	(4)	3
Other comprehensive income (loss), net of income taxes	19	8	30	(40)
Comprehensive income (loss)	828	832	1,722	886
Comprehensive income (loss) attributable to noncontrolling interests	(5)	(9)	(5)	(3)
Comprehensive income (loss) attributable to common shareholders	$ 833	$ 841	$ 1,727	$ 889
Average shares of common stock outstanding:				
Basic	315	324	316	326
Assumed exercise and/or distributions of stock-based awards	1	1	1	1
Diluted	316	325	317	327
Earnings per average common share				
Basic	$ 2.58	$ 2.57	$ 5.37	$ 2.85
Diluted	$ 2.58	$ 2.56	$ 5.35	$ 2.84

See the Combined Notes to Consolidated Financial Statements

Constellation Energy Corporation and Subsidiary Companies
Consolidated Statements of Cash Flows
(Unaudited)

(In millions)	Six Months Ended June 30, 2024	Six Months Ended June 30, 2023
Cash flows from operating activities		
Net income (loss)	$ 1,692	$ 926
Adjustments to reconcile net income (loss) to net cash flows provided by (used in) operating activities		
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	1,388	1,219
Deferred income taxes and amortization of ITCs	191	189
Net fair value changes related to derivatives	(776)	281
Net realized and unrealized (gains) losses on NDT funds	(197)	(270)
Net realized and unrealized (gains) losses on equity investments	11	(414)
Other non-cash operating activities	(65)	77
Changes in assets and liabilities:		
Accounts receivable	771	1,298
Inventories	58	124
Accounts payable and accrued expenses	(207)	(1,725)
Option premiums received (paid), net	129	(48)
Collateral received (posted), net	868	(474)
Income taxes	(86)	160
Pension and non-pension postretirement benefit contributions	(188)	(18)
Other assets and liabilities	(4,925)	(2,451)
Net cash flows provided by (used in) operating activities	(1,336)	(1,126)
Cash flows from investing activities		
Capital expenditures	(1,284)	(1,336)
Proceeds from NDT fund sales	2,890	3,116
Investment in NDT funds	(3,043)	(3,203)
Collection of DPP, net	4,096	1,582
Acquisitions of assets and businesses	(15)	(20)
Other investing activities	6	32
Net cash flows provided by (used in) investing activities	2,650	171
Cash flows from financing activities		
Change in short-term borrowings	(625)	(524)
Proceeds from short-term borrowings with maturities greater than 90 days	200	500
Repayments of short-term borrowings with maturities greater than 90 days	(539)	(200)
Issuance of long-term debt	900	1,791
Retirement of long-term debt	(65)	(121)
Dividends paid on common stock	(222)	(185)
Repurchases of common stock	(999)	(499)
Other financing activities	(35)	(10)
Net cash flows provided by (used in) financing activities	(1,385)	752
Increase (decrease) in cash, restricted cash, and cash equivalents	(71)	(203)
Cash, restricted cash, and cash equivalents at beginning of period	454	528
Cash, restricted cash, and cash equivalents at end of period	$ 383	$ 325
Supplemental cash flow information		
Increase (decrease) in capital expenditures not paid	$ 54	$ (44)
Increase (decrease) in DPP	4,455	2,335
Increase (decrease) in PP&E related to ARO update	(389)	—

See the Combined Notes to Consolidated Financial Statements

Constellation Energy Corporation and Subsidiary Companies
Consolidated Balance Sheets
(Unaudited)

(In millions)	June 30, 2024	December 31, 2023
ASSETS		
Current assets		
Cash and cash equivalents	$ 311	$ 368
Restricted cash and cash equivalents	72	86
Accounts receivable		
Customer accounts receivable (net of allowance for credit losses of $61 and $56 as of June 30, 2024 and December 31, 2023, respectively)	1,578	1,934
Other accounts receivable (net of allowance for credit losses of $5 as of June 30, 2024 and December 31, 2023)	633	917
Mark-to-market derivative assets	935	1,179
Inventories, net		
Natural gas, oil, and emission allowances	201	284
Materials and supplies	1,241	1,216
Renewable energy credits	487	660
Other	2,394	1,655
Total current assets	7,852	8,299
Property, plant, and equipment (net of accumulated depreciation and amortization of $17,618 and $17,423 as of June 30, 2024 and December 31, 2023, respectively)	21,973	22,116
Deferred debits and other assets		
Nuclear decommissioning trust funds	16,883	16,398
Investments	584	563
Goodwill	420	425
Mark-to-market derivative assets	993	995
Deferred income taxes	25	52
Other	2,610	1,910
Total deferred debits and other assets	21,515	20,343
Total assets[(a)]	$ 51,340	$ 50,758

See the Combined Notes to Consolidated Financial Statements

Constellation Energy Corporation and Subsidiary Companies
Consolidated Balance Sheets
(Unaudited)

(In millions)	June 30, 2024	December 31, 2023
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 680	$ 1,644
Long-term debt due within one year	1,035	121
Accounts payable and accrued expenses	2,422	2,612
Mark-to-market derivative liabilities	563	632
Renewable energy credit obligation	730	972
Other	371	338
Total current liabilities	5,801	6,319
Long-term debt	7,409	7,496
Deferred credits and other liabilities		
Deferred income taxes and unamortized ITCs	3,377	3,209
Asset retirement obligations	13,510	14,118
Pension obligations	877	1,070
Non-pension postretirement benefit obligations	749	732
Spent nuclear fuel obligation	1,331	1,296
Payables related to Regulatory Agreement Units	4,310	3,688
Mark-to-market derivative liabilities	555	419
Other	1,640	1,125
Total deferred credits and other liabilities	26,349	25,657
Total liabilities[(a)]	39,559	39,472
Commitments and contingencies (Note 13)		
Shareholders' equity		
Common stock (No par value, 1,000 shares authorized, 313 shares and 317 shares outstanding as of June 30, 2024 and December 31, 2023, respectively)	11,350	12,355
Retained earnings (deficit)	2,236	761
Accumulated other comprehensive income (loss), net	(2,161)	(2,191)
Total shareholders' equity	11,425	10,925
Noncontrolling interests	356	361
Total equity	11,781	11,286
Total liabilities and shareholders' equity	$ 51,340	$ 50,758

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(a) Our consolidated assets include $3,716 million and $3,355 million at June 30, 2024 and December 31, 2023, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Our consolidated liabilities include $992 million and $990 million at June 30, 2024 and December 31, 2023, respectively, of certain VIEs for which the VIE creditors do not have recourse to us. See Note 15 — Variable Interest Entities for additional information.

See the Combined Notes to Consolidated Financial Statements

Constellation Energy Corporation and Subsidiary Companies
Consolidated Statements of Changes in Equity
(Unaudited)

	Six Months Ended June 30, 2024					
	Shareholders' Equity					
(In millions, shares in thousands)	Issued Shares	Common Stock	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss), net	Noncontrolling Interests	Total Equity
Balance, December 31, 2023	317,472	$ 12,355	$ 761	$ (2,191)	$ 361	$ 11,286
Net Income (loss)	—	—	883	—	—	883
Employee incentive plans	661	(4)	—	—	—	(4)
Common stock dividends ($0.3525/common share)	—	—	(112)	—	—	(112)
Common stock repurchased	(2,900)	(504)	—	—	—	(504)
Other comprehensive income (loss), net of income taxes	—	—	—	11	—	11
Balance, March 31, 2024	315,233	$ 11,847	$ 1,532	$ (2,180)	$ 361	$ 11,560
Net Income (loss)	—	—	814	—	(5)	809
Employee incentive plans	72	8	—	—	—	8
Common stock dividends ($0.3525/common share)	—	—	(110)	—	—	(110)
Common stock repurchased	(2,091)	(505)	—	—	—	(505)
Other comprehensive income (loss), net of income taxes	—	—	—	19	—	19
Balance, June 30, 2024	313,214	$ 11,350	$ 2,236	$ (2,161)	$ 356	$ 11,781

	Six Months Ended June 30, 2023					
	Shareholders' Equity					
(In millions, shares in thousands)	Issued Shares	Common Stock	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss), net	Noncontrolling Interests	Total Equity
Balance, December 31, 2022	327,130	$ 13,274	$ (496)	$ (1,760)	$ 354	$ 11,372
Net Income (loss)	—	—	96	—	6	102
Employee incentive plans	528	6	—	—	—	6
Changes in equity of noncontrolling interests	—	—	—	—	(2)	(2)
Common stock dividends ($0.2820/common share)	—	—	(93)	—	—	(93)
Common stock repurchased	(3,239)	(251)	—	—	—	(251)
Other comprehensive income (loss), net of income taxes	—	—	—	(48)	—	(48)
Balance, March 31, 2023	324,419	$ 13,029	$ (493)	$ (1,808)	$ 358	$ 11,086
Net Income (loss)	—	—	833	—	(9)	824
Employee incentive plans	115	31	—	—	—	31
Changes in equity of noncontrolling interests	—	—	—	—	7	7
Common stock dividends ($0.2820/common share)	—	—	(92)	—	—	(92)
Common stock repurchased	(2,958)	(252)	—	—	—	(252)
Other comprehensive income, net of income taxes	—	—	—	8	—	8
Balance, June 30, 2023	321,576	$ 12,808	$ 248	$ (1,800)	$ 356	$ 11,612

See the Combined Notes to Consolidated Financial Statements

Constellation Energy Generation, LLC and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income
(Unaudited)

(In millions)	Three Months Ended June 30, 2024	Three Months Ended June 30, 2023	Six Months Ended June 30, 2024	Six Months Ended June 30, 2023
Operating revenues	$ 5,475	$ 5,446	$ 11,637	$ 13,011
Operating expenses				
Purchased power and fuel	2,292	2,887	5,709	8,616
Operating and maintenance	1,645	1,477	3,131	2,908
Depreciation and amortization	296	274	602	542
Taxes other than income taxes	142	139	282	271
Total operating expenses	4,375	4,777	9,724	12,337
Gain (loss) on sales of assets and businesses	—	—	—	26
Operating income (loss)	1,100	669	1,913	700
Other income and (deductions)				
Interest expense, net	(142)	(103)	(269)	(210)
Other, net	6	605	368	919
Total other income and (deductions)	(136)	502	99	709
Income (loss) before income taxes	964	1,171	2,012	1,409
Income tax (benefit) expense	154	342	318	472
Equity in income (losses) of unconsolidated affiliates	(1)	(5)	(2)	(11)
Net income (loss)	809	824	1,692	926
Net income (loss) attributable to noncontrolling interests	(5)	(9)	(5)	(3)
Net income (loss) attributable to membership interest	$ 814	$ 833	$ 1,697	$ 929
Comprehensive income (loss), net of income taxes				
Net income (loss)	$ 809	$ 824	$ 1,692	$ 926
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	(1)	(3)	(2)	(3)
Actuarial loss reclassified to periodic cost	21	8	39	13
Pension and non-pension postretirement benefit plan valuation adjustment	(2)	—	(5)	(53)
Unrealized gain (loss) on cash flow hedges	2	—	2	—
Unrealized gain (loss) on foreign currency translation	(1)	3	(4)	3
Other comprehensive income (loss), net of income taxes	19	8	30	(40)
Comprehensive income (loss)	828	832	1,722	886
Comprehensive income (loss) attributable to noncontrolling interests	(5)	(9)	(5)	(3)
Comprehensive income (loss) attributable to membership interest	$ 833	$ 841	$ 1,727	$ 889

See the Combined Notes to Consolidated Financial Statements

Constellation Energy Generation, LLC and Subsidiary Companies
Consolidated Statements of Cash Flows
(Unaudited)

(In millions)	Six Months Ended June 30, 2024	Six Months Ended June 30, 2023
Cash flows from operating activities		
Net income (loss)	$ 1,692	$ 926
Adjustments to reconcile net income (loss) to net cash flows provided by (used in) operating activities		
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	1,388	1,219
Deferred income taxes and amortization of ITCs	191	189
Net fair value changes related to derivatives	(776)	281
Net realized and unrealized (gains) losses on NDT funds	(197)	(270)
Net realized and unrealized (gains) losses on equity investments	11	(414)
Other non-cash operating activities	(82)	40
Changes in assets and liabilities:		
Accounts receivable	773	1,303
Receivables from and payables to affiliates, net	97	(39)
Inventories	58	124
Accounts payable and accrued expenses	(203)	(1,728)
Option premiums received (paid), net	129	(48)
Collateral received (posted), net	868	(474)
Income taxes	(86)	160
Pension and non-pension postretirement benefit contributions	(188)	(18)
Other assets and liabilities	(5,025)	(2,458)
Net cash flows provided by (used in) operating activities	(1,350)	(1,207)
Cash flows from investing activities		
Capital expenditures	(1,284)	(1,336)
Proceeds from NDT fund sales	2,890	3,116
Investment in NDT funds	(3,043)	(3,203)
Collection of DPP, net	4,096	1,582
Acquisitions of assets and businesses	(15)	(20)
Other investing activities	6	32
Net cash flows provided by (used in) investing activities	2,650	171
Cash flows from financing activities		
Change in short-term borrowings	(625)	(524)
Proceeds from short-term borrowings with maturities greater than 90 days	200	500
Repayments of short-term borrowings with maturities greater than 90 days	(539)	(200)
Issuance of long-term debt	900	1,791
Retirement of long-term debt	(65)	(121)
Distributions to member	(1,220)	(584)
Other financing activities	(19)	(10)
Net cash flows provided by (used in) financing activities	(1,368)	852
Increase (decrease) in cash, restricted cash, and cash equivalents	(68)	(184)
Cash, restricted cash, and cash equivalents at beginning of period	440	501
Cash, restricted cash, and cash equivalents at end of period	$ 372	$ 317
Supplemental cash flow information		
Increase (decrease) in capital expenditures not paid	$ 54	$ (44)
Increase (decrease) in DPP	4,455	2,335
Increase (decrease) in PP&E related to ARO update	(389)	—

See the Combined Notes to Consolidated Financial Statements

Constellation Energy Generation, LLC and Subsidiary Companies
Consolidated Balance Sheets
(Unaudited)

(In millions)		June 30, 2024		December 31, 2023
ASSETS				
Current assets				
Cash and cash equivalents	$	308	$	366
Restricted cash and cash equivalents		64		74
Accounts receivable				
Customer accounts receivable (net of allowance for credit losses of $61 and $56 as of June 30, 2024 and December 31, 2023, respectively)		1,578		1,934
Other accounts receivable (net of allowance for credit losses of $5 as of June 30, 2024 and December 31, 2023)		625		911
Mark-to-market derivative assets		935		1,179
Inventories, net				
Natural gas, oil, and emission allowances		201		284
Materials and supplies		1,241		1,216
Renewable energy credits		487		660
Other		2,394		1,655
Total current assets		7,833		8,279
Property, plant, and equipment (net of accumulated depreciation and amortization of $17,618 and $17,423 as of June 30, 2024 and December 31, 2023, respectively)		21,973		22,116
Deferred debits and other assets				
Nuclear decommissioning trust funds		16,883		16,398
Investments		584		563
Goodwill		420		425
Mark-to-market derivative assets		993		995
Deferred income taxes		25		52
Other		2,610		1,910
Total deferred debits and other assets		21,515		20,343
Total assets[a]	$	51,321	$	50,738

See the Combined Notes to Consolidated Financial Statements

Constellation Energy Generation, LLC and Subsidiary Companies
Consolidated Balance Sheets
(Unaudited)

(In millions)	June 30, 2024	December 31, 2023
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 680	$ 1,644
Long-term debt due within one year	1,035	121
Accounts payable and accrued expenses	2,258	2,486
Payables to affiliates	215	118
Mark-to-market derivative liabilities	563	632
Renewable energy credit obligation	730	972
Other	369	338
Total current liabilities	5,850	6,311
Long-term debt	7,409	7,496
Deferred credits and other liabilities		
Deferred income taxes and unamortized ITCs	3,377	3,209
Asset retirement obligations	13,510	14,118
Pension obligations	877	1,070
Non-pension postretirement benefit obligations	749	732
Spent nuclear fuel obligation	1,331	1,296
Payables related to Regulatory Agreement Units	4,310	3,688
Mark-to-market derivative liabilities	555	419
Other	1,477	1,025
Total deferred credits and other liabilities	26,186	25,557
Total liabilities[(a)]	39,445	39,364
Commitments and contingencies (Note 13)		
Equity		
Member's equity		
Membership interest	10,538	11,537
Undistributed earnings (deficit)	3,143	1,667
Accumulated other comprehensive income (loss), net	(2,161)	(2,191)
Total member's equity	11,520	11,013
Noncontrolling interests	356	361
Total equity	11,876	11,374
Total liabilities and equity	$ 51,321	$ 50,738

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(a) Our consolidated assets include $3,716 million and $3,355 million as of June 30, 2024 and December 31, 2023, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Our consolidated liabilities include $992 million and $990 million as of June 30, 2024 and December 31, 2023, respectively, of certain VIEs for which the VIE creditors do not have recourse to us. See Note 15 — Variable Interest Entities for additional information.

See the Combined Notes to Consolidated Financial Statements

Constellation Energy Generation, LLC and Subsidiary Companies
Consolidated Statements of Changes in Equity
(Unaudited)

	Six Months Ended June 30, 2024				
	Member's Equity				
(In millions)	Membership Interest	Undistributed Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss), net	Noncontrolling Interests	Total Equity
Balance, December 31, 2023	$ 11,537	$ 1,667	$ (2,191)	$ 361	$ 11,374
Net Income (loss)	—	883	—	—	883
Distributions to member	(499)	(111)	—	—	(610)
Other comprehensive income (loss), net of income taxes	—	—	11	—	11
Balance, March 31, 2024	$ 11,038	$ 2,439	$ (2,180)	$ 361	$ 11,658
Net Income (loss)	—	814	—	(5)	809
Distribution to member	(500)	(110)	—	—	(610)
Other comprehensive income (loss), net of income taxes	—	—	19	—	19
Balance, June 30, 2024	$ 10,538	$ 3,143	$ (2,161)	$ 356	$ 11,876

	Six Months Ended June 30, 2023				
	Member's Equity				
(In millions)	Membership Interest	Undistributed Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss), net	Noncontrolling Interests	Total Equity
Balance, December 31, 2022	$ 12,408	$ 412	$ (1,760)	$ 354	$ 11,414
Net Income (loss)	—	96	—	6	102
Changes in equity of noncontrolling interests	—	—	—	(2)	(2)
Distributions to member	(152)	(97)	—	—	(249)
Other comprehensive income (loss), net of income taxes	—	—	(48)	—	(48)
Balance, March 31, 2023	$ 12,256	$ 411	$ (1,808)	$ 358	$ 11,217
Net Income (loss)	—	833	—	(9)	824
Changes in equity of noncontrolling interests	—	—	—	7	7
Distribution to member	(244)	(91)	—	—	(335)
Other comprehensive income (loss), net of income taxes	—	—	8	—	8
Balance, June 30, 2023	$ 12,012	$ 1,153	$ (1,800)	$ 356	$ 11,721

See the Combined Notes to Consolidated Financial Statements

Combined Notes to Consolidated Financial Statements
(Dollars in millions, unless otherwise noted)

1. Basis of Presentation

Description of Business

We are a producer of carbon-free energy and a supplier of energy products and services. Our generating capacity includes primarily nuclear, wind, solar, natural gas and hydroelectric assets. Through our integrated business operations, we sell electricity, natural gas, and other energy-related products and sustainable solutions to various types of customers, including distribution utilities, municipalities, cooperatives, and commercial, industrial, governmental, and residential customers in markets across multiple geographic regions. We have five reportable segments: Mid-Atlantic, Midwest, New York, ERCOT and Other Power Regions.

Basis of Presentation

The accompanying Consolidated Financial Statements as of June 30, 2024 and for the three and six months ended June 30, 2024 and 2023 are unaudited but, in our opinion include all adjustments that are considered necessary for a fair statement of the financial statements in accordance with GAAP. All adjustments are of a normal, recurring nature, unless otherwise disclosed. The Consolidated Financial Statements include the accounts of our subsidiaries and all intercompany transactions have been eliminated. Constellation's December 31, 2023 Consolidated Balance Sheet was derived from audited financial statements. The interim financial statements are to be read in conjunction with prior annual financial statements and notes. Financial results for interim periods are not necessarily indicative of results that may be expected for any other interim period or for the fiscal year ending December 31, 2024. These Combined Notes to Consolidated Financial Statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations. Amounts disclosed relate to CEG Parent and Constellation unless specifically noted as relating to CEG Parent only. Unless otherwise indicated or the context otherwise requires, references herein to the terms "we," "us," and "our" refer collectively to CEG Parent and Constellation.

Summary of Significant Accounting Policies

See Note 1 — Basis of Presentation of our 2023 Form 10-K for additional information on significant accounting policies.

2. Mergers, Acquisitions, and Dispositions

Acquisition of Joint Ownership in South Texas Project

In November 2023, we completed the acquisition of NRG South Texas LP (renamed and converted as Constellation South Texas, LLC), which owns a 44% undivided ownership interest in the jointly owned STP, a 2,645 MW, dual-unit nuclear plant located in Bay City, Texas. The net cash paid was $1.65 billion, after certain purchase price adjustments. Other owners include City Public Service Board of San Antonio (CPS, 40%) and the City of Austin, Texas (Austin, 16%). See Note 2 — Mergers, Acquisitions, and Dispositions of our 2023 Form 10-K for additional information.

In May 2024, we executed a settlement agreement with all parties (CPS/City of San Antonio, Austin, and NRG), resolving all litigation involving our purchase of the ownership interest in STP, which was initiated by CPS and Austin in Texas state court and before the NRC. The terms of the settlement include us selling a 2% ownership interest in STP to CPS at the same price and terms that we paid NRG for our 44% interest, subject to regulatory approvals from the NRC and the Public Utility Commission of Texas. Pursuant to the settlement, CPS and Austin filed Notices of Dismissal with Prejudice with the Court, which ends the litigation, and likewise withdrew their pending objections to the sale with the NRC. As a result of the settlement, we have reflected assets and liabilities associated with a 2% undivided ownership interest in STP as held for sale. The held for sale amounts are included in the Other current assets and Other current liabilities balances on our Consolidated Balance Sheets as of June 30, 2024. Closing is expected to occur within the next year. Upon closing of the sale, we and CPS will each own a 42% interest in STP, and Austin's interest will remain at 16%. The terms of settlement are not expected to have a material impact on our consolidated financial statements.

(Dollars in millions, unless otherwise noted)

3. Revenue from Contracts with Customers

We recognize revenue from contracts with customers to depict the transfer of goods or services to customers at an amount that we expect to be entitled to in exchange for those goods or services. Our primary sources of revenue include competitive sales of power, natural gas, and other energy-related products and sustainable solutions.

See Note 4 — Revenue from Contracts with Customers of our 2023 Form 10-K for additional information regarding the performance obligations, revenue recognition, and payment terms associated with these sources of revenue.

Contract Balances

Contract Assets

We record contract assets for the revenue recognized on the construction and installation of energy efficiency assets and new power generating facilities before we have an unconditional right to bill for and receive the consideration from the customer. These contract assets are subsequently reclassified to receivables when the right to payment becomes unconditional. We record contract assets and contract receivables in Other current assets and Customer accounts receivable, net, respectively, in the Consolidated Balance Sheets.

The following table provides a rollforward of the contract assets reflected in the Consolidated Balance Sheets for the three and six months ended June 30, 2024 and 2023.

	2024	2023
Beginning balance as of January 1	$ 82	$ 130
Amounts reclassified to receivables	(15)	(11)
Revenues recognized	14	31
Ending balance as of March 31	81	150
Amounts reclassified to receivables	(4)	(76)
Revenues recognized	16	15
Ending balance as of June 30	$ 93	$ 89

Contract Liabilities

We record contract liabilities when consideration is received or due prior to the satisfaction of the performance obligations. We record contract liabilities in Other current liabilities and Other deferred credits and other liabilities in the Consolidated Balance Sheets. These contract liabilities primarily relate to upfront consideration received or due for equipment service plans, the Mystic COS, and the Illinois ZEC program. The Mystic COS, which ended in May 2024, included upfront consideration received that differs from the recognized earnings over the cost of the service period. The Illinois ZEC program introduces an annual cap on the total consideration to be received by us for each delivery period. The ZEC price is established on a per MWh of production basis with a maximum annual cap for total compensation to be received for each planning year, while requiring delivery of all ZECs produced by our participating facilities during each delivery period. ZECs delivered to Illinois utilities in excess of the annual cost cap may be paid in subsequent years if the payments do not exceed the prescribed annual cost cap for that year. The balance as of June 30, 2024 primarily related to equipment service plans. The balance as of December 31, 2023 primarily related to equipment services plans and the Mystic COS.

(Dollars in millions, unless otherwise noted)

The following table provides a rollforward of the contract liabilities reflected in the Consolidated Balance Sheets for the three and six months ended June 30, 2024 and 2023.

	2024	2023
Beginning balance as of January 1	$ 40	$ 47
Consideration received or due	49	131
Revenues recognized	(55)	(115)
Ending balance as of March 31	34	63
Consideration received or due	47	81
Revenues recognized	(46)	(92)
Ending balance as of June 30	$ 35	$ 52

Transaction Price Allocated to Remaining Performance Obligations

The following table shows the amounts of future revenues expected to be recorded in each year for performance obligations that are unsatisfied or partially unsatisfied as of June 30, 2024. This disclosure only includes contracts for which the total consideration is fixed and determinable at contract inception. The average contract term varies by customer type and commodity but ranges from one month to several years. This disclosure excludes mark-to-market derivatives and certain power and gas sales contracts which contain variable volumes and/or variable pricing.

	2024	2025	2026	2027	2028 and thereafter	Total
Remaining performance obligations	$ 92	$ 59	$ 30	$ 18	$ 130	$ 329

Transaction Price Allocated to Previously Satisfied Performance Obligations

Our Clinton and Quad Cities units contract with certain utilities in Illinois which requires delivery of all ZECs produced during each planning year (June through May), with total compensation limited by an annual cap for each planning year designed to limit the cost of ZECs to each utility's customers. ZECs delivered that, if paid, would result in the annual cap being exceeded may be paid in subsequent years at the vintage year price as long as the payments would not exceed the annual cap in the year paid. In each planning year since the program commenced June 2017, we delivered ZECs to the utilities in excess of the annual compensation cap.

The ZEC price and annual compensation cap effective for each planning year are administratively determined by the IPA. For the June 2023 through May 2024 planning year, the ZEC price has been established at $0.30 per ZEC, subject to an annual cap of $224 million. ZECs generated and delivered during this planning year will not exceed the annual cap, providing capacity to compensate for ZECs delivered in prior planning years in excess of the compensation cap. For the three and six months ended June 30, 2023, we recognized $218 million of revenue as a receivable for ZECs delivered in prior planning years, with payment expected in the third quarter of 2024. As of June 30, 2024, this receivable is included within Customer accounts receivable, net in the Consolidated Balance Sheets. For the June 2024 through May 2025 planning year, the ZEC price has been established at $9.38 per ZEC, subject to an annual cap of $222 million. Revenue recognized for ZECs delivered in prior planning years were not material for the three and six months ended June 30, 2024.

Revenue Disaggregation

We disaggregate the revenue recognized from contracts with customers into categories that depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors. See Note 4 — Segment Information for the presentation of revenue disaggregation.

4. Segment Information

Operating segments are determined based on information used by the CODM in deciding how to evaluate performance and allocate resources. We have five reportable segments consisting of the Mid-Atlantic, Midwest, New York, ERCOT, and all other power regions referred to collectively as "Other Power Regions."

The basis for our reportable segments is the integrated management of our electricity business that is located in different geographic regions, and largely representative of the footprints of ISO/RTO and/or NERC regions, which utilize multiple supply sources to provide electricity through various distribution channels (wholesale and retail). Our hedging strategies and risk metrics are also aligned to these same geographic regions. Descriptions of each of our five reportable segments are as follows:

- **Mid-Atlantic** represents operations in the eastern half of PJM, which includes New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia, and parts of Pennsylvania and North Carolina.
- **Midwest** represents operations in the western half of PJM and the United States footprint of MISO, excluding MISO's Southern Region.
- **New York** represents operations within NYISO.
- **ERCOT** represents operations within Electric Reliability Council of Texas that covers a majority of the state of Texas.
- **Other Power Regions:**
  - **New England** represents operations within ISO-NE.
  - **South** represents operations in FRCC, MISO's Southern Region, and the remaining portions of SERC not included within MISO or PJM.
  - **West** represents operations in WECC, which includes CAISO.
  - **Canada** represents operations across the entire country of Canada and includes AESO, OIESO, and the Canadian portion of MISO.

The CODM evaluates the performance of our electric business activities and allocates resources based on Operating revenues net of Purchased power and fuel expense (RNF). We believe this is a useful measurement of operational performance, although it is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report. Our operating revenues include all sales to third parties as well as government assistance. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy, and ancillary services. Fuel expense includes the fuel costs for our owned generation and fuel costs associated with tolling agreements. The results of our other business activities are not regularly reviewed by the CODM and are therefore not classified as operating segments or included in the regional reportable segment amounts. These activities include wholesale and retail sales of natural gas, energy-related sales in the United Kingdom, as well as sales of other energy-related products and sustainable solutions that are not significant to our overall results of operations. Further, our unrealized mark-to-market gains and losses on economic hedging activities and our amortization of certain intangible assets and liabilities relating to commodity contracts recorded at fair value from mergers and acquisitions are also excluded from the regional reportable segment amounts. The CODM does not use a measure of total assets in making decisions regarding allocating resources to or assessing the performance of these reportable segments.

The following tables disaggregate the revenue recognized from contracts with customers into categories that depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors. The disaggregation of revenues reflects our two primary products of power sales and natural gas sales, with further disaggregation of power sales provided by geographic region.

(Dollars in millions, unless otherwise noted)

The following tables also show the reconciliation of reportable segment revenues and RNF to our total revenues and RNF for the three and six months ended June 30, 2024 and 2023.

	Three Months Ended June 30, 2024				
	Revenues from external customers				
	Contracts with customers	Other[a]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 1,297	$ 4	$ 1,301	$ 3	$ 1,304
Midwest	993	175	1,168	—	1,168
New York	463	57	520	(6)	514
ERCOT	274	81	355	2	357
Other Power Regions	1,023	160	1,183	1	1,184
Total Reportable Segment Power Revenues	4,050	477	4,527	—	4,527
Total Natural Gas Revenues	231	349	580	—	580
Total Other Revenues[b]	125	243	368	—	368
Total Consolidated Operating Revenues	$ 4,406	$ 1,069	$ 5,475	$ —	$ 5,475

	Three Months Ended June 30, 2023				
	Revenues from external customers				
	Contracts with customers	Other[a]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 1,235	$ (27)	$ 1,208	$ (10)	$ 1,198
Midwest	1,352	(23)	1,329	1	1,330
New York	438	30	468	3	471
ERCOT	291	36	327	1	328
Other Power Regions	962	144	1,106	5	1,111
Total Reportable Segment Power Revenues	4,278	160	4,438	—	4,438
Total Natural Gas Revenues	280	376	656	—	656
Total Other Revenues[b]	143	209	352	—	352
Total Consolidated Operating Revenues	$ 4,701	$ 745	$ 5,446	$ —	$ 5,446

	Six Months Ended June 30, 2024				
	Revenues from external customers				
	Contracts with customers	Other[a]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 2,652	$ (108)	$ 2,544	$ 2	$ 2,546
Midwest	1,993	268	2,261	1	2,262
New York	955	64	1,019	8	1,027
ERCOT	511	164	675	3	678
Other Power Regions	2,458	364	2,822	(14)	2,808
Total Reportable Segment Power Revenues	8,569	752	9,321	—	9,321
Total Natural Gas Revenues	839	903	1,742	—	1,742
Total Other Revenues[b]	255	319	574	—	574
Total Consolidated Operating Revenues	$ 9,663	$ 1,974	$ 11,637	$ —	$ 11,637

(Dollars in millions, unless otherwise noted)

	Six Months Ended June 30, 2023				
	Revenues from external customers				
	Contracts with customers	Other[(a)]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 2,648	$ (163)	$ 2,485	$ (41)	$ 2,444
Midwest	2,546	(188)	2,358	3	2,361
New York	901	67	968	37	1,005
ERCOT	490	5	495	2	497
Other Power Regions	2,481	423	2,904	(1)	2,903
Total Reportable Segment Power Revenues	9,066	144	9,210	—	9,210
Total Natural Gas Revenues	1,176	966	2,142	—	2,142
Total Other Revenues[(b)]	290	1,369	1,659	—	1,659
Total Consolidated Operating Revenues	$ 10,532	$ 2,479	$ 13,011	$ —	$ 13,011

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(a) Includes revenues from nuclear PTCs beginning in 2024 as well as derivatives and leases in all periods presented.
(b) Represents activities not allocated to a region. See text above for a description of included activities. Includes unrealized mark-to-market gains of $192 million and $211 million for the three months ended June 30, 2024 and 2023, respectively, and unrealized mark-to-market gains of $254 million and $1,140 million for the six months ended June 30, 2024 and 2023, respectively.

	Three Months Ended June 30, 2024			Three Months Ended June 30, 2023		
	RNF from external customers	Intersegment RNF	Total RNF	RNF from external customers	Intersegment RNF	Total RNF
Mid-Atlantic	$ 756	$ 4	$ 760	$ 732	$ (9)	$ 723
Midwest	763	2	765	973	2	975
New York	379	(6)	373	314	5	319
ERCOT	212	2	214	166	(2)	164
Other Power Regions	292	1	293	218	3	221
Total RNF for Reportable Segments	2,402	3	2,405	2,403	(1)	2,402
Other[(a)]	781	(3)	778	156	1	157
Total RNF	$ 3,183	$ —	$ 3,183	$ 2,559	$ —	$ 2,559

	Six Months Ended June 30, 2024			Six Months Ended June 30, 2023		
	RNF from external customers	Intersegment RNF	Total RNF	RNF from external customers	Intersegment RNF	Total RNF
Mid-Atlantic	$ 1,431	$ 4	$ 1,435	$ 1,455	$ (41)	$ 1,414
Midwest	1,463	5	1,468	1,662	1	1,663
New York	709	8	717	538	40	578
ERCOT	433	(9)	424	220	(3)	217
Other Power Regions	683	(23)	660	474	(4)	470
Total RNF for Reportable Segments	4,719	(15)	4,704	4,349	(7)	4,342
Other[(a)]	1,209	15	1,224	46	7	53
Total RNF	$ 5,928	$ —	$ 5,928	$ 4,395	$ —	$ 4,395

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(a) Other represents activities not allocated to a region. See text above for a description of included activities. See Note 10 — Derivative Financial Instruments for more information on mark-to-market derivatives.

5. Government Assistance

As a result of the enactment of the IRA, we qualify for certain federal government incentives through eligible activities. These incentives include both refundable and transferable tax credits. The current GAAP framework does not address the receipt of government assistance by for-profit entities. We account for this government assistance by analogy to International Accounting Standard (IAS) 20, Accounting for Government Grants and Disclosure of Government Assistance, and recognize the benefits when there is reasonable assurance that we will comply with the required conditions and that the benefits will be received. We believe the reasonable assurance term as used in IAS 20 is analogous to the term probable as defined in Accounting Standards Codification 450-20 of GAAP.

Beginning in 2024, our nuclear units are eligible for a PTC extending through 2032. The nuclear PTC provides a transferable credit up to $15 per MWh (a base credit of $3 per MWh with a five times multiplier provided certain prevailing wage requirements are met) and is subject to phase-out when annual gross receipts are between $25.00 per MWh and $43.75 per MWh. We have determined that we will meet the annual prevailing wage requirements at all our nuclear units and are eligible for the five times multiplier. Both the amount of the PTC and the gross receipts thresholds adjust for inflation after 2024 through the duration of the program based on the GDP price deflator for the preceding calendar year. The benefits of the PTC may be realized through a credit against our federal income taxes or transferred via sale to an unrelated party. For the three and six months ended June 30, 2024, our Consolidated Statements of Operations and Comprehensive Income includes an estimate of $408 million and $712 million, respectively, in Operating revenues for nuclear PTCs earned based on qualifying production volumes during the respective periods. Nuclear PTCs are recorded within Other deferred debits and other assets within the Consolidated Balance Sheets and reclassified as a reduction to Accounts payable and accrued expenses when used to reduce our federal income tax payable. As of June 30, 2024, our Consolidated Balance Sheets reflect an estimated nuclear PTC receivable of $610 million within Other deferred debits and other assets and a reduction to Accounts payable and accrued expenses of $102 million for estimated nuclear PTCs that we have utilized as a credit against our current federal income taxes payable. There were no transfers of estimated nuclear PTCs to third parties during the three and six months ended June 30, 2024. Our estimate required the exercise of judgment in determining the amount of nuclear PTC expected for each of our nuclear units. Since the amount of nuclear PTC is a function of annual gross receipts, the actual amount of PTC earned cannot be determined until after the end of the calendar year and may be different from this initial estimate. Further, the nuclear PTC continues to be the subject of additional guidance expected to be issued from the U.S. Treasury and IRS that may materially impact the total amount of benefits we receive.

Many of the state-sponsored programs providing compensation for the emissions-free attributes of generation from certain of our nuclear units include contractual or other provisions that require us to refund that compensation up to the amount of the nuclear PTC received or pass through the entirety of the nuclear PTC received. As of June 30, 2024, we have recognized $404 million of estimated payables within Other deferred credits and other liabilities on our Consolidated Balance Sheets and recognized net operating revenue of $51 million and $120 million (pre-tax) associated with programs requiring refunds or pass through of the nuclear PTC in our Consolidated Statement of Operations and Comprehensive Income for the three and six months ended June 30, 2024, respectively. As with the actual amount of the PTC earned, which cannot be determined until after the end of the calendar year, the actual amounts due under state-sponsored programs may be different from our initial estimate.

6. Accounts Receivable

Unbilled Customer Revenue

We recorded $171 million and $372 million of unbilled customer revenues in Customer accounts receivables, net in the Consolidated Balance Sheets as of June 30, 2024 and December 31, 2023, respectively.

(Dollars in millions, unless otherwise noted)

Sales of Customer Accounts Receivable

In 2020, NER, a bankruptcy remote, special purpose entity, which is wholly owned by us, entered into a revolving accounts receivable financing arrangement with a number of financial institutions and a commercial paper conduit (Purchasers) to sell certain customer accounts receivable (Facility). The maximum funding limit of the Facility is $1.1 billion through August 2025. Under the Facility, NER may sell eligible short-term customer accounts receivable to the Purchasers in exchange for cash and subordinated interest. The transfers are reported as sales of receivables in the consolidated financial statements. The subordinated interest in collections upon the receivables sold to the Purchasers is referred to as the DPP, which is reflected in Other current assets in the Consolidated Balance Sheets.

The Facility requires the balance of eligible receivables to be maintained at or above the balance of cash proceeds received from the Purchasers. To the extent the eligible receivables decrease below such balance, we are required to repay cash to the Purchasers. When eligible receivables exceed cash proceeds, we have the ability to increase the cash received up to the maximum funding limit. These cash inflows and outflows impact the DPP.

The following tables summarize the impact of the sale of certain receivables:

	As of June 30, 2024	As of December 31, 2023
Derecognized receivables transferred at fair value	$ 1,703	$ 1,516
Less: Cash proceeds received	150	300
DPP	$ 1,553	$ 1,216

	Three Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	2024	2023
Loss on sale of receivables[(a)]	$ 17	$ 26	$ 32	$ 46

(a) Reflected in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income. This represents the amount by which the accounts receivable sold into the Facility are discounted, limited to credit losses.

	Six Months Ended June 30,	
	2024	2023
Proceeds from new transfers[(a)]	$ 1,402	$ 3,181
Cash collections received on DPP[(b)]	4,246	2,432
Cash collections reinvested in the Facility	$ 5,648	$ 5,613

(a) Customer accounts receivable sold into the Facility were $5,856 million and $5,516 million for the six months ended June 30, 2024 and 2023, respectively.
(b) Does not include the $150 million and $850 million net cash payments to the Purchasers for the six months ended June 30, 2024 and 2023, respectively.

Our risk of loss following the transfer of accounts receivable is limited to the DPP outstanding. Payment of DPP is not subject to significant risks other than delinquencies and credit losses on accounts receivable transferred.

We recognize the cash proceeds received upon sale in Cash flows from operating activities within the Changes in Other assets and liabilities line in the Consolidated Statements of Cash Flows, which were ($4,455) million and ($2,335) million for the six months ended June 30, 2024 and 2023, respectively. The collection and reinvestment of DPP is recognized in Cash flows from investing activities in the Collection of DPP, net line in the Consolidated Statements of Cash Flows, which were $4,096 million and $1,582 million for the six months ended June 30, 2024 and 2023, respectively.

See Note 12 — Fair Value of Financial Assets and Liabilities and Note 15 — Variable Interest Entities for additional information.

(Dollars in millions, unless otherwise noted)

Other Sales of Customer Accounts Receivables

We are required, under supplier tariffs, to sell customer receivables to utility companies. The following table presents the total receivables sold:

	Six Months Ended June 30,	
	2024	2023
Total receivables sold	$ 210	$ 249

7. Nuclear Decommissioning

Nuclear Decommissioning Asset Retirement Obligations

We have a legal obligation to decommission our nuclear power plants following the permanent cessation of operations. See Note 10 — Asset Retirement Obligations of our 2023 Form 10-K for additional information regarding AROs and the financial statement impact of changes in estimate.

The following table provides a rollforward of the nuclear decommissioning AROs reflected in the Consolidated Balance Sheets from December 31, 2023 to June 30, 2024:

Balance as of December 31, 2023[(a)]	$ 13,891
Net decrease due to changes in, and timing of, estimated future cash flows	(909)
Accretion expense	329
ARO transferred to Liabilities held for sale	(20)
Costs incurred related to decommissioning plants	(16)
Balance as of June 30, 2024[(a)]	$ 13,275

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(a) Includes $28 million and $30 million as the current portion of the ARO as of June 30, 2024 and December 31, 2023, respectively, which is included in Other current liabilities in the Consolidated Balance Sheets.

In the second quarter of 2024, we updated our retirement timing assumptions for the Braidwood and Byron plants, commensurate with an update to the estimated useful lives utilized for depreciation purposes that now includes an assumption for a subsequent license renewal period, provided economic levels remain supportive of extended operations. The $909 million net decrease due to changes in, and timing of, estimated future cash flows was primarily driven by the change in the assumed retirement dates for these plants. The change in depreciation expense was not material during the three and six months ended June 30, 2024, nor is the estimated annual impact material to future periods.

NDT Funds

We had NDT funds totaling $17,015 million and $16,398 million as of June 30, 2024 and December 31, 2023, respectively. As of June 30, 2024, $ 132 million of the NDT funds were current and included in Other current assets in the Consolidated Balance Sheets. As of December 31, 2023, none of the NDT funds were reflected in Other current assets. See Note 16 — Supplemental Financial Information for additional information on activities of the NDT funds.

Accounting Implications of the Regulatory Agreement Units

See Note 1 — Basis of Presentation and Note 10 — Asset Retirement Obligations of our 2023 Form 10-K for additional information on the Regulatory Agreement Units.

(Dollars in millions, unless otherwise noted)

The following table presents our noncurrent payables to ComEd, PECO, CenterPoint, and AEP Texas reflected as Payables related to Regulatory Agreement Units in the Consolidated Balance Sheets as of June 30, 2024 and December 31, 2023:

	June 30, 2024	December 31, 2023
ComEd	$ 3,566	$ 2,955
PECO	274	278
CenterPoint	349	338
AEP Texas	121	117
Payables related to Regulatory Agreement Units	$ 4,310	$ 3,688

NRC Minimum Funding Requirements

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts for radiological decommissioning of the facility at the end of its life.

In March 2024, we filed our annual decommissioning funding status report with the NRC for our shutdown units, including Zion Station which was transferred back to us in November 2023. The status report demonstrated adequate decommissioning funding assurance as of December 31, 2023 for all our shutdown units except for Peach Bottom Unit 1. Financial assurance for decommissioning Peach Bottom Unit 1 is provided by collections from PECO customers. Additionally in March 2024, STPNOC filed the decommissioning funding status report for STP. The status report demonstrated adequate funding assurance as of December 31, 2023. See Note 10 — Asset Retirement Obligations of our 2023 Form 10-K for additional information.

(Dollars in millions, unless otherwise noted)

8. Income Taxes

Rate Reconciliation

The effective income tax rate varies from the U.S. federal statutory rate principally due to the following:

	Three Months Ended June 30,	
	2024	2023
U.S. federal statutory rate	21.0 %	21.0 %
(Decrease) increase due to:		
State income taxes, net of federal income tax benefit	2.5	4.2
Qualified NDT fund income and losses	1.3	4.4
Amortization of investment tax credit, including deferred taxes on basis differences	(0.2)	(0.4)
PTCs and other credits	(9.6)	(0.5)
Noncontrolling interests	0.1	0.1
Other	0.9	0.4
Effective income tax rate	16.0 %	29.2 %

	Six Months Ended June 30,	
	2024	2023
U.S. federal statutory rate	21.0 %	21.0 %
(Decrease) increase due to:		
State income taxes, net of federal income tax benefit	(2.0)	4.0
Qualified NDT fund income and losses	5.3	9.4
Amortization of investment tax credit, including deferred taxes on basis differences	(0.2)	(0.5)
PTCs and other credits	(8.1)	(0.5)
Other	(0.2)	0.1
Effective income tax rate	15.8 %	33.5 %

Other Tax Matters

Tax Matters Agreement

In connection with the separation, we entered into a TMA with Exelon. The TMA governs the respective rights, responsibilities, and obligations between us and Exelon after the separation with respect to tax liabilities and benefits, tax attributes, tax returns, tax contests and other tax sharing regarding U.S. federal, state, local and foreign income taxes, other tax matters and related tax returns. See Note 14 — Income Taxes of our 2023 Form 10-K for additional information on the separation.

Responsibility and Indemnification for Taxes. As a former subsidiary of Exelon, we have joint and several liability with Exelon to the IRS and certain state jurisdictions relating to the taxable periods that we were included in federal and state filings. However, the TMA specifies the portion of this tax liability for which we will bear contractual responsibility, and we and Exelon agreed to indemnify each other against any amounts for which such indemnified party is not responsible. Specifically, we will be liable for taxes due and payable in connection with tax returns that we are required to file. We will also be liable for our share of certain taxes required to be paid by Exelon with respect to taxable years or periods (or portions thereof) ending on or prior to the separation to the extent that we would have been responsible for such taxes under the Exelon tax sharing agreement then existing. As of June 30, 2024 and December 31, 2023, our Consolidated Balance Sheets reflect $38 million and $37 million in Other deferred credits and other liabilities, respectively, for tax liabilities where we maintain contractual responsibility to Exelon.

(Dollars in millions, unless otherwise noted)

Tax Refunds and Attributes. The TMA provides for the allocation of certain pre-closing tax attributes between us and Exelon. Tax attributes will be allocated in accordance with the principles set forth in the existing Exelon tax sharing agreement, unless otherwise required by law. Under the TMA, we will be entitled to refunds for taxes for which we are responsible. In addition, it is expected that Exelon will have tax attributes that may be used to offset Exelon's future tax liabilities. A significant portion of such attributes were generated by our business. In February 2024, we executed an amendment to the TMA that modified the timing of Exelon's payment of amounts due to us. As of June 30, 2024, our Consolidated Balance Sheets reflects receivables of $137 million and $193 million in Other accounts receivable and Other deferred debits and other assets, respectively. As of December 31, 2023, our Consolidated Balance Sheets reflected receivables of $336 million and $178 million in Other accounts receivable and Other deferred debits and other assets, respectively.

9. Retirement Benefits

Components of Net Periodic Benefit (Credits) Costs

See Note 1 — Basis of Presentation of our 2023 10-K for additional information on where we report the service cost and other non-service cost (credit) components for all plans.

The following tables present the components of our net periodic benefit (credits) costs, prior to capitalization and co-owner allocations, for the three and six months ended June 30, 2024 and 2023:

	Pension Benefits		OPEB		Total Pension Benefits and OPEB	
	Three Months Ended June 30,		Three Months Ended June 30,		Three Months Ended June 30,	
	2024	2023	2024	2023	2024	2023
Components of net periodic benefit (credit) cost						
Service cost	$ 23	$ 23	$ 5	$ 4	$ 28	$ 27
Non-service components of pension benefits & OPEB (credit) cost						
Interest cost	96	98	18	19	114	117
Expected return on assets	(124)	(127)	(10)	(11)	(134)	(138)
Amortization of:						
Prior service (credit) cost	—	—	(1)	(2)	(1)	(2)
Actuarial (gain) loss	26	11	(2)	(4)	24	7
Settlement charges	1	—	—	—	1	—
Non-service components of pension benefits & OPEB (credit) cost	(1)	(18)	5	2	4	(16)
Net periodic benefit (credit) cost[a,b]	$ 22	$ 5	$ 10	$ 6	$ 32	$ 11

(Dollars in millions, unless otherwise noted)

	Pension Benefits		OPEB		Total Pension Benefits and OPEB	
	Six Months Ended June 30,		Six Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	2024	2023	2024	2023
Components of net periodic benefit (credit) cost:						
Service cost	$ 45	$ 45	$ 9	$ 8	$ 54	$ 53
Non-service components of pension benefits & OPEB (credit) cost:						
Interest cost	191	197	36	37	227	234
Expected return on assets	(248)	(254)	(21)	(22)	(269)	(276)
Amortization of:						
Prior service (credit) cost	—	—	(3)	(4)	(3)	(4)
Actuarial (gain) loss	51	23	(4)	(7)	47	16
Settlement charges	4	—	—	—	4	—
Non-service components of pension benefits & OPEB (credit) cost	(2)	(34)	8	4	6	(30)
Net periodic benefit (credit) cost[a,b]	$ 43	$ 11	$ 17	$ 12	$ 60	$ 23

(a) The pension benefit and OPEB service costs reflected in the Consolidated Statements of Operations and Comprehensive Income for the three and six months ended June 30, 2024 totaled $27 million and $51 million, respectively.
(b) The pension benefit and OPEB service costs reflected in the Consolidated Statements of Operations and Comprehensive Income for the three and six months ended June 30, 2023 totaled $23 million and $47 million, respectively.

10. Derivative Financial Instruments

We use derivative instruments to manage commodity price risk, interest rate risk, and foreign exchange risk related to ongoing business operations.

Authoritative guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings immediately. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include NPNS, cash flow hedges, and fair value hedges. All derivative instruments, excluding NPNS and cash flow hedges, are recorded at fair value through earnings. For all NPNS derivative instruments, accounts receivable or accounts payable are recorded when derivatives settle, and revenue or expense is recognized in earnings as the underlying physical commodity is sold or delivered.

Authoritative guidance about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Combined Notes to Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheets. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referenced contracts via one payment stream, which takes place as the contracts deliver, when collateral is requested or in the event of default. In the tables below, which present fair value balances, our energy-related economic hedges and proprietary trading derivatives are shown gross. The impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, including margin on exchange positions, is aggregated in the collateral and netting columns.

Our use of cash collateral is generally unrestricted unless we were downgraded below investment grade. As our senior unsecured debt rating is currently rated at BBB+ and Baa1 by S&P and Moody's, respectively, it would take a three notch downgrade by S&P or Moody's for us to go below investment grade.

Commodity Price Risk

We employ established policies and procedures to manage our risks associated with market fluctuations in commodity prices by entering into physical and financial derivative contracts, including swaps, futures, forwards, options, and short-term and long-term commitments to purchase and sell energy and energy-related products. We believe these instruments, which are either determined to be non-derivative or classified as economic hedges, mitigate exposure to fluctuations in commodity prices.

To the extent the amount of energy we produce or procure differs from the amount of energy we have contracted to sell and in connection with portfolio optimization, we are exposed to market fluctuations in the prices of electricity, natural gas, and other commodities. We use a variety of derivative and non-derivative instruments to manage the commodity price risk of our electric generation facilities, including power and gas sales, fuel and power purchases, natural gas transportation and pipeline capacity agreements, and other energy-related products marketed and purchased. To manage these risks, we may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from expected sales of power and gas and purchases of power and fuel. The objectives for executing such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return. We are also exposed to differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments which include derivative congestion products, whose changes in fair value are recognized in earnings each period, and auction revenue rights, which are accounted for on an accrual basis.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on owned and contracted generation positions that have not been hedged. Beginning in 2024, our nuclear fleet is eligible for the nuclear PTC provided by the IRA, an important tool in managing commodity price risk for each nuclear unit not already receiving state support. The nuclear PTC provides increasing levels of support as unit revenues decline below levels established in the IRA and is further adjusted for inflation after 2024 through the duration of the program based on the GDP price deflator for the preceding calendar year. See Note 5 — Government Assistance for additional information on the nuclear PTC.

In locations and periods where our load serving activities do not naturally offset existing generation portfolio risk, remaining commodity price exposure is managed through portfolio hedging activities. Portfolio hedging activities are generally concentrated in the prompt three years, when customer demand and market liquidity enable effective price risk mitigation. During this prompt three-year period, we seek to mitigate the price risk associated with our load serving contracts, non-nuclear generation, and any residual price risk for our nuclear generation that the nuclear PTC and state programs may not fully mitigate. We also enter transactions that further optimize the economic benefits of our overall portfolio.

Additionally, we are exposed to certain market risks through our proprietary trading activities. The proprietary trading activities are a complement to our energy marketing portfolio but represent a small portion of our overall energy marketing activities and are subject to limits established by the Executive Committee. Proprietary trading includes all contracts executed with the intent of benefiting from shifts or changes in market prices as opposed to those executed with the intent of hedging or managing risk. Gains and losses associated with proprietary trading are reported as Operating revenues in the Consolidated Statements of Operations and Comprehensive Income and are included in the Net fair value changes related to derivatives line in the Consolidated Statements of Cash Flows. For the three and six months ended June 30, 2024 and 2023, net pre-tax commodity mark-to-market gains and losses associated with proprietary trading activities were not material.

(Dollars in millions, unless otherwise noted)

The following tables provide a summary of the derivative fair value balances recorded as of June 30, 2024 and December 31, 2023:

June 30, 2024	Economic Hedges	Proprietary Trading	Collateral [(a)(b)]	Netting[(a)]	Total
Mark-to-market derivative assets (current)	$ 6,598	$ 1	$ 383	$ (6,059)	$ 923
Mark-to-market derivative assets (noncurrent)	4,386	—	321	(3,715)	992
Total mark-to-market derivative assets	10,984	1	704	(9,774)	1,915
Mark-to-market derivative liabilities (current)	(7,111)	(1)	490	6,059	(563)
Mark-to-market derivative liabilities (noncurrent)	(4,600)	—	330	3,715	(555)
Total mark-to-market derivative liabilities	(11,711)	(1)	820	9,774	(1,118)
Total mark-to-market derivative net assets (liabilities)	$ (727)	$ —	$ 1,524	$ —	$ 797
December 31, 2023					
Mark-to-market derivative assets (current)	$ 7,927	$ 2	$ 703	$ (7,472)	$ 1,160
Mark-to-market derivative assets (noncurrent)	3,345	—	330	(2,682)	993
Total mark-to-market derivative assets	11,272	2	1,033	(10,154)	2,153
Mark-to-market derivative liabilities (current)	(9,019)	(2)	922	7,472	(627)
Mark-to-market derivative liabilities (noncurrent)	(3,545)	—	445	2,682	(418)
Total mark-to-market derivative liabilities	(12,564)	(2)	1,367	10,154	(1,045)
Total mark-to-market derivative net assets (liabilities)	$ (1,292)	$ —	$ 2,400	$ —	$ 1,108

(a) We net all available amounts allowed in our Consolidated Balance Sheets in accordance with authoritative guidance for derivatives. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral.
(b) Includes $775 million and $1,712 million of variation margin posted on the exchanges as of June 30, 2024 and December 31, 2023, respectively.

Economic Hedges (Commodity Price Risk)

For the three and six months ended June 30, 2024 and 2023, we recognized the following net pre-tax commodity mark-to-market gains (losses), which are also located in the Net fair value changes related to derivatives line in the Consolidated Statements of Cash Flows.

	Three Months Ended June 30,		Six Months Ended June 30,	
Income Statement Location	2024	2023	2024	2023
Operating revenues	$ 192	$ 214	$ 255	$ 1,145
Purchased power and fuel	397	(218)	523	(1,412)
Total	$ 589	$ (4)	$ 778	$ (267)

Interest Rate and Foreign Exchange Risk

We utilize interest rate swaps to manage our interest rate exposure and foreign currency derivatives to manage foreign exchange rate exposure associated with international commodity purchases in currencies other than U.S. dollars, both of which are treated as economic hedges. The notional amounts were $526 million and $562 million as of June 30, 2024 and December 31, 2023, respectively.

The mark-to-market derivative assets and liabilities as of June 30, 2024 and December 31, 2023 and the mark-to-market gains and losses associated with management of interest rate and foreign currency risk for the three and six months ended June 30, 2024 and 2023 were not material. The mark-to-market gains and losses associated with management of interest rate and foreign currency exchange rate risk are also included in the Net fair value changes related to derivatives line in the Consolidated Statements of Cash Flows.

(Dollars in millions, unless otherwise noted)

Credit Risk

We would be exposed to credit-related losses in the event of non-performance by counterparties on executed derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts as of the reporting date.

For commodity derivatives, we enter into enabling agreements that allow for payment netting with our counterparties, which reduces our exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allows for cross product netting. In addition to payment netting language in the enabling agreement, our credit department establishes credit limits, margining thresholds and collateral requirements for each counterparty, which are defined in the derivative contracts. Counterparty credit limits are based on an internal credit review process that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings by credit rating agencies, and other risk management criteria. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with us, as specified in each enabling agreement. Our credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

The following tables provide information on the credit exposure for all derivative instruments, NPNS and payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of June 30, 2024. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties. The amounts in the tables below exclude credit risk exposure from individual retail counterparties and exposure through RTOs, ISOs, NYMEX, ICE, NASDAQ, NGX, and Nodal commodity exchanges.

Rating as of June 30, 2024	Total Exposure Before Credit Collateral	Credit Collateral[(a)]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 988	$ 50	$ 938	1	$ 235
Non-investment grade	38	29	9	—	—
No external ratings					
Internally rated — investment grade	94	—	94	—	—
Internally rated — non-investment grade	237	59	178	—	—
Total	$ 1,357	$ 138	$ 1,219	1	$ 235

(a) As of June 30, 2024, credit collateral held from counterparties where we had credit exposure included $46 million of cash and $92 million of letters of credit. The credit collateral does not include non-liquid collateral.

Net Credit Exposure by Type of Counterparty	As of June 30, 2024
Investor-owned utilities, marketers, power producers	$ 991
Energy cooperatives and municipalities	88
Financial Institutions	60
Other	80
Total	$ 1,219

(Dollars in millions, unless otherwise noted)

Credit-Risk-Related Contingent Features

As part of the normal course of business, we routinely enter into physically or financially settled contracts for the purchase and sale of capacity, electricity, fuels, emissions allowances, and other energy-related products. Certain of our derivative instruments contain provisions that require us to post collateral. We also enter into commodity transactions on exchanges where the exchanges act as the counterparty to each trade. Transactions on the exchanges must adhere to comprehensive collateral and margining requirements. This collateral may be posted in the form of cash or credit support with thresholds contingent upon our credit ratings from S&P and Moody's. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk-related contingent features stipulate that if we were to be downgraded or lose our investment grade credit ratings (based on our senior unsecured debt rating), we would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, we believe an amount of several months of future payments (e.g., capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below.

The aggregate fair value of all derivative instruments with credit-risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the exchanges that are fully collateralized) is detailed in the table below:

Credit-Risk-Related Contingent Features	June 30, 2024	December 31, 2023
Gross fair value of derivative contracts containing this feature	$ (1,829)	$ (1,894)
Offsetting fair value of in-the-money contracts under master netting arrangements	837	925
Net fair value of derivative contracts containing this feature	$ (992)	$ (969)

As of June 30, 2024 and December 31, 2023, we posted or held the following amounts of cash collateral and letters of credit on derivative contracts with external counterparties, after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

	June 30, 2024	December 31, 2023
Cash collateral posted[(a)]	$ 1,594	$ 2,449
Letters of credit posted[(a)]	1,168	777
Cash collateral held[(a)]	80	64
Letters of credit held[(a)]	119	61
Additional collateral required in the event of a credit downgrade below investment grade (at BB+/Ba1)[(b)(c)(d)]	1,950	1,914

(a) The cash collateral and letters of credit amounts are inclusive of NPNS contracts.
(b) Certain of our contracts contain provisions that allow a counterparty to request additional collateral when there has been a subjective determination that our credit quality has deteriorated, generally termed “adequate assurance”. Due to the subjective nature of these provisions, we estimate the amount of collateral that we may ultimately be required to post in relation to the maximum exposure with the counterparty.
(c) The downgrade collateral is inclusive of all contracts in a liability position regardless of accounting treatment and excludes any contracts with individual retail counterparties.
(d) A loss of investment grade credit rating would require a three notch downgrade from their current levels of BBB+ and Baa1 at S&P and Moody's, respectively.

We routinely enter into supply forward contracts with certain utilities with one-sided collateral postings only from us. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices rise above the benchmark price levels, we are required to post collateral once certain unsecured credit limits are exceeded.

(Dollars in millions, unless otherwise noted)

11. Debt and Credit Agreements

Short-Term Borrowings

We meet our short-term liquidity requirements primarily through the issuance of commercial paper. We may use our credit facility for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit.

Credit Agreements

In June 2024, we amended our existing $3.5 billion revolving credit facility (RCF), to increase the available aggregate commitment to $4.5 billion and extend the maturity date from January 2027 to June 2029. The RCF may be drawn down in the form of loans and/or to support commercial paper and letters of credit issuances.

The RCF fixed facility fee rate is 0.175% and borrowings under the RCF bear interest at a rate based upon either the Daily Simple SOFR rate or a Term SOFR rate, plus an adder based upon our credit ratings. The adders for the Daily Simple SOFR based borrowings and Term SOFR borrowings are 7.5 basis points and 107.5 basis points, respectively. The letters of credit bear interest at a rate of 1.075%.

If we were to lose our investment grade credit rating, the maximum adders for Daily Simple SOFR rate borrowings and Term SOFR rate borrowings would be 100 basis points and 200 basis points, respectively. The credit agreements also require us to pay facility fees based upon the aggregate commitments. The fees vary depending upon our credit rating.

As of June 30, 2024 and December 31, 2023, we had the following aggregate bank commitments, credit facility borrowings and available capacity under our respective credit facilities:

Facility Type	Aggregate Bank Commitment	Facility Draws	Outstanding Letters of Credit	Outstanding Commercial Paper(a)	Available Capacity as of June 30, 2024
Revolving Credit Facility	$ 4,500	$ —	$ 151	$ 480	$ 3,869
Bilaterals[b]	1,850	—	1,114	—	736
Liquidity Facility	971	—	792	—	116 [c]
Project Finance	137	—	118	—	19
Total	$ 7,458	$ —	$ 2,175	$ 480	$ 4,740

Facility Type	Aggregate Bank Commitment	Facility Draws	Outstanding Letters of Credit	Outstanding Commercial Paper(a)	Available Capacity as of December 31, 2023
Revolving Credit Facility	$ 3,500	$ —	$ 60	$ 1,107	$ 2,333
Bilaterals	1,500	—	878	—	622
Liquidity Facility	971	—	720	—	191 [c]
Project Finance	137	—	117	—	20
Total	$ 6,108	$ —	$ 1,775	$ 1,107	$ 3,166

(a) Our commercial paper program is supported by the revolving credit agreement. In order to maintain our commercial paper program in the amounts indicated above, we must have a credit facility in place, at least equal to the amount of our commercial paper program. As of June 30, 2024 and December 31, 2023, the maximum program size of our commercial paper program was $4.5 billion and $3.5 billion, respectively. We do not issue commercial paper in an aggregate amount exceeding the then available capacity under our credit facility. The weighted average interest rate on commercial paper borrowings was 5.57% and 5.66% as of June 30, 2024 and December 31, 2023, respectively.

(b) In March 2024, we initiated a new bilateral credit agreement for $200 million, with no maturity date. In May 2024, we initiated a new bilateral credit agreement for $150 million, with no maturity date. In June 2024, a bilateral credit agreement initiated in November 2019 was extended for an additional two years to June 2026.

(c) The maximum amount of the bank commitment is not to exceed $971 million. The aggregate available capacity of the facility is subject to market fluctuations based on the value of U.S. Treasury Securities which determines the amount of collateral held in the trust. We may post additional collateral to borrow up to the maximum bank commitment. As of June 30, 2024 and December 31, 2023, without posting additional collateral, the actual availability of facility, prior to outstanding letters of credit was $908 million and $911 million, respectively.

(Dollars in millions, unless otherwise noted)

Short-Term Loan Agreements

As of June 30, 2024 and December 31, 2023, we had the following short-term loan agreements:

Month Initiated	Interest Rate	Maturity	Outstanding Amount as of June 30, 2024	Outstanding Amount as of December 31, 2023
January 2023	1 month SOFR + 0.80%	January 2024	$ —	$ 100
February 2023	1 month SOFR + 1.05%	February 2024	—	400
February 2024	1 month SOFR + 0.90%	February 2025	200	—

Long-Term Debt

Debt Issuances and Redemptions

During the six months ended June 30, 2024, the following long-term debt was issued (redeemed):

Type	Interest Rate	Maturity	Amount
Green Senior Notes[(a)]	5.75 %	March 2054	$ 900
Energy Efficiency Project Financing[(b)]	2.20% - 4.96%	December 2024	1
CR Nonrecourse Debt	3-month SOFR + 2.76%	December 2027	(23)
Continental Wind Nonrecourse Debt	6.00 %	February 2033	(16)
West Medway II Nonrecourse Debt	1 month SOFR + 3.225%	March 2026	(15)
Antelope Valley DOE Nonrecourse Debt	2.29% - 3.56%	January 2037	(8)
RPG Nonrecourse Debt	4.11 %	March 2035	(3)
Total long-term debt issued (redeemed)			$ 836

(a) The Green Senior Notes were issued to finance or refinance, in whole or in part, one or more new or existing Eligible Projects. Eligible Projects are defined as investments and expenditures made by us in the 24 months prior to or after the issuance of the notes within the following eligible green categories: clean generation fleet, clean hydrogen, energy storage, and clean commercial offerings.
(b) Energy Efficiency Project Financing represents funding to install energy conservation measures. The maturity dates represent the expected date of project completion, upon which the respective customer assumes the outstanding debt.

Debt Covenants

As of June 30, 2024, we are in compliance with all debt covenants.

12. Fair Value of Financial Assets and Liabilities

We measure and classify fair value measurements in accordance with the hierarchy as defined by GAAP. The hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1 — quoted prices (unadjusted) in active markets for identical assets or liabilities that we have the ability to liquidate as of the reporting date.
- Level 2 — inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data.
- Level 3 — unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability.

(Dollars in millions, unless otherwise noted)

Fair Value of Financial Liabilities Recorded at Amortized Cost

The following table presents the carrying amounts and fair values of our long-term debt and SNF obligation as of June 30, 2024 and December 31, 2023. We have no financial liabilities classified as Level 1.

The carrying amounts of the short-term liabilities as presented in the Consolidated Balance Sheets are representative of their fair value (Level 2) because of the short-term nature of these instruments.

	June 30, 2024				December 31, 2023			
	Carrying Amount	Fair Value			Carrying Amount	Fair Value		
		Level 2	Level 3	Total		Level 2	Level 3	Total
Long-Term Debt, including amounts due within one year	$ 8,444	$ 7,781	$ 726	$ 8,507	$ 7,617	$ 7,140	$ 774	$ 7,914
SNF Obligation	1,331	1,281	—	1,281	1,296	1,222	—	1,222

Valuation Techniques Used to Determine Fair Value and Net Asset Value

Our valuation techniques used to measure the fair value and net asset value of the assets and liabilities are in accordance with the policies discussed in Note 18 — Fair Value of Financial Assets and Liabilities of our 2023 Form 10-K.

(Dollars in millions, unless otherwise noted)

Recurring Fair Value Measurements

The following table present assets and liabilities measured and recorded at fair value in the Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2024 and December 31, 2023:

	As of June 30, 2024				As of December 31, 2023			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Cash equivalents[(a)]	$ 34	$ —	$ —	$ 34	$ 42	$ —	$ —	$ 42
NDT fund investments								
Cash equivalents[(b)]	159	160	—	319	356	87	—	443
Equities	5,016	1,937	1	6,954	4,574	1,990	1	6,565
Fixed income	2,190	1,385	350	3,925	2,043	1,523	277	3,843
Private credit	—	—	141	141	—	—	151	151
Assets measured at NAV	—	—	—	5,676	—	—	—	5,396
NDT fund investments subtotal[(c)]	7,365	3,482	492	17,015	6,973	3,600	429	16,398
Rabbi trust investments	52	36	1	89	48	33	1	82
Investments in equities	362	—	—	362	372	—	—	372
Mark-to-market derivative assets								
Economic hedges	1,456	5,865	3,677	10,998	2,330	5,821	3,143	11,294
Proprietary trading	—	—	1	1	—	—	2	2
Effect of netting and allocation of collateral[(d)]	(1,213)	(5,080)	(2,778)	(9,071)	(1,996)	(5,195)	(1,931)	(9,122)
Mark-to-market derivative assets subtotal	243	785	900	1,928	334	626	1,214	2,174
DPP consideration	—	1,553	—	1,553	—	1,216	—	1,216
Total assets measured at fair value	8,056	5,856	1,393	20,981	7,769	5,475	1,644	20,284
Liabilities								
Mark-to-market derivative liabilities								
Economic hedges	(1,547)	(6,346)	(3,819)	(11,712)	(2,681)	(7,154)	(2,736)	(12,571)
Proprietary trading	—	—	(1)	(1)	—	—	(2)	(2)
Effect of netting and allocation of collateral[(d)]	1,481	5,882	3,232	10,595	2,587	6,542	2,393	11,522
Mark-to-market derivative liabilities subtotal	(66)	(464)	(588)	(1,118)	(94)	(612)	(345)	(1,051)
Deferred compensation obligation	—	(84)	—	(84)	—	(69)	—	(69)
Total liabilities measured at fair value	(66)	(548)	(588)	(1,202)	(94)	(681)	(345)	(1,120)
Total net assets	$ 7,990	$ 5,308	$ 805	$ 19,779	$ 7,675	$ 4,794	$ 1,299	$ 19,164

(a) CEG Parent has $43 million and $54 million of Level 1 cash equivalents as of June 30, 2024 and December 31, 2023, respectively. We exclude cash of $297 million and $349 million as of June 30, 2024 and December 31, 2023, respectively, and restricted cash of $41 million and $49 million as of June 30, 2024 and December 31, 2023, respectively. CEG Parent has excluded an additional $2 million of cash as of both June 30, 2024 and December 31, 2023.
(b) Includes net liabilities of $190 million and $115 million as of June 30, 2024 and December 31, 2023, respectively, which consist of receivables related to pending securities sales, interest and dividend receivables, repurchase agreement obligations, and payables related to pending securities purchases. The repurchase agreements are generally short-term in nature with durations generally of 30 days or less.
(c) Includes total NDT derivative assets and liabilities that are not material, which have notional amounts of $998 million and $948 million as of June 30, 2024 and December 31, 2023, respectively. The notional principal amounts provide one measure of the transaction volume outstanding as of the periods ended and do not represent the amount of our exposure to credit or market loss.
(d) Includes $775 million and $1,712 million of variation margin posted on the exchanges as of June 30, 2024 and December 31, 2023, respectively.

(Dollars in millions, unless otherwise noted)

As of June 30, 2024, our NDTs have outstanding commitments to invest in private credit, private equity, and real estate investments of $420 million, $190 million, and $395 million, respectively. These commitments will be funded by our existing NDT funds.

Equity Security Investments without Readily Determinable Fair Values. We hold investments without readily determinable fair values with carrying amounts of $128 million and $103 million as of June 30, 2024 and December 31, 2023, respectively. Changes in fair value, cumulative adjustments, and impairments were not material for the three and six months ended June 30, 2024 and the year ended December 31, 2023.

Reconciliation of Level 3 Assets and Liabilities

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three and six months ended June 30, 2024 and 2023:

	For the Three Months Ended June 30, 2024			
	NDT Fund Investments	Mark-to-Market Derivatives	Life Insurance Contracts	Total
Balance as of April 1, 2024	$ 460	$ 518	$ 1	$ 979
Total realized / unrealized gains (losses)				
Included in net income (loss)	—	(185) [(a)]	—	(185)
Included in Payable related to Regulatory Agreement Units	1	—	—	1
Change in collateral	—	(40)		(40)
Purchases, sales, issuances and settlements				
Purchases	33	14	—	47
Sales	—	(39)	—	(39)
Settlements	(2)	—	—	(2)
Transfers into Level 3	—	30 [(b)]	—	30
Transfers out of Level 3	—	14 [(b)]	—	14
Balance as of June 30, 2024	$ 492	$ 312	$ 1	$ 805
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of June 30, 2024	$ —	$ (4)	$ —	$ (4)

	For the Three Months Ended June 30, 2023			
	NDT Fund Investments	Mark-to-Market Derivatives	Life Insurance Contracts	Total
Balance as of April 1, 2023	$ 421	$ 747	$ 1	$ 1,169
Total realized / unrealized gains (losses)				
Included in net income (loss)	1	(245) [(a)]	—	(244)
Included in Payable related to Regulatory Agreement Units	4	—	—	4
Change in collateral	—	70	—	70
Purchases, sales, issuances and settlements				
Purchases	—	19	—	19
Sales	—	(1)	—	(1)
Settlements	(5)	—	—	(5)
Transfers into Level 3	—	67 [(b)]	—	67
Transfers out of Level 3	—	(6) [(b)]	—	(6)
Balance as of June 30, 2023	$ 421	$ 651	$ 1	$ 1,073
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of June 30, 2023	$ 1	$ (6)	$ —	$ (5)

(Dollars in millions, unless otherwise noted)

	For the Six Months Ended June 30, 2024			
	NDT Fund Investments	Mark-to-Market Derivatives	Life Insurance Contracts	Total
Balance as of January 1, 2024	$ 429	$ 869	$ 1	$ 1,299
Total realized / unrealized gains (losses)				
Included in net income (loss)	—	(491) [(a)]	—	(491)
Included in Payable related to Regulatory Agreement Units	4	—	—	4
Change in collateral	—	(7)	—	(7)
Purchases, sales, issuances and settlements				
Purchases	66	18	—	84
Sales	—	(83)	—	(83)
Settlements	(7)	(2)	—	(9)
Transfers into Level 3	—	39 [(b)]	—	39
Transfers out of Level 3	—	(31) [(b)]	—	(31)
Balance as of June 30, 2024	$ 492	$ 312	$ 1	$ 805
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of June 30, 2024	$ —	$ 25	$ —	$ 25

	For the Six Months Ended June 30, 2023			
	NDT Fund Investments	Mark-to-Market Derivatives	Life Insurance Contracts	Total
Balance as of January 1, 2023	$ 423	$ 219	$ 1	$ 643
Total realized / unrealized gains (losses)				
Included in net income (loss)	1	260 [(a)]	—	261
Included in Payable related to Regulatory Agreement Units	4	—	—	4
Change in collateral	—	105	—	105
Purchases, sales, issuances and settlements				
Purchases	—	85	—	85
Sales	—	(5)	—	(5)
Settlements	(7)	—	—	(7)
Transfers into Level 3	—	59 [(b)]	—	59
Transfers out of Level 3	—	(72) [(b)]	—	(72)
Balance as of June 30, 2023	$ 421	$ 651	$ 1	$ 1,073
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of June 30, 2023	$ 1	$ 705	$ —	$ 706

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(a) Includes a reduction of $181 million and $518 million for realized gains due to the settlement of derivative contracts for the three and six months ended June 30, 2024, respectively. Includes a reduction of $239 million and $445 million for realized gains due to the settlement of derivative contracts for the three and six months ended June 30, 2023, respectively.

(b) Transfers into and out of Level 3 generally occur when the contract tenor becomes less and more observable, respectively, primarily due to changes in market liquidity or assumptions for certain commodity contracts.

(Dollars in millions, unless otherwise noted)

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three and six months ended June 30, 2024 and 2023:

	For the Three Months Ended June 30,					
	Operating Revenues		Purchased Power and Fuel		Other, net	
	2024	2023	2024	2023	2024	2023
Total gains (losses) included in net income	$ (103)	$ (29)	$ (82)	$ (216)	$ —	$ 1
Total unrealized gains (losses)	113	209	(117)	(215)	—	1

	For the Six Months Ended June 30,					
	Operating Revenues		Purchased Power and Fuel		Other, net	
	2024	2023	2024	2023	2024	2023
Total gains (losses) included in net income	$ (275)	$ 517	$ (218)	$ (257)	$ —	$ 1
Total unrealized gains (losses)	261	1,047	(236)	(342)	—	1

Mark-to-Market Derivatives

The following table presents the significant inputs to the forward curve used to value these positions:

Type of trade	Fair Value as of June 30, 2024	Fair Value as of December 31, 2023	Valuation Technique	Unobservable Input	2024 Range & Arithmetic Average		2023 Range & Arithmetic Average	
Mark-to market derivatives—Economic hedges(a)(b)	$ (142)	$ 407	Discounted Cash Flow	Forward power price	$3.49 - $178	$48	$9.64 - $216	$48
				Forward gas price	$0.80 - $14	$3.38	$1.20 - $14	$3.09
			Option Model	Volatility percentage	26% - 88%	51%	23% - 200%	87%

(a) The valuation techniques, unobservable inputs, ranges, and arithmetic averages are the same for the asset and liability positions.
(b) The fair values do not include cash collateral posted on Level 3 positions of $454 million and $462 million as of June 30, 2024 and December 31, 2023, respectively.

The inputs listed above, which are as of the balance sheet date, would have a direct impact on the fair values of the above instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of our commodity derivatives are forward commodity prices and for options is price volatility. Increases (decreases) in the forward commodity price in isolation would result in significantly higher (lower) fair values for long positions (contracts that give us the obligation or option to purchase a commodity), with offsetting impacts to short positions (contracts that give us the obligation or right to sell a commodity). Increases (decreases) in volatility would increase (decrease) the value for the holder of the option (writer of the option). Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the heat rate or renewable factors would increase the fair value accordingly. Generally, interrelationships exist between market prices of natural gas and power. As such, an increase in natural gas pricing would potentially have a similar impact on forward power markets.

(Dollars in millions, unless otherwise noted)

13. Commitments and Contingencies

Commitments

Commercial Commitments. Commercial commitments as of June 30, 2024, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2024	2025	2026	2027	2028	2029 and beyond
Letters of credit	$ 2,175	$ 1,672	$ 374	$ 1	$ 9	$ 118	$ 1
Surety bonds[(a)]	736	521	215	—	—	—	—
Total commercial commitments	$ 2,911	$ 2,193	$ 589	$ 1	$ 9	$ 118	$ 1

(a) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.

Environmental Remediation Matters

General. Our operations have in the past, and may in the future, require substantial expenditures to comply with environmental laws. Additionally, under Federal and state environmental laws, we are generally liable for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances generated by us. We own or lease several real estate parcels, including parcels on which our operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, we are currently involved in proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future. Unless otherwise disclosed, we cannot reasonably estimate whether we will incur significant liabilities for additional investigation and remediation costs at these or additional sites identified by us, environmental agencies, or others. Additional costs could have a material, unfavorable impact on our consolidated financial statements.

As of June 30, 2024 and December 31, 2023, we had accrued undiscounted amounts for environmental liabilities of $56 million and $61 million, respectively, in Accounts payable and accrued expenses and $161 million and $88 million, respectively, in Other deferred credits and other liabilities in the Consolidated Balance Sheets. See Note 19 — Commitments and Contingencies of our 2023 Form 10-K for additional information on environmental remediation matters. As of June 30, 2024, and through the date of filing, there have been no material changes in amounts recognized for-the matters discussed in our 2023 Form 10-K.

Litigation

General. We are involved in various other litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. We maintain accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of reasonably possible loss, particularly where (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

See Note 19 — Commitments and Contingencies of our 2023 Form 10-K for additional information on litigation matters. As of June 30, 2024, and through the date of filing, there have been no significant developments to the matters discussed in our 2023 Form 10-K.

Asbestos Personal Injury Claims. We maintain a reserve for claims associated with asbestos-related personal injury actions at certain facilities that are currently owned by us or were previously owned by ComEd, PECO, or BGE. The estimated liabilities are recorded on an undiscounted basis and exclude the estimated legal costs associated with handling these matters, which could be material.

At June 30, 2024 and December 31, 2023, we recorded estimated liabilities of approximately $129 million and $131 million, respectively, in total for asbestos-related bodily injury claims. As of June 30, 2024, approximately $16 million of this amount related to 207 open claims presented to us, while the remaining $113 million is for estimated future asbestos-related bodily injury claims anticipated to arise through 2055, based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, we monitor actual experience against the number of forecasted claims to be received and expected claim payments and evaluate whether adjustments to the estimated liabilities are necessary.

14. Shareholders' Equity

Share Repurchase Program (CEG Parent)

During 2023, our Board of Directors authorized the repurchase of up to $2 billion of the Company's outstanding common stock. In April 2024, our Board of Directors approved a $1 billion increase to the program, authorizing up to $3 billion in total repurchases. As of the date of filing, there was approximately $991 million of remaining authority to repurchase shares of the Company's outstanding common stock. No other repurchase plans or programs have been authorized. See Note 20 — Shareholders' Equity of our 2023 Form 10-K for additional information on our share repurchase program.

During the six months ended June 30, 2024, we repurchased from the open market 1.2 million shares of our common stock for a total cost, inclusive of taxes and transaction costs, of $150 million. There were no open market repurchases for the three months ended June 30, 2024. During the three and six months ended June 30, 2023, we repurchased from the open market 3.0 million and 6.2 million shares, respectively, of our common stock for a total cost, inclusive of taxes and transaction costs, of $252 million and $503 million, respectively.

In 2024, we entered into accelerated share repurchase (ASR) agreements with financial institutions to initiate share repurchases of our common stock. Under the ASR agreements, we paid a specified amount to the financial institution and received an initial delivery of shares of common stock, which resulted in an immediate reduction in the number of our shares outstanding. Based on the terms of the ASR agreements below, we received an initial share delivery based on 80% of the ASR agreements' cost. Upon settlement of the ASR agreements, the financial institution delivers additional incremental shares. The total number of shares ultimately delivered, and therefore the average price paid per share, is determined at the end of the applicable purchase period of each ASR agreement based on the average of the daily-volume weighted average share price, less a discount.

The following table summarizes each ASR agreement for the six months ended June 30, 2024:

(in millions, except average price paid per share)

ASR Agreement Initiation	Total Cost	Initial Shares Received	ASR Agreement Settlement	Additional Shares Received	Total Number of Shares Purchased	Average Price Paid per Share
March 2024	$ 354	1.7	May 2024	0.2	1.9	$ 182.65
May 2024	$ 505	1.8	July 2024	0.6	2.4	$ 211.40

(Dollars in millions, unless otherwise noted)

Changes in Accumulated Other Comprehensive Loss (All Registrants)

The following tables present changes in AOCI, net of tax, by component:

Three Months Ended June 30, 2024	Gains (losses) on Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items[(a)]	Foreign Currency Items	Total
Beginning balance	$ (10)	$ (2,143)	$ (27)	$ (2,180)
OCI before reclassifications	—	(2)	(1)	(3)
Amounts reclassified from AOCI	2	20	—	22
Net current-period OCI	2	18	(1)	19
Ending balance	$ (8)	$ (2,125)	$ (28)	$ (2,161)

Three Months Ended June 30, 2023	Gains (losses) on Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items[(a)]	Foreign Currency Items	Total
Beginning balance	$ (9)	$ (1,773)	$ (26)	$ (1,808)
OCI before reclassifications	(1)	—	3	2
Amounts reclassified from AOCI	1	5	—	6
Net current-period OCI	—	5	3	8
Ending balance	$ (9)	$ (1,768)	$ (23)	$ (1,800)

Six Months Ended June 30, 2024	Gains (losses) on Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items[(a)]	Foreign Currency Items	Total
Beginning balance	$ (10)	$ (2,157)	$ (24)	$ (2,191)
OCI before reclassifications	—	(5)	(4)	(9)
Amounts reclassified from AOCI	2	37	—	39
Net current-period OCI	2	32	(4)	30
Ending balance	$ (8)	$ (2,125)	$ (28)	$ (2,161)

Six Months Ended June 30, 2023	Gains (losses) on Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items[(a)]	Foreign Currency Items	Total
Beginning balance	$ (9)	$ (1,725)	$ (26)	$ (1,760)
OCI before reclassifications	(1)	(53)	3	(51)
Amounts reclassified from AOCI	1	10	—	11
Net current-period OCI	—	(43)	3	(40)
Ending balance	$ (9)	$ (1,768)	$ (23)	$ (1,800)

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(a) AOCI amounts are included in the computation of net periodic pension and OPEB cost. See Note 9 — Retirement Benefits for additional information. See our Statements of Operations and Comprehensive Income for individual components of AOCI.

(Dollars in millions, unless otherwise noted)

The following table presents income tax (expense) benefit allocated to each component of our other comprehensive income (loss):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	2024	2023
Pension and non-pension postretirement benefit plans:				
Actuarial loss reclassified to periodic benefit cost	$ (6)	$ (3)	$ (12)	$ (5)
Pension and non-pension postretirement benefit plans valuation adjustment	—	—	2	18

15. Variable Interest Entities

At June 30, 2024 and December 31, 2023, we consolidated several VIEs or VIE groups for which we are the primary beneficiary (see *Consolidated VIEs* below) and had significant interests in several other VIEs for which we do not have the power to direct the entities' activities and, accordingly, we were not the primary beneficiary (see *Unconsolidated VIEs* below). Consolidated and unconsolidated VIEs are aggregated to the extent that the entities have similar risk profiles.

(Dollars in millions, unless otherwise noted)

Consolidated VIEs

The table below shows the carrying amounts and classification of the consolidated VIEs' assets and liabilities included in the consolidated financial statements as of June 30, 2024 and December 31, 2023. The assets, except as noted in the footnotes to the table below, can only be used to settle obligations of the VIEs. The liabilities, except as noted in the footnotes to the table below, are such that creditors, or beneficiaries, do not have recourse to our general credit.

	June 30, 2024	December 31, 2023
Cash and cash equivalents	$ 56	$ 48
Restricted cash and cash equivalents	57	47
Accounts receivable		
Customer accounts receivable, net	29	19
Other accounts receivable, net	9	10
Inventories, net		
Materials and supplies	13	14
Other current assets	1,596	1,249
Total current assets	1,760	1,387
Property, plant, and equipment, net	1,968	1,979
Other noncurrent assets	154	166
Total noncurrent assets	2,122	2,145
Total assets[(a)]	$ 3,882	$ 3,532
Long-term debt due within one year	$ 64	$ 63
Accounts payable and accrued expenses	55	31
Other current liabilities	—	—
Total current liabilities	119	94
Long-term debt	676	704
Asset retirement obligations	195	190
Other noncurrent liabilities	2	2
Total noncurrent liabilities	873	896
Total liabilities	$ 992	$ 990

(a) Our balances include unrestricted assets for current unamortized energy contract assets of $22 million and $22 million, disclosed within other current assets in the table above and noncurrent unamortized energy contract assets of $144 million and $155 million, disclosed within other noncurrent assets in the table above as of June 30, 2024 and December 31, 2023, respectively.

(Dollars in millions, unless otherwise noted)

As of June 30, 2024 and December 31, 2023, our consolidated VIEs included the following:

Consolidated VIE or VIE groups:	Reason entity is a VIE:	Reason we are the primary beneficiary:
CRP - A collection of wind and solar project entities. We have a 51% equity ownership in CRP. See additional discussion below.	Similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general partner.	We conduct the operational activities.
Bluestem Wind Energy Holdings, LLC - A Tax Equity structure which is consolidated by CRP.	Similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general partner.	We conduct the operational activities.
Antelope Valley - A solar generating facility, which is 100% owned by us. Antelope Valley sells all of its output to PG&E through a PPA.	The PPA contract absorbs variability through a performance guarantee.	We conduct all activities.
NER - A bankruptcy remote, special purpose entity which is 100% owned by us, which purchases certain of our customer accounts receivable arising from the sale of retail electricity. NER's assets will be available first and foremost to satisfy the claims of the creditors of NER. Refer to Note 6 — Accounts Receivable for additional information on the sale of receivables.	Equity capitalization is insufficient to support its operations.	We conduct all activities.

Unconsolidated VIEs

Our variable interests in unconsolidated VIEs generally include equity investments and energy purchase and sale contracts. For the equity investments, the carrying amount of the investments is reflected in the Consolidated Balance Sheets in Investments. For the energy purchase and sale contracts (commercial agreements), the carrying amount of assets and liabilities in the Consolidated Balance Sheets that relate to our involvement with the VIEs are predominantly related to working capital accounts and generally represent the amounts owed by, or owed to, us for the deliveries associated with the current billing cycles under the commercial agreements.

As of June 30, 2024 and December 31, 2023, we had significant unconsolidated variable interests in several VIEs for which we were not the primary beneficiary. These interests include certain equity method investments and certain commercial agreements.

The following table presents summary information about our significant unconsolidated VIE entities:

	June 30, 2024			December 31, 2023		
	Commercial Agreement VIEs	Equity Investment VIEs	Total	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[(a)]	$ 680	$ —	$ 680	$ 704	$ —	$ 704
Total liabilities[(a)]	64	—	64	77	—	77
Our ownership interest in VIE[(a)]	—	—	—	—	—	—
Other ownership interests in VIE[(a)]	616	—	616	627	—	627

(a) These items represent amounts on the unconsolidated VIE balance sheets, not in the Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs. We do not have any exposure to loss as we do not have a carrying amount in the equity investment VIEs as of June 30, 2024 and December 31, 2023.

(Dollars in millions, unless otherwise noted)

As of June 30, 2024 and December 31, 2023 the unconsolidated VIEs consist of:

Unconsolidated VIE groups:	Reason entity is a VIE:	Reason we are not the primary beneficiary:
Energy Purchase and Sale agreements - We have several energy purchase and sale agreements with generating facilities.	PPA contracts that absorb variability through fixed pricing.	We do not conduct the operational activities.

16. Supplemental Financial Information

Supplemental Statement of Operations and Comprehensive Income Information

The following tables provide additional information about items recorded in the Consolidated Statements of Operations and Comprehensive Income.

	Operating revenues			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	2024	2023
Operating lease income	$ 13	$ 13	$ 17	$ 17
Variable lease income	68	66	119	124

	Taxes other than income taxes			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	2024	2023
Gross receipts[(a)]	$ 32	$ 35	$ 65	$ 68
Property	73	65	139	121
Payroll	35	36	73	70

(a) Represent gross receipts taxes related to our retail operations. The offsetting collection of gross receipts taxes from customers is recorded in Operating revenues in the Consolidated Statements of Operations and Comprehensive Income.

	Other, net			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	2024	2023
Decommissioning-related activities:				
Net realized income on NDT funds[(a)]				
Regulatory Agreement Units	$ 91	$ 135	$ 257	$ 449
Non-Regulatory Agreement Units	32	91	115	285
Net unrealized gain (loss) on NDT funds				
Regulatory Agreement Units	(14)	56	211	85
Non-Regulatory Agreement Units	5	27	139	45
Regulatory offset to NDT fund-related activities[(b)]	(63)	(154)	(375)	(429)
Total decommissioning-related activities	51	155	347	435
Non-service net periodic benefit credit[(c)]	(4)	14	(6)	27
Net realized and unrealized gains (losses) from equity investments	(58)	419	(11)	414
Other	17	17	38	43
Total Other, net	$ 6	$ 605	$ 368	$ 919

(Dollars in millions, unless otherwise noted)

(a) Realized income includes interest, dividends and realized gains and losses on sales of NDT fund investments.
(b) Includes the elimination of decommissioning-related activities and the elimination of income taxes related to all NDT fund activity for the Regulatory Agreement Units.
(c) The non-service credit (cost) components are included in Other, net, in accordance with single employer plan accounting. See Note 9 — Retirement Benefits for additional information.

Supplemental Cash Flow Information

The following tables provide additional information about items recorded within our Consolidated Statements of Cash Flows.

	Depreciation, amortization, and accretion	
	Six Months Ended June 30,	
	2024	2023
Property, plant, and equipment[(a)]	$ 590	$ 531
Amortization of intangible assets, net[(a)]	12	11
Amortization of energy contract assets and liabilities[(b)]	17	17
Nuclear fuel[(c)]	433	373
ARO accretion[(d)]	336	287
Total depreciation, amortization, and accretion	$ 1,388	$ 1,219

(a) Included in Depreciation and amortization expense in the Consolidated Statements of Operations and Comprehensive Income.
(b) Included in Operating revenues or Purchased power and fuel expense in the Consolidated Statements of Operations and Comprehensive Income.
(c) Included in Purchased power and fuel expense in the Consolidated Statements of Operations and Comprehensive Income.
(d) Included in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income.

	Other non-cash operating activities			
	CEG Parent		Constellation	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	2024	2023
Other decommissioning-related activity[(a)]	$ (246)	$ (217)	$ (246)	$ (217)
Energy-related options[(b)]	30	121	30	121
(Gain) loss on sale of receivables	32	46	32	46
Amortization of operating ROU asset	25	24	25	24
Long-term incentive plan	15	34	—	—
Pension and non-pension postretirement benefit costs	56	23	56	23

(a) Includes the elimination of decommissioning-related activities for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income, and income taxes related to all NDT fund activity for these units.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.

(Dollars in millions, unless otherwise noted)

The following table provides a reconciliation of cash, restricted cash, and cash equivalents reported within our Consolidated Balance Sheets that sum to the total of the same amounts in the Consolidated Statements of Cash Flows.

	CEG Parent	Constellation
June 30, 2024		
Cash and cash equivalents	$ 311	$ 308
Restricted cash and cash equivalents	72	64
Total cash, restricted cash, and cash equivalents	$ 383	$ 372
December 31, 2023		
Cash and cash equivalents	$ 368	$ 366
Restricted cash and cash equivalents	86	74
Total cash, restricted cash, and cash equivalents	$ 454	$ 440
June 30, 2023		
Cash and cash equivalents	$ 269	$ 269
Restricted cash and cash equivalents	56	48
Total cash, restricted cash, and cash equivalents	$ 325	$ 317

For additional information on restricted cash, see Note 1 — Basis of Presentation of our 2023 Form 10-K.

Supplemental Balance Sheet Information

The following table provides additional information about items recorded within our Consolidated Balance Sheets.

	Accounts payable and accrued expenses	
June 30, 2024	CEG Parent	Constellation
Accounts payable	$ 1,360	$ 1,348
Compensation-related accruals[(a)]	536	402
Taxes accrued[(b)]	201	183
December 31, 2023		
Accounts payable	$ 1,302	$ 1,289
Compensation-related accruals[(a)]	680	576
Taxes accrued	399	390

(a) Primarily includes accrued payroll, bonuses and other incentives, vacation, and benefits.
(b) Includes $102 million related to nuclear PTC that was used to offset the current tax liability. See Note 5 — Government Assistance for additional information on the nuclear PTC.

Item 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

(Dollars in millions except per share data, unless otherwise noted)

Executive Overview

We are a supplier of clean energy. Our generating capacity includes primarily nuclear, wind, solar, natural gas and hydroelectric assets. Through our integrated business operations, we sell electricity, natural gas, and other energy-related products and sustainable solutions to various types of customers, including distribution utilities, municipalities, cooperatives, and commercial, industrial, governmental, and residential customers in markets across multiple geographic regions. We have five reportable segments: Mid-Atlantic, Midwest, New York, ERCOT and Other Power Regions.

Significant Transactions and Developments

Nuclear PTC

As a result of the enactment of the IRA, we qualify for certain federal government incentives through eligible activities. These incentives include both refundable and transferable tax credits. Beginning in 2024, our nuclear units are eligible for a PTC extending through 2032. The nuclear PTC provides a transferable credit up to $15 per MWh (a base credit of $3 per MWh with a five times multiplier provided certain prevailing wage requirements are met) and is subject to phase-out when annual gross receipts are between $25.00 per MWh and $43.75 per MWh. We have determined that we will meet the annual prevailing wage requirements at all our nuclear units and are eligible for the five times multiplier. Both the amount of the PTC and the gross receipts thresholds adjust annually for inflation over the duration of the program, and the benefits of the PTC may be realized through a credit against our federal income taxes or transferred via sale to an unrelated party. For the three and six months ended June 30, 2024, our Consolidated Statements of Operations and Comprehensive Income include an estimate of $408 million and $712 million, respectively, in Operating revenues for nuclear PTC earned based on qualifying production volumes during the respective periods. See Note 5 — Government Assistance of the Combined Notes to Consolidated Financial Statements for additional information.

Share Repurchase Program

In April 2024, our Board of Directors approved a $1 billion increase to the previously announced share repurchase program, authorizing total repurchases of up to $3 billion. As of the date of filing, we have purchased a total of approximately 16.1 million shares for a total cost of $2 billion, with remaining authority to purchase up to $991 million of the Company's outstanding common stock. See Note 14 — Shareholders' Equity of the Combined Notes to Consolidated Financial Statements for additional information.

Other Key Business Drivers

Russia and Ukraine Conflict

We are closely monitoring developments of the ongoing Russia and Ukraine conflict, including United States, United Kingdom, European Union, and Canadian sanctions, and legislation that may impact exports and imports of Russian nuclear fuel supply and enrichment activities, as well as the potential for Russia to limit energy deliveries. We are cognizant of the recent enactment of the "Prohibiting Russian Uranium Imports Act" that bans the import of low-enriched uranium into the U.S. that is produced in Russia or by Russian entities, absent a waiver from the DOE. The passage of this bill will allow the Department of Energy to begin the process of distributing billions of dollars that were previously appropriated to support expansion of the domestic nuclear fuel cycle within the United States to improve carbon-free energy security. To-date, our nuclear fuel deliveries have not been affected by the Russia and Ukraine conflict. Our nuclear fuel is obtained predominantly through long-term uranium supply and service contracts. We work with a diverse set of domestic and international suppliers years in advance to procure our nuclear fuel and generally have enough nuclear fuel to support all our refueling needs for multiple years regardless of sanctions. Recognizing the potential for the continuing conflict to impact our longer-term security and cost of supply, we have entered into contracts to increase the size of our nuclear fuel inventory. We are taking this affirmative action by working with our diverse set of suppliers to ensure we can secure the nuclear fuel needed to continue to operate our nuclear fleet long-term and provide the necessary fuel to bridge potential Russian supply disruption into 2029, which is the date multiple suppliers are expected to have incremental additional capacity online.

Environmental Regulation

Regulation of GHGs from Power Plants under the Clean Air Act. In April 2024, EPA issued a final rule that regulates greenhouse gases from existing coal, new natural gas fired power plants, and existing oil/gas steam generators under Clean Air Act section 111. The applicable standards are subcategorized by retirement date for existing coal and capacity factor for existing gas. We are evaluating market impacts of this rule, which will be affected by upcoming state implementation and ongoing litigation. EPA has solicited comment on approaches for regulating GHGs from existing gas plants in a docket that closed in May 2024. We cannot reasonably predict the outcome of this matter.

Good Neighbor Rule. On June 5, 2023, the EPA published a final rule called “Federal 'Good Neighbor Plan' for the 2015 Ozone National Ambient Air Quality Standards” also known as the "Transport Rule". The rule, among other things, establishes nitrogen oxides emissions budgets requiring fossil fuel-fired power plants in 23 states to participate in an allowance-based ozone season trading program beginning in 2023. On February 13, 2023, EPA disapproved state implementation plans submitted by 21 states for failure to address their obligations under the "good neighbor" provisions of the Clean Air Act. However, several Regional Courts of Appeals issued orders staying, pending judicial review, EPA's disapproval of several state plans (including Texas). In June 2024, the Supreme Court stayed EPA's rule for the duration of the litigation. The rule is currently under review on the merits before the D.C. Circuit and we cannot reasonably predict the outcome of this litigation.

Critical Accounting Policies and Estimates

Management makes a number of significant estimates, assumptions, and judgements in the preparation of our financial statements. At June 30, 2024, our critical accounting policies and estimates had not changed significantly from December 31, 2023, with the exception of accounting for government grants and disclosure of government assistance. See Note 5 — Government Assistance of the Combined Notes to Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Critical Accounting Policies and Estimates in our 2023 Form 10-K for further information.

Financial Results of Operations

GAAP Results of Operations. The following table sets forth our consolidated GAAP Net Income (Loss) Attributable to Common Shareholders for the three and six months ended June 30, 2024 compared to the same period in 2023. For additional information regarding the financial results for the three and six months ended June 30, 2024 and 2023, see the discussions of Results of Operations below.

	Three Months Ended June 30,		Unfavorable Variance	Six Months Ended June 30,		Favorable Variance
	2024	2023		2024	2023	
GAAP Net Income (Loss) Attributable to Common Shareholders	$ 814	$ 833	$ (19)	$ 1,697	$ 929	$ 768

Adjusted (non-GAAP) Operating Earnings. We utilize Adjusted (non-GAAP) Operating Earnings (and/or its per share equivalent) in our internal analysis, and in communications with investors and analysts, as a consistent measure for comparing our financial performance and discussing the factors and trends affecting our business. The presentation of Adjusted (non-GAAP) Operating Earnings is intended to complement and should not be considered an alternative to, nor more useful than, the presentation of GAAP Net Income.

The table below provides a reconciliation of GAAP Net Income to Adjusted (non-GAAP) Operating Earnings. Adjusted (non-GAAP) Operating Earnings is not a standardized financial measure and may not be comparable to other companies' presentations of similarly titled measures.

Unless otherwise noted, the income tax impact of each reconciling adjustment between GAAP Net Income (Loss) Attributable to Common Shareholders and Adjusted (non-GAAP) Operating Earnings is based on the marginal statutory federal and state income tax rates, taking into account whether the income or expense item is taxable or deductible, respectively, in whole or in part. For all adjustments except the NDT fund investment returns, which are included in decommissioning-related activities, the marginal statutory income tax rate was 25.1% for both the three and six months ended June 30, 2024 and 2023. Under IRS regulations, NDT fund investment returns are taxed at different rates for investments if they are in qualified or non-qualified funds. The effective tax rates for the unrealized and realized gains and losses related to NDT funds were 66.9% and 54.9% for the three months ended June 30, 2024 and 2023, respectively and 56.2% and 54.3%for the six months ended June 30, 2024 and 2023, respectively. The following table provides a reconciliation between GAAP Net Income and Adjusted (non-GAAP) Operating Earnings for the three and six months ended June 30, 2024 compared to the same period in 2023.

	Three Months Ended June 30,			
	2024		2023	
		Earnings Per Share[(a)]		Earnings Per Share[(a)]
Net Income (Loss) Attributable to Common Shareholders	$ 814	$ 2.58	$ 833	$ 2.56
Unrealized (Gain) Loss on Fair Value Adjustments (net of taxes of $136 and $108, respectively)[(b)]	(405)	(1.28)	(320)	(0.99)
Plant Retirements and Divestitures (net of taxes of $9 and $—, respectively)	26	0.08	1	—
Decommissioning-Related Activities (net of taxes of $3 and $64, respectively)[(c)]	36	0.11	(3)	(0.01)
Pension & OPEB Non-Service (Credits) Costs (net of taxes of $— and $3, respectively)	1	—	(10)	(0.03)
Separation Costs (net of taxes of $1 and $9, respectively)[(d)]	4	0.01	27	0.08
ERP System Implementation Costs (net of taxes of $1 and $2, respectively)[(e)]	2	0.01	7	0.02
Change in Environmental Liabilities (net of taxes of $18 and $—, respectively)	55	0.17	1	—
Noncontrolling Interests (net of taxes of $— and $—, respectively)[(g)]	(2)	(0.01)	(1)	—
Adjusted (non-GAAP) Operating Earnings	$ 531	$ 1.68	$ 535	$ 1.64

	Six Months Ended June 30,							
	2024				2023			
			Earnings Per Share[a]				Earnings Per Share[a]	
Net Income (Loss) Attributable to Common Shareholders	$	1,697	$	5.35	$	929	$	2.84
Unrealized (Gain) Loss on Fair Value Adjustments (net of taxes of $193 and $32, respectively)[b]		(575)		(1.81)		(93)		(0.29)
Plant Retirements and Divestitures (net of taxes of $13 and $6, respectively)		38		0.12		(17)		(0.05)
Decommissioning-Related Activities (net of taxes of $136 and $181, respectively)[c]		(32)		(0.10)		(78)		(0.24)
Pension & OPEB Non-Service (Credits) Costs (net of taxes of $1 and $7, respectively)		4		0.01		(20)		(0.06)
Separation Costs (net of taxes of $3 and $17, respectively)[d]		9		0.03		50		0.15
ERP System Implementation Costs (net of taxes of $2 and $4, respectively)[e]		5		0.02		10		0.03
Change in Environmental Liabilities (net of taxes of $19 and $4, respectively)		55		0.17		13		0.04
Income Tax-Related Adjustments[f]		(88)		(0.28)		—		—
Noncontrolling Interests (net of taxes of $— and $—, respectively)[g]		(3)		(0.01)		(3)		(0.01)
Adjusted (non-GAAP) Operating Earnings	$	1,110	$	3.50	$	791	$	2.42

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(a) Amounts may not sum due to rounding. Earnings per share amount is based on average diluted common shares outstanding of 316 million and 325 million for the three months ended June 30, 2024 and 2023, respectively and 317 million and 327 million for the six months ended June 30, 2024 and 2023, respectively.
(b) Includes mark-to-market on economic hedges, interest rate swaps, and fair value adjustments related to gas imbalances and equity investments.
(c) Reflects all gains and losses associated with NDTs, ARO accretion, ARC depreciation, ARO remeasurement, and impacts of contractual offset for Regulatory Agreement Units.
(d) Represents certain incremental costs related to the separation (system-related costs, third-party costs paid to advisors, consultants, lawyers, and other experts assisting in the separation), including a portion of the amounts billed to us pursuant to the TSA.
(e) Reflects costs related to a multi-year ERP system implemented in the first quarter of 2024.
(f) In 2024, primarily reflects the adjustment to deferred income taxes due to changes in forecasted apportionment.
(g) Represents elimination of the noncontrolling interests related to certain adjustments.

Results of Operations

	Three Months Ended June 30, 2024	Three Months Ended June 30, 2023	Favorable (Unfavorable) Variance	Six Months Ended June 30, 2024	Six Months Ended June 30, 2023	Favorable (Unfavorable) Variance
Operating revenues	$ 5,475	$ 5,446	$ 29	$ 11,637	$ 13,011	$ (1,374)
Operating expenses						
Purchased power and fuel	2,292	2,887	595	5,709	8,616	2,907
Operating and maintenance	1,645	1,477	(168)	3,131	2,908	(223)
Depreciation and amortization	296	274	(22)	602	542	(60)
Taxes other than income taxes	142	139	(3)	282	271	(11)
Total operating expenses	4,375	4,777	402	9,724	12,337	2,613
Gain (loss) on sales of assets and businesses	—	—	—	—	26	(26)
Operating income (loss)	1,100	669	431	1,913	700	1,213
Other income and (deductions)						
Interest expense, net	(142)	(103)	(39)	(269)	(210)	(59)
Other, net	6	605	(599)	368	919	(551)
Total other income and (deductions)	(136)	502	(638)	99	709	(610)
Income (loss) before income taxes	964	1,171	(207)	2,012	1,409	603
Income tax (benefit) expense	154	342	188	318	472	154
Equity in income (losses) of unconsolidated affiliates	(1)	(5)	4	(2)	(11)	9
Net income (loss)	809	824	(15)	1,692	926	766
Net income (loss) attributable to noncontrolling interests	(5)	(9)	4	(5)	(3)	(2)
Net income (loss) attributable to common shareholders	$ 814	$ 833	$ (19)	$ 1,697	$ 929	768

Three Months Ended June 30, 2024 Compared to Three Months Ended June 30, 2023. The variance in Net income (loss) attributable to common shareholders was unfavorable by ($19) million primarily due to:

- Lower unrealized gains resulting from an investment that became a publicly traded company in the second quarter of 2023;
- Unfavorable ZEC and CMC program revenues primarily due to estimated refunds required by certain state-sponsored programs in connection with the nuclear PTCs, as well as lower revenue recognized for ZECs delivered under the Illinois ZEC program in prior planning years;
- Higher labor, contracting, and materials;
- Unfavorable increase in environmental liabilities; and
- Unfavorable net realized and unrealized NDT activity.

The unfavorable items were partially offset by:

- Favorable mark-to-market activity and other fair value adjustments;
- Favorable market and portfolio conditions primarily driven by increased load and generation-to-load optimization;
- Favorable nuclear PTCs related to the IRA beginning in 2024; and
- Favorable impacts of nuclear outages.

Six Months Ended June 30, 2024 Compared to Six Months Ended June 30, 2023. The variance in Net income (loss) attributable to common shareholders was favorable by $768 million primarily due to:

- Favorable mark-to-market activity and other fair value adjustments;
- Favorable market and portfolio conditions primarily driven by increased load and generation-to-load optimization;
- Favorable nuclear PTCs related to the IRA beginning in 2024; and
- Favorable impacts of nuclear outages.

The favorable items were partially offset by:

- Unfavorable ZEC and CMC program revenues primarily due to estimated refunds required by certain state-sponsored programs in connection with the nuclear PTCs, as well as lower revenue recognized for ZECs delivered under the Illinois ZEC program in prior planning years;
- Lower unrealized gains resulting from an investment that became a publicly traded company in the second quarter of 2023;
- Higher labor, contracting, and materials;
- Unfavorable increase in environmental liabilities;
- Higher Interest expense; and
- Unfavorable net realized and unrealized NDT activity.

Operating revenues. Our five reportable segments are Mid-Atlantic, Midwest, New York, ERCOT, and Other Power Regions. See Note 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on these reportable segments.

Wholesale and retail sales of natural gas, as well as sales of other energy-related products and sustainable solutions and other miscellaneous business activities that are not significant to overall results of operations are reported under Other and not allocated to a region.

For the three and six months ended June 30, 2024 compared to 2023, Operating revenues were as follows:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2024	2023	Variance	% Change[(a)]	2024	2023	Variance	% Change[(a)]
Mid-Atlantic	$ 1,304	$ 1,198	$ 106	8.8 %	$ 2,546	$ 2,444	$ 102	4.2 %
Midwest	1,168	1,330	(162)	(12.2) %	2,262	2,361	(99)	(4.2) %
New York	514	471	43	9.1 %	1,027	1,005	22	2.2 %
ERCOT	357	328	29	8.8 %	678	497	181	36.4 %
Other Power Regions	1,184	1,111	73	6.6 %	2,808	2,903	(95)	(3.3) %
Total reportable segment electric revenues	4,527	4,438	89	2.0 %	9,321	9,210	111	1.2 %
Other	756	797	(41)	(5.1) %	2,062	2,661	(599)	(22.5) %
Mark-to-market gains (losses)	192	211	(19)		254	1,140	(886)	
Total Operating revenues	$ 5,475	$ 5,446	$ 29	0.5 %	$ 11,637	$ 13,011	$ (1,374)	(10.6) %

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(a) % Change in mark-to-market is not a meaningful measure.

Sales and Supply Sources. Our sales and supply sources by region are summarized below:

Supply Source (GWhs)	Three Months Ended June 30, 2024	Three Months Ended June 30, 2023	Variance	% Change	Six Months Ended June 30, 2024	Six Months Ended June 30, 2023	Variance	% Change
Nuclear Generation[a]								
Mid-Atlantic	13,229	12,837	392	3.1 %	26,419	26,018	401	1.5 %
Midwest	23,625	22,966	659	2.9 %	47,546	45,952	1,594	3.5 %
New York	6,685	6,092	593	9.7 %	12,764	12,389	375	3.0 %
ERCOT	1,775	—	1,775	100.0 %	3,978	—	3,978	100.0 %
Total Nuclear Generation	45,314	41,895	3,419	8.2 %	90,707	84,359	6,348	7.5 %
Natural Gas, Oil, and Renewables								
Mid-Atlantic	612	384	228	59.4 %	1,480	1,106	374	33.8 %
Midwest	284	221	63	28.5 %	623	560	63	11.3 %
ERCOT[b]	3,592	4,429	(837)	(18.9)%	7,107	7,715	(608)	(7.9)%
Other Power Regions	1,617	1,713	(96)	(5.6)%	5,168	4,616	552	12.0 %
Total Natural Gas, Oil, and Renewables	6,105	6,747	(642)	(9.5)%	14,378	13,997	381	2.7 %
Purchased Power								
Mid-Atlantic	3,316	3,428	(112)	(3.3)%	6,685	7,448	(763)	(10.2)%
Midwest	225	200	25	12.5 %	533	623	(90)	(14.4)%
ERCOT	1,060	1,597	(537)	(33.6)%	1,725	2,949	(1,224)	(41.5)%
Other Power Regions	9,643	9,736	(93)	(1.0)%	20,042	19,658	384	2.0 %
Total Purchased Power	14,244	14,961	(717)	(4.8)%	28,985	30,678	(1,693)	(5.5)%
Total Supply/Sales by Region								
Mid-Atlantic	17,157	16,649	508	3.1 %	34,584	34,572	12	— %
Midwest	24,134	23,387	747	3.2 %	48,702	47,135	1,567	3.3 %
New York	6,685	6,092	593	9.7 %	12,764	12,389	375	3.0 %
ERCOT[b]	6,427	6,026	401	6.7 %	12,810	10,664	2,146	20.1 %
Other Power Regions	11,260	11,449	(189)	(1.7)%	25,210	24,274	936	3.9 %
Total Supply/Sales by Region	65,663	63,603	2,060	3.2 %	134,070	129,034	5,036	3.9 %

(a) Includes the proportionate share of output where we have an undivided ownership interest in jointly-owned generating plants.
(b) 2023 values have been revised from those previously reported to reflect gross generation inclusive of behind the meter consumption.

Nuclear Fleet Capacity Factor. The following table presents nuclear fleet operating data for our plants that, reflects ownership percentage of stations operated by us and excludes Salem and STP, which are operated by PSEG and STPNOC, respectively. The nuclear fleet capacity factor presented in the table is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at its net monthly mean capacity for that time period. We consider capacity factor to be a useful measure to analyze the nuclear fleet performance between periods. We have included the analysis below as a complement to the financial information provided in accordance with GAAP. However, these measures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or be more useful than the GAAP information provided elsewhere in this report.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	2024	2023
Nuclear fleet capacity factor	95.4 %	92.4 %	94.4 %	92.6 %
Refueling outage days	49	94	127	180
Non-refueling outage days	3	25	13	34

Nuclear PTC. Beginning in 2024, our nuclear units are eligible for a PTC extending through 2032. The nuclear PTC provides a transferable credit up to $15 per MWh (a base credit of $3 per MWh with a five times multiplier provided certain prevailing wage requirements are met) and is subject to phase-out when annual gross receipts are between $25.00 per MWh and $43.75 per MWh. We have determined that we will meet the annual prevailing wage requirements at all our nuclear units and are eligible for the five times multiplier. Both the amount of the PTC and the gross receipts thresholds adjust for inflation after 2024 through the duration of the program based on the GDP price deflator for the preceding calendar year. The benefits of the PTC may be realized through a credit against our federal income taxes or transferred via sale to an unrelated party.

Many of the state-sponsored programs (i.e., ZECs and CMCs) providing compensation for the emissions-free attributes of generation from certain of our nuclear units include contractual or other provisions that require us to refund that compensation up to the amount of the nuclear PTC received or pass through the entirety of the nuclear PTC received. See Note 5 — Government Assistance of the Combined Notes to Consolidated Financial Statements for additional information on the nuclear PTC.

ZEC Prices. We are compensated through state programs for the carbon-free attributes of our nuclear generation. Gross revenues from ZEC programs are a significant contributor to our total operating revenues. The following table includes the average ZEC reference prices ($/MWh) for each of our major regions in which state programs have been enacted. Prices reflect the weighted average price for the various delivery periods within the three and six months ended June 30, 2024 and 2023.

	Three Months Ended June 30,				Six Months Ended June 30,			
State (Region)[a]	2024	2023	Variance	% Change	2024	2023	Variance	% Change
New Jersey (Mid-Atlantic)[b]	$ 10.00	$ 9.92	$ 0.08	0.8 %	$ 10.00	$ 9.90	$ 0.10	1.0 %
Illinois (Midwest)	3.33	8.11	(4.78)	(58.9)%	1.81	10.06	(8.25)	(82.0)%
New York (New York)	18.27	18.27	—	— %	18.27	19.83	(1.56)	(7.9)%

(a) See ITEM 1. BUSINESS, Environmental Matters of our 2023 Form 10-K for additional information on the plants receiving payments through state programs.
(b) The ZEC price is expected to be $10.00/MWh for each delivery period and is subject to an annual update once full year generation is known. Following the latest annual update in August 2023, the ZEC price for the delivery period beginning June 2022 through May 2023 was calculated to be $9.88.

Illinois CMC Price. The price received (paid) for each CMC is determined by the IPA monthly and is based on the accepted CMC bid, less the sum of (a) monthly weighted average PJM Busbar price, (b) ComEd zone capacity price and (c) any federal tax credit or subsidy received and is subject to a customer protection cap ($30.30 per MWh for initial delivery period June 2022 through May 2023, $32.50 per MWh for the period June 2023 through May 2024, and $33.43 per MWh for the period June 2024 through May 2025). If the monthly CMC price per MWh calculation results in a net positive value, ComEd will multiply that value by the delivered quantity and pay the total to us. If the CMC price per MWh calculation results in a net negative value, we will multiply this value by the delivered quantity and pay the net value to ComEd. The average CMC prices per MWh were $10.10 and $7.00 for the three months ended June 30, 2024 and 2023, respectively, and $8.83 and $4.25 for the six months ended June 30, 2024 and 2023, respectively.

Capacity Prices. We participate in capacity auctions in each of our major regions, except ERCOT which does not have a capacity market. We also incur capacity costs associated with load served, which are factored into customer sales prices. Capacity prices have a significant impact on our operating revenues and purchased power and fuel expense. We report capacity on a net monthly basis within each region in either Operating revenues or Purchased power and fuel expense, depending on our net monthly position. The following table presents the average capacity prices ($/MW Day) for each of our major regions. Prices reflect the weighted average prices for the various auction periods within the three and six months ended June 30, 2024 and 2023.

	Three Months Ended June 30,				Six Months Ended June 30,			
Location (Region)	2024	2023	Variance	% Change	2024	2023	Variance	% Change
Eastern Mid-Atlantic Area Council (Mid-Atlantic)	$ 50.86	$ 81.74	$ (30.88)	(37.8)%	$ 50.18	$ 89.80	$ (39.62)	(44.1)%
ComEd (Midwest)	32.39	57.35	(24.96)	(43.5)%	33.26	63.16	(29.90)	(47.3)%
Rest of State (New York)	98.33	138.89	(40.56)	(29.2)%	102.42	121.28	(18.86)	(15.6)%
Southeast New England (Other)	360.97	106.67	254.30	238.4 %	213.82	116.67	97.15	83.3 %

Electricity Prices. As a producer and supplier of electricity, the price of electricity has a significant impact on our operating revenues and purchased power cost. We report the sale and purchase of electricity in the spot market on a net hourly basis in either Operating revenues or Purchased power and fuel expense within each region, depending on our net hourly position. The price of electricity is impacted by several variables, including but not limited to, the price of fuels, generation resources in the region, weather, on-going competition, emerging technologies, as well as macroeconomic and regulatory factors. The following table presents an average day-ahead around-the-clock reference price ($/MWh) for the periods presented for each of our major regions and does not necessarily reflect prices we ultimately realized.

	Three Months Ended June 30,				Six Months Ended June 30,			
Location (Region)	2024	2023	Variance	% Change	2024	2023	Variance	% Change
PJM West (Mid-Atlantic)	$ 30.80	$ 29.43	$ 1.37	4.7 %	$ 31.62	$ 31.27	$ 0.35	1.1 %
ComEd (Midwest)	22.41	22.62	(0.21)	(0.9)%	24.24	24.71	(0.47)	(1.9)%
Central (New York)	27.22	20.82	6.40	30.7 %	31.05	25.49	5.56	21.8 %
North (ERCOT)	30.90	40.39	(9.49)	(23.5)%	28.31	31.82	(3.51)	(11.0)%
Southeast Massachusetts (Other)[(a)]	29.46	29.17	0.29	1.0 %	36.82	40.51	(3.69)	(9.1)%

(a) Reflects New England, which comprises the majority of the activity in the Other region.

For the three and six months ended June 30, 2024 compared to 2023, changes in **Operating revenues** by region were approximately as follows:

	Three Months Ended June 30			Six Months Ended June 30		
	Variance	% Change[(a)]	Significant Drivers	Variance	% Change[(a)]	Significant Drivers
Mid-Atlantic	106	8.8 %	• favorable estimated nuclear PTC revenue of $95	$ 102	4.2 %	• favorable estimated nuclear PTC revenue of $180 • favorable retail load revenue of $70 primarily due to higher contracted energy prices and load volumes; partially offset by • unfavorable wholesale load revenue of ($65) due to lower volumes and contracted energy prices • unfavorable settled economic hedges of ($60) due to settled prices relative to hedged prices
Midwest	(162)	(12.2)%	• unfavorable net ZEC and CMC program revenue of ($330) due to a decrease in realized ZEC revenue and estimated pass through associated with nuclear PTC on CMCs • unfavorable settled economic hedges of ($90) due to settled prices relative to hedged prices; partially offset by • favorable estimated nuclear PTC revenue of $270	(99)	(4.2) %	• unfavorable net ZEC and CMC program revenue of ($430) due to a decrease in ZEC revenue realized and estimated pass through associated with nuclear PTC on CMCs • unfavorable net generation and wholesale load revenue of ($80) primarily due to lower load volumes partially offset by higher generation volumes • unfavorable settled economic hedges of ($50) due to settled prices relative to hedged prices; partially offset by • favorable estimated nuclear PTC revenue of $465
New York	43	9.1 %	• favorable estimated nuclear PTC revenue of $45	22	2.2 %	• favorable retail load revenue of $95 primarily due to higher contracted energy prices and load volumes • favorable estimated nuclear PTC revenue of $65; partially offset by • unfavorable net ZEC program revenue of ($80) due to decrease in ZEC price in current planning year and estimated pass through associated with nuclear PTC • unfavorable settled economic hedges of ($80) due to settled prices relative to hedged price

	Three Months Ended June 30			Six Months Ended June 30		
	Variance	% Change(a)	Significant Drivers	Variance	% Change(a)	Significant Drivers
ERCOT	29	8.8 %	• no individually significant drivers	181	36.4 %	• favorable settled economic hedges of $105 due to settled prices relative to hedged prices • favorable net generation and wholesale load revenue of $85 due to higher load volumes
Other Power Regions	73	6.6 %	• favorable retail load revenue of $60 primarily due to higher contracted energy prices	(95)	(3.3)%	• unfavorable wholesale load revenue of ($130) primarily due to lower contracted prices and load volumes; partially offset by • favorable retail load revenue of $85 primarily due to higher contracted energy prices
Other	(41)	(5.1) %	• unfavorable gas revenue, including settled economic hedges, of ($80) primarily due to lower gas prices	(599)	(22.5)%	• unfavorable gas revenue, including settled economic hedges, of ($390) primarily due to lower gas prices • unfavorable revenues in the United Kingdom, including settled economic hedges of ($170) primarily due to lower energy prices
Mark-to-market(b)	(19)		• gains on economic hedging activities of $192 in 2024 compared to gains of $211 in 2023	(886)		• gains on economic hedging activities of $254 in 2024 compared to gains of $1,140 in 2023
Total	$ 29	0.5 %		$ (1,374)	(10.6)%	

(a) % Change in mark-to-market is not a meaningful measure.
(b) See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on mark-to-market gains and losses.

Purchased power and fuel. See Operating revenues above for discussion of our reportable segments and hedging strategies and for supplemental statistical data, including supply sources by region, nuclear fleet capacity factor, capacity prices, and electricity prices.

Wholesale and retail natural gas activity, as well as other miscellaneous business activities that are not significant to overall results of operations are reported under Other and are not allocated to a region.

For the three and six months ended June 30, 2024 compared to 2023, Purchased power and fuel expense were as follows:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2024	2023	Variance	% Change[(a)]	2024	2023	Variance	% Change[(a)]
Mid-Atlantic	$ 544	$ 475	$ (69)	(14.5) %	$ 1,111	$ 1,030	$ (81)	(7.9) %
Midwest	403	355	(48)	(13.5) %	794	698	(96)	(13.8) %
New York	141	152	11	7.2 %	310	427	117	27.4 %
ERCOT	143	164	21	12.8 %	254	280	26	9.3 %
Other Power Regions	891	890	(1)	(0.1) %	2,148	2,433	285	11.7 %
Total electric purchased power and fuel	2,122	2,036	(86)	(4.2) %	4,617	4,868	251	5.2 %
Other	567	632	65	10.3 %	1,613	2,334	721	30.9 %
Mark-to-market losses (gains)	(397)	219	616		(521)	1,414	1,935	
Total Purchased power and fuel	$ 2,292	$ 2,887	$ 595	20.6 %	$ 5,709	$ 8,616	$ 2,907	33.7 %

(a) % Change in mark-to-market is not a meaningful measure.

For the three and six months ended June 30, 2024 compared to 2023, changes in **Purchased power and fuel** expense by region were approximately as follows:

	Three Months Ended June 30			Six Months Ended June 30		
	Variance	% Change[(a)]	Significant Drivers	Variance	% Change[(a)]	Significant Drivers
Mid-Atlantic	$ (69)	(14.5)%	• no individually significant drivers	$ (81)	(7.9)%	• no individually significant drivers
Midwest	(48)	(13.5)%	• no individually significant drivers	(96)	(13.8)%	• unfavorable cost of ($80) associated with purchased power to supply load relative to generation volumes and net capacity impact due to higher capacity prices
New York	11	7.2 %	• no individually significant drivers	117	27.4 %	• favorable settlement of economic hedges of $160 due to settled prices relative to hedged prices
ERCOT	21	12.8 %	• no individually significant drivers	26	9.3 %	• no individually significant drivers
Other Power Regions	(1)	(0.1)%	• favorable purchased power and fuel of $70 primarily due to lower energy prices partially offset by higher load served; partially offset by • unfavorable settlement of economic hedges of $50 due to settled prices relative to hedged prices	285	11.7 %	• favorable purchased power and fuel of $350 primarily due to lower energy prices partially offset by higher load served; partially offset by • unfavorable settlement of economic hedges of $55 due to settled prices relative to hedged prices
Other	65	10.3 %	• favorable net gas purchases, inclusive of settled economic hedges, of $85 primarily due to lower gas prices	721	30.9 %	• favorable net gas purchases, inclusive of settled economic hedges of $550 primarily due to lower gas prices • favorable purchases in the United Kingdom, inclusive of settled economic hedges of $150 primarily due to lower energy prices
Mark-to-market[(b)]	616		• gains on economic hedging activities of $397 in 2024 compared to losses of ($219) in 2023	1,935		• gains on economic hedging activities of $521 in 2024 compared to losses of ($1,414) in 2023
Total	$ 595	20.6 %		$ 2,907	33.7 %	

(a) % Change in mark-to-market is not a meaningful measure.
(b) See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on mark-to-market gains and losses.

The changes in **Operating and maintenance expense** consisted of the following:

	2024 vs. 2023 Increase (Decrease)	
	Three Months Ended June 30	Six Months Ended June 30
Labor, contracting, and materials[(a)]	$ 210	$ 331
Change in environmental liabilities	73	57
Nuclear refueling outage costs, including the co-owned Salem and STP generating units	(56)	(94)
Separation costs	(31)	(56)
Other	(28)	(15)
Total increase	$ 168	$ 223

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(a) Primarily reflects increased employee-related costs, including labor and other incentives.

Other, net was unfavorable for the three and six months ended June 30, 2024 compared to the same period in 2023, due to activity described in the table below:

	Other, net Income (Deductions)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	2024	2023
Decommissioning-related activities[(a)]	$ 51	$ 155	$ 347	$ 435
Non-service net periodic benefit credit[(b)]	(4)	14	(6)	27
Net realized and unrealized gains (losses) from equity investments	(58)	419	(11)	414
Other	17	17	38	43
Other, net	$ 6	$ 605	$ 368	$ 919

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(a) Includes net realized and net unrealized gains (losses) on NDT fund investments, the elimination of decommissioning-related activities, and the elimination of income taxes related to all NDT fund activity for the Regulatory Agreement Units. See Note 7 — Nuclear Decommissioning and Note 16 — Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements for additional information.
(b) The non-service credit (cost) components are included in Other, net, in accordance with single employer plan accounting. See Note 9 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information.

Effective income tax rates were 16.0% and 29.2% for the three months ended June 30, 2024 and 2023, respectively and 15.8% and 33.5% for the six months ended June 30, 2024 and 2023, respectively. The change in effective tax rate in 2024 is primarily due to the increase in pre-tax book income inclusive of the nuclear PTC, which is not taxable, and a state tax benefit due to a change in forecasted apportionment. See Note 8 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Liquidity and Capital Resources

All results included throughout the liquidity and capital resources section are presented on a GAAP basis.

Our operating and capital expenditures requirements are provided by internally generated cash flows from operations, the sale of certain receivables, as well as funds from external sources in the capital markets and through bank borrowings. Our business is capital intensive and requires considerable capital resources. We annually evaluate our financing plan and credit line sizing, focusing on maintaining our investment grade ratings while meeting our cash needs to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and OPEB obligations, and invest in new and existing ventures. A broad spectrum of financing alternatives beyond the core financing options can be used to meet our needs and fund growth, including monetizing assets in the portfolio via project financing, asset sales, and the use of other financing structures (e.g., joint ventures, minority partners, etc.). Our access to external financing on reasonable terms depends on our credit ratings and current overall capital market business conditions. See the “Credit Matters and Cash Requirements” section below for additional information. We expect cash flows to be sufficient to meet operating expenses, financing costs, and capital expenditure requirements. See Note 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on our debt and credit agreements.

NRC Minimum Funding Requirements

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that sufficient funds will be available in certain minimum amounts for radiological decommissioning of the facility. These NRC minimum funding levels are typically based upon the assumption that decommissioning activities will commence after the end of the current licensed life of each unit. If a unit fails the NRC minimum funding test, then the plant’s owners or parent companies would be required to take steps, such as providing financial guarantees through surety bonds, letters of credit, or parent company guarantees or making additional cash contributions to the NDT fund to ensure sufficient funds are available. See Note 7 — Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional information regarding the latest funding status report filed with the NRC.

As of June 30, 2024, the TMI Unit 1 NDT is fully funded under the SAFSTOR scenario that is the planned decommissioning option, as described in the TMI Unit 1 PSDAR filed with the NRC in April 2019. Additionally, as of June 30, 2024, we have adequate NDT funds for the remaining radiological decommissioning costs at Zion Station related to the Independent Spent Fuel Storage Installation. Decommissioning costs other than radiological may require funding from us. See Liquidity and Capital Resources — NRC Minimum Funding Requirements of our 2023 Form 10-K for information regarding the risk of additional financial assurance for shutdown units.

Cash Flows from Operating Activities

Our cash flows from operating activities primarily result from the sale of electric energy and energy-related products and sustainable solutions to customers. Our future cash flows from operating activities may be affected by future demand for, and market prices of, energy and our ability to continue to produce and supply power at competitive costs, as well as to obtain collections from customers and the sale of certain receivables.

The following table provides a summary of the change in cash flows from operating activities for the six months ended June 30, 2024 and 2023:

	Six Months Ended June 30,		
Cash flows from operating activities	**2024**	**2023**	**Change**
Net income (loss)	$ 1,692	$ 926	$ 766
Adjustments to reconcile net income (loss) to cash:			
Changes in working capital and other noncurrent assets and liabilities[(a)]	(4,389)	(2,594)	(1,795)
Pension and non-pension postretirement benefit contributions	(188)	(18)	(170)
Option premiums received (paid), net	129	(48)	177
Collateral received (posted), net	868	(474)	1,342
Total non-cash operating activities[(b)]	552	1,082	(530)
Net cash flows provided by (used in) operating activities	$ (1,336)	$ (1,126)	$ (210)

(a) Includes changes in Accounts receivable, Inventories, Accounts payable and accrued expenses, Income taxes, and Other assets and liabilities.
(b) See the Consolidated Statements of Cash Flows for details of non-cash operating activities, includes Depreciation, amortization, and accretion, Deferred income taxes and amortization of ITCs, Net fair value changes related to derivatives, and Net realized and unrealized activity associated with NDTs and equity investments. See Note 16 — Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements for additional information on the Other non-cash operating activities line.

Changes in our cash flows from operations were generally consistent with changes in results of operations, as adjusted by changes in working capital in the normal course of business, except as discussed below. Significant operating cash flow impacts for the six months ended June 30, 2024 and 2023 were as follows:

- A net increase in cash outflows for **changes in working capital and other noncurrent assets and liabilities** primarily relates to a decrease in Other assets and liabilities, primarily driven by an increase in cash collections applied to DPP causing an inverse change in other assets and liabilities, due to a decrease in the drawn customer accounts receivable Facility balance in 2024 compared to 2023. Additionally, there was an increase in Other deferred debits and other assets, mainly driven by the nuclear PTC in the current year. See Note 5 — Government Assistance and Note 6 — Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information on the nuclear PTC and the sales of customer accounts receivable, respectively.

- Increase in cash outflows for **pension and non-pension postretirement benefit contributions** is primarily due to our annual qualified pension contribution of $161 million made in February 2024, whereas there were no annual qualified contributions made during the six months ended June 30, 2023. See Note 9 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information on pension and non-pension postretirement benefit plans.

- **Option premiums received (paid), net** relates to options contracts that we purchase and sell as part of our established policies and procedures to manage risks associated with market fluctuations in commodity prices. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on derivative contracts.

- Depending upon whether we are in a net mark-to-market liability or asset position, **collateral** may be required to be posted with or collected from our counterparties. In addition, the collateral posting and collection requirements differ depending on whether the transactions are on an exchange or in the over-the-counter markets. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on collateral.

Cash Flows from Investing Activities

The following table provides a summary of the change in cash flows from investing activities for the six months ended June 30, 2024 and 2023:

	Six Months Ended June 30,		
Cash flows from investing activities	**2024**	**2023**	**Change**
Collection of DPP, net	$ 4,096	$ 1,582	$ 2,514
Capital expenditures	(1,284)	(1,336)	52
Acquisitions of assets and businesses	(15)	(20)	5
Investment in NDT funds, net	(153)	(87)	(66)
Other investing activities	6	32	(26)
Net cash flows provided by (used in) investing activities	$ 2,650	$ 171	$ 2,479

Significant investing cash flow impact for the six months ended June 30, 2024 and 2023 was as follows:

- **Collection of DPP, net** increased primarily due to the increased cash collections applied to DPP as a result of a decrease in the drawn Facility balance in 2024 compared to 2023. In addition, more cash collections were reinvested in the Facility in 2024. See Note 6 — Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information.

Cash Flows from Financing Activities

The following table provides a summary of the change in cash flows from financing activities for the six months ended June 30, 2024 and 2023:

	Six Months Ended June 30,		
Cash flows from financing activities	2024	2023	Change
Long-term debt, net	$ 835	$ 1,670	$ (835)
Changes in short-term borrowings, net	(964)	(224)	(740)
Repurchases of common stock	(999)	(499)	(500)
Dividends paid on common stock	(222)	(185)	(37)
Other financing activities	(35)	(10)	(25)
Net cash flows provided by (used in) financing activities	$ (1,385)	$ 752	$ (2,137)

Significant financing cash flow impacts for the six months ended June 30, 2024 and 2023 were as follows:

- **Long-term debt, net,** varies due to debt issuances and redemptions each year. Refer to Note 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.
- **Changes in short-term borrowings, net**, is driven by repayments on and issuances of notes due within one year of issuance. Refer to Note 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on short-term borrowings.
- **Repurchases of common stock** is related to our share repurchase program that commenced in March 2023. See Note 14 — Shareholders' Equity of the Combined Notes to Consolidated Financial Statements for additional information.

Quarterly dividends declared by our Board of Directors during the six months ended June 30, 2024 and for the third quarter of 2024 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share
First Quarter of 2024	February 26, 2024	March 8, 2024	March 19, 2024	$ 0.3525
Second Quarter of 2024	May 1, 2024	May 29, 2024	June 10, 2024	$ 0.3525
Third Quarter of 2024	July 30, 2024	August 12, 2024	September 6, 2024	$ 0.3525

Credit Matters and Cash Requirements

We fund liquidity needs for capital expenditures, working capital, energy hedging and other financial commitments through cash flows from operations, public debt offerings, commercial paper markets and large, diversified credit facilities. As of June 30, 2024, we have access to facilities with aggregate bank commitments of $7.5 billion. We had access to the commercial paper markets and had availability under our revolving credit facilities during the second quarter of 2024 to fund our short-term liquidity needs, when necessary. We routinely review the sufficiency of our liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels, and the impacts of hypothetical credit downgrades. We closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising, and merger activity. See PART I, ITEM 1A. RISK FACTORS of our 2023 Form 10-K for additional information regarding the effects of uncertainty in the capital and credit markets.

We believe our cash flow from operating activities, access to credit markets and our credit facilities provide sufficient liquidity to support the estimated future cash requirements discussed below.

If we had lost our investment grade credit rating as of June 30, 2024, we would have been required to provide incremental collateral estimated to be approximately $2.0 billion to meet collateral obligations for derivatives, non-derivatives, NPNS, and applicable payables and receivables, net of the contractual right of offset under master netting agreements. A loss of investment grade credit rating would have required a three notch downgrade by S&P or Moody's from their current levels of BBB+ and Baa1, to BB+ and Ba1 or below, respectively. As of June 30, 2024, we had $4.7 billion of available capacity under our credit facilities and $0.3 billion of cash on hand. In the event of a credit downgrade below investment grade and a resulting requirement to provide incremental collateral exceeding available capacity under our credit facilities and cash on hand, we could be required to access additional liquidity through the capital markets. See Note 10 — Derivative Financial Instruments and Note 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

Pension and Other Postretirement Benefits

We consider various factors when making pension funding decisions, including actuarially-determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act, and management of the pension obligation. The Pension Protection Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification). The contributions below reflect a funding strategy to improve funded status with the objective of achieving 100% funded status over time. Based on this funding strategy and current market conditions, which are both subject to change, our annual qualified pension contribution was made in February 2024 for $161 million.

Unlike the qualified pension plans, our non-qualified pension plans are not funded, given that they are not subject to statutory minimum contribution requirements. OPEB plans are also not subject to statutory minimum contribution requirements, though we have funded certain parts of our plans. For our funded OPEB plans, we consider several factors in determining the level of our contributions, including liabilities management and levels of benefit claims paid. The estimated benefit payments to the non-qualified pension plans in 2024 are approximately $23 million and the planned contributions to the OPEB plans, including estimated benefit payments to unfunded plans, is $23 million. Refer to ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - Liquidity and Capital Resources of our 2023 Form 10-K for additional information on pension and other postretirement benefits.

Cash Requirements for Other Financial Commitments

Refer to ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - Liquidity and Capital Resources of our 2023 Form 10-K for additional information on our cash requirements for financial commitments.

Sales of Customer Accounts Receivable

We have an accounts receivable financing facility with a number of financial institutions and a commercial paper conduit to sell certain receivables, which expires in August 2025 unless renewed by the mutual consent of the parties in accordance with its terms. See Note 6 — Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information.

Project Financing

Project financing is based upon a nonrecourse financial structure, in which project debt is paid back from the cash generated by a specific asset or portfolio of assets. Borrowings under these agreements are secured by the assets and equity of each respective project. Lenders do not have recourse against us in the event of a default. If a project financing entity does not maintain compliance with its specific debt covenants, there could be a requirement to accelerate repayment of the associated debt or other project-related borrowings earlier than the stated maturity dates. In these instances, if such repayment were not satisfied, or restructured, the lenders or security holders would generally have rights to foreclose against the project-specific assets and related collateral. The potential requirement to repay the debt or other borrowings earlier than otherwise anticipated could lead to impairments due to a higher likelihood of disposing of the respective project-specific assets significantly before the end of their useful lives. See Note 17 — Debt and Credit Agreements of our 2023 Form 10-K for additional information on project finance credit facilities and nonrecourse debt.

Credit Facilities

We meet our short-term liquidity requirements primarily through the issuance of commercial paper. We may use our credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit. See Note 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on our credit facilities.

Security Ratings

Our access to the capital markets, including the commercial paper market, and our financing costs in those markets, may depend on our securities ratings.

Our borrowings are not subject to default or prepayment as a result of a downgrade of our securities, although such a downgrade could increase fees and interest charges under our credit agreements.

As part of the normal course of business, we enter into contracts that contain express provisions or otherwise permit us and our counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable contracts law, if we are downgraded by a credit rating agency, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance, which could include the posting of additional collateral. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

Our credit ratings from S&P and Moody's are BBB+ and Baa1, respectively, as of June 30, 2024. In March 2024, Moody's raised our issuer credit rating to 'Baa1' from 'Baa2' citing confidence in our ability to maintain credit metrics and strong financial performance.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

(Dollars in millions, unless otherwise noted)

We are exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates, and equity prices. We manage these risks through risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. We report risk management issues to the Executive Committee and the Audit and Risk Committee of the Board of Directors. The following discussion serves as an update to ITEM 7A — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK of our 2023 Annual Report on Form 10-K incorporated herein by reference.

Commodity Price Risk

Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental, regulatory and environmental policies, and other factors. To the extent the total amount of energy we produce or procure differs from the amount of energy we have contracted to sell, we are exposed to market fluctuations in commodity prices. We seek to mitigate our commodity price risk through the sale and purchase of electricity, natural gas and oil, and other commodities.

Electricity available from our owned or contracted generation supply in excess of our obligations to customers is sold into the wholesale markets. To reduce commodity price risk caused by market fluctuations, we enter into non-derivative contracts as well as derivative contracts, including swaps, futures, forwards, and options, with approved counterparties to hedge anticipated exposures. We use derivative instruments as economic hedges to mitigate exposure to fluctuations in commodity prices. We expect the settlement of the majority of our economic hedges will occur during 2024 through 2026.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on owned and contracted generation positions that have not been hedged. Beginning in 2024, our nuclear fleet is eligible for the nuclear PTC provided by the IRA, an important tool in managing commodity price risk for each nuclear unit not already receiving state support. The nuclear PTC provides increasing levels of support as unit revenues decline below levels established in the IRA and is further adjusted for inflation after 2024 through the duration of the program based on the GDP price deflator for the preceding calendar year. See Note 5 — Government Assistance of the Combined Notes to Consolidated Financial Statements for additional information on the nuclear PTC.

In locations and periods where our load serving activities do not naturally offset existing generation portfolio risk, remaining commodity price exposure is managed through portfolio hedging activities. Portfolio hedging activities are generally concentrated in the prompt three years, when customer demand and market liquidity enable effective price risk mitigation. During this prompt three-year period, we seek to mitigate the price risk associated with our load serving contracts, non-nuclear generation, and any residual price risk for our nuclear generation that the nuclear PTC and state programs may not fully mitigate. We also enter transactions that further optimize the economic benefits of our overall portfolio.

The forecasted market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for our entire economic hedge portfolio associated with a $5/MWh reduction in the annual average around-the-clock energy price based on June 30, 2024 market conditions and hedged position results in an immaterial impact to net income (loss) for 2024 and 2025, respectively, largely due to the nuclear PTC. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Fuel Procurement

We procure natural gas through long-term and short-term contracts, and spot-market purchases. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, including contracts sourced from Russia, and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Supply market conditions may make our procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. We engage a diverse set of suppliers to ensure we can secure the nuclear fuel needed to continue to operate our nuclear fleet long-term. Approximately 45% of our uranium concentrate requirements for the remainder of 2024 through 2029 are supplied by three suppliers. To-date, we have not experienced any counterparty credit risk associated with these suppliers stemming from the Russia and Ukraine conflict. In the event of non-performance by these or other suppliers, we believe that replacement uranium concentrate can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Geopolitical developments, including the Russia and Ukraine conflict and United States, United Kingdom, European Union, and Canadian sanctions against Russia, have the potential to impact delivery from multiple suppliers in the international uranium processing industry. Non-performance by these counterparties could have a material adverse impact on our consolidated financial statements. To-date, we have not experienced any delivery or non-performance issues from our suppliers, nor any degradation in the quality of fuel we have received, and we are closely monitoring developments from the conflict. See ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Other Key Business Drivers for more information on the Russia and Ukraine conflict.

Trading and Non-Trading Marketing Activities

The following table provides detail on changes in our commodity mark-to-market net asset or liability balance sheet position from December 31, 2023 to June 30, 2024. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings. This table excludes all NPNS contracts and does not segregate proprietary trading activity. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of June 30, 2024 and December 31, 2023.

Balance as of December 31, 2023[(a)]	$	1,108
Total change in fair value of contracts recorded in result of operations		(202)
Reclassification to realized at settlement of contracts recorded in results of operations		981
Changes in allocated collateral		(876)
Net option premium paid (received)		(129)
Option premium amortization		(30)
Upfront payments and amortizations[(b)]		(55)
Balance as of June 30, 2024[(a)]	$	797

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(a) Amounts are shown net of collateral paid to and received from counterparties.
(b) Includes derivative contracts acquired or sold through upfront payments or receipts of cash, excluding option premiums, and the associated amortizations.

Fair Values

The following table presents maturity and source of fair value for mark-to-market commodity contract net assets (liabilities). See Note 12 — Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

	Maturities Within						
	2024	2025	2026	2027	2028	2029 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts[(a)(b)]:							
Actively quoted prices (Level 1)	$ (12)	$ 101	$ 70	$ 20	$ (2)	$ —	$ 177
Prices provided by external sources (Level 2)	(95)	203	109	86	(1)	6	308
Prices based on model or other valuation methods (Level 3)	286	16	(36)	(41)	(2)	89	312
Total	$ 179	$ 320	$ 143	$ 65	$ (5)	$ 95	$ 797

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(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in the results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $1,524 million at June 30, 2024.

Credit Risk

We would be exposed to credit-related losses in the event of non-performance by counterparties that execute derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for a detailed discussion of credit risk.

Credit-Risk-Related Contingent Features

As part of the normal course of business, we routinely enter into physically or financially settled contracts for the purchase and sale of electric capacity, electricity, fuels, emissions allowances, and other energy-related products. In accordance with the contracts and applicable law, if we are downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on our net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding collateral requirements and Note 13 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding the letters of credit supporting the cash collateral.

We transact output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on our consolidated financial statements. As market prices rise above or fall below contracted price levels, we are required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with us. To post collateral, we depend on access to bank credit facilities, which serve as liquidity sources to fund collateral requirements. See ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Liquidity and Capital Resources — Credit Matters and Cash Requirements — Credit Facilities for additional information.

RTOs and ISOs

We participate in all of the established wholesale energy markets that are administered by PJM, ISO-NE, NYISO, CAISO, MISO, SPP, AESO, and ERCOT. ERCOT is not subject to regulation by FERC but performs a similar function in Texas to that performed by RTOs and ISOs in markets regulated by FERC. In these areas, power and related products are traded through bilateral agreements between buyers and sellers and in the energy markets that are administered by the RTOs or ISOs, as applicable. In areas where there is no RTO or ISO to administer energy markets, electricity and related products are purchased and sold solely through bilateral agreements. For activity administered by an RTO or ISO, the RTO or ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the RTOs and ISOs may, under certain circumstances, require that losses arising from the default of one member be shared by the remaining participants. Non-performance or non-payment by a major member of an RTO or ISO could result in a material adverse impact on our consolidated financial statements.

Exchange Traded Transactions

We enter into commodity transactions on NYMEX, ICE, NASDAQ, NGX, and the Nodal exchange (each an Exchange and, collectively, Exchanges). The Exchange clearinghouses act as the counterparty to each trade. Transactions on the Exchanges must adhere to comprehensive collateral and margining requirements. As a result, transactions on Exchanges are significantly collateralized and have limited counterparty credit risk.

Interest Rate and Foreign Exchange Risk

We use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. We may also utilize interest rate swaps to manage our interest rate exposure. A hypothetical 50 basis point increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would not have resulted in a material decrease in our pre-tax income for the six months ended June 30, 2024. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, we utilize foreign currency derivatives, which are typically designated as economic hedges. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Equity Price Risk

We maintain trust funds, as required by the NRC, to fund the costs of decommissioning our nuclear plants. Our NDT funds are reflected at fair value in the Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate us for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. We actively monitor the investment performance of the trust funds and periodically review asset allocations in accordance with our NDT fund investment policy.

A hypothetical 25 basis points increase in interest rates and 10% decrease in equity prices would have resulted in a $946 million reduction in the fair value of our NDT trust assets as of June 30, 2024. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See Note 7 — Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements and Liquidity and Capital Resources section of ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information.

Our employee benefit plan trusts also hold investments in equity and debt securities. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Critical Accounting Policies and Estimates in our 2023 Form 10-K for further information.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

During the second quarter of 2024, our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures related to the recording, processing, summarizing, and reporting of information in periodic reports that we file or submit with the SEC. These disclosure controls and procedures have been designed to ensure that (a) information relating to our consolidated subsidiaries, is accumulated and made known to our management, including our principal executive officer and principal financial officer, by other employees as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded, processed, summarized, and reported, as applicable, within the time periods specified in the SEC's rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Accordingly, as of June 30, 2024, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective to accomplish their objectives.

Changes in Internal Control Over Financial Reporting

We continually strive to improve our disclosure controls and procedures to enhance the quality of our financial reporting and to maintain dynamic systems that change as conditions warrant. There have been no changes in internal control over financial reporting that occurred during the second quarter of 2024 that have materially affected, or are reasonably likely to materially affect, any of our internal control over financial reporting.

PART II. OTHER INFORMATION

(Dollars in millions except per share data, unless otherwise noted)

ITEM 1. LEGAL PROCEEDINGS

We are parties to various lawsuits and regulatory proceedings in the ordinary course of business. For information regarding material lawsuits and proceedings, see Note 13 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements in PART I, ITEM 1. FINANCIAL STATEMENTS of this report. Such descriptions are incorporated herein by these references.

ITEM 1A. RISK FACTORS

At June 30, 2024, our risk factors were consistent with the risk factors described in our 2023 Form 10-K in ITEM 1A. RISK FACTORS.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Issuer Purchases of Equity Securities (CEG Parent)

During 2023, our Board of Directors authorized the repurchase of up to $2 billion of the Company's outstanding common stock. In April 2024, our Board of Directors approved a $1 billion increase to the program, authorizing up to $3 billion in total repurchases. No other repurchase plans or programs have been authorized. See Note 14 — Shareholders' Equity of the Combined Notes to Consolidated Financial Statements for additional information regarding our share repurchase program.

The following table provides information regarding our share repurchases under the program during the three months ended June 30, 2024.

Period	Total Number of Shares Purchased[(a)(b)(c)]	Average Price Paid per Share	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Programs[(d)]
April 1 to April 30, 2024	—	$ —	$ 1,496
May 1 to May 31, 2024	2,091,037	(b)(c)	991
June 1 to June 30, 2024	—	—	991
Total	2,091,037		$ 991

(a) We have not made any purchases of shares other than in connection with the publicly announced share repurchase program described above.
(b) Includes 0.2 million additional shares delivered under the March 2024 ASR agreement upon settlement. As of May 2024, the March 2024 ASR agreement was settled in full at an average price paid per share of $182.65.
(c) Includes 1.8 million shares received from initial delivery under the May 2024 ASR agreement. As of July 2024, the May 2024 ASR agreement was settled in full and 0.6 million additional shares were delivered. The average price paid for all shares delivered under the May 2024 ASR agreement was $211.40.
(d) Approximate dollar value of shares that may yet be purchased under the program includes taxes and commissions.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

ITEM 5. OTHER INFORMATION

Rule 10b5-1 Trading Plans

During the three months ended June 30, 2024, none of our directors or executive officers (as defined in Rule 16a-1 under the Exchange Act) adopted or terminated any contract, instruction or written plan for the purchase or sale of our securities that was intended to satisfy the affirmative defense conditions of Rule 10b5-1(c) or any "non-Rule 10b5-1 trading arrangement" (as defined in Item 408 under Regulation S-K of the Exchange Act).

ITEM 6. EXHIBITS

Certain of the following exhibits are incorporated herein by reference under Rule 12b-32 of the Exchange Act. Certain other instruments which would otherwise be required to be listed below have not been so listed because such instruments do not authorize securities in an amount which exceeds 10% of the total assets of the applicable Registrant and its subsidiaries on a consolidated basis and the relevant Registrant agrees to furnish a copy of any such instrument to the SEC upon request.

Exhibit No.	Description
10.1	Amended and Restated Credit Agreement dated as of June 14, 2024, among Constellation JPMorgan Chase Bank, N.A. as Administrative Agent, and the various financial institutions signatory thereto (File No. 001-41137, Form 8-K dated June 14, 2024, Exhibit 10.1)
101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH	Inline XBRL Taxonomy Extension Schema Document.
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document.
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act as to the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2024 filed by the following officers for the following companies:

Exhibit No.	Description
31-1	Filed by Joseph Dominguez for Constellation Energy Corporation
31-2	Filed by Daniel L. Eggers for Constellation Energy Corporation
31-3	Filed by Joseph Dominguez for Constellation Energy Generation, LLC
31-4	Filed by Daniel L. Eggers for Constellation Energy Generation, LLC

Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code (Sarbanes — Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2024 filed by the following officers for the following companies:

Exhibit No.	Description
32-1	Filed by Joseph Dominguez for Constellation Energy Corporation
32-2	Filed by Daniel L. Eggers for Constellation Energy Corporation
32-3	Filed by Joseph Dominguez for Constellation Energy Generation, LLC
32-4	Filed by Daniel L. Eggers for Constellation Energy Generation, LLC

SIGNATURES

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

CONSTELLATION ENERGY CORPORATION

/s/ JOSEPH DOMINGUEZ	/s/ DANIEL L. EGGERS
Joseph Dominguez President and Chief Executive Officer (Principal Executive Officer)	Daniel L. Eggers Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ MATTHEW N. BAUER	
Matthew N. Bauer Senior Vice President and Controller (Principal Accounting Officer)	

August 6, 2024

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

CONSTELLATION ENERGY GENERATION, LLC

/s/ JOSEPH DOMINGUEZ	/s/ DANIEL L. EGGERS
Joseph Dominguez President and Chief Executive Officer (Principal Executive Officer)	Daniel L. Eggers Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ MATTHEW N. BAUER	
Matthew N. Bauer Senior Vice President and Controller (Principal Accounting Officer)	

August 6, 2024