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 September 30, 2023
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 Exelon 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 October 31, 2023 was as follows:

Constellation Energy Corporation Common Stock, without par value	319,381,684
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
CR	Constellation Renewables, LLC (formerly ExGen Renewables IV, LLC)
CRP	Constellation Renewables Partners, LLC (formerly ExGen Renewables Partners, LLC)
FitzPatrick	James A. FitzPatrick nuclear generating station
Ginna	R. E. Ginna nuclear generating station
NER	NewEnergy Receivables LLC
NMP	Nine Mile Point nuclear generating station
RPG	Renewable Power Generation, LLC
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
PHI	Pepco Holdings LLC (formerly Pepco Holdings, Inc.)
Pepco	Potomac Electric Power Company
DPL	Delmarva Power & Light Company
ACE	Atlantic City Electric Company
BSC	Exelon Business Services Company, LLC

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

AESO	Alberta Electric Systems Operator
AOCI	Accumulated Other Comprehensive Income (Loss)
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
CAISO	California ISO
CODM	Chief Operating Decision Maker
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
CMC	Carbon Mitigation Credit
DOE	United States Department of Energy
DOJ	United States Department of Justice
DPP	Deferred Purchase Price
EBITDA	Earnings Before Interest, Tax, Depreciation and Amortization
EMA	Employee Matters Agreement
EMT	Everett Marine Terminal
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 Program
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
GWh	Gigawatt hour
ICE	Intercontinental Exchange
IPA	Illinois Power Agency
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ITC	Investment Tax Credit
LIBOR	London Interbank Offered Rate
MDE	Maryland Department of the Environment
MDPSC	Maryland Public Service Commission
MISO	Midcontinent Independent System Operator, Inc.
MW	Megawatt
MWh	Megawatt hour
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
NRG	NRG Energy, Inc.
NYISO	New York ISO
NYMEX	New York Mercantile Exchange
NYPSC	New York Public Service Commission
OCI	Other Comprehensive Income
OIESO	Ontario Independent Electricity System Operator
OPEB	Other Postretirement Employee Benefits
PA DEP	Pennsylvania Department of Environmental Protection
PAPUC	Pennsylvania Public Utility Commission
PG&E	Pacific Gas and Electric Company
PJM	PJM Interconnection, LLC
PPA	Power Purchase Agreement
PP&E	Property, Plant, and Equipment
PRP	Potentially Responsible Parties
PSDAR	Post-shutdown Decommissioning Activities Report
PSEG	Public Service Enterprise Group Incorporated
PTC	Production Tax Credit
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
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 and the Former PECO units)
RGGI	Regional Greenhouse Gas Initiative
RMC	Risk Management Committee
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
SNF	Spent Nuclear Fuel
SOFR	Secured Overnight Financing Rate
SPP	Southwest Power Pool
TMA	Tax Matters Agreement
TSA	Transition Services Agreement
U.S. Court of Appeals for the D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
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, (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 2022 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 September 30, 2023	Three Months Ended September 30, 2022	Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022
Operating revenues				
Operating revenues	$ 6,111	$ 6,051	$ 19,122	$ 16,947
Operating revenues from affiliates	—	—	—	160
Total operating revenues	6,111	6,051	19,122	17,107
Operating expenses				
Purchased power and fuel	3,367	4,695	11,983	11,749
Purchased power and fuel from affiliates	—	—	—	5
Operating and maintenance	1,353	989	4,263	3,422
Operating and maintenance from affiliates	—	—	—	44
Depreciation and amortization	266	262	808	818
Taxes other than income taxes	148	145	419	415
Total operating expenses	5,134	6,091	17,473	16,453
(Loss) gain on sales of assets and businesses	—	(1)	28	13
Operating income (loss)	977	(41)	1,677	667
Other income and (deductions)				
Interest expense, net	(82)	(75)	(292)	(186)
Interest expense to affiliates	—	—	—	(1)
Other, net	—	(196)	919	(1,169)
Total other income and (deductions)	(82)	(271)	627	(1,356)
Income (loss) before income taxes	895	(312)	2,304	(689)
Income taxes	205	(123)	677	(504)
Equity in losses of unconsolidated affiliates	—	(4)	(11)	(10)
Net income (loss)	690	(193)	1,616	(195)
Net loss attributable to noncontrolling interests	(41)	(5)	(44)	(1)
Net income (loss) attributable to common shareholders	$ 731	$ (188)	$ 1,660	$ (194)
Comprehensive income (loss), net of income taxes				
Net income (loss)	$ 690	$ (193)	$ 1,616	$ (195)
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	—	(2)	(3)	(4)
Actuarial loss reclassified to periodic cost	5	28	18	73
Pension and non-pension postretirement benefit plan valuation adjustment	—	4	(53)	4
Unrealized loss on cash flow hedges	—	(1)	—	(1)
Unrealized (loss) gain on foreign currency translation	(2)	(6)	1	(4)
Other comprehensive income (loss), net of income taxes	3	23	(37)	68
Comprehensive income (loss)	693	(170)	1,579	(127)
Comprehensive loss attributable to noncontrolling interests	(41)	(5)	(44)	(1)
Comprehensive income (loss) attributable to common shareholders	$ 734	$ (165)	$ 1,623	$ (126)
Average shares of common stock outstanding:				
Basic	322	327	324	327
Assumed exercise and/or distributions of stock-based awards	1	1	1	1
Diluted	323	328	325	328
Earnings per average common share				
Basic	$ 2.27	$ (0.57)	$ 5.12	$ (0.59)
Diluted	$ 2.26	$ (0.57)	$ 5.11	$ (0.59)

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Nine Months Ended September 30, 2023	2022
Cash flows from operating activities		
Net income (loss)	$ 1,616	$ (195)
Adjustments to reconcile net income (loss) to net cash flows (used in) provided by operating activities		
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	1,840	1,810
Deferred income taxes and amortization of ITCs	189	(915)
Net fair value changes related to derivatives	146	544
Net realized and unrealized (gains) losses on NDT funds	(154)	1,032
Net realized and unrealized (gains) losses on equity investments	(490)	27
Other non-cash operating activities	147	291
Changes in assets and liabilities:		
Accounts receivable	942	(150)
Receivables from and payables to affiliates, net	—	20
Inventories	90	(166)
Accounts payable and accrued expenses	(1,526)	789
Option premiums paid, net	(36)	(163)
Collateral (posted) received, net	(222)	766
Income taxes	277	364
Pension and non-pension postretirement benefit contributions	(46)	(229)
Other assets and liabilities	(4,892)	(3,756)
Net cash flows (used in) provided by operating activities	(2,119)	69
Cash flows from investing activities		
Capital expenditures	(1,735)	(1,090)
Proceeds from NDT fund sales	4,221	3,034
Investment in NDT funds	(4,374)	(3,212)
Collection of DPP, net	4,058	3,095
Proceeds from sales of assets and businesses	24	41
Other investing activities	(15)	3
Net cash flows provided by investing activities	2,179	1,871
Cash flows from financing activities		
Change in short-term borrowings	(959)	(209)
Proceeds from short-term borrowings with maturities greater than 90 days	527	—
Repayments of short-term borrowings with maturities greater than 90 days	(200)	(1,180)
Issuance of long-term debt	3,192	9
Retirement of long-term debt	(150)	(1,143)
Retirement of long-term debt to affiliate	—	(258)
Contributions from Exelon	—	1,750
Dividends paid on common stock	(277)	(139)
Repurchases of common stock	(750)	—
Other financing activities	6	(43)
Net cash flows provided by (used in) financing activities	1,389	(1,213)
Increase in cash, restricted cash, and cash equivalents	1,449	727
Cash, restricted cash, and cash equivalents at beginning of period	528	576
Cash, restricted cash, and cash equivalents at end of period	$ 1,977	$ 1,303
Supplemental cash flow information		
Decrease in capital expenditures not paid	$ (63)	$ (17)
Increase in DPP	5,288	3,733
Increase in PP&E related to ARO update	762	342

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	September 30, 2023	December 31, 2022
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,889	$ 422
Restricted cash and cash equivalents	88	106
Accounts receivable		
Customer accounts receivable (net of allowance for credit losses of $58 and $46 as of September 30, 2023 and December 31, 2022, respectively)	1,541	2,585
Other accounts receivable (net of allowance for credit losses of $5 as of September 30, 2023 and December 31, 2022)	723	731
Mark-to-market derivative assets	1,467	2,368
Inventories, net		
Natural gas, oil, and emission allowances	289	429
Materials and supplies	1,133	1,076
Renewable energy credits	593	617
Other	2,179	1,026
Total current assets	9,902	9,360
Property, plant, and equipment (net of accumulated depreciation and amortization of $17,265 and $16,726 as of September 30, 2023 and December 31, 2022, respectively)	20,849	19,822
Deferred debits and other assets		
Nuclear decommissioning trust funds	14,573	14,114
Investments	727	202
Mark-to-market derivative assets	970	1,261
Deferred income taxes	43	44
Other	1,901	2,106
Total deferred debits and other assets	18,214	17,727
Total assets[a]	$ 48,965	$ 46,909

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	September 30, 2023	December 31, 2022
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 527	$ 1,159
Long-term debt due within one year	116	143
Accounts payable and accrued expenses	2,252	3,734
Mark-to-market derivative liabilities	1,108	1,558
Renewable energy credit obligation	857	901
Other	403	344
Total current liabilities	5,263	7,839
Long-term debt	7,512	4,466
Deferred credits and other liabilities		
Deferred income taxes and unamortized ITCs	3,208	3,031
Asset retirement obligations	13,797	12,699
Pension obligations	610	605
Non-pension postretirement benefit obligations	642	609
Spent nuclear fuel obligation	1,278	1,230
Payables related to Regulatory Agreement Units	2,923	2,897
Mark-to-market derivative liabilities	536	983
Other	1,196	1,178
Total deferred credits and other liabilities	24,190	23,232
Total liabilities[(a)]	36,965	35,537
Commitments and contingencies (Note 13)		
Shareholders' equity		
Common stock (No par value, 1,000 shares authorized, 319 shares and 327 shares outstanding as of September 30, 2023 and December 31, 2022, respectively)	12,576	13,274
Retained earnings (deficit)	887	(496)
Accumulated other comprehensive loss, net	(1,797)	(1,760)
Total shareholders' equity	11,666	11,018
Noncontrolling interests	334	354
Total equity	12,000	11,372
Total liabilities and shareholders' equity	$ 48,965	$ 46,909

(a) Our consolidated assets include $3,832 million and $2,641 million at September 30, 2023 and December 31, 2022, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Our consolidated liabilities include $1,017 million and $1,041 million at September 30, 2023 and December 31, 2022, 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)

	Nine Months Ended September 30, 2023					
	Shareholders' Equity					
(In millions, shares in thousands)	Issued Shares	Common Stock	Retained Earnings (Deficit)	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Equity
Balance, December 31, 2022	327,130	$ 13,274	$ (496)	$ (1,760)	$ 354	$ 11,372
Net income	—	—	96	—	6	102
Employee incentive plans	528	6	—	—	—	6
Changes in equity of noncontrolling interests	—	—	—	—	(2)	(2)
Common stock dividends ($0.28/ common share)	—	—	(93)	—	—	(93)
Common stock repurchased	(3,239)	(251)	—	—	—	(251)
Other comprehensive 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 ($0.28/ 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
Net income (loss)	—	—	731	—	(41)	690
Employee incentive plans	144	21	—	—	—	21
Changes in equity of noncontrolling interests	—	—	—	—	19	19
Common stock dividends ($0.28/ common share)	—	—	(92)	—	—	(92)
Common stock repurchased	(2,338)	(253)	—	—	—	(253)
Other comprehensive income, net of income taxes	—	—	—	3		3
Balance, September 30, 2023	319,382	$ 12,576	$ 887	$ (1,797)	$ 334	$ 12,000

See the Combined Notes to Consolidated Financial Statements

(In millions, shares in thousands)	Nine Months Ended September 30, 2022						
	Shareholders' Equity						
	Issued Shares	Common Stock	Retained Earnings (Deficit)	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Predecessor Member's Equity[(a)]	Total Equity
Balance, December 31, 2021	—	$ —	$ —	$ (31)	$ 395	$ 11,250	$ 11,614
Net income from January 1, 2022 to January 31, 2022	—	—	—	—	—	151	151
Separation-related adjustments	—	—	—	(2,006)	7	1,802	(197)
Changes in equity of noncontrolling interests from January 1, 2022 to January 31, 2022	—	—	—	—	(7)	—	(7)
Consummation of separation	326,664	13,203	—	—	—	(13,203)	—
Net (loss) income from February 1, 2022 to March 31, 2022	—	—	(45)	—	5	—	(40)
Employee incentive plan activity from February 1, 2022 to March 31, 2022	35	9	—	—	—	—	9
Common stock dividends ($0.14/common share) from February 1, 2022 to March 31, 2022	—	—	(46)	—	—	—	(46)
Other comprehensive income, net of income taxes from February 1, 2022 to March 31, 2022	—	—	—	21	—	—	21
Balance, March 31, 2022	326,699	$ 13,212	$ (91)	$ (2,016)	$ 400	$ —	$ 11,505
Net loss	—	—	(111)	—	(2)	—	(113)
Employee incentive plans	146	29	—	—	—	—	29
Changes in equity of noncontrolling interests	—	—	—	—	(9)	—	(9)
Common stock dividends ($0.14/common share)	—	—	(47)	—	—	—	(47)
Other comprehensive income, net of income taxes	—	—	—	24	—	—	24
Balance, June 30, 2022	326,845	$ 13,241	$ (249)	$ (1,992)	$ 389	$ —	$ 11,389
Net loss	—	—	(188)	—	(5)	—	(193)
Employee incentive plans	173	14	—	—	—	—	14
Changes in equity of non-controlling interests	—	—	—	—	(18)	—	(18)
Common stock dividends ($0.14/common share)	—	—	(46)	—	—	—	(46)
Other comprehensive income, net of income taxes	—	—	—	23	—	—	23
Balance, September 30, 2022	327,018	$ 13,255	$ (483)	$ (1,969)	$ 366	$ —	$ 11,169

(a) Represents Constellation's predecessor member's equity prior to the separation transaction. Upon completion of the separation, the predecessor member's equity was transferred to CEG Parent's Common stock. See Note 1 — Basis of Presentation for additional information on the separation.

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 September 30, 2023	Three Months Ended September 30, 2022	Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022
Operating revenues				
Operating revenues	$ 6,111	$ 6,051	$ 19,122	$ 16,947
Operating revenues from affiliates	—	—	—	160
Total operating revenues	6,111	6,051	19,122	17,107
Operating expenses				
Purchased power and fuel	3,367	4,695	11,983	11,749
Purchased power and fuel from affiliates	—	—	—	5
Operating and maintenance	1,353	989	4,263	3,422
Operating and maintenance from affiliates	—	—	—	44
Depreciation and amortization	266	262	808	818
Taxes other than income taxes	148	145	419	415
Total operating expenses	5,134	6,091	17,473	16,453
(Loss) gain on sales of assets and businesses	—	(1)	28	13
Operating income (loss)	977	(41)	1,677	667
Other income and (deductions)				
Interest expense, net	(82)	(75)	(292)	(186)
Interest expense to affiliates	—	—	—	(1)
Other, net	—	(196)	919	(1,169)
Total other income and (deductions)	(82)	(271)	627	(1,356)
Income (loss) before income taxes	895	(312)	2,304	(689)
Income taxes	205	(123)	677	(504)
Equity in losses of unconsolidated affiliates	—	(4)	(11)	(10)
Net income (loss)	690	(193)	1,616	(195)
Net loss attributable to noncontrolling interests	(41)	(5)	(44)	(1)
Net income (loss) attributable to membership interests	$ 731	$ (188)	$ 1,660	$ (194)
Comprehensive income (loss), net of income taxes				
Net income (loss)	$ 690	$ (193)	$ 1,616	$ (195)
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	—	(2)	(3)	(4)
Actuarial loss reclassified to periodic cost	5	28	18	73
Pension and non-pension postretirement benefit plan valuation adjustment	—	4	(53)	4
Unrealized loss on cash flow hedges	—	(1)	—	(1)
Unrealized (loss) gain on foreign currency translation	(2)	(6)	1	(4)
Other comprehensive income (loss), net of income taxes	3	23	(37)	68
Comprehensive income (loss)	693	(170)	1,579	(127)
Comprehensive loss attributable to noncontrolling interests	(41)	(5)	(44)	(1)
Comprehensive income (loss) attributable to membership interests	$ 734	$ (165)	$ 1,623	$ (126)

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022
Cash flows from operating activities		
Net income (loss)	$ 1,616	$ (195)
Adjustments to reconcile net income (loss) to net cash flows used in operating activities		
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	1,840	1,810
Deferred income taxes and amortization of ITCs	189	(915)
Net fair value changes related to derivatives	146	544
Net realized and unrealized (gains) losses on NDT funds	(154)	1,032
Net realized and unrealized (gains) losses on equity investments	(490)	27
Other non-cash operating activities	99	252
Changes in assets and liabilities:		
Accounts receivable	936	(126)
Receivables from and payables to affiliates, net	23	62
Inventories	90	(166)
Accounts payable and accrued expenses	(1,546)	733
Option premiums paid, net	(36)	(163)
Collateral (posted) received, net	(222)	766
Income taxes	277	364
Pension and non-pension postretirement benefit contributions	(46)	(229)
Other assets and liabilities	(4,953)	(3,803)
Net cash flows used in operating activities	(2,231)	(7)
Cash flows from investing activities		
Capital expenditures	(1,735)	(1,090)
Proceeds from NDT fund sales	4,221	3,034
Investment in NDT funds	(4,374)	(3,212)
Collection of DPP, net	4,058	3,095
Proceeds from sales of assets and businesses	24	41
Other investing activities	(15)	3
Net cash flows provided by investing activities	2,179	1,871
Cash flows from financing activities		
Change in short-term borrowings	(959)	(209)
Proceeds from short-term borrowings with maturities greater than 90 days	527	—
Repayments of short-term borrowings with maturities greater than 90 days	(200)	(1,180)
Issuance of long-term debt	3,192	9
Retirement of long-term debt	(150)	(1,143)
Retirement of long-term debt to affiliate	—	(258)
Distributions to member	(909)	(139)
Contributions from Exelon	—	1,750
Other financing activities	(3)	(56)
Net cash flows provided by (used in) financing activities	1,498	(1,226)
Increase in cash, restricted cash, and cash equivalents	1,446	638
Cash, restricted cash, and cash equivalents at beginning of period	501	576
Cash, restricted cash, and cash equivalents at end of period	$ 1,947	$ 1,214
Supplemental cash flow information		
Decrease in capital expenditures not paid	$ (63)	$ (17)
Increase in DPP	5,288	3,733
Increase in PP&E related to ARO update	762	342

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	September 30, 2023		December 31, 2022	
ASSETS				
Current assets				
Cash and cash equivalents	$	1,888	$	403
Restricted cash and cash equivalents		59		98
Accounts receivable				
Customer accounts receivable (net of allowance for credit losses of $58 and $46 as of September 30, 2023 and December 31, 2022, respectively)		1,541		2,585
Other accounts receivable (net of allowance for credit losses of $5 as of September 30, 2023 and December 31, 2022)		716		718
Mark-to-market derivative assets		1,467		2,368
Inventories, net				
Natural gas, oil, and emission allowances		289		429
Materials and supplies		1,133		1,076
Renewable energy credits		593		617
Other		2,179		1,026
Total current assets		9,865		9,320
Property, plant, and equipment (net of accumulated depreciation and amortization of $17,265 and $16,726 as of September 30, 2023 and December 31, 2022, respectively)		20,849		19,822
Deferred debits and other assets				
Nuclear decommissioning trust funds		14,573		14,114
Investments		727		202
Mark-to-market derivative assets		970		1,261
Deferred income taxes		43		44
Other		1,901		2,106
Total deferred debits and other assets		18,214		17,727
Total assets[(a)]	$	48,928	$	46,869

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	September 30, 2023	December 31, 2022
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 527	$ 1,159
Long-term debt due within one year	116	143
Accounts payable and accrued expenses	2,116	3,679
Payables to affiliates	68	45
Mark-to-market derivative liabilities	1,108	1,558
Renewable energy credit obligation	857	901
Other	403	344
Total current liabilities	5,195	7,829
Long-term debt	7,512	4,466
Deferred credits and other liabilities		
Deferred income taxes and unamortized ITCs	3,208	3,031
Asset retirement obligations	13,797	12,699
Pension obligations	610	605
Non-pension postretirement benefit obligations	642	609
Spent nuclear fuel obligation	1,278	1,230
Payables related to Regulatory Agreement Units	2,923	2,897
Mark-to-market derivative liabilities	536	983
Other	1,119	1,106
Total deferred credits and other liabilities	24,113	23,160
Total liabilities[(a)]	36,820	35,455
Commitments and contingencies (Note 13)		
Equity		
Member's equity		
Membership interest	11,778	12,408
Undistributed earnings	1,793	412
Accumulated other comprehensive loss, net	(1,797)	(1,760)
Total member's equity	11,774	11,060
Noncontrolling interests	334	354
Total equity	12,108	11,414
Total liabilities and equity	$ 48,928	$ 46,869

(a) Our consolidated assets include $3,832 million and $2,641 million as of September 30, 2023 and December 31, 2022, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Our consolidated liabilities include $1,017 million and $1,041 million as of September 30, 2023 and December 31, 2022, 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)

	Nine Months Ended September 30, 2023				
	Member's Equity				
(In millions)	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Equity
Balance, December 31, 2022	$ 12,408	$ 412	$ (1,760)	$ 354	$ 11,414
Net income	—	96	—	6	102
Changes in equity of noncontrolling interests	—	—	—	(2)	(2)
Distributions to member	(152)	(97)	—	—	(249)
Other comprehensive 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, net of income taxes	—	—	8	—	8
Balance, June 30, 2023	$ 12,012	$ 1,153	$ (1,800)	$ 356	$ 11,721
Net income (loss)	—	731	—	(41)	690
Changes in equity of noncontrolling interests	—	—	—	19	19
Distribution to member	(234)	(91)	—	—	(325)
Other comprehensive income, net of income taxes	—	—	3	—	3
Balance, September 30, 2023	$ 11,778	$ 1,793	$ (1,797)	$ 334	$ 12,108

See the Combined Notes to Consolidated Financial Statements

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

	Nine Months Ended September 30, 2022				
	Member's Equity				
(In millions)	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Equity
Balance, December 31, 2021	$ 10,482	$ 768	$ (31)	$ 395	$ 11,614
Net income	—	106	—	5	111
Separation-related adjustments	1,844	(11)	(2,006)	7	(166)
Changes in equity of noncontrolling interests	—	—	—	(7)	(7)
Distributions to member	—	(46)	—	—	(46)
Other comprehensive income, net of income taxes	—	—	21	—	21
Balance, March 31, 2022	$ 12,326	$ 817	$ (2,016)	$ 400	$ 11,527
Net loss	—	(111)	—	(2)	(113)
Changes in equity of noncontrolling interests	—	—	—	(9)	(9)
Distribution to member	—	(47)	—	—	(47)
Other comprehensive income, net of income taxes	—	—	24	—	24
Balance, June 30, 2022	$ 12,326	$ 659	$ (1,992)	$ 389	$ 11,382
Net loss	—	(188)	—	(5)	(193)
Changes in equity of noncontrolling interests	—	—	—	(18)	(18)
Distributions to member	—	(46)	—	—	(46)
Other comprehensive income, net of income taxes	—	—	23	—	23
Balance, September 30, 2022	$ 12,326	$ 425	$ (1,969)	$ 366	$ 11,148

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 clean 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

On February 21, 2021, the board of directors of Exelon authorized management to pursue a plan to separate its competitive generation and customer-facing energy businesses (separation), conducted through Constellation Energy Generation, LLC (“Constellation”, formerly Exelon Generation Company, LLC) and its subsidiaries, into an independent, publicly-traded company. CEG Parent, a direct, wholly owned subsidiary of Exelon, was newly formed for the purpose of consummating the separation and had not engaged in any business activities nor had any assets or liabilities prior to the separation. On February 1, 2022, the separation was completed and CEG Parent holds all the interests in Constellation previously held by Exelon.

As an individual registrant, Constellation has historically filed consolidated financial statements to reflect its financial position and operating results as a stand-alone, wholly owned subsidiary of Exelon. The accompanying Consolidated Financial Statements as of September 30, 2023 and for the three and nine months ended September 30, 2023 and 2022 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, except as otherwise disclosed. The Consolidated Financial Statements include the accounts of our subsidiaries and all intercompany transactions have been eliminated. CEG Parent's prior period financial statements have been adjusted to reflect the balances of Constellation in accordance with applicable guidance. Constellation's December 31, 2022 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, 2023. 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.

Separation from Exelon

On February 1, 2022, Exelon completed the separation through a pro-rata distribution of all of the outstanding shares of CEG Parent's common stock, no par value, on the basis of one such share for every three shares of Exelon common stock held on January 20, 2022, the record date of the distribution. CEG Parent is an independent, publicly traded company listed on the Nasdaq Stock Market under the symbol “CEG”, and regular-way trading began on February 2, 2022. Exelon no longer retains any ownership interest in CEG Parent or Constellation.

Prior to completion of the separation, our financial statements include certain transactions with affiliates of Exelon, which are disclosed as related party transactions. After February 1, 2022, all transactions with Exelon or its affiliates are no longer related party transactions.

In order to govern the ongoing relationships with Exelon after the separation, and to facilitate an orderly transition, we entered into several agreements with Exelon, including a Separation Agreement, TSA, EMA, and TMA.

Pursuant to the Separation Agreement, we received a cash contribution of $1.75 billion from Exelon on January 31, 2022, the proceeds of which were used to settle $258 million of an intercompany loan from Exelon and $200 million of short-term debt outstanding prior to separation, in addition to a $192 million contribution to our pension plans. We also entered into two new five-year facility agreements providing $4.5 billion of capacity.

The amounts Exelon billed us for services pursuant to the TSA were $33 million and $68 million for the three months ended September 30, 2023 and 2022, respectively, and were $127 million and $193 million for the nine months ended September 30, 2023 and 2022, respectively. The amounts we billed Exelon for services pursuant to the TSA were $4 million and $12 million for the three months ended September 30, 2023 and 2022, respectively, and were $13 million and $32 million for the nine months ended September 30, 2023 and 2022, respectively.

See Note 1 — Basis of Presentation of our 2022 Form 10-K for additional information on the separation from Exelon.

Summary of Significant Accounting Policies

See Note 1 — Basis of Presentation of our 2022 Form 10-K for additional information on significant accounting policies.

2. Mergers, Acquisitions, and Dispositions

Acquisition of Joint Ownership in South Texas Project

On November 1, 2023 we acquired NRG South Texas LP, which owns a 44% undivided ownership interest in the jointly owned South Texas Project Nuclear Generating Station (STP), a 2,645-megawatt, dual-unit nuclear plant located in Bay City, Texas, for a cash purchase price of $1.75 billion. On September 29, 2023, we issued senior notes for net proceeds of approximately $1.4 billion. The net proceeds from the offerings and cash on hand was used to fund the consideration, fees, and expenses related to the acquisition. The current renewed NRC licenses for the STP units expire in 2047/2048 and the NRC licensed operator is STP Nuclear Operating Company (STPNOC), acting on behalf of the joint owners. Other owners include City Public Service Board of San Antonio (CPS, 40%) and the City of Austin, Texas (Austin Energy, 16%). This acquisition is complementary to and aligned strategically with our existing clean energy business operations.

The transaction will be accounted for as a business combination and we will record the fair value of our proportionate share of the assets acquired and liabilities assumed as of the acquisition date. To the extent that the purchase price is greater than the fair value of the net assets acquired, goodwill will be recorded. To the extent the fair value of the net assets acquired is greater than the purchase price, a bargain purchase gain will be recorded. Certain disclosures have been omitted given the initial accounting for the acquisition was not complete at the time these consolidated financial statements were issued. Disclosures related to the acquisition date fair value of the assets acquired and liabilities assumed, among other relevant disclosures, will be made in our 2023 Form 10-K.

As part of the transaction, we acquired ownership of two decommissioning trust funds established to provide funding for decontamination and decommissioning of STP. The trust funds have been funded with amounts collected from predecessor utilities. We expect to maintain these funds and the ability to collect additional funds if needed in the future from ratepayers and any excess of funds upon completion of decommissioning are required to be returned to ratepayers. As such, our accounting for the future decommissioning of our interest in STP will mirror that of our existing Regulatory Agreement Units. Refer to Note 1 — Basis of Presentation and Note 10 – Asset Retirement Obligations of our 2022 Form 10-K for additional information on our accounting policy for Regulatory Agreement Units.

On July 28, 2023 NRG accepted service of a lawsuit filed by the City of San Antonio, Texas, acting by and through CPS, in the 130th District Court of Matagorda County, Texas against NRG and certain of its subsidiaries, claiming the existence of a right of first refusal that applies to the transaction contemplated between us and NRG. On July 31, 2023 we intervened in the lawsuit and Austin Energy also intervened in the lawsuit claiming a similar right of first refusal. Per the terms of the Equity Purchase Agreement, NRG made representations that no right of first refusal applied to the transaction contemplated between us.

The ongoing legal proceeding did not prohibit NRG and CEG from consummating the transaction, and Constellation is working with all parties to reach a resolution to the matter. We cannot reasonably predict the outcome of this lawsuit, however, we do not expect it to have a material impact to our consolidated financial statements.

3. Regulatory Matters

As discussed in Note 3 — Regulatory Matters of our 2022 Form 10-K, we are involved in various regulatory and legislative proceedings. The following discusses developments in 2023 and updates to the 2022 Form 10-K.

PJM Performance Bonuses

On December 23, 2022, and continuing through the morning of December 25, 2022, winter storm Elliott blanketed the entirety of PJM's footprint with record low temperatures and extreme weather conditions. A significant portion of PJM's fossil generation fleet failed to perform as reserves were called. In accordance with PJM's tariff, funds collected from non-performance charges are redistributed as bonuses to generating resources that overperformed during the event, including our nuclear fleet. Our estimated receivable for performance bonuses (net of non-performance charges) requires the application of significant judgement and assumptions that include potential impacts of generator defaults and litigation. 15 complaints have been filed at FERC by underperforming generators alleging, among other things, that PJM's tariff is unjust and unreasonable, and that PJM violated its tariff or otherwise acted negligently in operating the system during that period and seeking to reduce or eliminate any penalty. We are actively engaged in these proceedings. On June 5, 2023, FERC established settlement judge procedures to assist the parties to these proceedings in reaching a satisfactory resolution of the issues raised. On September 1, 2023, the FERC settlement judge issued a final status report stating that the majority of participants indicated that they reached a settlement in principle. On September 29, 2023, the proposed settlement was filed with FERC. Over 80 parties are signatories to the settlement, but the settlement is contested by one net bonus payment recipient. The settling parties have requested FERC approval by December 29, 2023.

We cannot reasonably predict the timing or nature of a FERC decision on the settlement, nor the outcome of the complaint proceedings if FERC rejects the settlement; however, it is reasonably possible that the ultimate impact to our consolidated financial statements could differ materially once these uncertainties are resolved.

New England Regulatory Matters

Mystic Units 8 and 9 Cost of Service Agreement. The Mystic Cost of Service Agreement (Mystic COS) requires an annual process whereby we identify and support our projected costs under the agreement and/or true-up previous projections to the actual costs incurred. The first annual process resulted in a filing at FERC on September 15, 2021 and included our projection of capital expenditures to be recovered under the Mystic COS between June 1, 2022 and December 31, 2022. On April 28, 2022, FERC issued an order setting for settlement and/or hearing the issue of whether our projected 2022 capital expenditures can be recovered. On February 6, 2023, we reached a settlement in principle with certain parties to the proceeding, and an offer of settlement was filed at FERC on March 15, 2023. On August 1, 2023, FERC approved the settlement without modification. The settlement reduces the recovery we receive for capital projects over the term of the Mystic COS. The settlement also eliminates the possibility that we would need to refund certain costs recovered under the COS Agreement for the EMT facility if the EMT facility continues operating post-Cost-of-Service (EMT Clawback Issue), thus resolving an issue remanded to FERC by the D.C. Circuit in the August 2022 decision. The approval of this offer of settlement does not have a material financial statement impact. On September 15, 2022, we made our second annual filing at FERC, which included (1) our projection of capital expenditures to be recovered under the Mystic COS between January 1, 2023 and December 31, 2023, and (2) an updated projection of the Annual Fixed Revenue Requirement, the Maximum Monthly Fixed Cost Payment, and the Fixed Operating and Maintenance/ Return on Investment component of the Monthly Fuel Cost Charge, including an update to rate base for the period between January 1, 2018 and December 31, 2021. That filing is currently pending at FERC. On September 15, 2023, we made our third annual filing at FERC, which included (1) our projection of capital expenditures to be recovered under the Mystic COS between January 1, 2024 and May 31, 2024, and (2) a "true-up" of previous projections for actual costs incurred in 2022. No formal challenges to the third annual filing have been filed. The true-up did not have a material impact on our consolidated financial statements.

On March 28, 2023, FERC issued an order on remand from the D.C. Circuit's August 2022 decision (FERC Remand Order). The D.C. Circuit's August 2022 decision remanded back to FERC certain issues related to the Mystic COS. The FERC Remand Order affirmed that 91% of EMT's fixed costs will be recovered via the Mystic COS, subject to the reinstatement of a margin sharing mechanism on forward sales of vapor. It also granted our motion to hold in abeyance the EMT Clawback Issue, as that matter was resolved by the settlement agreement filed at FERC in March 2023. No party sought rehearing of the FERC Remand Order's holding regarding our recovery of 91% of EMT's costs. We sought rehearing of other aspects of that March 2023 order pertaining to the scope of items subject to challenge in the true-up proceedings. On October 6, 2023, FERC granted our rehearing requests.

Operating License Renewals

Conowingo Hydroelectric Project (Conowingo). On December 20, 2022, the U.S. Court of Appeals for the D.C. Circuit issued a decision vacating FERC's decision to grant Conowingo its 50-year license renewal and sending the matter back to FERC for further proceedings. Upon issuance of the mandate from the U.S. Court of Appeals for the D.C. Circuit, we began operating under an annual license, which renews automatically, containing the same terms as the license that was in effect prior to the March 19, 2021 FERC order.

We and MDE previously filed with FERC a Joint Offer of Settlement (Offer of Settlement) that would resolve all outstanding issues relating to the water quality certification pursuant to Section 401 of the Clean Water Act (401 Certification) for Conowingo. On June 1, 2023, MDE informed us that as a result of the U.S. Court of Appeals decision, they would be resuming their administrative reconsideration of the 401 Certification. On August 1, 2023, in response to the procedure outlined by the MDE, supplemental briefs on the 401 Certification were filed by the Lower Susquehanna Riverkeeper Association and Waterkeepers Chesapeake (jointly) and us.

We are unable to further predict the outcome of these proceedings at this time.

4. 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 2022 Form 10-K for additional information regarding the primary 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.

(Dollars in millions, unless otherwise noted)

The following table provides a rollforward of the contract assets reflected in the Consolidated Balance Sheets for the three and nine months ended September 30, 2023 and 2022.

	Contract Assets
Balance as of December 31, 2022	$ 130
Amounts reclassified to receivables	(11)
Revenues recognized	31
Balance as of March 31, 2023	150
Amounts reclassified to receivables	(76)
Revenues recognized	15
Balance as of June 30, 2023	89
Amounts reclassified to receivables	(32)
Revenues recognized	12
Balance as of September 30, 2023	$ 69
Balance as of December 31, 2021	$ 149
Amounts reclassified to receivables	(16)
Revenues recognized	9
Balance as of March 31, 2022	142
Amounts reclassified to receivables	(13)
Revenues recognized	10
Balance as of June 30, 2022	139
Amounts reclassified to receivables	(5)
Revenues recognized	21
Balance as of September 30, 2022	$ 155

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 includes upfront consideration received or due 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. As of September 30, 2023, there were no outstanding contract liabilities included in Other current liabilities and Other deferred credits and other liabilities in the Consolidated Balance Sheets for the Illinois ZEC program.

(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 nine months ended September 30, 2023 and 2022.

	Contract Liabilities
Balance as of December 31, 2022	$ 47
Consideration received or due	131
Revenues recognized	(115)
Balance as of March 31, 2023	63
Consideration received or due	81
Revenues recognized	(92)
Balance as of June 30, 2023	52
Consideration received or due	56
Revenues recognized	(68)
Balance as of September 30, 2023	$ 40
Balance as of December 31, 2021	$ 75
Consideration received or due	50
Revenues recognized	(63)
Balance as of March 31, 2022	62
Consideration received or due	27
Revenues recognized	(63)
Balance as of June 30, 2022	26
Consideration received or due	71
Revenues recognized	(68)
Balance as of September 30, 2022	$ 29

The following table reflects revenues recognized in the three and nine months ended September 30, 2023 and 2022, which were included in contract liabilities at December 31, 2022 and 2021, respectively:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Revenues recognized	$ 1	$ 2	$ 25	$ 70

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 September 30, 2023. 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 our power and gas sales contracts as they contain variable volumes and/or variable pricing.

	2023	2024	2025	2026	2027 and thereafter	Total
Remaining performance obligations	$ 65	$ 155	$ 39	$ 15	$ 136	$ 410

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 1 to May 31), 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 on June 1, 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 1, 2023 to May 31, 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. During the second quarter of 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 September 30, 2023, this receivable is included within Customer accounts receivable, net in the Consolidated Balance Sheets.

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 5 — Segment Information for the presentation of revenue disaggregation.

5. 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 of similarly titled measures or deemed more useful than the GAAP information provided elsewhere in these financial statements. Our operating revenues include all sales to third parties and affiliate sales to Exelon's utility subsidiaries prior to the separation. 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, as well as other miscellaneous business activities 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.

(Dollars in millions, unless otherwise noted)

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.

The following tables also show the reconciliation of reportable segment revenues and RNF to our total revenues and RNF for the three and nine months ended September 30, 2023 and 2022.

	Three Months Ended September 30, 2023				
	Revenues from external customers				
	Contracts with customers	Other[(a)]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 1,493	$ (78)	$ 1,415	$ (4)	$ 1,411
Midwest	1,160	(43)	1,117	—	1,117
New York	522	(14)	508	4	512
ERCOT	489	69	558	1	559
Other Power Regions	1,284	309	1,593	(1)	1,592
Total Competitive Businesses Electric Revenues	4,948	243	5,191	—	5,191
Competitive Businesses Natural Gas Revenues	220	385	605	—	605
Competitive Businesses Other Revenues[(b)]	145	170	315	—	315
Total Consolidated Operating Revenues	$ 5,313	$ 798	$ 6,111	$ —	$ 6,111

	Three Months Ended September 30, 2022				
	Revenues from external customers				
	Contracts with customers	Other[(a)]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 1,561	$ 97	$ 1,658	$ 1	$ 1,659
Midwest	1,182	(133)	1,049	(2)	1,047
New York	536	(110)	426	(3)	423
ERCOT	328	168	496	(6)	490
Other Power Regions	1,315	611	1,926	10	1,936
Total Competitive Businesses Electric Revenues	4,922	633	5,555	—	5,555
Competitive Businesses Natural Gas Revenues	471	599	1,070	—	1,070
Competitive Businesses Other Revenues[(b)]	154	(728)	(574)	—	(574)
Total Consolidated Operating Revenues	$ 5,547	$ 504	$ 6,051	$ —	$ 6,051

(Dollars in millions, unless otherwise noted)

	Nine Months Ended September 30, 2023				
	Revenues from external customers				
	Contracts with customers	Other[a]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 4,140	$ (241)	$ 3,899	$ (45)	$ 3,854
Midwest	3,707	(231)	3,476	3	3,479
New York	1,424	53	1,477	41	1,518
ERCOT	979	73	1,052	4	1,056
Other Power Regions	3,766	732	4,498	(3)	4,495
Total Competitive Businesses Electric Revenues	14,016	386	14,402	—	14,402
Competitive Businesses Natural Gas Revenues	1,394	1,352	2,746	—	2,746
Competitive Businesses Other Revenues[b]	435	1,539	1,974	—	1,974
Total Consolidated Operating Revenues	$ 15,845	$ 3,277	$ 19,122	$ —	$ 19,122

	Nine Months Ended September 30, 2022				
	Revenues from external customers[c]				
	Contracts with customers	Other[a]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 3,894	$ 70	$ 3,964	$ 3	$ 3,967
Midwest	3,749	(401)	3,348	(3)	3,345
New York	1,492	(314)	1,178	—	1,178
ERCOT	744	476	1,220	(10)	1,210
Other Power Regions	3,756	1,423	5,179	10	5,189
Total Competitive Businesses Electric Revenues	13,635	1,254	14,889	—	14,889
Competitive Businesses Natural Gas Revenues	1,770	1,778	3,548	—	3,548
Competitive Businesses Other Revenues[b]	416	(1,746)	(1,330)	—	(1,330)
Total Consolidated Operating Revenues	$ 15,821	$ 1,286	$ 17,107	$ —	$ 17,107

(a) Includes revenues from derivatives and leases.
(b) Represents activities not allocated to a region. See text above for a description of included activities. Includes unrealized mark-to-market gains of $177 million and losses of $681 million for the three months ended September 30, 2023 and 2022, respectively, and unrealized mark-to-market gains of $1,317 million and losses of $1,899 million for the nine months ended September 30, 2023 and 2022, respectively.
(c) Includes all wholesale and retail electric sales to third parties and affiliate sales to Exelon's utility subsidiaries prior to the separation on February 1, 2022. See Note 17 - Related Party Transactions for additional information.

(Dollars in millions, unless otherwise noted)

	Three Months Ended September 30, 2023			Three Months Ended September 30, 2022		
	RNF from external customers	Intersegment RNF	Total RNF	RNF from external customers	Intersegment RNF	Total RNF
Mid-Atlantic	$ 747	$ (3)	$ 744	$ 553	$ 2	$ 555
Midwest	776	2	778	572	—	572
New York	311	6	317	268	(1)	267
ERCOT	211	(4)	207	104	(38)	66
Other Power Regions	434	(3)	431	274	(17)	257
Total RNF for Reportable Segments	2,479	(2)	2,477	1,771	(54)	1,717
Other[(a)]	265	2	267	(415)	54	(361)
Total RNF	$ 2,744	$ —	$ 2,744	$ 1,356	$ —	$ 1,356

	Nine Months Ended September 30, 2023			Nine Months Ended September 30, 2022		
	RNF from external customers	Intersegment RNF	Total RNF	RNF from external customers[(b)]	Intersegment RNF	Total RNF
Mid-Atlantic	$ 2,202	$ (44)	$ 2,158	$ 1,606	$ 6	$ 1,612
Midwest	2,439	2	2,441	2,008	2	2,010
New York	851	46	897	822	5	827
ERCOT	429	(6)	423	321	(86)	235
Other Power Regions	909	(8)	901	741	(31)	710
Total RNF for Reportable Segments	6,830	(10)	6,820	5,498	(104)	5,394
Other[(a)]	309	10	319	(145)	104	(41)
Total RNF	$ 7,139	$ —	$ 7,139	$ 5,353	$ —	$ 5,353

(a) Other represents activities not allocated to a region. See text above for a description of included activities.
(b) Includes purchases and sales from/to third parties and affiliate sales to Exelon's utility subsidiaries prior to the separation on February 1, 2022. See Note 17 - Related Party Transactions for additional information.

6. Accounts Receivable

Unbilled Customer Revenue

We recorded $213 million and $564 million of unbilled customer revenues in Customer accounts receivables, net in the Consolidated Balance Sheets as of September 30, 2023 and December 31, 2022, respectively.

Sales of Customer Accounts Receivable

On April 8, 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). On August 16, 2022, we entered into an amendment on the Facility, which increased the maximum funding limit of the Facility from $900 million to $1.1 billion and extended the term of the Facility through August 15, 2025, unless renewed by the mutual consent of the parties in accordance with its terms. 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.

(Dollars in millions, unless otherwise noted)

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

	As of September 30, 2023	As of December 31, 2022
Derecognized receivables transferred at fair value	$ 1,708	$ 1,615
Less: Cash proceeds received	—	1,100
DPP	$ 1,708	$ 515

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Loss on sale of receivables[a]	$ 12	$ 15	$ 58	$ 39

(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.

	Nine Months Ended September 30,	
	2023	2022
Proceeds from new transfers[a]	$ 3,632	$ 4,807
Cash collections received on DPP[b]	5,158	3,295
Cash collections reinvested in the Facility	$ 8,790	$ 8,102

(a) Customer accounts receivable sold into the Facility were $8,920 million and $8,540 million for the nine months ended September 30, 2023 and 2022, respectively.
(b) Does not include $1,100 million cash payments to the Purchasers in 2023.

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 in the Consolidated Statements of Cash Flows. The collection and reinvestment of DPP is recognized in Cash flows from investing activities in the Consolidated Statements of Cash Flows.

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

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.

	Nine Months Ended September 30,	
	2023	2022
Total receivables sold	$ 274	$ 312

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 2022 Form 10-K for additional information regarding AROs and the financial statement impact of changes in estimate.

(Dollars in millions, unless otherwise noted)

The following table provides a rollforward of the nuclear decommissioning AROs reflected in the Consolidated Balance Sheets from December 31, 2022 to September 30, 2023:

Balance as of December 31, 2022[a]	$	12,500
Net increase due to changes in, and timing of, estimated future cash flows		677
Accretion expense		423
Costs incurred related to decommissioning plants		(23)
Balance as of September 30, 2023[a]	$	13,577

(a) Includes $34 million and $40 million as the current portion of the ARO as of September 30, 2023 and December 31, 2022, respectively, which is included in Other current liabilities in the Consolidated Balance Sheets.

During the nine months ended September 30, 2023, the net $677 million increase in the ARO for the changes in the amounts and timing of estimated decommissioning cash flows was driven by multiple adjustments, including the following:

- An increase of approximately $720 million due to an increase in cost escalation rates, partially offset by an increase in discount rates
- Net increase of approximately $470 million due to updated cost assumptions for dry cask storage across the fleet and revised cost studies for Dresden, Limerick and Peach Bottom
- Net decrease of approximately $520 million due to changes in assumed retirement dates for Ginna and NMP Unit 1

The 2023 ARO update resulted in a decrease of $68 million in Operating and maintenance expense for the three and nine months ended September 30, 2023 in the Consolidated Statement of Operations and Comprehensive Income. The 2022 ARO updates resulted in a decrease of $226 million in Operating and maintenance expense for the three and nine months ended September 30, 2022 in the Consolidated Statement of Operations and Comprehensive Income.

Ginna and NMP Unit 1 Retirement Assumptions

In the third quarter of 2023, we extended our retirement assumptions for Ginna and NMP Unit 1; while the current ZEC program in New York ends in 2029, the state has acknowledged our nuclear assets are vital to achieving its clean energy goals and we believe New York will continue to promote policies that support nuclear in the state beyond 2029.

NDT Funds

We had NDT funds totaling $14,573 million and $14,127 million as of September 30, 2023 and December 31, 2022, respectively. As of September 30, 2023, there was no current portion of the NDT funds. $13 million of the NDT funds were current as of December 31, 2022, and included in Other current assets in the Consolidated Balance Sheets. 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 2022 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 and PECO which are recorded as Payables related to Regulatory Agreement Units in the Consolidated Balance Sheets as of September 30, 2023 and December 31, 2022:

	September 30, 2023	December 31, 2022
ComEd	$ 2,716	$ 2,660
PECO	207	237
Payables related to Regulatory Agreement Units	$ 2,923	$ 2,897

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.

We filed our biennial decommissioning funding status report with the NRC on March 23, 2023 for all units, including our shutdown units, except for Zion Station which is included in a separate report to the NRC submitted by ZionSolutions, LLC. The status report demonstrated adequate decommissioning funding assurance as of December 31, 2022 for all units except for Peach Bottom Unit 1. As a former PECO plant, financial assurance for decommissioning Peach Bottom Unit 1 is provided by the NDT fund, collections from PECO customers, and the ability to adjust those collections in accordance with the approved PAPUC tariff. See Note 10 — Asset Retirement Obligations of our 2022 Form 10-K for information regarding the amount collected from PECO customers for decommissioning costs.

Impact of Separation from Exelon

Satisfying a condition precedent, on December 16, 2021, the NYPSC authorized our separation from Exelon and accepted the terms of a Joint Proposal that became binding upon closing of the separation on February 1, 2022. As part of the Joint Proposal, among other items, we have projected completion of radiological decommissioning and site restoration activities necessary to achieve a partial site release from the NRC (release of the site for unrestricted use, except for any on-site dry cask storage) within 20 years from the end of licensed life for each of our Ginna and FitzPatrick units and from the end of licensed life for the last of the NMP operating units. While there is flexibility under the Joint Proposal, there was an increase to the AROs associated with our New York nuclear plants during the first quarter of 2022.

The Joint Proposal also required a contribution of $15 million to the NDT for NMP Unit 2 in January 2022 and requires various financial assurance mechanisms through the duration of decommissioning and site restoration, including a minimum NDT balance for each unit, adjusted for specific stages of decommissioning, and a parent guaranty for site restoration costs updated annually as site restoration progresses, which must be replaced with a third-party surety bond or equivalent financial instrument in the event we fall below investment grade.

See Note 1 — Basis of Presentation for additional information.

(Dollars in millions, unless otherwise noted)

8. Income Taxes

Rate Reconciliation

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

	Three Months Ended September 30,	
	2023[a]	2022[b]
U.S. federal statutory rate	21.0 %	21.0 %
Increase (decrease) due to:		
State income taxes, net of federal income tax benefit	4.3	(9.5)
Qualified NDT fund income and losses	(2.6)	22.1
Amortization of investment tax credit, including deferred taxes on basis differences	(0.5)	1.9
Production tax credits and other credits	(0.6)	8.0
Noncontrolling interests	0.7	(0.5)
Other	0.6	(3.6)
Effective income tax rate[c]	22.9 %	39.4 %

	Nine Months Ended September 30,	
	2023[a]	2022[b]
U.S. federal statutory rate	21.0 %	21.0 %
Increase (decrease) due to:		
State income taxes, net of federal income tax benefit	4.1	(9.0)
Qualified NDT fund income and losses	4.7	48.6
Amortization of investment tax credit, including deferred taxes on basis differences	(0.5)	2.0
Production tax credits and other credits	(0.6)	8.3
Noncontrolling interests	0.3	—
Other	0.4	2.2
Effective income tax rate[c]	29.4 %	73.1 %

(a) Positive percentages represent income tax expense. Negative percentages represent income tax benefit.
(b) As there was a pre-tax loss during 2022, negative percentages represent income tax expense. Positive percentages represent income tax benefit.
(c) Constellation does not expect the effective tax rate to deviate from the statutory tax rate with the exception of realized and unrealized gains and losses from the qualified NDT funds.

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.

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 federal and state tax filings we were included in prior to the separation. The TMA specifies the portion of this tax liability for which we bear contractual responsibility. Specifically, we are 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 September 30, 2023 and December 31, 2022, our Consolidated Balance Sheets reflect a payable of $35 million and $32 million, respectively, for tax liabilities where we maintain contractual responsibility to Exelon, with $15 million and $18 million in Other accounts receivable, respectively, and $50 million in Noncurrent other liabilities.

Tax Refunds and Attributes. The TMA provides for the allocation of certain pre-closing tax attributes between us and Exelon, along with our share of refunds for taxes claimed by Exelon for periods prior to separation. Upon separation, certain attributes that were generated by our business were allocated to Exelon, and under the TMA, Exelon will reimburse Constellation when those attributes are utilized. As of September 30, 2023, our Consolidated Balance Sheet reflects receivables of $307 million and $222 million in Other accounts receivable and Other deferred debits and other assets, respectively. As of December 31, 2022, our Consolidated Balance Sheet reflected receivables of $168 million and $362 million in Other accounts receivable and Other deferred debits and other assets, respectively.

9. Retirement Benefits

Defined Benefit Pension and OPEB

During the first quarter of 2023, we received an updated valuation of our pension and OPEB obligations to reflect actual census data as of January 1, 2023. This valuation resulted in increases to the pension and OPEB obligations totaling $48 million and $21 million, respectively, with an offset to accumulated other comprehensive loss of $53 million (after-tax). The key assumptions used in the updated valuation of our pension and OPEB obligations, such as discount rate and expected long-term rate of return on plan assets, were unchanged from those used as of December 31, 2022.

Components of Net Periodic Benefit Costs (Credits)

We report the service cost and other non-service cost (credit) components of net periodic benefit costs (credits) for all plans separately in our Consolidated Statements of Operations and Comprehensive Income. Effective February 1, 2022, the service cost component is included in Operating and maintenance expense and Property, plant, and equipment, net (where criteria for capitalization of direct labor has been met) while the non-service cost (credit) components are included in Other, net, in accordance with single employer plan accounting.

Prior to separation, we were allocated our portion of pension and OPEB service and non-service costs (credits) from Exelon, which was included in Operating and maintenance expense. Our portion of the total net periodic benefit costs allocated to us from Exelon in 2022 prior to separation was not material and remains in total Operating and maintenance expense.

(Dollars in millions, unless otherwise noted)

The following tables present the components of our net periodic benefit costs (credits), prior to capitalization and co-owner allocations, for the three and nine months ended September 30, 2023 and 2022:

	Pension Benefits		OPEB		Total Pension Benefits and OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,		Three Months Ended September 30,	
	2023	2022	2023	2022	2023	2022
Components of net periodic benefit cost (credit)						
Service cost	$ 22	$ 31	$ 4	$ 6	$ 26	$ 37
Non-service components of pension benefits & OPEB cost (credit)						
Interest cost	99	74	19	14	118	88
Expected return on assets	(127)	(143)	(11)	(14)	(138)	(157)
Amortization of:						
Prior service credit	—	—	(2)	(2)	(2)	(2)
Actuarial loss (gain)	12	37	(3)	—	9	37
Settlement charges	—	5	—	—	—	5
Non-service components of pension benefits & OPEB (credit) cost	(16)	(27)	3	(2)	(13)	(29)
Net periodic benefit cost[(a,b)]	$ 6	$ 4	$ 7	$ 4	$ 13	$ 8

	Pension Benefits		OPEB		Total Pension Benefits and OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022	2023	2022
Components of net periodic benefit cost (credit)						
Service cost	$ 67	$ 94	$ 12	$ 18	$ 79	$ 112
Non-service components of pension benefits & OPEB cost (credit)						
Interest cost	296	217	56	42	352	259
Expected return on assets	(381)	(423)	(34)	(42)	(415)	(465)
Amortization of:						
Prior service cost (credit)	—	1	(5)	(5)	(5)	(4)
Actuarial loss (gain)	35	111	(10)	(1)	25	110
Settlement charges	—	5	—	—	—	5
Non-service components of pension benefits & OPEB (credit) cost	(50)	(89)	7	(6)	(43)	(95)
Net periodic benefit cost[(a,b)]	$ 17	$ 5	$ 19	$ 12	$ 36	$ 17

(a) The pension benefit and OPEB service costs reflected in the Consolidated Statements of Operations and Comprehensive Income for the three and nine months ended September 30, 2023 totaled $24 million and $71 million, respectively. The pension benefit and OPEB non-service costs (credits) reflected in the Consolidated Statements of Operations and Comprehensive Income for the three and nine months ended September 30, 2023 totaled ($14) million and ($41) million, respectively.

(b) The pension benefit and OPEB service costs reflected in the Consolidated Statements of Operations and Comprehensive Income for the three and nine months ended September 30, 2022 totaled $33 million and $98 million, respectively. The pension benefit and OPEB non-service (credits) costs reflected in the Consolidated Statements of Operations and Comprehensive Income for the three and nine months ended September 30, 2022 totaled ($27) million and ($85) 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 economic hedges related to commodities, referred to as economic 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 are downgraded 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 commodity 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, 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.

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 our RMC.

(Dollars in millions, unless otherwise noted)

The following tables provide a summary of the derivative fair value balances recorded as of September 30, 2023 and December 31, 2022:

September 30, 2023	Economic Hedges	Proprietary Trading	Collateral (a)(b)	Netting[a]	Total
Mark-to-market derivative assets (current assets)	$ 6,689	$ 3	$ 298	$ (5,546)	$ 1,444
Mark-to-market derivative assets (noncurrent assets)	3,351	—	175	(2,562)	964
Total mark-to-market derivative assets	10,040	3	473	(8,108)	2,408
Mark-to-market derivative liabilities (current liabilities)	(7,069)	(2)	418	5,546	(1,107)
Mark-to-market derivative liabilities (noncurrent liabilities)	(3,343)	—	245	2,562	(536)
Total mark-to-market derivative liabilities	(10,412)	(2)	663	8,108	(1,643)
Total mark-to-market derivative net (liabilities) assets	$ (372)	$ 1	$ 1,136	$ —	$ 765
December 31, 2022					
Mark-to-market derivative assets (current assets)	$ 15,296	$ 10	$ 161	$ (13,123)	$ 2,344
Mark-to-market derivative assets (noncurrent assets)	5,100	—	217	(4,074)	1,243
Total mark-to-market derivative assets	20,396	10	378	(17,197)	3,587
Mark-to-market derivative liabilities (current liabilities)	(15,049)	(6)	374	13,123	(1,558)
Mark-to-market derivative liabilities (noncurrent liabilities)	(5,203)	—	146	4,074	(983)
Total mark-to-market derivative liabilities	(20,252)	(6)	520	17,197	(2,541)
Total mark-to-market derivative net assets	$ 144	$ 4	$ 898	$ —	$ 1,046

(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 $616 million of variation margin posted and $836 million of variation margin held from the exchanges as of September 30, 2023 and December 31, 2022, respectively.

Economic Hedges (Commodity Price Risk)

For the three and nine months ended September 30, 2023 and 2022, 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 September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Income Statement Location	Gains (Losses)		Gains (Losses)	
Operating revenues	$ 173	$ (691)	$ 1,317	$ (1,913)
Purchased power and fuel	(36)	171	(1,448)	1,346
Total	$ 137	$ (520)	$ (131)	$ (567)

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. For merchant revenues not already hedged via comprehensive state programs, such as the CMC in Illinois, historically we have used a three-year ratable sales plan to align our hedging strategy with our financial objectives. As a result, our prompt three-year merchant revenues have been hedged on an approximate rolling 90%/60%/30% basis. We may also enter into transactions that are outside of this ratable hedging program. As of September 30, 2023, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 97%-100% and 80%-83% for 2023 and 2024, respectively. Going forward, we will continue to be proactive in managing our overall portfolio exposure to commodity risk, but will also manage our generation portfolio through the nuclear PTC, which, starting in 2024, provides downside commodity price protection for our nuclear units. Like our traditional hedging program, the nuclear PTC is an important tool in managing commodity risk.

(Dollars in millions, unless otherwise noted)

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 $434 million and $524 million as of September 30, 2023 and December 31, 2022, respectively.

The following table provides the mark-to-market derivative assets and liabilities as of September 30, 2023 and December 31, 2022:

	September 30, 2023			December 31, 2022		
	Economic Hedges	Netting[(a)]	Total	Economic Hedges	Netting[(a)]	Total
Mark-to-market derivative assets (current assets)	$ 24	$ (1)	$ 23	$ 29	$ (5)	$ 24
Mark-to-market derivative assets (noncurrent assets)	6	—	6	18	—	18
Total mark-to-market derivative assets	30	(1)	29	47	(5)	42
Mark-to-market derivative liabilities (current liabilities)	(2)	1	(1)	(5)	5	—
Mark-to-market derivative liabilities (noncurrent liabilities)	—	—	—	—	—	—
Total mark-to-market derivative liabilities	(2)	1	(1)	(5)	5	—
Total mark-to-market derivative net assets	$ 28	$ —	$ 28	$ 42	$ —	$ 42

(a) We net all available amounts 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.

The mark-to-market gains and losses associated with management of interest rate and foreign currency exchange rate risk for the three and nine months ended September 30, 2023 and 2022 were not material.

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 risk management capabilities. 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 September 30, 2023. 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, nuclear fuel procurement contracts, and exposure through RTOs, ISOs, NYMEX, ICE, NASDAQ, NGX, and Nodal commodity exchanges.

(Dollars in millions, unless otherwise noted)

Rating as of September 30, 2023	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	$ 963	$ 60	$ 903	1	$ 197
Non-investment grade	17	9	8	—	—
No external ratings					
Internally rated — investment grade	97	—	97	—	—
Internally rated — non-investment grade	279	42	237	—	—
Total	$ 1,356	$ 111	$ 1,245	1	$ 197

(a) As of September 30, 2023, credit collateral held from counterparties where we had credit exposure included $51 million of cash and $60 million of letters of credit. The credit collateral does not include non-liquid collateral.

Net Credit Exposure by Type of Counterparty	As of September 30, 2023
Investor-owned utilities, marketers, power producers	$ 1,018
Energy cooperatives and municipalities	99
Financial Institutions	32
Other	96
Total	$ 1,245

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. 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 rating from each of the major credit rating agencies. 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 rating (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 (i.e. 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	September 30, 2023	December 31, 2022
Gross fair value of derivative contracts containing this feature	$ (1,953)	$ (4,736)
Offsetting fair value of in-the-money contracts under master netting arrangements	909	2,048
Net fair value of derivative contracts containing this feature	$ (1,044)	$ (2,688)

As of September 30, 2023 and December 31, 2022, 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.

(Dollars in millions, unless otherwise noted)

	September 30, 2023	December 31, 2022
Cash collateral posted[a]	$ 1,870	$ 1,636
Letters of credit posted[a]	514	947
Cash collateral held[a]	753	765
Letters of credit held[a]	76	115
Additional collateral required in the event of a credit downgrade below investment grade (at BB+/Ba1)[b][c][d]	1,919	3,337

(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.
(d) A loss of investment grade credit rating would require a significant reduction in credit ratings from their current levels of BBB and Baa2 at S&P and Moody's, respectively.

We entered 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, counterparty suppliers, including us, are required to post collateral once certain unsecured credit limits are exceeded.

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.

Commercial Paper

The following table reflects our commercial paper program supported by the revolving credit agreements as of September 30, 2023 and December 31, 2022:

Outstanding Commercial Paper as of		Weighted Average Interest Rate on Commercial Paper Borrowings as of	
September 30, 2023	December 31, 2022	September 30, 2023	December 31, 2022
$ —	$ 959	— %	4.90 %

Credit Agreements

On February 1, 2022, we entered into a credit agreement establishing a $3.5 billion five-year revolving credit facility at a variable interest rate of SOFR plus 1.275% and on February 9, 2022 we entered into a $1 billion five-year liquidity facility with the primary purpose of supporting our letter of credit issuances. Many of our bilateral credit agreements remain in effect. See below for additional details.

(Dollars in millions, unless otherwise noted)

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

				Available Capacity as of September 30, 2023	
Facility Type	Aggregate Bank Commitment	Facility Draws	Outstanding Letters of Credit	Actual	To Support Additional Commercial Paper
Syndicated Revolver	$ 3,500	$ —	$ 63	$ 3,437	$ 3,437
Bilaterals[a]	1,310	—	946	364	—
Liquidity Facility	971	—	600	279 [b]	—
Project Finance	137	—	114	23	—
Total	$ 5,918	$ —	$ 1,723	$ 4,103	$ 3,437

(a) On January 20, 2023, a bilateral credit agreement initiated on August 24, 2022 decreased from $100 million to $10 million. On March 29, 2023, we initiated a new bilateral credit agreement for $100 million, with a maturity date of March 29, 2025. On January 31, 2023, a bilateral credit agreement initiated on May 15, 2020 increased from $200 million to $250 million, and on March 31, 2023 this agreement increased to $300 million. On April 4, 2023, a bilateral credit agreement initiated on January 5, 2016 was extended for three years to April 3, 2026.

(b) 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 September 30, 2023, without posting additional collateral, the actual availability of facility, prior to outstanding letters of credit was $879 million.

Short-Term Loan Agreements

On March 31, 2020, we entered into a term loan agreement for $300 million. We repaid $100 million of the term loan on March 29, 2022. The remaining $200 million from the loan agreement was renewed on March 29, 2022 and repaid on March 29, 2023. Pursuant to the loan agreement, loans made thereunder bore interest at a variable rate equal to SOFR plus 0.80% and all indebtedness thereunder was unsecured. The loan was reflected in Short-term borrowings in the Consolidated Balance Sheet as of December 31, 2022.

On January 26, 2023, we entered into a term loan agreement for $100 million. The loan agreement has an expiration of January 25, 2024. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to SOFR plus 0.80% and all indebtedness thereunder is unsecured. The loan was reflected in Short-term borrowings in the Consolidated Balance Sheet as of September 30, 2023.

On February 9, 2023, we entered into a term loan agreement for $400 million. The loan agreement has an expiration of February 8, 2024. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to SOFR plus 1.05% and all indebtedness thereunder is unsecured. The loan was reflected in Short-term borrowings in the Consolidated Balance Sheet as of September 30, 2023.

(Dollars in millions, unless otherwise noted)

Long-Term Debt

Debt Issuances and Redemptions

During the nine months ended September 30, 2023, the following long-term debt was issued:

Type	Interest Rate	Maturity	Amount	Use of Proceeds
2053 Senior Notes	6.50 %	October 1, 2053	$ 900	To fund the acquisition of NRG South Texas Project LP and general corporate purposes.
2028 Senior Notes	5.60 %	March 1, 2028	750	To fund general corporate purposes, including repayment of short-term borrowings
2033 Senior Notes	5.80 %	March 1, 2033	600	To fund general corporate purposes, including repayment of short-term borrowings
2034 Senior Notes	6.13 %	January 15, 2034	500	To fund the acquisition of NRG South Texas Project LP and general corporate purposes.
Tax-Exempt Notes Reoffering	4.10% - 4.45%	2025-2053[(a)]	435	To fund general corporate purposes, including repayment of short-term borrowings
Energy Efficiency Project Financing[(b)]	2.20% - 4.96%	May 31, 2023 - May 1, 2024	8	Funding to install energy conservation measures

(a) The Tax Exempt Notes have a maturity date of March 1, 2025 - April 1, 2053, and a mandatory purchase date that ranges from March 1, 2025 - June 1, 2029.
(b) For Energy Efficiency Project Financing, the maturity dates represent the expected date of project completion, upon which the respective customer assumes the outstanding debt.

During the nine months ended September 30, 2023, the following long-term debt was redeemed:

Type	Interest Rate	Maturity	Amount
Energy Efficiency Project Financing	3.71%	May 31, 2023	$ 43
CR Nonrecourse Debt	3-month SOFR + 2.76% [(a)]	December 15, 2027	39
Continental Wind Nonrecourse Debt	6.00%	February 28, 2033	26
West Medway II Nonrecourse Debt	1-month SOFR + 2.975% - 3.225% [(b)]	March 31, 2026	19
Antelope Valley DOE Nonrecourse Debt	2.29% - 3.56%	January 5, 2037	14
RPG Nonrecourse Debt	4.11%	March 31, 2035	9

(a) The interest rate for long-term debt redemptions prior to June 2023 were based on LIBOR + 2.50%. Beginning in June 2023, these redemptions are based on SOFR + 2.76%.
(b) The interest rate for long-term debt redemptions prior to May 2023 were based on LIBOR + 2.875%. Beginning in May 2023, these redemptions are based on SOFR + the variable interest rate of 2.975% - 3.225%.

Debt Covenants

As of September 30, 2023, 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:

(Dollars in millions, unless otherwise noted)

- 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.

Fair Value of Financial Liabilities Recorded at Amortized Cost

The following table presents the carrying amounts and fair values of the short-term liabilities, long-term debt, and the SNF obligation as of September 30, 2023 and December 31, 2022. 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.

	September 30, 2023				December 31, 2022			
	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	$ 7,628	$ 6,682	$ 757	$ 7,439	$ 4,609	$ 3,688	$ 859	$ 4,547
SNF Obligation	1,278	1,183	—	1,183	1,230	1,021	—	1,021

Valuation Techniques Used to Determine Fair Value

Our valuation techniques used to measure the fair 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 2022 Form 10-K.

Valuation Techniques Used to Determine Net Asset Value

Certain NDT Fund Investments are not classified within the fair value hierarchy and are included under the heading "Not subject to leveling" in the table below. These investments are measured at fair value using NAV per share as a practical expedient and include commingled funds, mutual funds which are not publicly quoted, managed private credit funds, private equity and real estate funds.

For commingled funds and mutual funds, which are not publicly quoted, the fair value is primarily derived from the quoted prices in active markets on the underlying securities and can typically be redeemed monthly with 30 or less days of notice and without further restrictions. For managed private credit funds, the fair value is determined using a combination of valuation models including cost models, market models, and income models and typically cannot be redeemed until maturity of the term loan. Private equity and real estate investments include those in limited partnerships that invest in operating companies and real estate holding companies that are not publicly traded on a stock exchange, such as, leveraged buyouts, growth capital, venture capital, distressed investments, investments in natural resources, and direct investments in pools of real estate properties. These investments typically cannot be redeemed and are generally liquidated over a period of 8 to 10 years from the initial investment date, which is based on our understanding of the investment funds. Private equity and real estate valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include inputs such as cost, operating results, discounted future cash flows, market based comparable data, and independent appraisals from sources with professional qualifications. These valuation inputs are unobservable.

Recurring Fair Value Measurements

The following tables 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 September 30, 2023 and December 31, 2022:

(Dollars in millions, unless otherwise noted)

	As of September 30, 2023					As of December 31, 2022				
	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
Assets										
Cash equivalents[a]	$ 21	$ —	$ —	$ —	$ 21	$ 41	$ —	$ —	$ —	$ 41
NDT fund investments										
Cash equivalents[b]	520	80	—	—	600	349	88	—	—	437
Equities	3,664	1,599	—	1,043	6,306	3,462	1,498	—	1,421	6,381
Fixed income										
Corporate debt[c]	—	922	273	—	1,195	—	885	264	—	1,149
U.S. Treasury and agencies	1,963	75	—	—	2,038	1,996	46	—	—	2,042
Foreign governments	—	40	—	—	40	—	39	—	—	39
State and municipal debt	—	51	—	—	51	—	53	—	—	53
Other	10	18	—	1,880	1,908	21	21	—	1,649	1,691
Fixed income subtotal	1,973	1,106	273	1,880	5,232	2,017	1,044	264	1,649	4,974
Private credit	—	—	148	628	776	—	—	159	643	802
Private equity	—	—	—	748	748	—	—	—	687	687
Real estate	—	—	—	1,003	1,003	—	—	—	1014	1,014
NDT fund investments subtotal[d][e]	6,157	2,785	421	5,302	14,665	5,828	2,630	423	5,414	14,295
Rabbi trust investments										
Cash equivalents	1	—	—	—	1	1	—	—	—	1
Mutual funds	42	—	—	—	42	39	—	—	—	39
Life insurance contracts	—	30	1	—	31	—	27	1	—	28
Rabbi trust investments subtotal	43	30	1	—	74	40	27	1	—	68
Investments in equities[f]	556	—	—	—	556	6	—	—	—	6
Mark-to-market derivative assets										
Economic hedges	1,689	4,478	3,903	—	10,070	3,505	11,353	5,585	—	20,443
Proprietary trading	—	1	2	—	3	—	4	6	—	10
Effect of netting and allocation of collateral[g][h]	(1,585)	(3,562)	(2,489)	—	(7,636)	(2,951)	(10,348)	(3,525)	—	(16,824)
Mark-to-market derivative assets subtotal	104	917	1,416	—	2,437	554	1,009	2,066	—	3,629
DPP consideration	—	1,708	—	—	1,708	—	515	—	—	515
Total assets	6,881	5,440	1,838	5,302	19,461	6,469	4,181	2,490	5,414	18,554
Liabilities										
Mark-to-market derivative liabilities										
Economic hedges	(1,758)	(4,817)	(3,839)	—	(10,414)	(3,171)	(11,498)	(5,588)	—	(20,257)
Proprietary trading	—	(1)	(1)	—	(2)	—	(4)	(2)	—	(6)
Effect of netting and allocation of collateral[g][h]	1,919	4,048	2,805	—	8,772	3,279	10,700	3,743	—	17,722
Mark-to-market derivative liabilities subtotal	161	(770)	(1,035)	—	(1,644)	108	(802)	(1,847)	—	(2,541)
Deferred compensation obligation	—	(60)	—	—	(60)	—	(57)	—	—	(57)
Total liabilities	161	(830)	(1,035)	—	(1,704)	108	(859)	(1,847)	—	(2,598)
Total net assets	$ 7,042	$ 4,610	$ 803	$ 5,302	$ 17,757	$ 6,577	$ 3,322	$ 643	$ 5,414	$ 15,956

(a) CEG Parent has $51 million and $49 million of Level 1 cash equivalents as of September 30, 2023 and December 31, 2022, respectively. We exclude cash of $1,877 million and $390 million as of September 30, 2023 and December 31, 2022, respectively, and restricted cash of $49 million and $70 million as of September 30, 2023 and December 31, 2022, respectively. CEG Parent does not exclude any additional cash as of September 30, 2023 and excludes $19 million of cash as of December 31, 2022.
(b) Includes $116 million and $99 million of cash received from outstanding repurchase agreements as of September 30, 2023 and December 31, 2022, respectively, and is offset by an obligation to repay upon settlement of the agreement as discussed in (e) below.
(c) Includes investments in equities sold short of ($52) million and ($45) million as of September 30, 2023 and December 31, 2022, respectively, held in an investment vehicle primarily to hedge the equity option component of convertible debt.
(d) Includes net derivative assets of $1 million and net derivative liabilities of $1 million, which have total notional amounts of $580 million and $494 million as of September 30, 2023 and December 31, 2022, respectively. The notional principal amounts for these instruments 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.
(e) Excludes net liabilities of $92 million and $168 million as of September 30, 2023 and December 31, 2022, respectively, which include certain derivative assets that have notional amounts of $154 million and $59 million as of September 30, 2023 and December 31, 2022, respectively. These items 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.
(f) Includes an equity investment that became publicly traded in the second quarter of 2023 and now has a readily determinable fair value (and no longer is accounted for as an equity method investment due to lack of significant influence). We recorded the fair value of this investment in Investments on the Consolidated Balance Sheets based on the quoted market price of the stock, which resulted in an unrealized gain of $493 million within Other, net in the Consolidated Statements of Operations and Comprehensive Income for the nine months ended September 30, 2023.
(g) Net collateral posted to counterparties totaled $334 million, $486 million, and $316 million allocated to Level 1, Level 2, and Level 3 mark-to-market derivatives, respectively, as of September 30, 2023. Net collateral posted to counterparties totaled $328 million, $352 million, and $218 million allocated to Level 1, Level 2, and Level 3 mark-to-market derivatives, respectively, as of December 31, 2022.
(h) Includes $616 million of variation margin posted and $836 million of variation margin held with the exchanges as of September 30, 2023 and December 31, 2022, respectively.

As of September 30, 2023, we have outstanding commitments to invest in private credit, private equity, and real estate investments of $203 million, $95 million, and $442 million, respectively. These commitments will be funded by our existing NDT funds.

We hold investments without readily determinable fair values with carrying amounts of $94 million and $46 million as of September 30, 2023 and December 31, 2022, respectively. Changes in fair value, cumulative adjustments, and impairments were not material for the three and nine months ended September 30, 2023 and the year ended December 31, 2022.

(Dollars in millions, unless otherwise noted)

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 nine months ended September 30, 2023 and 2022:

	For the Three Months Ended September 30, 2023			
	NDT Fund Investments	Mark-to-Market Derivatives	Life Insurance Contracts	Total
Balance as of July 1, 2023	$ 421	$ 651	$ 1	$ 1,073
Total realized / unrealized losses				
Included in net income	—	(236) [a]	—	(236)
Change in collateral	—	(7)	—	(7)
Purchases, sales, issuances and settlements				
Purchases	—	35	—	35
Sales	—	(3)	—	(3)
Settlements	—	32	—	32
Transfers out of Level 3	—	(91) [b]	—	(91)
Balance as of September 30, 2023	$ 421	$ 381	$ 1	$ 803
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities as of September 30, 2023	$ —	$ 54	$ —	$ 54

	For the Three Months Ended September 30, 2022			
	NDT Fund Investments	Mark-to-Market Derivatives	Life Insurance Contracts	Total
Balance as of July 1, 2022	$ 431	$ (743)	$ 1	$ (311)
Total realized / unrealized losses				
Included in net income	—	(925) [a]	—	(925)
Included in Payable related to Regulatory Agreement Units	(2)	—	—	(2)
Change in collateral	—	(58)		(58)
Purchases, sales, issuances and settlements				
Purchases	—	333	—	333
Sales	—	(7)	—	(7)
Transfers into Level 3	1	1 [b]	—	2
Transfers out of Level 3	—	(54) [b]	—	(54)
Balance as of September 30, 2022	$ 430	$ (1,453)	$ 1	$ (1,022)
The amount of total losses included in income attributed to the change in unrealized losses related to assets and liabilities as of September 30, 2022	$ (1)	$ (889)	$ —	$ (890)

(Dollars in millions, unless otherwise noted)

	For the Nine Months Ended September 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				
Included in net income	1	24 [(a)]	—	25
Included in Payable related to Regulatory Agreement Units	4	—	—	4
Change in collateral	—	99	—	99
Purchases, sales, issuances and settlements				
Purchases	—	120	—	120
Sales	—	(9)	—	(9)
Settlements	(7)	32	—	25
Transfers into Level 3	—	59 [(b)]	—	59
Transfers out of Level 3	—	(163) [(b)]	—	(163)
Balance as of September 30, 2023	$ 421	$ 381	$ 1	$ 803
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities as of September 30, 2023	$ 1	$ 759	$ —	$ 760

	For the Nine Months Ended September 30, 2022			
	NDT Fund Investments	Mark-to-Market Derivatives	Life Insurance Contracts	Total
Balance as of January 1, 2022	$ 464	$ (94)	$ —	$ 370
Total realized / unrealized (losses) gains				
Included in net income	(2)	(1,823) [(a)]	(2)	(1,827)
Included in Payable related to Regulatory Agreement Units	(11)	—	—	(11)
Change in collateral	—	(312)	—	(312)
Impacts of separation	—	—	3	3
Purchases, sales, issuances and settlements				
Purchases	5	499	—	504
Sales	—	(44)	—	(44)
Settlements	(28)	(30)	—	(58)
Transfers into Level 3	2	418 [(b)]	—	420
Transfers out of Level 3	—	(67) [(b)]	—	(67)
Balance as of September 30, 2022	$ 430	$ (1,453)	$ 1	$ (1,022)
The amount of total losses included in income attributed to the change in unrealized losses related to assets and liabilities as of September 30, 2022	$ (2)	$ (1,951)	$ (2)	$ (1,955)

(a) Includes a reduction of $258 million and $703 million for realized gains due to the settlement of derivative contracts for the three and nine months ended September 30, 2023, respectively. Includes a reduction of $35 million for realized gains and an addition of $98 million for realized losses due to the settlement of derivative contracts for the three and nine months ended September 30, 2022, respectively.

(b) Transfers into and out of Level 3 generally occur when the contract tenor becomes less or 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 nine months ended September 30, 2023 and 2022:

	For the Three Months Ended September 30,					
	Operating Revenues		Purchased Power and Fuel		Other, net	
	2023	2022	2023	2022	2023	2022
Total losses included in net income	$ (129)	$ (545)	$ (75)	$ (380)	$ —	$ —
Total unrealized gains (losses)	97	(768)	(43)	(121)	—	(1)

	For the Nine Months Ended September 30,					
	Operating Revenues		Purchased Power and Fuel		Other, net	
	2023	2022	2023	2022	2023	2022
Total gains (losses) included in net income	$ 388	$ (1,786)	$ (332)	$ (67)	$ 1	$ (4)
Total unrealized gains (losses)	1,144	(2,353)	(385)	402	1	(4)

Mark-to-Market Derivatives

The following table presents the significant inputs to the forward curve used to value level 3 mark-to-market derivative positions:

Type of trade	Fair Value as of September 30, 2023	Fair Value as of December 31, 2022	Valuation Technique	Unobservable Input	2023 Range & Arithmetic Average				2022 Range & Arithmetic Average			
Mark-to-market derivatives—Economic hedges[(a)(b)]	$ 64	$ (3)	Discounted Cash Flow	Forward power price	$11	-	$219	$51	$0.63	-	$283	$72
				Forward gas price	$1.77	-	$16	$3.75	$1.67	-	$26	$4.57
			Option Model	Volatility percentage	76%	-	161%	111%	97%	-	119%	111%

(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 $316 million and $218 million as of September 30, 2023 and December 31, 2022, 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 price volatility for options. 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; i.e. an increase in natural gas pricing would have a similar impact on forward power markets. See Note 10 — Derivative Financial Instruments for additional information on mark-to-market derivatives.

(Dollars in millions, unless otherwise noted)

13. Commitments and Contingencies

Commitments

Commercial Commitments. Commercial commitments as of September 30, 2023, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2023	2024	2025	2026	2027	2028 and beyond
Letters of credit	$ 1,723	$ 1,103	$ 506	$ —	$ —	$ —	$ 114
Surety bonds[(a)]	897	369	528	—	—	—	—
Total commercial commitments	$ 2,620	$ 1,472	$ 1,034	$ —	$ —	$ —	$ 114

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

Prior Merger Commitment. Consistent with a 2012 MDPSC order approving a prior merger, certain commitments were made for the development of new generation in Maryland, 55 MW of which remains unsatisfied to date. In 2016, we terminated rights to a development project intended to satisfy the remaining commitment and recorded a pre-tax $50 million loss contingency within Operating and maintenance expense in our Consolidated Statements of Operations and Comprehensive Income, representing the potential liquidated damages payment due for the shortfall, consistent with the terms of the original MDPSC order. In September 2022, a previously executed PPA with a third party became effective upon satisfaction of all conditions precedent (including an extension of time to complete the merger commitment from the MDPSC) and will result in the construction of a wind farm project with an expected commercial operation date of December 31, 2024. The satisfaction of the conditions precedent to the PPA, coupled with the milestones contained in the PPA to ensure the facility is constructed, demonstrate that the merger commitment is likely to be met through support of a PPA enabling the project to be constructed rather than a liquidated damages payment. As a result, we have reversed the previously recognized loss contingency and recorded a pre-tax gain of $50 million within Operating and maintenance expense in our Consolidated Statements of Operations and Comprehensive Income for the three and nine months ended September 30, 2022.

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 financial statements.

We had accrued undiscounted amounts for environmental liabilities of $137 million and $119 million as of September 30, 2023 and December 31, 2022, respectively, in Accrued expenses and Other deferred credits and other liabilities in the Consolidated Balance Sheets.

Cotter Corporation. The EPA has advised Cotter Corporation (N.S.L.) (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at two sites in Missouri. In 2000, ComEd sold Cotter to an unaffiliated third-party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising from these two Missouri superfund sites, West Lake Landfill and Latty Avenue. In connection with Exelon's 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to us, and ultimately retained by us per the terms of our separation from Exelon. See Note 1 — Basis of Presentation for additional information on the separation and Note 19 - Commitments and Contingencies of our 2022 Form 10-K for additional information on the West Lake Landfill.

Latty Avenue and Vicinity Properties. In August 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government's clean-up costs for contamination attributable to low level radioactive residues at a former storage and reprocessing facility named Latty Avenue near St. Louis, Missouri.

Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under the Formerly Utilized Sites Remedial Action Program. On August 3, 2020, the DOJ advised Cotter that it is seeking approximately $90 million from all the PRPs. In December 2021, a good faith offer was submitted to the government. After subsequent communications with DOJ, Cotter proposed, and DOJ agreed to consider mediation to facilitate a settlement. Pursuant to a series of agreements since 2011, the DOJ and Cotter have extended the Statute of Limitations through February 29, 2024. In April 2023, Cotter was informed by the DOJ about potential additional liability for all PRPs of approximately $90 million associated with the Latty Avenue site as well as certain allegedly contaminated properties in the vicinity of Latty Avenue, for which the government claims that Cotter is a PRP.

We have determined that a loss associated with these claims are probable and have recorded an estimated liability, included in the total amount as discussed above, that reflects management's best estimate of Cotter's allocable share of the cost. It is reasonably possible that Cotter's allocable share could differ significantly, which could have a material impact on our consolidated financial statements.

Litigation and Regulatory Matters

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 September 30, 2023 and December 31, 2022, we recorded estimated liabilities of approximately $103 million and $95 million, respectively, in total for asbestos-related bodily injury claims. As of September 30, 2023, approximately $27 million of this amount related to 247 open claims presented to us, while the remaining $76 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.

Impacts of the February 2021 Extreme Cold Weather Event and Texas-based Generating Assets Outages. Beginning on February 15, 2021, our Texas-based generating assets within the ERCOT market, specifically Colorado Bend II, Wolf Hollow II, and Handley, experienced outages as a result of extreme cold weather conditions. In addition, those weather conditions drove increased demand for service, dramatically increased wholesale power prices, and also increased gas prices in certain regions. See Note 3 — Regulatory Matters of our 2022 Form 10-K for additional information.

Various lawsuits have been filed against us since March 2021 related to these events, including:

- On March 5, 2021, we, along with more than 150 power generators and transmission and distribution companies, were sued by approximately 160 individually named plaintiffs, purportedly on behalf of all Texans who allegedly suffered loss of life or sustained personal injury, property damage or other losses as a result of the weather events. The plaintiffs alleged that the defendants failed to properly prepare for the cold weather and failed to properly conduct their operations, seeking compensatory as well as punitive damages. Thereafter, numerous other plaintiffs filed multiple lawsuits against more than 300 defendants, including us, involving similar allegations of liability and claims of personal injury and property damage all arising out of the February weather events. These additional lawsuits allege wrongful death, property damage, or other losses. Co-defendants in these lawsuits include ERCOT, transmission and distribution utilities and other generators.

- On December 28, 2021, approximately 130 insurance companies which insured Texas homeowners and businesses filed a subrogation lawsuit against multiple defendants alleging that defendants were at fault for the energy failure that resulted from the winter storm, causing significant property damage to the insureds. Subsequently, several hundred other insurance companies filed similar claims. All of these cases were combined in a Multi-District-Litigation (MDL) pending in Texas state court, which established a bellwether process to consider initial motions to dismiss by the different industry groups of defendants. Defendants filed motions to dismiss the amended complaints in five bellwether cases in July 2022. On February 3, 2023, the court granted the motions to dismiss pertaining to us in part and denied them in part, leaving the plaintiffs' negligence and nuisance claims to proceed. As a result, we remain a defendant in the lawsuits, although we, along with the other generators, have sought relief from the court of appeals in Texas. Since the motions to dismiss were partially denied, thousands of new claimants, many in multiple mass tort actions, have filed lawsuits in various Texas state courts naming us, among hundreds of other defendants. The majority of these cases have been transferred to the MDL, and the expectation is the remainder will be transferred. The MDL now involves over 200 cases brought by approximately 30,000 plaintiffs, including more than 1,300 insurance companies, and we are defendants in the majority of them. We also are named in an alleged class action that seeks to assert claims on behalf of over 4.1 million Texans within ERCOT who lost power during Winter Storm Uri.

We dispute liability and deny that we are responsible for any of plaintiffs’ alleged claims and are vigorously contesting them. No loss contingencies have been reflected in the consolidated financial statements with respect to these matters, nor can we currently estimate a range of loss. It is reasonably possible, however, that resolution of these matters could have a material, unfavorable impact on our consolidated financial statements.

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.

14. Shareholders' Equity

Share Repurchase Program (CEG Parent)

On February 16, 2023, as part of our capital allocation plan, our Board of Directors announced a share repurchase program with a $1 billion authority without expiration. Share repurchases may be made through a variety of methods, which may include open market or privately negotiated transactions, provided that the amounts spent do not exceed what is authorized. Any repurchased shares are constructively retired and cancelled. The program does not obligate us to acquire a minimum number of shares during any period and our repurchase of CEG's common stock may be limited, suspended, or discounted at any time at our discretion and without prior notice. Repurchases under this program commenced in March 2023.

During the three and nine months ended September 30, 2023, we repurchased from the open market 2.3 million and 8.5 million shares of our common stock for a total cost, inclusive of taxes and transaction costs, of $253 million and $756 million, respectively. As of September 30, 2023, there was $244 million of remaining authority to repurchase shares. No other repurchase plans or programs have been authorized by our Board of Directors.

(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 September 30, 2023	Losses on Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items(a)	Foreign Currency Items	Total
Beginning balance	$ (9)	$ (1,768)	$ (23)	$ (1,800)
OCI before reclassifications	—	—	(2)	(2)
Amounts reclassified from AOCI	—	5	—	5
Net current-period OCI	—	5	(2)	3
Ending balance	$ (9)	$ (1,763)	$ (25)	$ (1,797)

Three Months Ended September 30, 2022	Losses on Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items(a)	Foreign Currency Items	Total
Beginning balance	$ (8)	$ (1,963)	$ (21)	$ (1,992)
OCI before reclassifications	—	—	(6)	(6)
Amounts reclassified from AOCI	(1)	30	—	29
Net current-period OCI	(1)	30	(6)	23
Ending balance	$ (9)	$ (1,933)	$ (27)	$ (1,969)

Nine Months Ended September 30, 2023	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)	1	(53)
Amounts reclassified from AOCI	1	15	—	16
Net current-period OCI	—	(38)	1	(37)
Ending balance	$ (9)	$ (1,763)	$ (25)	$ (1,797)

Nine Months Ended September 30, 2022	Losses on Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items(a)	Foreign Currency Items	Total
Beginning balance	$ (8)	$ —	$ (23)	$ (31)
Separation-related adjustments	—	(2,006)	—	(2,006)
OCI before reclassifications	(1)	—	(4)	(5)
Amounts reclassified from AOCI	—	73	—	73
Net current-period OCI	(1)	(1,933)	(4)	(1,938)
Ending balance	$ (9)	$ (1,933)	$ (27)	$ (1,969)

(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 loss:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Pension and non-pension postretirement benefit plans:				
Actuarial loss reclassified to periodic benefit cost	$ (3)	$ (9)	$ (8)	$ (24)
Pension and non-pension postretirement benefit plans valuation adjustment	—	—	18	680

15. Variable Interest Entities

At September 30, 2023 and December 31, 2022, 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.

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 September 30, 2023 and December 31, 2022. 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.

	September 30, 2023	December 31, 2022
Cash and cash equivalents	$ 78	$ 51
Restricted cash and cash equivalents	47	46
Accounts receivable		
Customer accounts receivable	25	20
Other accounts receivable	10	9
Inventories, net		
Materials and supplies	14	12
Other current assets	1,742	549
Total current assets	1,916	687
Property, plant, and equipment, net	1,927	1,965
Other noncurrent assets	173	190
Total noncurrent assets	2,100	2,155
Total assets[a]	$ 4,016	$ 2,842
Long-term debt due within one year	$ 63	$ 60
Accounts payable	31	17
Accrued expenses	18	23
Other current liabilities	1	2
Total current liabilities	113	102
Long-term debt	714	764
Asset retirement obligations	187	173
Other noncurrent liabilities	3	3
Total noncurrent liabilities	904	940
Total liabilities[b]	$ 1,017	$ 1,042

(Dollars in millions, unless otherwise noted)

(a) Our balances include unrestricted assets for current unamortized energy contract assets of $23 million and $23 million, disclosed within other current assets in the table above, noncurrent unamortized energy contract assets of $161 million and $178 million, disclosed within other noncurrent assets in the table above as of September 30, 2023 and December 31, 2022, respectively.
(b) As of September 30, 2023, our balance does not include any liabilities with recourse. Our balance includes liabilities with recourse of $1 million as of December 31, 2022.

As of September 30, 2023 and December 31, 2022, 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.

CRP - CRP is a collection of wind and solar project entities and some of these project entities are VIEs that are consolidated by CRP. While we or CRP own 100% of the solar entities and 100% of the majority of the wind entities, it has been determined that the wholly owned solar and wind entities are VIEs because the entities' customers absorb price variability from the entities through fixed price power and/or REC purchase agreements. Additionally, for the wind entities that have minority interests, it has been determined that these entities are VIEs because the governance rights of some investors are not proportional to their financial rights. We are the primary beneficiary of these solar and wind entities that qualify as VIEs because we control operations and direct all activities of the facilities. There is limited recourse to us related to certain solar and wind entities.

In 2017, our interests in CRP were contributed to and are pledged for the CR non-recourse debt project financing structure. Refer to Note 17 — Debt and Credit Agreements of our 2022 Form 10-K for additional information.

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.

(Dollars in millions, unless otherwise noted)

As of September 30, 2023 and December 31, 2022, 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:

	September 30, 2023			December 31, 2022		
	Commercial Agreement VIEs	Equity Investment VIEs	Total	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[(a)]	$ 695	$ —	$ 695	$ 716	$ —	$ 716
Total liabilities[(a)]	72	—	72	55	—	55
Our ownership interest in VIE[(a)]	—	—	—	—	—	—
Other ownership interests in VIE[(a)]	623	—	623	661	—	661

(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 September 30, 2023 and December 31, 2022.

As of September 30, 2023 and December 31, 2022 the unconsolidated VIEs consist of:

Unconsolidated VIE groups:	Reason entity is a VIE:	Reason we are not the primary beneficiary:
Equity investments in distributed energy companies. We sold this investment in the fourth quarter of 2022 resulting in it no longer being classified as an unconsolidated VIE.	Similar structures to a limited partnership and the limited partners do not have kick-out rights with respect to the general partner.	We do not conduct the operational activities.
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 Information

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

	Operating revenues			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Operating lease income	$ 29	$ 29	$ 46	$ 46
Variable lease income	73	77	197	204

	Taxes other than income taxes			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Gross receipts[(a)]	$ 37	$ 39	$ 105	$ 100
Property	67	67	188	206
Payroll	39	36	108	99

(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.

(Dollars in millions, unless otherwise noted)

	Other, net			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Decommissioning-related activities:				
Net realized income on NDT funds[(a)]				
Regulatory Agreement Units	$ 126	$ 61	$ 575	$ 333
Non-Regulatory Agreement Units	37	15	322	115
Net unrealized losses on NDT funds				
Regulatory Agreement Units	(242)	(386)	(156)	(1,777)
Non-Regulatory Agreement Units	(123)	(225)	(78)	(1,077)
Regulatory offset to NDT fund-related activities[(b)]	93	262	(335)	1,160
Total decommissioning-related activities	(109)	(273)	328	(1,246)
Non-service net periodic benefit credit[(c)]	14	27	41	79
Net realized and unrealized gains (losses) from equity investments[(d)]	76	(2)	490	(27)
Return to provision adjustment[(e)]	(5)	26	(5)	(32)
Other[(f)]	24	26	65	57
Total Other, net	$ —	$ (196)	$ 919	$ (1,169)

(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) Prior to separation, we were allocated our portion of pension and OPEB non-service credits (costs) from Exelon, which was included in Operating and maintenance expense. Effective February 1, 2022, 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.
(d) For 2023, includes unrealized gain resulting from equity investment that became publicly traded in the second quarter of 2023 and now has a readily determinable fair value (and no longer is accounted for as an equity method investment due to lack of significant influence). We recorded the fair value of this investment in Investments on the Consolidated Balance Sheets based on quoted market price of the stock. See Note 12 — Fair Value of Financial Assets and Liabilities for additional information.
(e) This reflects amounts contractually owed to Exelon under the TMA, which is offset in Income taxes. See Note 8 — Income Taxes for additional information.
(f) Includes amounts we billed Exelon for services pursuant to the TSA. See Note 1 — Basis of Presentation for additional information.

(Dollars in millions, unless otherwise noted)

Supplemental Cash Flow Information

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

	Depreciation, amortization, and accretion	
	Nine Months Ended September 30,	
	2023	2022
Property, plant, and equipment[(a)]	$ 791	$ 798
Amortization of intangible assets, net[(a)]	17	20
Amortization of energy contract assets and liabilities[(b)]	26	28
Nuclear fuel[(c)]	573	561
ARO accretion[(d)]	433	403
Total depreciation, amortization, and accretion	$ 1,840	$ 1,810

(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	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Other decommissioning-related activity[(a)]	(330)	(116)	(330)	(116)
Energy-related options[(b)]	159	239	159	239
Asset impairments	71	—	71	—
Loss on sale of receivables	58	39	58	39
Amortization of operating ROU asset	57	65	57	65
Long-term incentive plan	44	35	—	—
Pension and non-pension postretirement benefit costs	36	12	36	12
Gain on sales of assets and businesses	(28)	(13)	(28)	(13)
Fair value adjustments related to gas imbalances	9	65	9	65
Prior merger commitment[(c)]	—	(50)	—	(50)

(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.
(c) Reversal of a charge related to a prior 2012 merger commitment. See Note 13 — Commitments and Contingencies for additional information.

(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
September 30, 2023		
Cash and cash equivalents	$ 1,889	$ 1,888
Restricted cash and cash equivalents	88	59
Total cash, restricted cash, and cash equivalents	$ 1,977	$ 1,947
December 31, 2022		
Cash and cash equivalents	$ 422	$ 403
Restricted cash and cash equivalents	106	98
Total cash, restricted cash, and cash equivalents	$ 528	$ 501
September 30, 2022		
Cash and cash equivalents	$ 1,192	$ 1,131
Restricted cash and cash equivalents	111	83
Total cash, restricted cash, and cash equivalents	$ 1,303	$ 1,214

For additional information on restricted cash, see Note 1 — Basis of Presentation of our 2022 Form 10-K.

Supplemental Balance Sheet Information

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

	Accounts payable and accrued expenses	
September 30, 2023	CEG Parent	Constellation
Accounts payable	$ 1,317	$ 1,283
Compensation-related accruals[a]	$ 534	$ 440
December 31, 2022		
Accounts payable	$ 2,828	$ 2,810
Compensation-related accruals[a]	$ 540	$ 502

(a) Primarily includes accrued payroll, bonuses and other incentives, vacation, and benefits.

17. Related Party Transactions

Prior to completion of the separation on February 1, 2022, we engaged in transactions with affiliates of Exelon in the normal course of business, these affiliate transactions are summarized in the tables below. After February 1, 2022, all transactions with Exelon or its affiliates are no longer related party transactions.

(Dollars in millions, unless otherwise noted)

Operating Revenues from Affiliates

The following table presents our Operating revenues from affiliates:

	Nine Months Ended September 30, 2022[a]
ComEd[b]	$ 58
PECO[b]	33
BGE[b]	18
PHI	51
Pepco[b]	39
DPL[b]	10
ACE[b]	2
Total operating revenues from affiliates	$ 160

(a) Represents only January 2022 activity prior to separation on February 1, 2022.
(b) See Note 24 - Related Party Transactions of our 2022 Form 10-K for additional information on the Exelon utility subsidiaries.

Service Company Costs for Corporate Support

We received a variety of corporate support services from Exelon. Through its business services subsidiary, BSC, Exelon provided support services at cost, including legal, human resources, financial, information technology, and supply management services. The costs of BSC were directly charged or allocated to us. Certain of these services continue after the separation and are covered by the TSA. The operating and maintenance service company costs from affiliates allocated to us prior to the separation were $44 million for the nine months ended September 30, 2022. The capitalized service company costs allocated to us prior to the separation were $15 million for the nine months ended September 30, 2022.

See Note 1 — Basis of Presentation for additional information on the separation from Exelon.

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

(Dollars in millions, 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

Separation from Exelon

On February 21, 2021, Exelon's Board of Directors approved a plan to separate its competitive generation and customer-facing energy businesses into a stand-alone publicly traded company (separation). Exelon completed the separation on February 1, 2022. We incurred separation costs of $18 million and $30 million for the three months ended September 30, 2023 and 2022, respectively, and $84 million and $99 million for the nine months ended September 30, 2023 and 2022, respectively, which are primarily recorded in Operating and maintenance expense. The separation costs are primarily comprised of system-related costs, third-party costs paid to advisors, consultants, lawyers, and other experts assisting in the separation. See Note 1 — Basis of Presentation of the Combined Notes to Consolidated Financial Statements for additional information.

Share Repurchase Program

On February 16, 2023, our Board of Directors announced a share repurchase program with a $1 billion authority without expiration. Repurchases under this program commenced in March 2023. During the three and nine months ended September 30, 2023, we repurchased from the open market 2.3 million and 8.5 million shares of our common stock for a total cost, inclusive of taxes and transaction costs, of $253 million and $756 million, respectively. See Note 14 — Shareholders' Equity of the Combined Notes to Consolidated Financial Statements for additional information.

Acquisition of Joint Ownership in South Texas Project

On November 1, 2023, we acquired NRG South Texas LP, which owns a 44% undivided ownership interest in the jointly owned South Texas Project Nuclear Generating Station (STP), a 2,645-megawatt, dual-unit nuclear plant located in Bay City, Texas, for a cash purchase price of $1.75 billion. This acquisition is complementary to and aligned strategically with our existing clean energy business operations. See Note 2 — Mergers, Acquisitions, and Dispositions of the Combined notes to the Consolidated Financial Statements for additional information on this acquisition.

Revenue Recognized for Illinois ZECs Delivered in Prior Planning Years

Our Clinton and Quad Cities units contract with certain utilities in Illinois which requires delivery of all ZECs produced during each planning year (June 1 to May 31), 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 on June 1, 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 1, 2023 to May 31, 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. During the second quarter of 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 September 30, 2023, this receivable is included within Customer accounts receivable, net in the Consolidated Balance Sheets.

Other Key Business Drivers

Russia and Ukraine Conflict

We are closely monitoring developments of the Russia and Ukraine conflict including United States, United Kingdom, European Union, and Canadian sanctions 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. 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 through 2028, which is the date multiple suppliers are expected to have incremental additional capacity online. We are also continuing to work with federal policymakers and other stakeholders to facilitate the expansion of the domestic nuclear fuel cycle within the United States to improve carbon-free energy security.

Critical Accounting Policies and Estimates

Management makes a number of significant estimates, assumptions, and judgements in the preparation of our financial statements. At September 30, 2023, the Registrants' critical accounting policies and estimates had not changed significantly from December 31, 2022. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Critical Accounting Policies and Estimates in our 2022 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 nine months ended September 30, 2023 compared to the same periods in 2022. For additional information regarding the financial results for the three and nine months ended September 30, 2023 and 2022 see the discussions of Results of Operations below.

	Three Months Ended September 30,		Favorable Variance	Nine Months Ended September 30,		Favorable Variance
	2023	2022		2023	2022	
GAAP Net Income (Loss) Attributable to Common Shareholders	$ 731	$ (188)	$ 919	$ 1,660	$ (194)	$ 1,854

Adjusted EBITDA (non-GAAP). In analyzing and planning for our business, we supplement our use of GAAP Net Income (Loss) Attributable to Common Shareholders with Adjusted EBITDA (non-GAAP) as a performance measure. Adjusted EBITDA (non-GAAP) reflects an additional way of viewing our business that, when viewed with our GAAP results and the accompanying reconciliation to GAAP Net Income (Loss) Attributable to Common Shareholders included in the table below, may provide a more complete understanding of factors and trends affecting our core business. Adjusted EBITDA (non-GAAP) should not be relied upon to the exclusion of GAAP financial measures and is, by definition, an incomplete understanding of our business, and must be considered in conjunction with GAAP measures. In addition, Adjusted EBITDA (non-GAAP) is neither a standardized financial measure, nor a presentation defined under GAAP and may not be comparable to other companies' presentations of similarly titled financial measures or deemed more useful than the GAAP information provided elsewhere in this report.

The following table provides a reconciliation between Net Income (Loss) Attributable to Common Shareholders as determined in accordance with GAAP and Adjusted EBITDA (non-GAAP) for the three and nine months ended September 30, 2023 compared to the same periods in 2022.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Net Income (Loss) Attributable to Common Shareholders	$ 731	$ (188)	$ 1,660	$ (194)
Income Taxes[(a)]	209	(149)	682	(472)
Depreciation and Amortization	266	262	808	818
Interest Expense, Net	82	75	292	187
Unrealized (Gain) Loss on Fair Value Adjustments[(b)]	(215)	550	(344)	645
Asset Impairments	71	—	71	—
Plant Retirements and Divestitures	—	5	(28)	(3)
Decommissioning-Related Activities[(c)]	79	88	(277)	1,126
Pension & OPEB Non-Service Credits	(14)	(27)	(41)	(85)
Separation Costs[(d)]	18	30	84	99
Acquisition-Related Costs	—	—	2	—
ERP System Implementation Costs[(e)]	5	5	20	16
Change in Environmental Liabilities	13	3	29	12
Prior Merger Commitment[(f)]	—	(50)	—	(50)
Noncontrolling Interests[(g)]	(46)	(12)	(70)	(37)
Adjusted EBITDA (non-GAAP)	$ 1,199	$ 592	$ 2,888	$ 2,062

(a) Includes amounts contractually owed to Exelon under the TMA reflected in Other, net.
(b) Includes mark-to-market on economic hedges and fair value adjustments related to gas imbalances and equity investments.
(c) Reflects all gains and losses associated with NDTs, ARO accretion, ARO remeasurement, and any earnings neutral 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 implementation.
(f) Reversal of a charge related to a 2012 merger commitment.
(g) Represents elimination from results for the noncontrolling interests related to certain adjustments.

Results of Operations

	Three Months Ended September 30, 2023	Three Months Ended September 30, 2022	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022	Favorable (Unfavorable) Variance
Operating revenues	$ 6,111	$ 6,051	$ 60	$ 19,122	$ 17,107	$ 2,015
Operating expenses						
Purchased power and fuel	3,367	4,695	1,328	11,983	11,754	(229)
Operating and maintenance	1,353	989	(364)	4,263	3,466	(797)
Depreciation and amortization	266	262	(4)	808	818	10
Taxes other than income taxes	148	145	(3)	419	415	(4)
Total operating expenses	5,134	6,091	957	17,473	16,453	(1,020)
(Loss) gain on sales of assets and businesses	—	(1)	1	28	13	(15)
Operating income (loss)	977	(41)	1,018	1,677	667	1,010
Other income and (deductions)						
Interest expense, net	(82)	(75)	(7)	(292)	(187)	(105)
Other, net	—	(196)	196	919	(1,169)	2,088
Total other income and (deductions)	(82)	(271)	189	627	(1,356)	1,983
Income (loss) before income taxes	895	(312)	1,207	2,304	(689)	2,993
Income taxes	205	(123)	(328)	677	(504)	(1,181)
Equity in losses of unconsolidated affiliates	—	(4)	4	(11)	(10)	(1)
Net income (loss)	690	(193)	883	1,616	(195)	1,811
Net loss attributable to noncontrolling interests	(41)	(5)	(36)	(44)	(1)	(43)
Net income (loss) attributable to common shareholders	$ 731	$ (188)	$ 919	$ 1,660	$ (194)	1,854

Three Months Ended September 30, 2023 Compared to Three Months Ended September 30, 2022. The variance in Net income (loss) attributable to common shareholders was favorable by $919 million primarily due to:

- Favorable market and portfolio conditions primarily driven by higher realized margins on load contracts and generation-to-load optimization;
- Favorable mark-to-market activity and other fair value adjustments;
- Favorable net realized and unrealized NDT activity; and
- Favorable impact of net realized and unrealized equity investment activity.

The favorable items were partially offset by:

- Impact of our annual update to the nuclear ARO for Non-Regulatory Agreement Units;
- Higher labor, contracting and materials; and
- Lower ZEC revenues primarily driven by lower Illinois ZEC prices in the current planning year.

Nine Months Ended September 30, 2023 Compared to Nine Months Ended September 30, 2022. The variance in Net income (loss) attributable to common shareholders was favorable by $1,854 million primarily due to:

- Favorable net realized and unrealized NDT activity;
- Favorable market and portfolio conditions primarily driven by higher realized margins on load contracts and generation-to-load optimization;
- Unrealized gains resulting from an investment that became a publicly traded company in the second quarter of 2023;
- Favorable mark-to-market activity and other fair value adjustments; and
- Higher ZEC revenues primarily driven by revenue recognized for ZECs delivered under the Illinois ZEC program in prior planning years.

The favorable items were partially offset by:

- Higher labor, contracting and materials;
- Lower capacity revenues;
- Impact of our annual update to the nuclear ARO for Non-Regulatory Agreement Units;
- Unfavorable impacts of nuclear outages; and
- Higher interest expense.

Operating revenues. 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 with these same geographic regions. Our five reportable segments are Mid-Atlantic, Midwest, New York, ERCOT, and Other Power Regions. See Note 5 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on these reportable segments.

The following business activities are not allocated to a region and are reported under Other: wholesale and retail sales of natural gas, as well as other miscellaneous business activities that are not significant to overall results of operations.

For the three and nine months ended September 30, 2023 compared to 2022, Operating revenues by region were as follows:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2023	2022	Variance	% Change (a)	2023	2022	Variance	% Change (a)
Mid-Atlantic	$ 1,411	$ 1,659	$ (248)	(14.9)%	$ 3,854	$ 3,967	$ (113)	(2.8)%
Midwest	1,117	1,047	70	6.7 %	3,479	3,345	134	4.0 %
New York	512	423	89	21.0 %	1,518	1,178	340	28.9 %
ERCOT	559	490	69	14.1 %	1,056	1,210	(154)	(12.7)%
Other Power Regions	1,592	1,936	(344)	(17.8)%	4,495	5,189	(694)	(13.4)%
Total electric revenues	5,191	5,555	(364)	(6.6)%	14,402	14,889	(487)	(3.3)%
Other	743	1,177	(434)	(36.9)%	3,403	4,117	(714)	(17.3)%
Mark-to-market gains (losses)	177	(681)	858		1,317	(1,899)	3,216	
Total Operating revenues	$ 6,111	$ 6,051	$ 60	1.0 %	$ 19,122	$ 17,107	$ 2,015	11.8 %

(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 September 30, 2023	2022	Variance	% Change	Nine Months Ended September 30, 2023	2022	Variance	% Change
Nuclear Generation[a]								
Mid-Atlantic	13,654	13,540	114	0.8 %	39,672	39,272	400	1.0 %
Midwest	24,023	24,275	(252)	(1.0)%	69,975	71,079	(1,104)	(1.6)%
New York	6,448	5,979	469	7.8 %	18,837	18,563	274	1.5 %
Total Nuclear Generation	44,125	43,794	331	0.8 %	128,484	128,914	(430)	(0.3)%
Natural Gas, Oil, and Renewables								
Mid-Atlantic	361	230	131	57.0 %	1,466	1,573	(107)	(6.8)%
Midwest	155	126	29	23.0 %	715	774	(59)	(7.6)%
ERCOT	5,146	4,987	159	3.2 %	12,286	10,873	1,413	13.0 %
Other Power Regions	1,929	2,401	(472)	(19.7)%	6,544	7,179	(635)	(8.8)%
Total Natural Gas, Oil, and Renewables	7,591	7,744	(153)	(2.0)%	21,011	20,399	612	3.0 %
Purchased Power								
Mid-Atlantic	6,166	6,508	(342)	(5.3)%	13,615	12,164	1,451	11.9 %
Midwest	104	74	30	40.5 %	726	425	301	70.8 %
ERCOT	1,612	705	907	128.7 %	4,561	2,855	1,706	59.8 %
Other Power Regions	13,221	13,869	(648)	(4.7)%	32,875	39,964	(7,089)	(17.7)%
Total Purchased Power	21,103	21,156	(53)	(0.3)%	51,777	55,408	(3,631)	(6.6)%
Total Supply/Sales by Region								
Mid-Atlantic	20,181	20,278	(97)	(0.5)%	54,753	53,009	1,744	3.3 %
Midwest	24,282	24,475	(193)	(0.8)%	71,416	72,278	(862)	(1.2)%
New York	6,448	5,979	469	7.8 %	18,837	18,563	274	1.5 %
ERCOT	6,758	5,692	1,066	18.7 %	16,847	13,728	3,119	22.7 %
Other Power Regions	15,150	16,270	(1,120)	(6.9)%	39,419	47,143	(7,724)	(16.4)%
Total Supply/Sales by Region	72,819	72,694	125	0.2 %	201,272	204,721	(3,449)	(1.7)%

(a) Includes the proportionate share of output where we have an undivided ownership interest in jointly-owned generating plants and the total output for fully owned plants.

Nuclear Fleet Capacity Factor. The following table presents nuclear fleet operating data for our plants, which reflects ownership percentage of stations operated by us, excluding Salem, which is operated by PSEG. 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 of similarly titled measures or be more useful than the GAAP information provided elsewhere in this report.

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Nuclear fleet capacity factor	97.2 %	96.4 %	94.1 %	94.5 %
Refueling outage days	20	5	200	147
Non-refueling outage days	10	26	44	51

ZEC Prices. We are compensated through state programs for the carbon-free attributes for certain of our nuclear generation. 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 nine months ended September 30, 2023 and 2022.

	Three Months Ended September 30,				Nine Months Ended September 30,			
State (Region)(a)	2023	2022	Variance	% Change	2023	2022	Variance	% Change
New Jersey (Mid-Atlantic)[b]	$ 10.00	$ 9.88	$ 0.12	1.2 %	$ 9.93	$ 9.95	$ (0.02)	(0.2)%
Illinois (Midwest)[c]	0.30	12.01	(11.71)	(97.5)%	6.81	14.50	(7.69)	(53.0)%
New York (New York)	18.27	21.38	(3.11)	(14.5)%	19.31	21.38	(2.07)	(9.7)%

(a) The Salem, Clinton, Quad Cities, FitzPatrick, Ginna, and NMP plants are receiving payments under their respective 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, on August 16, 2023 the ZEC price for the delivery period beginning June 1, 2022 through May 31, 2023 was calculated to be $9.88.
(c) See Note 4 — Revenue from Contracts with Customers of the Combined Notes to Consolidated Financial Statements for additional information on the Illinois ZEC program.

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 1, 2022 through May 31, 2023 and $32.50 per MWh for the period June 1, 2023 through May 31, 2024). 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 $2.12 and ($51.70) for the three months ended September 30, 2023 and 2022, respectively and $3.54 and ($51.85) for the nine months ended September 30, 2023 and 2022, respectively. See Note 3 - Regulatory Matters of our 2022 Form 10-K for additional information on the Illinois CMC program.

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, depending on our net monthly position. The following table presents the average capacity reference prices ($/MW Day) for each of our major regions. Prices reflect the weighted average prices for the various auction periods within the three and nine months ended September 30, 2023 and 2022.

Location (Region)	Three Months Ended September 30, 2023	2022	Variance	% Change	Nine Months Ended September 30, 2023	2022	Variance	% Change
Eastern Mid-Atlantic Area Council (Mid-Atlantic)	$ 49.49	$ 97.86	$ (48.37)	(49.4)%	$ 76.36	$ 135.57	$ (59.21)	(43.7)%
ComEd (Midwest)	34.13	68.96	(34.83)	(50.5)%	53.48	139.29	(85.81)	(61.6)%
Rest of State (New York)	199.89	108.22	91.67	84.7 %	147.48	89.67	57.81	64.5 %
Southeast New England (Other)	66.67	126.67	(60.00)	(47.4)%	100.00	142.06	(42.06)	(29.6)%

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.

Location (Region)	Three Months Ended September 30, 2023	2022	Variance	% Change	Nine Months Ended September 30, 2023	2022	Variance	% Change
PJM West (Mid-Atlantic)	$ 33.31	$ 90.43	$ (57.12)	(63.2)%	$ 31.95	$ 74.33	$ (42.38)	(57.0)%
ComEd (Midwest)	30.85	81.99	(51.14)	(62.4)%	26.75	62.90	(36.15)	(57.5)%
Central (New York)	29.58	74.96	(45.38)	(60.5)%	26.85	60.89	(34.04)	(55.9)%
North (ERCOT)	129.60	97.58	32.02	32.8 %	64.41	68.47	(4.06)	(5.9)%
Southeast Massachusetts (Other)[(a)]	33.45	86.27	(52.82)	(61.2)%	38.15	89.01	(50.86)	(57.1)%

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

For the three and nine months ended September 30, 2023 compared to 2022, changes in **Operating revenues** by region were approximately as follows:

	Three Months Ended September 30 Variance	% Change[(a)]	Description	Nine Months Ended September 30 Variance	% Change[(a)]	Description
Mid-Atlantic	(248)	(14.9)%	• unfavorable settled economic hedges of ($200) due to settled prices relative to hedged prices • unfavorable retail load revenue of ($50) primarily due to lower contracted energy prices	(113)	(2.8)%	• unfavorable settled economic hedges of ($380) due to settled prices relative to hedged prices; partially offset by • favorable wholesale load revenue of $285 primarily due to higher contracted energy prices and higher volumes

	Three Months Ended September 30			Nine Months Ended September 30		
	Variance	% Change[(a)]	Description	Variance	% Change[(a)]	Description
Midwest	70	6.7 %	• favorable net generation revenue and CMC activity of $175 primarily due to our generation volume and realized prices relative to our purchased power to supply load • favorable settled economic hedges of $55 due to settled prices relative to hedged prices; partially offset by • unfavorable wholesale load revenue of ($90) primarily due to lower volumes • unfavorable ZEC revenue of ($55) primarily due to a decrease in the ZEC price in current planning year • unfavorable retail load revenue of ($30) primarily due to lower contracted energy prices partially offset by higher load volumes	134	4.0 %	• favorable ZEC revenue of $140 primarily due to revenue recognized for Illinois ZECs delivered in prior planning years partially offset by a decrease in the ZEC price in current planning year • favorable settled economic hedges of $90 due to settled prices relative to hedged prices • favorable retail load revenue of $25 primarily due to higher load volumes, partially offset by lower contracted energy prices; partially offset by • unfavorable net generation and wholesale load revenue of ($175) primarily due to lower nuclear generation and lower load volumes, partially offset by CMC program activity and net capacity revenue
New York	89	21.0 %	• favorable settled economic hedges of $100 due to settled prices relative to hedged prices • favorable retail load revenue of $35 primarily due to higher contracted energy prices; partially offset by • unfavorable net generation revenue of ($40) primarily due to lower energy prices partially offset by higher nuclear generation	340	28.9 %	• favorable settled economic hedges of $360 due to settled prices relative to hedged prices • favorable retail load revenue of $80 primarily due to higher contracted energy prices; partially offset by • unfavorable net generation revenue of ($110) primarily due to lower energy prices
ERCOT	69	14.1 %	• favorable wholesale load revenue of $180 primarily due to higher volumes; partially offset by • unfavorable settled economic hedges of ($130) due to settled prices relative to hedged prices	(154)	(12.7)%	• unfavorable settled economic hedges of ($460) due to settled prices relative to hedged prices; partially offset by • favorable wholesale load revenue of $295 primarily due to higher volumes

	Three Months Ended September 30			Nine Months Ended September 30		
	Variance	% Change[(a)]	Description	Variance	% Change[(a)]	Description
Other Power Regions	(344)	(17.8)%	• unfavorable settled economic hedges of ($270) due to settled prices relative to hedged prices • unfavorable wholesale load revenue of ($100) primarily due to lower volumes; partially offset by • favorable retail load revenue of $30 primarily due to higher contracted energy prices	(694)	(13.4)%	• unfavorable settled economic hedges of ($730) due to settled prices relative to hedged prices • unfavorable wholesale load revenue of ($140) primarily due to lower volumes; partially offset by • favorable retail load revenue of $170 primarily due to higher contracted energy prices
Other	(434)	(36.9)%	• unfavorable gas revenue, including settled economic hedges, of ($460) primarily due to lower gas prices; partially offset by • favorable energy revenue of $35 primarily due to higher energy prices	(714)	(17.3)%	• unfavorable gas revenue, including settled economic hedges, of ($785) primarily due to lower gas prices; partially offset by • favorable energy revenue of $65 primarily due to higher energy prices
Mark-to-market[(b)]	858		• gains on economic hedging activities of $177 in 2023 compared to losses of ($681) in 2022	3,216		• gains on economic hedging activities of $1,317 in 2023 compared to losses of ($1,899) in 2022
Total	$ 60	1.0 %		$ 2,015	11.8 %	

(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.

The following business activities are not allocated to a region and are reported under Other: wholesale and retail sales of natural gas, as well as other miscellaneous business activities that are not significant to overall purchased power and fuel expense or results of operations.

For the three and nine months ended September 30, 2023 compared to 2022, Purchased power and fuel expense by region were as follows:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2023	2022	Variance	% Change (a)	2023	2022	Variance	% Change (a)
Mid-Atlantic	$ 667	$ 1,104	$ 437	39.6 %	$ 1,696	$ 2,355	$ 659	28.0 %
Midwest	339	475	136	28.6 %	1,038	1,335	297	22.2 %
New York	195	156	(39)	(25.0)%	621	351	(270)	(76.9)%
ERCOT	352	424	72	17.0 %	633	975	342	35.1 %
Other Power Regions	1,161	1,679	518	30.9 %	3,594	4,479	885	19.8 %
Total electric purchased power and fuel	2,714	3,838	1,124	29.3 %	7,582	9,495	1,913	20.1 %
Other	613	1,014	401	39.5 %	2,947	3,587	640	17.8 %
Mark-to-market losses (gains)	40	(157)	(197)		1,454	(1,328)	(2,782)	
Total Purchased power and fuel	$ 3,367	$ 4,695	$ 1,328	28.3 %	$ 11,983	$ 11,754	$ (229)	(1.9)%

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

For the three and nine months ended September 30, 2023 compared to 2022, changes in **Purchased power and fuel** expense by region were approximately as follows:

	Three Months Ended September 30			Nine Months Ended September 30		
	Variance	% Change[(a)]	Description	Variance	% Change[(a)]	Description
Mid-Atlantic	$ 437	39.6 %	• favorable purchased power and net capacity impact of $490 primarily due to lower energy prices and higher nuclear generation partially offset by lower capacity prices earned; partially offset by • unfavorable environmental products activity of ($75) primarily due to higher REC prices	$ 659	28.0 %	• favorable purchased power and net capacity impact of $815 primarily due to lower energy prices partially offset by lower capacity prices earned; partially offset by • unfavorable environmental products activity of ($115) primarily due to higher load served and higher REC prices • unfavorable settlement of economic hedges of ($45) due to settled prices relative to hedged prices
Midwest	136	28.6 %	• favorable cost associated with power delivery and net capacity impact of $135 primarily due to lower energy prices partially offset by lower capacity prices earned	297	22.2 %	• favorable cost associated with power delivery and net capacity impact of $325 primarily due to lower energy prices partially offset by lower capacity prices earned
New York	(39)	(25.0)%	• unfavorable settlement of economic hedges of ($35) due to settled prices relative to hedged prices	(270)	(76.9)%	• unfavorable settlement of economic hedges of ($360) due to settled prices relative to hedged prices; partially offset by • favorable cost associated with power delivery and net capacity impact of $95 primarily due to lower energy prices and higher capacity prices earned
ERCOT	72	17.0 %	• favorable settlement of economic hedges of $150 due to settled prices relative to hedged prices • favorable fuel cost of $35 primarily due to lower gas prices; partially offset by • unfavorable purchased power of ($105) primarily due to higher energy prices and higher load served	342	35.1 %	• favorable settlement of economic hedges of $210 due to settled prices relative to hedged prices • favorable fuel cost of $75 primarily due to lower gas prices partially offset by higher generation • favorable purchased power of $70 primarily due to lower energy prices and higher generation partially offset by higher load served

	Three Months Ended September 30			Nine Months Ended September 30		
	Variance	% Change[(a)]	Description	Variance	% Change[(a)]	Description
Other Power Regions	518	30.9 %	• favorable purchased power and fuel of $920 primarily due to lower energy prices and lower load served; partially offset by • unfavorable settlement of economic hedges of ($405) due to settled prices relative to hedged prices	885	19.8 %	• favorable purchased power and fuel of $2,505 primarily due to lower energy prices and lower load served; partially offset by • unfavorable settlement of economic hedges of ($1,600) due to settled prices relative to hedged prices
Other	401	39.5 %	• favorable net gas purchase costs and settlement of economic hedges of $430 primarily due to lower gas prices; partially offset by • unfavorable energy purchases of ($55) primarily due to higher energy prices	640	17.8 %	• favorable net gas purchase costs and settlement of economic hedges of $620 primarily due to lower gas prices • favorable fair value adjustment related to gas imbalances of $50; partially offset by • unfavorable energy purchases of ($30) primarily due to higher energy prices
Mark-to-market[(b)]	(197)		• losses on economic hedging activities of ($40) in 2023 compared to gains of $157 in 2022	(2,782)		• losses on economic hedging activities of ($1,454) in 2023 compared to gains of $1,328 in 2022
Total	$ 1,328	28.3 %		$ (229)	(1.9)%	

(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.

For the three and nine months ended September 30, 2023 compared to 2022, changes in **Operating and maintenance expense** consisted of the following:

	Three Months Ended September 30	Nine Months Ended September 30
	(Decrease) Increase	(Decrease) Increase
Labor, contracting, and materials[(a)]	$ 93	$ 309
Decommissioning-related activities[(b)]	155	171
Nuclear refueling outage costs, including the co-owned Salem generating units	15	109
Asset impairments	71	71
Prior merger commitment[(c)]	50	50
Insurance, IT & Travel	18	46
Credit loss expense	(3)	24
Other	(35)	17
Total increase	$ 364	$ 797

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

(b) Primarily reflects a decreased benefit related to the annual nuclear ARO update for non-regulatory units.
(c) Reflects absence of a prior year gain recognized as a reversal of charge related to a 2012 merger commitment. See Note 13 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

Interest expense, net increased for the nine months ended September 30, 2023 compared to the same period in 2022, primarily due to the issuance of senior notes and tax exempt bonds, increased fees and interest on short term borrowings, and changes in the 13-week Treasury rate for our SNF obligation. See Note 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on our senior notes and tax-exempt bonds. See Note 17 — Debt and Credit Agreements of our 2022 Form 10-K for additional information on our short-term borrowings. See Note 19 — Commitments and Contingencies of our 2022 Form 10-K for additional information on our SNF obligation.

Other, net was favorable for the three and nine months ended September 30, 2023 compared to the same period in 2022, due to activity described in the table below:

	Other, net			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	(Unfavorable) Favorable		(Unfavorable) Favorable	
	2023	2022	2023	2022
Decommissioning-related activities[(a)]	$ (109)	$ (273)	$ 328	$ (1,246)
Non-service net periodic benefit credit[(b)]	14	27	41	79
Net realized and unrealized gains (losses) from equity investments[(c)]	76	(2)	490	(27)
Return to provision adjustment[(d)]	(5)	26	(5)	(32)
Other[(e)]	24	26	65	57
Other, net	$ —	$ (196)	$ 919	$ (1,169)

(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) Prior to separation, we were allocated our portion of pension and OPEB non-service credits (costs) from Exelon, which was included in Operating and maintenance expense. Effective February 1, 2022, 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.
(c) For 2023, includes unrealized gain resulting from equity investment that became publicly traded in the second quarter of 2023 and now has a readily determinable fair value (and no longer is accounted for as an equity method investment due to lack of significant influence). We recorded the fair value of this investment in Investments on the Consolidated Balance Sheets based on quoted market price of the stock. See Note 12 — Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements for additional information.
(d) This reflects amounts contractually owed to Exelon under the TMA, which is offset in Income taxes.
(e) Includes amounts we billed Exelon for services pursuant to the TSA. See Note 1 — Basis of Presentation of the Combined Notes to Consolidated Financial Statements for additional information.

Effective income tax rates were 22.9% and 39.4% for the three months ended September 30, 2023 and 2022, respectively, and 29.4% and 73.1% for the nine months ended September 30, 2023 and 2022, respectively. We do not expect the effective tax rate to deviate from the statutory tax rate with the exception of realized and unrealized gains and losses of the nuclear decommissioning trust funds. In 2022, the rate was also impacted by one-time adjustments. See Note 8 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Net income attributable to noncontrolling interests primarily relates to CRP for the three and nine months ended September 30, 2023 and 2022.

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. If these conditions deteriorate to the extent that we no longer have access to the capital markets at reasonable terms, we have access to credit facilities with aggregate bank commitments of $5.9 billion. We utilize our credit facilities to support our commercial paper programs, provide for other short-term borrowings and to issue letters of credit. 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.

Pursuant to the Separation Agreement between us and Exelon, we received a cash payment of $1.75 billion from Exelon on January 31, 2022. See Note 1 — Basis of Presentation of the Combined Notes to Consolidated Financial Statements for additional information on the separation.

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 September 30, 2023, 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 on April 5, 2019. See Liquidity and Capital Resources — NRC Minimum Funding Requirements of our 2022 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.

See Note 3 — Regulatory Matters and Note 13 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information on regulatory and legal proceedings and proposed legislation.

The following table provides a summary of the change in cash flows from operating activities for the nine months ended September 30, 2023 and 2022:

Cash flows from operating activities	Nine Months Ended September 30, 2023	2022	Change
Net income (loss)	$ 1,616	$ (195)	$ 1,811
Adjustments to reconcile net income (loss) to cash:			
Changes in working capital and other noncurrent assets and liabilities[(a)]	(5,109)	(2,899)	(2,210)
Collateral (posted) received, net	(222)	766	(988)
Option premiums paid, net	(36)	(163)	127
Pension and non-pension postretirement benefit contributions	(46)	(229)	183
Total non-cash operating activities[(b)]	1,678	2,789	(1,111)
Net cash flows (used in) provided by operating activities	$ (2,119)	$ 69	$ (2,188)

(a) Includes changes in Accounts receivable, Receivables from and payables to affiliates, 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. In addition, significant operating cash flow impacts for the nine months ended September 30, 2023 and 2022 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 Accounts payable and accrued expenses, primarily driven by lower gas prices and a decrease in ComEd CMC program activity for the current year. This was partially offset by a decrease in Accounts receivable, mainly driven by higher contracted prices and volumes at year end 2022 including the impact of the December 2022 weather event. Additionally, there was a decrease in Other assets and liabilities, primarily driven by an increase in cash collections applied to DPP due to a decrease in the drawn Facility balance in 2023 compared to 2022. See Note 6 — Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information on accounts receivable.

- 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.

- **Option premiums 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.

- Decrease in cash outflows for **pension and non-pension postretirement benefit contributions** is primarily due to our annual qualified pension contribution of $21 million and $192 million made in July 2023 and February 2022, respectively. See Note 9 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information on pension and non-pension postretirement benefit plans.

Cash Flows from Investing Activities

The following table provides a summary of the change in cash flows from investing activities for the nine months ended September 30, 2023 and 2022:

	Nine Months Ended September 30,		
Cash flows from investing activities	2023	2022	Change
Collection of DPP, net	$ 4,058	$ 3,095	$ 963
Investment in NDT funds, net	(153)	(178)	25
Proceeds from sales of assets and businesses	24	41	(17)
Capital expenditures	(1,735)	(1,090)	(645)
Other investing activities	(15)	3	(18)
Net cash flows provided by investing activities	$ 2,179	$ 1,871	$ 308

Significant investing cash flow impacts for the nine months ended September 30, 2023 and 2022 were 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 2023 compared to 2022. In addition, more cash collections were reinvested in the Facility in 2023. See Note 6 — Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information.

- Increase in **capital expenditures** are primarily due to the timing of cash expenditures for capital projects. See Liquidity and Capital Resources — Credit Matters and Cash Requirements of our 2022 Form 10-K for information for additional information on projected capital expenditure spending.

Cash Flows from Financing Activities

The following table provides a summary of the change in cash flows from financing activities for the nine months ended September 30, 2023 and 2022:

	Nine Months Ended September 30,		
Cash flows from financing activities	2023	2022	Change
Long-term debt, net	$ 3,042	$ (1,392)	$ 4,434
Changes in short-term borrowings, net	(632)	(1,389)	757
Dividends paid on common stock	(277)	(139)	(138)
Repurchases of common stock	(750)	—	(750)
Contributions from Exelon	—	1,750	(1,750)
Other financing activities	6	(43)	49
Net cash flows provided by (used in) financing activities	$ 1,389	$ (1,213)	$ 2,602

Significant financing cash flow impacts for the nine months ended September 30, 2023 and 2022 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.

- Refer to ITEM 5 — MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES in our 2022 Form 10-K for further information on dividend restrictions. See below for quarterly **dividends** declared.

- **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.

- **Contribution from Exelon** is related to a cash contribution of $1.75 billion from Exelon on January 31, 2022, pursuant to the Separation Agreement. See Note 1 — Basis of Presentation of the Combined Notes to Consolidated Financial Statements for additional information on the separation.

Dividends

Quarterly dividends declared by our Board of Directors during the nine months ended September 30, 2023 and for the fourth quarter of 2023 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share	
First Quarter of 2023	February 15, 2023	February 27, 2023	March 10, 2023	$	0.282
Second Quarter of 2023	April 25, 2023	May 12, 2023	June 9, 2023	$	0.282
Third Quarter of 2023	August 1, 2023	August 14, 2023	September 8, 2023	$	0.282
Fourth Quarter of 2023	November 1, 2023	November 17, 2023	December 8, 2023	$	0.282

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 September 30, 2023, we have access to facilities with aggregate bank commitments of $5.9 billion. We had access to the commercial paper markets and had availability under our revolving credit facilities during the third quarter of 2023 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 2022 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 September 30, 2023, we would have been required to provide incremental collateral estimated to be approximately $1.9 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 significant reduction in credit ratings from their current levels of BBB and Baa2 at S&P and Moody's, respectively, to BB+ and Ba1 or below. As of September 30, 2023, we had $4.1 billion of available capacity and $1.9 billion of cash on hand. In the event of a credit downgrade below investment grade and a resulting requirement to provide incremental collateral exceeding our available capacity 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 of 2006 (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 make levelized annual contributions with the objective of achieving 100% funded status over time. This level funding strategy helps minimize volatility of future period required pension contributions. Based on this funding strategy and current market conditions, which are both subject to change, our annual qualified pension contribution was made in July 2023 for $21 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 2023 are approximately $10 million and the planned contributions to the OPEB plans, including estimated benefit payments to unfunded plans, is $30 million. Refer to ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - Liquidity and Capital Resources of our 2022 Form 10-K for additional information on pension and other postretirement benefits.

Cash Requirements for Other Financial Commitments

On November 1, 2023, we acquired NRG South Texas LP for a cash purchase price of $1.75 billion. We used the proceeds from the third quarter 2023 senior note issuances in the aggregate principal amount of $1.4 billion, together with available cash balances, to fund the acquisition. See Note 2 — Mergers, Acquisitions, and Dispositions and Note 11 — Debt and Credit Agreements of the Combined notes to the Consolidated Financial Statements for additional information on this acquisition.

Refer to ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - Liquidity and Capital Resources of our 2022 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 on August 15, 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 2022 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 Baa2, respectively, as of September 30, 2023 and have not changed during the nine months ended September 30, 2023.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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. After the separation on February 1, 2022, reporting on risk management issues is to the Executive Committee, the Risk Management Committees of our generation and customer-facing businesses, 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 2022 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 generate and purchase 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 2023 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. For merchant revenues not already hedged via comprehensive state programs, such as the CMC in Illinois, historically we have used a three-year ratable sales plan to align our hedging strategy with our financial objectives. As a result, our prompt three-year merchant revenues have been hedged on an approximate rolling 90%/60%/30% basis. We may also enter into transactions that are outside of this ratable hedging program. As of September 30, 2023, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 97%-100% and 80%-83% for 2023 and 2024, respectively. Going forward, we will continue to be proactive in managing our overall portfolio exposure to commodity risk, but will also manage our generation portfolio through the nuclear PTC, which, starting in 2024, provides downside commodity price protection for our nuclear units. Like our traditional hedging program, the nuclear PTC is an important tool in managing commodity risk.

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 $5.00/MWh reduction in the annual average around-the-clock energy price based on September 30, 2023 market conditions and hedged position would have no change on the pre-tax net income for 2023 and a decrease in pre-tax net income of approximately $153 million for 2024.

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 assemblies are 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 55% of our uranium concentrate requirements for the remainder of 2023 through 2028 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 detailing our trading and non-trading marketing activities is included to address the recommended disclosures by the energy industry's Committee of Chief Risk Officers.

The following table provides detail on changes in our commodity mark-to-market net asset or liability balance sheet position from December 31, 2022 to September 30, 2023. 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 recorded as of September 30, 2023 and December 31, 2022.

	Mark-to-market Energy Contract Net Assets
Balance as of December 31, 2022	$ 1,046 [a]
Total change in fair value during 2023 of contracts recorded in result of operations	(1,427)
Reclassification to realized at settlement of contracts recorded in results of operations	1,295
Changes in allocated collateral	238
Net option premium paid	36
Option premium amortization	(159)
Upfront payments and amortizations[b]	(262)
Foreign currency translation	(2)
Balance as of September 30, 2023	$ 765 [a]

(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						
	2023	2024	2025	2026	2027	2028 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts[a][b]:							
Actively quoted prices (Level 1)	$ 38	$ 60	$ 108	$ 51	$ 13	$ (5)	$ 265
Prices provided by external sources (Level 2)	(155)	79	125	72	(1)	(1)	119
Prices based on model or other valuation methods (Level 3)	256	114	36	(23)	(8)	6	381
Total	$ 139	$ 253	$ 269	$ 100	$ 4	$ —	$ 765

(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/(received) from counterparties (and offset against mark-to-market assets and liabilities) of $1,136 million at September 30, 2023.

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, or some, of the established, wholesale spot energy markets that are administered by PJM, ISO-NE, NYISO, CAISO, MISO, SPP, AESO, OIESO, and ERCOT. ERCOT is not subject to regulation by FERC but performs a similar function in Texas to that performed by RTOs in markets regulated by FERC. In these areas, power is traded through bilateral agreements between buyers and sellers and on the spot energy markets that are administered by the RTOs or ISOs, as applicable. In areas where there is no spot energy market, electricity is purchased and sold solely through bilateral agreements. For sales into the spot markets 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 on spot energy market transactions be shared by the remaining participants. Non-performance or non-payment by a major member of the 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 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 result in a material decrease in our pre-tax income for the nine months ended September 30, 2023. 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 result in a $695 million reduction in the fair value of the trust assets as of September 30, 2023. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See Liquidity and Capital Resources section of ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

During the third quarter of 2023, 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 September 30, 2023, 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 third quarter of 2023 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 3 — Regulatory Matters and 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 September 30, 2023, our risk factors were consistent with the risk factors described in our 2022 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)

On February 16, 2023, as part of our capital allocation plan, our Board of Directors announced a share repurchase program with a $1 billion authority without expiration. Share repurchases may be made through a variety of methods, which may include open market transactions, privately negotiated transactions, or purchases pursuant to a Rule 10b5-1 trading plan, provided that the amounts spent do not exceed what is authorized. Any repurchased shares are constructively retired and cancelled. The program does not obligate us to acquire a minimum number of shares during any period and our repurchase of CEG's common stock may be limited, suspended, or discontinued at any time at our discretion and without prior notice. Repurchases under this program commenced in March 2023.

On August 7, 2023, we entered into a stock purchase plan for the purchase of shares of our common stock (August 2023 Stock Purchase Plan), designed to comply with Rule 10b5-1 under the Exchange Act. Under its terms, the August 2023 Stock Purchase Plan would expire at the later of the completion of the maximum purchase amount of $250 million of shares of our common stock, or September 30, 2023.

The following table provides information regarding our share repurchases under the program during the three months ended September 30, 2023. All repurchases disclosed were made pursuant to the August 2023 Stock Purchase Plan:

Period	Total Number of Shares Purchased[(a)]	Average Price Paid per Share[(b)]	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Programs[(c)]
July 1, 2023 to July 31, 2023	—	$ —	$ 497,000,000
August 1, 2023 to August 31, 2023	1,525,109	$ 105.87	$ 334,000,000
September 1, 2023 to September 30, 2023	812,605	$ 108.89	$ 244,000,000
Total	2,337,714	$ 106.92	$ 244,000,000

(a) We have not made any purchases of shares other than in connection with the publicly announced share repurchase program described above.
(b) Average price paid per share for open market transactions excludes taxes and commissions.
(c) 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 September 30, 2023, 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). See ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS for more information on the Rule 10b5-1 Stock Purchase Plan the Company entered into during the period.

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
4.1	Form of Constellation Energy Generation, LLC 6.125% Senior Notes due January 15, 2034
4.2	Form of Constellation Energy Generation, LLC 6.500% Senior Notes due October 1, 2053
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)

* Filed herewith.

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 September 30, 2023 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 September 30, 2023 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	Daniel L. Eggers
President and Chief Executive Officer (Principal Executive Officer)	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)

November 6, 2023

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	Daniel L. Eggers
President and Chief Executive Officer (Principal Executive Officer)	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)	

November 6, 2023