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, 2026
or

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

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

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

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

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

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

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

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

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

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

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

The number of shares outstanding of each registrant’s common stock as of October 31, 2026 was as follows:

Constellation Energy Corporation Common Stock, without par value	351,608,504
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
Registrants	CEG Parent and Constellation, collectively
Calpine	Calpine Corporation
Calvert Cliffs	Calvert Cliffs nuclear generating station
CCFC	Calpine Construction Finance Company, L.P.
CDHI	Calpine Development Holdings, LLC
Crane	Crane Clean Energy Center (formerly known as Three Mile Island Unit 1)
CRP	Constellation Renewables Partners, LLC
FitzPatrick	James A. FitzPatrick nuclear generating station
GPC	Geysers Power Company, LLC
Greenfield L.P.	Greenfield Energy Centre L.P.
Limerick	Limerick nuclear generating station
NER	NewEnergy Receivables LLC
Nine Mile Point	Nine Mile Point nuclear generating station
Nova Power	Nova Power, LLC
Pin Oak Creek	Pin Oak Creek Energy Center
STP	South Texas Project nuclear generating station

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

AB	Assembly Bill
AEP Texas	American Electric Power Texas
AESO	Alberta Electric System Operator
AOCI	Accumulated Other Comprehensive Income (Loss)
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ASR	Accelerated Share Repurchase
CAISO	California ISO
CenterPoint	CenterPoint Energy Houston Electric, LLC
CMC	Carbon Mitigation Credit
CO_2	Carbon Dioxide
CODM	Chief Operating Decision Maker
ComEd	Commonwealth Edison Company
CORRA	Canadian Overnight Repo Rate Average
CWIP	Construction Work In Progress
DOE	United States Department of Energy
DOJ	United States Department of Justice
EFOF	Equivalent Forced Outage Factor
EGU	Electric Generating Units
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
Exchange Act	Securities Exchange Act of 1934, as amended
Exelon	Exelon Corporation
FERC	Federal Energy Regulatory Commission

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

Former ComEd Units	Braidwood, Byron, Dresden, LaSalle and Quad Cities nuclear generating units
Former PECO Units	Limerick, Peach Bottom, and Salem nuclear generating units
FRCC	Florida Reliability Coordinating Council
GAAP	Generally Accepted Accounting Principles in the United States
GDP	Gross Domestic Product
Geysers Assets	Geothermal power plant assets acquired through Calpine, including steam extraction and gathering assets
GHG	Greenhouse Gas
GW	Gigawatt
GWh	Gigawatt hour
Heat Rate	A measure of the amount of fuel required to produce a unit of power
ICE	Intercontinental Exchange
IPA	Illinois Power Agency
IRA	Inflation Reduction Act of 2022
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ITC	Investment Tax Credit
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
MWh	Megawatt hour
NASDAQ	Nasdaq Stock Market, LLC
NAV	Net Asset Value
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
NOx	Nitrogen oxide
NPNS	Normal Purchase Normal Sale scope exception
NRC	Nuclear Regulatory Commission
NYISO	New York ISO
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
OIESO	Ontario Independent Electricity System Operator
OPEB	Other Postretirement Employee Benefits
PECO	PECO Energy Company
Pension Protection Act	Pension Protection Act of 2006
PG&E	Pacific Gas and Electric Company
PJM	PJM Interconnection, LLC
PPA	Power Purchase Agreement
PP&E	Property, Plant, and Equipment
PSDAR	Post-shutdown Decommissioning Activities Report

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

PSEG	Public Service Enterprise Group Incorporated
PTC	Production Tax Credit
Regulatory Agreement Units	Nuclear generating units or portions thereof whose decommissioning-related activities are subject to contractual elimination under regulatory accounting (includes the Former ComEd Units, the Former PECO Units and STP)
RISEC	Rhode Island State Energy Center
RNF	Operating Revenues Net of Purchased Power and Fuel Expense
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
S&P	S&P Global Ratings, a Standard & Poor's Financial Services LLC business
SB	Senate Bill
SEC	United States Securities and Exchange Commission
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SNF	Spent Nuclear Fuel
SO_2	Sulfur dioxide
SOFR	Secured Overnight Financing Rate
SPP	Southwest Power Pool
STPNOC	STP Nuclear Operating Company
TMA	Tax Matters Agreement
TWh	Terawatt-hour
U.S. Treasury	U.S. Department of the Treasury
UEC	Unamortized Energy Contract
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council
ZEC	Zero Emission Credit

FILING FORMAT

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

CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING INFORMATION

This report contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties. Words such as “could,” “may,” “expects,” “anticipates,” “will,” “targets,” “goals,” “projects,” “intends,” “plans,” “believes,” “seeks,” “estimates,” “predicts,” and variations on such words, and similar expressions that reflect our current views with respect to future events and operational, economic, and financial performance, are intended to identify such forward-looking statements. These forward-looking statements include, but are not limited to, statements regarding the acquisition of Calpine Corporation, the pro forma combined company and its operations, strategies and plans, enhancements to investment-grade credit profile, synergies, opportunities and anticipated future performance and capital structure, and expected accretion to earnings per share and free cash flow. Information adjusted for the acquisition should not be considered a forecast of future results.

Forward-looking statements are based on current expectations, estimates and assumptions that involve a number of risks and uncertainties that could cause actual results to differ materially from those projected. 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 2025 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 18 — 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 15 — 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.

AVAILABLE 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. We file our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and all amendments to those reports with the SEC. In addition, as soon as reasonably practicable after such materials are furnished to the SEC, we make copies of these documents available to the public free of charge through 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,		Nine Months Ended September 30,	
	2026	2025	2026	2025
Operating revenues	$ 9,550	$ 6,570	$ 28,176	$ 19,459
Operating expenses				
Purchased power and fuel	4,400	3,567	14,775	11,083
Operating and maintenance	1,991	1,511	6,024	4,673
Depreciation and amortization	454	241	1,340	743
Taxes other than income taxes	225	165	661	472
Total operating expenses	7,070	5,484	22,800	16,971
Gain (loss) on sales of assets	12	—	28	—
Operating income (loss)	2,492	1,086	5,404	2,488
Other income and (deductions)				
Interest expense, net	(217)	(134)	(753)	(398)
Other, net	(44)	443	605	729
Total other income and (deductions)	(261)	309	(148)	331
Income (loss) before income taxes	2,231	1,395	5,256	2,819
Income tax (benefit) expense	405	466	1,333	928
Equity in income (losses) of unconsolidated affiliates	9	—	23	—
Net income (loss)	1,835	929	3,946	1,891
Net income (loss) attributable to noncontrolling interests	—	(1)	8	4
Net income (loss) attributable to common shareholders	$ 1,835	$ 930	$ 3,938	$ 1,887
Comprehensive income (loss), net of income taxes				
Net income (loss)	$ 1,835	$ 929	$ 3,946	$ 1,891
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	—	(1)	(1)	(3)
Actuarial loss reclassified to periodic cost	31	19	85	54
Pension and non-pension postretirement benefit plan valuation adjustment	—	—	(25)	(34)
Unrealized gain (loss) on cash flow hedges	1	2	4	5
Unrealized gain (loss) on foreign currency translation	—	(8)	(4)	20
Other comprehensive income (loss), net of income taxes	32	12	59	42
Comprehensive income (loss)	1,867	941	4,005	1,933
Comprehensive income (loss) attributable to noncontrolling interests	—	(1)	8	4
Comprehensive income (loss) attributable to common shareholders	$ 1,867	$ 942	$ 3,997	$ 1,929
Average shares of common stock outstanding:				
Basic	354	313	356	313
Assumed exercise and/or distributions of stock-based awards	—	—	—	1
Diluted	354	313	356	314
Earnings per average common share				
Basic	$ 5.19	$ 2.98	$ 11.06	$ 6.02
Diluted	$ 5.19	$ 2.97	$ 11.06	$ 6.02

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, 2026	2025
Cash flows from operating activities		
Net income (loss)	$ 3,946	$ 1,891
Adjustments to reconcile net income (loss) to net cash flows provided by (used in) operating activities		
Depreciation, amortization, and accretion, including nuclear fuel and contract amortization	2,898	1,945
Deferred income taxes and amortization of ITCs	932	248
Net fair value changes related to derivatives	(776)	328
Net realized and unrealized (gains) losses on NDT funds	(384)	(588)
Net realized and unrealized (gains) losses on equity investments	32	256
Other non-cash operating activities	(93)	(74)
Changes in assets and liabilities:		
Accounts receivable	462	(184)
Inventories	(181)	(62)
Accounts payable and accrued expenses	(1,099)	(25)
Option premiums received (paid), net	(36)	49
Collateral received (posted), net	25	(192)
Income taxes	177	423
Pension and non-pension postretirement benefit contributions	(225)	(193)
Other assets and liabilities	(699)	(390)
Net cash flows provided by (used in) operating activities	4,979	3,432
Cash flows from investing activities		
Capital expenditures	(3,461)	(1,963)
Proceeds from NDT fund sales	6,423	5,525
Investment in NDT funds	(6,688)	(5,773)
Acquisition of Calpine, net of cash and restricted cash acquired	(2,537)	—
Other investing activities	199	(10)
Net cash flows provided by (used in) investing activities	(6,064)	(2,221)
Cash flows from financing activities		
Change in short-term borrowings	2,092	—
Proceeds from short-term borrowings with maturities greater than 90 days	4,500	1,650
Repayments of short-term borrowings with maturities greater than 90 days	(4,250)	—
Issuance of long-term debt	5,001	—
Retirement of long-term debt	(5,460)	(1,036)
Dividends paid on common stock	(459)	(365)
Repurchases of common stock	(3,001)	(400)
Other financing activities	(77)	(98)
Net cash flows provided by (used in) financing activities	(1,654)	(249)
Increase (decrease) in cash, restricted cash, and cash equivalents	(2,739)	962
Cash, restricted cash, and cash equivalents at beginning of period	3,748	3,129
Cash, restricted cash, and cash equivalents at end of period	$ 1,009	$ 4,091
Supplemental disclosure of non-cash investing and financing activities		
Common stock issued for acquisition of Calpine	$ 17,509	$ —
Exchange of Calpine senior notes for Constellation senior notes	2,290	—
Increase (decrease) in PP&E related to ARO update	(712)	188

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	September 30, 2026	December 31, 2025
ASSETS		
Current assets		
Cash and cash equivalents	$ 603	$ 3,641
Restricted cash and cash equivalents	406	107
Accounts receivable, net	4,537	4,266
Derivative assets	2,187	945
Inventories, net	3,386	1,736
Renewable energy credits	968	789
Assets held for sale	5,661	126
Other	1,171	509
Total current assets	18,919	12,119
Property, plant, and equipment (net of accumulated depreciation and amortization of $20,196 and $19,072, respectively)	41,738	22,474
Deferred debits and other assets		
Nuclear decommissioning trust funds	20,382	19,336
Goodwill	11,499	420
Derivative assets	2,073	450
Other	4,574	2,450
Total deferred debits and other assets	38,528	22,656
Total assets[(a)]	$ 99,185	$ 57,249
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 3,989	$ 1,650
Long-term debt due within one year	359	92
Accounts payable and accrued expenses	4,900	4,294
Derivative liabilities	970	467
Renewable energy credit obligation	1,021	1,075
Other	1,493	366
Total current liabilities	12,732	7,944
Long-term debt	19,039	7,250
Deferred credits and other liabilities		
Deferred income taxes and unamortized ITCs	8,854	3,544
Asset retirement obligations	12,887	13,193
Pension and non-pension postretirement benefit obligations	1,838	1,977
Payables related to Regulatory Agreement Units	5,826	5,334
Derivative liabilities	723	414
Other	4,247	2,740
Total deferred credits and other liabilities	34,375	27,202
Total liabilities[(a)]	66,146	42,396
Commitments and contingencies (Note 15)		
Shareholders' equity		
Common stock (No par value, 1,000 shares authorized, 352 and 312 shares outstanding, respectively)	25,702	11,043
Retained earnings (deficit)	9,376	5,899
Accumulated other comprehensive income (loss), net	(2,366)	(2,425)
Total shareholders' equity	32,712	14,517
Noncontrolling interests	327	336
Total equity	33,039	14,853
Total liabilities and shareholders' equity	$ 99,185	$ 57,249

(a) Our consolidated assets include $4,711 million and $4,551 million as of September 30, 2026 and December 31, 2025, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Our consolidated liabilities include $1,677 million and $914 million at September 30, 2026 and December 31, 2025, respectively, of certain VIEs for which the VIE creditors do not have recourse to us. See Note 17 — 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, 2026					
	Shareholders' Equity					
(In millions, shares in thousands)	Issued Shares	Common Stock	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss), net	Noncontrolling Interests	Total Equity
Balance, December 31, 2025	312,355	$ 11,043	$ 5,899	$ (2,425)	$ 336	$ 14,853
Net income (loss)	—	—	1,590	—	13	1,603
Employee incentive plans	628	24	—	—	—	24
Changes in equity of noncontrolling interests	—	—	—	—	(12)	(12)
Common stock dividends ($0.4265/common share)	—	—	(155)	—	—	(155)
Common stock issued to acquire Calpine	49,376	17,507	—	—	—	17,507
Balance, March 31, 2026	362,359	$ 28,574	$ 7,334	$ (2,425)	$ 337	$ 33,820
Net income (loss)	—	—	513	—	(5)	508
Employee incentive plans	81	71	—	—	—	71
Changes in equity of noncontrolling interests	—	—	—	—	(21)	(21)
Common stock dividends ($0.4265/common share)	—	—	(155)	—	—	(155)
Common stock repurchased	(7,138)	(1,971)	—	—	—	(1,971)
Sale of noncontrolling interests	—	9	—	—	34	43
Other comprehensive income (loss), net of income taxes	—	—	—	27	—	27
Balance, June 30, 2026	355,302	$ 26,683	$ 7,692	$ (2,398)	$ 345	$ 32,322
Net income (loss)	—	—	1,835	—	—	1,835
Employee incentive plans	92	47	—	—	—	47
Changes in equity of noncontrolling interests	—	—	—	—	(18)	(18)
Common stock dividends ($0.4265/common share)	—	—	(151)	—	—	(151)
Common stock repurchased	(3,792)	(1,030)	—	—	—	(1,030)
Common stock issued to acquire Calpine	5	2	—	—	—	2
Other comprehensive income (loss), net of income taxes	—	—	—	32	—	32
Balance, September 30, 2026	351,607	$ 25,702	$ 9,376	$ (2,366)	$ 327	$ 33,039

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, 2025					
	Shareholders' Equity					
(In millions, shares in thousands)	Issued Shares	Common Stock	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss), net	Noncontrolling Interests	Total Equity
Balance, December 31, 2024	312,838	$ 11,402	$ 4,066	$ (2,302)	$ 373	$ 13,539
Net income (loss)	—	—	118	—	11	129
Employee incentive plans	547	(49)	—	—	—	(49)
Changes in equity of noncontrolling interests	—	—	—	—	(6)	(6)
Common stock dividends ($0.3878/common share)	—	—	(122)	—	—	(122)
Capped call option contracts	—	(150)	—	—	—	(150)
Other comprehensive income (loss), net of income taxes	—	—	—	(7)	—	(7)
Balance, March 31, 2025	313,385	$ 11,203	$ 4,062	$ (2,309)	$ 378	$ 13,334
Net income (loss)	—	—	839	—	(6)	833
Employee incentive plans	117	37	—	—	—	37
Changes in equity of noncontrolling interests	—	—	—	—	(15)	(15)
Common stock dividends ($0.3878/common share)	—	—	(122)	—	—	(122)
Common stock repurchased	(1,099)	(404)	—	—	—	(404)
Capped call option contracts	—	103	—	—	—	103
Other comprehensive income (loss), net of income taxes	—	—	—	37	—	37
Balance, June 30, 2025	312,403	$ 10,939	$ 4,779	$ (2,272)	$ 357	$ 13,803
Net income (loss)	—	—	930	—	(1)	929
Employee incentive plans	58	30	—	—	—	30
Changes in equity of noncontrolling interests	—	—	—	—	(14)	(14)
Common stock dividends ($0.3878/common share)	—	—	(121)	—	—	(121)
Common stock repurchased	(183)	—	—	—	—	—
Capped call option contracts	—	53				53
Other comprehensive income, net of income taxes	—	—	—	12	—	12
Balance, September 30, 2025	312,278	$ 11,022	$ 5,588	$ (2,260)	$ 342	$ 14,692

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, 2026	Three Months Ended September 30, 2025	Nine Months Ended September 30, 2026	Nine Months Ended September 30, 2025
Operating revenues	$ 9,550	$ 6,570	$ 28,176	$ 19,459
Operating expenses				
Purchased power and fuel	4,400	3,567	14,775	11,083
Operating and maintenance	1,991	1,511	6,024	4,673
Depreciation and amortization	454	241	1,340	743
Taxes other than income taxes	225	165	661	472
Total operating expenses	7,070	5,484	22,800	16,971
Gain (loss) on sales of assets	12	—	28	—
Operating income (loss)	2,492	1,086	5,404	2,488
Other income and (deductions)				
Interest expense, net	(217)	(134)	(753)	(398)
Other, net	(44)	443	605	729
Total other income and (deductions)	(261)	309	(148)	331
Income (loss) before income taxes	2,231	1,395	5,256	2,819
Income tax (benefit) expense	405	466	1,333	928
Equity in income (losses) of unconsolidated affiliates	9	—	23	—
Net income (loss)	1,835	929	3,946	1,891
Net income (loss) attributable to noncontrolling interests	—	(1)	8	4
Net income (loss) attributable to membership interest	$ 1,835	$ 930	$ 3,938	$ 1,887
Comprehensive income (loss), net of income taxes				
Net income (loss)	$ 1,835	$ 929	$ 3,946	$ 1,891
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	—	(1)	(1)	(3)
Actuarial loss reclassified to periodic cost	31	19	85	54
Pension and non-pension postretirement benefit plan valuation adjustment	—	—	(25)	(34)
Unrealized gain (loss) on cash flow hedges	1	2	4	5
Unrealized gain (loss) on foreign currency translation	—	(8)	(4)	20
Other comprehensive income (loss), net of income taxes	32	12	59	42
Comprehensive income (loss)	1,867	941	4,005	1,933
Comprehensive income (loss) attributable to noncontrolling interests	—	(1)	8	4
Comprehensive income (loss) attributable to membership interest	$ 1,867	$ 942	$ 3,997	$ 1,929

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, 2026	2025
Cash flows from operating activities		
Net income (loss)	$ 3,946	$ 1,891
Adjustments to reconcile net income (loss) to net cash flows provided by (used in) operating activities		
Depreciation, amortization, and accretion, including nuclear fuel and contract amortization	2,898	1,945
Deferred income taxes and amortization of ITCs	932	248
Net fair value changes related to derivatives	(776)	328
Net realized and unrealized (gains) losses on NDT funds	(384)	(588)
Net realized and unrealized (gains) losses on equity investments	32	256
Other non-cash operating activities	(181)	(139)
Changes in assets and liabilities:		
Accounts receivable	465	(201)
Receivables from and payables to affiliates, net	(167)	(51)
Inventories	(181)	(62)
Accounts payable and accrued expenses	(1,118)	(36)
Option premiums received (paid), net	(36)	49
Collateral received (posted), net	25	(192)
Income taxes	177	423
Pension and non-pension postretirement benefit contributions	(225)	(193)
Other assets and liabilities	(434)	(346)
Net cash flows provided by (used in) operating activities	4,973	3,332
Cash flows from investing activities		
Capital expenditures	(3,461)	(1,963)
Proceeds from NDT fund sales	6,423	5,525
Investment in NDT funds	(6,688)	(5,773)
Acquisition of Calpine, net of cash and restricted cash acquired	(2,537)	—
Other investing activities	201	(10)
Net cash flows provided by (used in) investing activities	(6,062)	(2,221)
Cash flows from financing activities		
Change in short-term borrowings	2,092	—
Proceeds from short-term borrowings with maturities greater than 90 days	4,500	1,650
Repayments of short-term borrowings with maturities greater than 90 days	(4,250)	—
Issuance of long-term debt	5,001	—
Retirement of long-term debt	(5,460)	(1,036)
Distributions to member	(3,460)	(914)
Contributions from member	—	156
Other financing activities	(69)	(45)
Net cash flows provided by (used in) financing activities	(1,646)	(189)
Increase (decrease) in cash, restricted cash, and cash equivalents	(2,735)	922
Cash, restricted cash, and cash equivalents at beginning of period	3,720	3,115
Cash, restricted cash, and cash equivalents at end of period	$ 985	$ 4,037
Supplemental disclosure of non-cash investing and financing activities		
Acquisition of Calpine	$ 17,505	$ —
Exchange of Calpine senior notes for Constellation senior notes	2,290	—
Increase (decrease) in PP&E related to ARO update	(712)	188

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	September 30, 2026	December 31, 2025
ASSETS		
Current assets		
Cash and cash equivalents	$ 601	$ 3,641
Restricted cash and cash equivalents	384	79
Accounts receivable, net	4,519	4,251
Derivative assets	2,187	945
Inventories, net	3,386	1,736
Renewable energy credits	968	789
Assets held for sale	5,661	126
Other	1,170	508
Total current assets	18,876	12,075
Property, plant, and equipment (net of accumulated depreciation and amortization of $20,196 and $19,072, respectively)	41,738	22,474
Deferred debits and other assets		
Nuclear decommissioning trust funds	20,382	19,336
Goodwill	11,499	420
Derivative assets	2,073	450
Other	4,567	2,443
Total deferred debits and other assets	38,521	22,649
Total assets[(a)]	$ 99,135	$ 57,198
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 3,989	$ 1,650
Long-term debt due within one year	359	92
Accounts payable and accrued expenses	4,775	4,033
Payables to affiliates	198	365
Derivative liabilities	970	467
Renewable energy credit obligation	1,021	1,075
Other	1,491	358
Total current liabilities	12,803	8,040
Long-term debt	19,039	7,250
Deferred credits and other liabilities		
Deferred income taxes and unamortized ITCs	8,854	3,544
Asset retirement obligations	12,887	13,193
Pension and non-pension postretirement benefit obligations	1,838	1,977
Payables related to Regulatory Agreement Units	5,826	5,334
Derivative liabilities	723	414
Other	4,199	2,583
Total deferred credits and other liabilities	34,327	27,045
Total liabilities[(a)]	66,169	42,335
Commitments and contingencies (Note 15)		
Equity		
Member's equity		
Membership interest	24,718	10,144
Undistributed earnings (deficit)	10,287	6,808
Accumulated other comprehensive income (loss), net	(2,366)	(2,425)
Total member's equity	32,639	14,527
Noncontrolling interests	327	336
Total equity	32,966	14,863
Total liabilities and equity	$ 99,135	$ 57,198

(a) Our consolidated assets include $4,711 million and $4,551 million as of September 30, 2026 and December 31, 2025, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Our consolidated liabilities include $1,677 million and $914 million as of September 30, 2026 and December 31, 2025, respectively, of certain VIEs for which the VIE creditors do not have recourse to us. See Note 17 — 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, 2026				
	Member's Equity				
(In millions)	Membership Interest	Undistributed Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss), net	Noncontrolling Interests	Total Equity
Balance, December 31, 2025	$ 10,144	$ 6,808	$ (2,425)	$ 336	$ 14,863
Net income (loss)	—	1,590	—	13	1,603
Changes in equity of noncontrolling interests	—	—	—	(12)	(12)
Contribution from member	30	—	—	—	30
Distributions to member	—	(155)	—	—	(155)
Acquisition of Calpine	17,503	—	—	—	17,503
Balance, March 31, 2026	$ 27,677	$ 8,243	$ (2,425)	$ 337	$ 33,832
Net income (loss)	—	513	—	(5)	508
Changes in equity of noncontrolling interests	—	—	—	(21)	(21)
Contribution from member	22	—	—	—	22
Distributions to member	(1,971)	(154)	—	—	(2,125)
Sale of noncontrolling interests	9	—	—	34	43
Other comprehensive income (loss), net of income taxes	—	—	27	—	27
Balance, June 30, 2026	$ 25,737	$ 8,602	$ (2,398)	$ 345	$ 32,286
Net income (loss)	—	1,835	—	—	1,835
Changes in equity of noncontrolling interests	—	—	—	(18)	(18)
Contribution from member	9	—	—	—	9
Distributions to member	(1,030)	(150)	—	—	(1,180)
Acquisition of Calpine	2	—	—	—	2
Other comprehensive income (loss), net of income taxes	—	—	32	—	32
Balance, September 30, 2026	$ 24,718	$ 10,287	$ (2,366)	$ 327	$ 32,966

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, 2025				
	Member's Equity				
(In millions)	Membership Interest	Undistributed Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss), net	Noncontrolling Interests	Total Equity
Balance, December 31, 2024	$ 10,538	$ 4,974	$ (2,302)	$ 373	$ 13,583
Net income (loss)	—	118	—	11	129
Changes in equity of noncontrolling interests	—	—	—	(6)	(6)
Distributions to member	(150)	(122)	—	—	(272)
Other comprehensive income (loss), net of income taxes	—	—	(7)	—	(7)
Balance, March 31, 2025	$ 10,388	$ 4,970	$ (2,309)	$ 378	$ 13,427
Net income (loss)	—	839	—	(6)	833
Changes in equity of noncontrolling interests	—	—	—	(15)	(15)
Contribution from member	103	—	—	—	103
Distributions to member	(400)	(121)	—	—	(521)
Other comprehensive income (loss), net of income taxes	—	—	37	—	37
Balance, June 30, 2025	$ 10,091	$ 5,688	$ (2,272)	$ 357	$ 13,864
Net income (loss)	—	930	—	(1)	929
Changes in equity of noncontrolling interests	—	—	—	(14)	(14)
Contribution from member	53	—	—	—	53
Distributions to member	—	(121)	—	—	(121)
Other comprehensive income (loss), net of income taxes	—	—	12	—	12
Balance, September 30, 2025	$ 10,144	$ 6,497	$ (2,260)	$ 342	$ 14,723

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 the nation's largest producer of clean and reliable energy and a leading supplier of energy products and services. Our fleet of generation assets includes nuclear, natural gas, oil, hydroelectric, geothermal, wind, and solar facilities. 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, public sector, and residential customers in markets across multiple geographic regions. We have six reportable segments: Mid-Atlantic, Midwest, New York, ERCOT, Other Power Regions, and Calpine.

Basis of Presentation

The accompanying Consolidated Financial Statements as of September 30, 2026 and for the three and nine months ended September 30, 2026 and 2025 are unaudited but, in our opinion, include all adjustments that are considered necessary for a fair statement of the results for the periods reported herein in accordance with GAAP. All adjustments are of a normal, recurring nature, unless otherwise disclosed. The Consolidated Financial Statements include the accounts of our subsidiaries and all intercompany transactions have been eliminated in consolidation. Our December 31, 2025 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, 2026. 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. Certain prior period amounts have been reclassified to conform to the presentation in the current period. Amounts disclosed relate to CEG Parent and Constellation unless specifically noted as relating to CEG Parent only. Unless otherwise indicated or the context otherwise requires, references herein to the terms “we,” “us,” and “our” refer collectively to CEG Parent and Constellation.

Summary of Significant Accounting Policies

See Note 1 — Basis of Presentation of our 2025 Form 10-K for additional information on significant accounting policies.

2. Mergers, Acquisitions, and Dispositions

Agreement to Acquire Rhode Island State Energy Center

In September 2026, we entered into an agreement to acquire all of the equity interests in RISEC Holdings, LLC, the owner of the Rhode Island State Energy Center, from Shell Energy North America (US), L.P. for $715 million, subject to customary purchase price adjustments. The Rhode Island State Energy Center is a natural gas-fired combined-cycle electric generation facility with a generating capacity of 609 MW. Completion of the transaction is subject to receipt of required regulatory approvals and other customary closing conditions.

Acquisition of Calpine Corporation

On January 7, 2026 (the Acquisition Date), we acquired all of the outstanding equity interests in Calpine in a cash and stock transaction. Pursuant to the Merger Agreement and related transaction steps, Calpine was converted into a limited liability company, Calpine LLC, and became a wholly owned subsidiary of Constellation.

This acquisition is complementary to, and aligns strategically with, our existing business operations and provides both increased scale and meaningful market diversification. The merger couples the largest producer of clean, emissions-free energy in the United States with the reliable, dispatchable natural gas assets of Calpine, and also creates the nation’s leading competitive retail electric supplier, providing increased scale, diversification and complementary capabilities that enable us to meet growing demand with a broad array of energy and

sustainability products. The addition of Calpine strengthens our essential role in providing clean, reliable energy as the nation seeks to transition to a more sustainable future, and will improve our position to pursue investments in new and existing technologies to meet growing demand.

The merger consideration consisted of 50 million newly issued shares of our common stock, no par value, and approximately $4.5 billion in cash. In connection with the merger, certain of the newly issued shares are subject to a lock-up period, with 50% of the shares released on June 30, 2026, and the remaining 50% scheduled for release on June 30, 2027. In June 2026, the lock-up restrictions were waived for 11 million of these shares to permit their sale in an underwritten secondary public offering, which included two million shares that were repurchased by the Company. We did not sell any shares or receive any proceeds from the offering.

Calpine operates a competitive retail electric supplier platform serving approximately 62 TWhs of load annually. Calpine also owns and operates a generation fleet of natural gas, oil, geothermal, battery storage, and solar assets with approximately 23 GWs of generation capacity, after considering divestitures required by certain regulatory approvals for the transaction.

The transaction was accounted for as a business combination using the acquisition method of accounting where we are considered the acquirer for accounting purposes. We recognized the identifiable assets acquired and liabilities assumed at their estimated fair values as of January 7, 2026, with any excess of the consideration transferred over the fair value of net identifiable assets recognized as goodwill.

Required Divestitures

Under the terms of the DOJ resolution, which provided the final regulatory clearance for the merger, we were required to enter into definitive agreements to divest our minority interest in the Gregory Power Plant, five generation assets in PJM, and the Brazos Valley Energy Center (f/k/a Jack A. Fusco Energy Center) in ERCOT within 240 days after the acquisition closed, or by September 4, 2026.

In January 2026, we completed the divestiture of Calpine's minority ownership interest in the Gregory Power Plant for $136 million. In October 2026, we completed the divestiture of the Brazos Valley Energy Center, a 606 MW natural gas-fired plant in ERCOT, to LS Power Equity Advisors, LLC (LS Power) for $860 million before closing adjustments, which we expect to result in a gain on sale of approximately $250 million in the fourth quarter of 2026.

In March 2026, we entered into an agreement with LS Power whereby we will sell five generation assets in PJM to LS Power, which comprise approximately 4.4 GW of predominantly natural gas-fired generation capacity located in Delaware and Pennsylvania, for aggregate consideration of $5.0 billion before closing adjustments. Closing of the transaction, which we expect to occur by the end of this year, is subject to receipt of applicable regulatory approvals and other customary closing conditions.

Consideration Transferred

The following table summarizes the components of the total merger consideration transferred. There was no contingent consideration associated with the acquisition.

Fair value of CEG Parent common stock issued[(a)]	$	17,603
Cash consideration[(b)]		4,342
Fair value of common stock subject to vesting period attributable to post-combination expense[(c)]		(94)
Effective settlement of preexisting relationships		(14)
Total merger consideration	$	21,837

(a) Represents the fair value of approximately 50 million shares of CEG Parent common stock issued in connection with the acquisition, calculated using CEG Parent's closing stock price of $354.58 on January 6, 2026, the last trading day prior to the Acquisition Date. The fair value of the stock consideration is based on an observable market price and represents a Level 1 fair value measurement.

(b) Represents cash paid to Calpine shareholders in connection with the acquisition. The amount reflects the $4.5 billion base cash consideration per the Merger Agreement, reduced by certain adjustments based on contractual terms also specified in the Merger Agreement.

(c) Certain CEG Parent common stock issued to Calpine employees in exchange for their equity interests is subject to a vesting period of up to 26 months and has been excluded from merger consideration. These amounts will be recognized as stock-based compensation expense over the applicable vesting period in accordance with authoritative guidance.

Purchase Price Allocation

The following table summarizes the Acquisition Date fair value of the consideration transferred and the identifiable assets acquired and liabilities assumed. Accounting guidance provides that the allocation of the purchase price may be modified up to one year from the date of acquisition to the extent that additional information is obtained about the facts and circumstances that existed as of the acquisition date. Any change could result in a change in the amount of goodwill recognized. During the third quarter of 2026, we recorded adjustments to the purchase price allocation based on additional information related to facts and circumstances that existed as of the Acquisition Date which was obtained subsequent to the Acquisition Date. The adjustments, including the resulting effect on goodwill, were not material.

Assets acquired:		
Cash and cash equivalents	$	1,540
Restricted cash and cash equivalents		261
Accounts receivable		761
Derivative assets		2,140
Inventories		989
Assets held for sale[(a)]		5,603
Property, plant, and equipment		18,490
Renewable energy credits		180
Unamortized energy contracts[(b)]		2,133
Other assets		700
Total assets acquired	$	32,797
Liabilities assumed:		
Accounts payable and accrued expenses	$	1,548
Long-term debt (including amounts due within one year)[(c)]		12,551
Derivative liabilities		644
Renewable energy credit obligation		258
Deferred income taxes and unamortized ITCs		4,118
Asset retirement obligations		359
Unamortized energy contracts[(b)]		1,815
Other liabilities		746
Total liabilities assumed		22,039
Net identifiable assets acquired		10,758
Goodwill[(d)]		11,079
Total consideration transferred	$	21,837

(a) Assets Held for Sale. Reflects the Acquisition Date fair value, less costs to sell, for the six generating assets required to be divested. Depreciation and amortization of these assets ceased upon classification as held for sale. No impairment has been recognized subsequent to initial classification. The following table presents the carrying amounts of the major classes of assets and liabilities classified as held for sale as of the Acquisition Date:

Assets held for sale:		
Property, plant and equipment	$	5,454
Inventories		136
Other assets		13
Total assets held for sale	$	5,603
Liabilities associated with assets held for sale:		
Asset retirement obligations	$	16
Other liabilities		82
Total liabilities associated with assets held for sale	$	98

(b) Unamortized Energy Contracts. The following table summarizes the classification and amounts of UECs in the Consolidated Balance Sheets as of the Acquisition Date:

Other current assets	$	517
Other deferred debits and other assets		1,616
Other current liabilities		367
Other deferred credits and other liabilities		1,448

(c) Long-term Debt (including amounts due within one year). We assumed total debt of $12,551 million at estimated fair value as of the Acquisition Date, comprising $279 million classified as Long-term debt due within one year and $12,272 million classified as Long-term debt, in the Consolidated Balance Sheets. See Note 13 — Debt and Credit Agreements for additional information.

(d) Goodwill. Represents the excess of the purchase price over the estimated fair value of the net assets acquired. Goodwill recognized primarily reflects the expected benefits from increased scale and meaningful market diversification, complementary generation, development activities, retail capabilities, and an enhanced ability to meet growing demand with a broader array of energy and sustainability products, to the extent such benefits are not separately recognizable as identifiable intangible assets. Because the design, restructuring, and integration activities of the combined organization are still ongoing, the $11.1 billion of goodwill has been provisionally allocated to the Calpine segment as of September 30, 2026. This provisional allocation may be revised as future organizational, restructuring, and integration activities are completed. The goodwill recognized in connection with the acquisition is not expected to be deductible for income tax purposes.

Valuation of Significant Assets and Liabilities

The fair values assigned to the assets acquired and liabilities assumed were determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows; discount rates reflecting the risks inherent in the future cash flows; and future market prices, among others. These estimates and assumptions were applied to the valuation of significant acquired assets and assumed liabilities, including property, plant and equipment, assets held for sale, and unamortized energy contracts, and required assessments of current and projected market conditions and operating strategies. Forecasting future cash flows requires assumptions regarding, among other things, forecasted commodity prices for the sale of power and purchases of fuel and the expected operations of the assets, and judgments are also made to determine the expected useful lives assigned to each class of assets acquired and the duration of liabilities assumed.

Other Key Accounting Impacts & Judgments

Identifiable intangible assets acquired and liabilities assumed in connection with the acquisition include customer relationships, trade names, and energy contracts, recorded at estimated fair value. The weighted average amortization periods reflect weighted average useful lives of 15 years for customer relationships, five years for trade names, and six years for energy contracts.

We also recognized the fair value of acquired commodity and interest rate derivatives and related hedging relationships as of the Acquisition Date; related gains or losses subsequent to acquisition will be recognized in earnings consistent with our accounting policies. For additional information on derivative instruments, see Note 12 — Derivative Financial Instruments.

The amounts recognized for property, plant and equipment, identifiable intangible assets and liabilities (including customer relationships, trade names, and unamortized energy contracts) and their useful lives, lease assets and liabilities, asset retirement and environmental obligations, contingencies, and income taxes (including deferred taxes) are provisional and subject to revision during the measurement period.

Acquisition-related costs (e.g., advisory, legal, valuation, and other professional fees) are expensed as incurred and reflected within Operating and maintenance expenses in the Consolidated Statements of Operations and Comprehensive Income. These costs, which are not included in the consideration transferred, were not material for the three and nine months ended September 30, 2026.

Unaudited Pro Forma Results

The following unaudited pro forma financial information for the three and nine months ended September 30, 2026 and 2025 is presented as if the acquisition had occurred on January 1, 2025. The unaudited pro forma financial information is presented for informational purposes only and is not necessarily indicative of the results of operations that would have occurred had the acquisition been completed on that date or of future results.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Unaudited pro forma financial information	**2026**	**2025**	**2026**	**2025**
Operating revenues	$ 9,550	$ 9,446	$ 28,406	$ 27,248
Net income[(a)]	1,835	1,550	3,938	2,666

(a) Reflects Net income attributable to common shareholders for CEG Parent and Net income attributable to membership interest for Constellation.

The unaudited pro forma financial information presented above includes adjustments for incremental depreciation and amortization as a result of the fair value determination of the net assets acquired, the effects of the acquisition on tax expense (benefit), and other acquisition accounting adjustments.

As discussed in Note 5 — Segment Information, Calpine is now presented as a reportable segment, and RNF is the segment performance metric, a component of which includes revenue. Operating revenues attributable to Calpine following the Acquisition Date were $3,489 million and $8,531 million for the three and nine months ended September 30, 2026, respectively. However, as a result of the commencement of integration activities for certain functions and the consolidation of financing activities (see Note 13 — Debt and Credit Agreements), it is impracticable to determine Calpine's earnings since the Acquisition Date.

3. Regulatory Matters

As discussed in Note 3 — Regulatory Matters of our 2025 Form 10-K, we are involved in various regulatory and legislative proceedings. The following discusses developments in 2026 and updates to the 2025 Form 10-K.

Capacity Interconnection Rights for Crane Clean Energy Center

In 2024, we announced the restart of Three Mile Island Unit 1, renamed as the Crane Clean Energy Center. The restart is supported by a 20-year PPA with Microsoft to purchase the output generated from the renewed plant. The restart of the plant and delivery of electricity under the PPA is subject to certain regulatory approvals,

including the NRC comprehensive safety and environmental review, as well as permits from relevant state and local agencies.

PJM's Phase I System Impact Study for Crane identified contingent transmission upgrades that would need to be completed for Crane to be fully deliverable to the grid, some of which suggested projected in-service dates extending as late as December 2030.

In March 2026, we filed a waiver request with FERC to allow the transfer of capacity interconnection rights (CIRs) from Eddystone to Crane with the aim of reducing the number of contingent upgrades that would need to be completed prior to Crane being fully deliverable to the grid. Eddystone Units 3 and 4 were previously announced as having a planned retirement date of May 31, 2025, but have been required to continue operating as energy-only resources under DOE emergency orders issued in 2025 and 2026 for grid reliability. Transferring the Eddystone CIRs to Crane will not affect PJM's ability to operate and dispatch Eddystone for reliability in compliance with the DOE's orders. In June 2026, FERC granted the waiver request and we subsequently transferred the CIRs to Crane.

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 2025 Form 10-K for additional information regarding the performance obligations, revenue recognition, and payment terms associated with these sources of revenue.

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, 2026. This disclosure only includes components of contracts for which consideration is fixed and determinable. The average contract term varies by customer type and commodity but ranges from one month to several years. This disclosure excludes derivatives and certain power and gas sales contracts which contain variable volumes and/or variable pricing.

	2026	2027	2028	2029	2030	2031 and thereafter	Total
Remaining performance obligations	$ 439	$ 1,873	$ 1,655	$ 1,538	$ 969	$ 5,646	$ 12,120

Transaction Price Allocated to Previously Satisfied Performance Obligations

Our Clinton and Quad Cities units contract with certain utilities in Illinois which requires delivery of all ZECs produced during each planning year (June through May), with total compensation limited by an annual cap for each planning year designed to limit the cost of ZECs to each utility's customers. ZECs delivered that, if paid, would result in the annual cap being exceeded may be paid in subsequent years at the vintage year price as long as the payments would not exceed the annual cap in the year paid. The program commenced June 2017 and continues through May 2027. In various planning years since the program began, 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 2026 through May 2027 planning year, the final year of the program, the ZEC price has been established at $1.02 per ZEC, subject to an annual cap of $228 million. ZECs generated and delivered during the current planning year will not exceed the annual cap, and as a result we recognized $85 million of revenue during the second quarter of 2026 as a receivable for all remaining ZECs delivered in prior planning years, with payment expected in the third quarter of 2027. As of September 30, 2026, this receivable is included within Accounts receivable, net in the Consolidated Balance Sheets.

For the June 2025 through May 2026 planning year, the ZEC price was established at $1.17 per ZEC, subject to an annual cap of $224 million. ZECs generated and delivered during this planning year did not exceed the annual cap, and as a result we recognized $201 million of revenue during the second quarter of 2025 as a receivable for ZECs delivered in prior planning years, with payment received in the third quarter of 2026.

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. The following tables disaggregate the revenue recognized from contracts with customers between power revenues, capacity revenues, natural gas revenues, and other revenues. Power revenues and capacity revenues are further disaggregated by ISO/RTO and/or geographic location, which include PJM, MISO, ERCOT, NYISO, ISO-NE, West (which includes operations in CAISO, Arizona and Oregon), SERC (which includes operations in SERC not included in MISO or PJM), SPP, and International Power (which includes operations in the United Kingdom and Canada).

Three Months Ended September 30, 2026	Power and Power-related Revenues[a]	Capacity Revenues[b]	Other Revenues	Total
PJM	$ 2,991	$ 171	$ —	$ 3,162
MISO	311	12	—	323
ERCOT	566	105	—	671
NYISO	560	14	—	574
ISO-NE	749	2	—	751
West	363	190	—	553
SERC/SPP	28	2	—	30
International Power	229	—	—	229
Total power revenues	5,797	496	—	6,293
Gas revenues[c]	—	—	322	322
Other revenues[d]	—	—	161	161
Total revenue from contracts with customers	5,797	496	483	6,776
Other revenue sources[e]	—	—	2,774	2,774
Total Operating revenues	$ 5,797	$ 496	$ 3,257	$ 9,550

Three Months Ended September 30, 2025	Power and Power-related Revenues[a]	Capacity Revenues[b]	Other Revenues	Total
PJM	$ 2,636	$ 97	$ —	$ 2,733
MISO	286	1	—	287
ERCOT	373	—	—	373
NYISO	582	—	—	582
ISO-NE	926	—	—	926
West	304	1	—	305
SERC/SPP	21	5	—	26
International Power	121	—	—	121
Total power revenues	5,249	104	—	5,353
Gas revenues[c]	—	—	256	256
Other revenues[d]	—	—	94	94
Total revenue from contracts with customers	5,249	104	350	5,703
Other revenue sources[e]	—	—	867	867
Total Operating revenues	$ 5,249	$ 104	$ 1,217	$ 6,570

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

Note 4 — Revenue from Contracts with Customers

Nine Months Ended September 30, 2026	Power and Power-related Revenues[a]	Capacity Revenues[b]	Other Revenues	Total
PJM	$ 9,065	$ 425	$ —	$ 9,490
MISO	827	26	—	853
ERCOT	1,348	301	—	1,649
NYISO	1,820	40	—	1,860
ISO-NE	2,418	8	—	2,426
West	778	501	—	1,279
SERC/SPP	114	7	—	121
International Power	423	—	—	423
Total power revenues	16,793	1,308	—	18,101
Gas revenues[c]	—	—	1,592	1,592
Other revenues[d]	—	—	467	467
Total revenue from contracts with customers	16,793	1,308	2,059	20,160
Other revenue sources[e]	—	—	8,016	8,016
Total Operating revenues	$ 16,793	$ 1,308	$ 10,075	$ 28,176

Nine Months Ended September 30, 2025	Power and Power-related Revenues[a]	Capacity Revenues[b]	Other Revenues	Total
PJM	$ 7,881	$ 142	$ —	$ 8,023
MISO	791	1	—	792
ERCOT	1,003	—	—	1,003
NYISO	1,771	—	—	1,771
ISO-NE	2,818	—	—	2,818
West	628	3	—	631
SERC/SPP	81	12	—	93
International Power	211	—	—	211
Total power revenues	15,184	158	—	15,342
Gas revenues[c]	—	—	1,359	1,359
Other revenues[d]	—	—	268	268
Total revenue from contracts with customers	15,184	158	1,627	16,969
Other revenue sources[e]	—	—	2,490	2,490
Total Operating revenues	$ 15,184	$ 158	$ 4,117	$ 19,459

(a) Represents power and power-related revenues, including state-sponsored program revenues, ancillary revenues, and revenues from bundled contracts with customers.
(b) Represents revenues from regulated capacity auctions as well as bilateral capacity revenues recognized at negotiated contract prices.
(c) Represents natural gas sales and other gas-related revenues.
(d) Other revenues primarily includes the sales of other energy-related products and sustainable solutions.
(e) Other revenue sources primarily includes revenues accounted for as derivatives, leases, and amortization of intangible assets and liabilities related to commodity contracts recorded at fair value from acquisitions.

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 six reportable segments consisting of the Mid-Atlantic, Midwest, New York, ERCOT, all other power regions referred to collectively as “Other Power Regions,” and Calpine.

Following the acquisition of Calpine on January 7, 2026, Calpine's operations are being reported as a new reportable segment given the results of its operations are currently reviewed by the CODM separately from our historical reporting segments.

With the exception of Calpine, 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 six 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.
- **Calpine** represents operations acquired through the merger with Calpine on January 7, 2026, which are located throughout the country, including CAISO, ERCOT, PJM, ISO-NE, NYISO, MISO, SERC, Arizona, Oregon, as well as Canada.

Our CEO is considered the CODM and evaluates the performance of our electric business activities and allocates resources based on segment RNF, primarily through review of budget-to-actual variance analyses. RNF is Operating revenues net of Purchased power and fuel expenses. 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 nor deemed more useful than the GAAP information provided elsewhere in this report. In our evaluation of operating segments, we noted the CODM reviews a variety of performance and profitability measures at a consolidated level with a primary focus on RNF reporting at the geographic regional level, with the exception of Calpine which is currently reviewed on a standalone basis. Our operating revenues include all sales to third parties as well as government assistance. Purchased power and fuel expenses are considered the most significant segment expense. 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 nor included in the reportable segment amounts. These activities include wholesale and retail sales of natural gas, with the exception of Calpine's natural gas sales which are included in the Calpine segment, energy-related sales in the United Kingdom, as well as sales of other energy-related products and sustainable solutions

that are not significant to our overall results of operations. Further, our unrealized 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 reportable segment amounts. The CODM does not use a measure of total assets in making decisions regarding allocating resources to or assessing the performance of these reportable segments.

The following tables, which relate directly to our Consolidated Statements of Operations and Comprehensive Income, provide the reconciliation of Operating revenues, Purchased power and fuel expenses, and RNF for our reportable segments for the three and nine months ended September 30, 2026 and 2025.

	2026			2025		
Three Months Ended September 30,	**Operating revenues**	**Purchased power and fuel expenses**	**RNF**	**Operating revenues**	**Purchased power and fuel expenses**	**RNF**
Mid-Atlantic	$ 1,877	$ (850)	$ 1,027	$ 1,763	$ (871)	$ 892
Midwest	1,562	(630)	932	1,390	(447)	943
New York	569	(157)	412	558	(159)	399
ERCOT	592	(247)	345	628	(213)	415
Other Power Regions	1,099	(839)	260	1,543	(1,200)	343
Calpine	3,384	(1,457)	1,927	—	—	—
Total reportable segments	9,083	(4,180)	4,903	5,882	(2,890)	2,992
Other[a]	467	(220)	247	688	(677)	11
Total consolidated results	$ 9,550	$ (4,400)	$ 5,150	$ 6,570	$ (3,567)	$ 3,003
Nine Months Ended September 30,						
Mid-Atlantic	$ 5,279	$ (2,451)	$ 2,828	$ 4,876	$ (2,393)	$ 2,483
Midwest	4,862	(2,098)	2,764	4,317	(1,489)	2,828
New York	1,702	(491)	1,211	1,655	(458)	1,197
ERCOT	1,408	(571)	837	1,489	(589)	900
Other Power Regions	3,551	(2,734)	817	4,277	(3,560)	717
Calpine	7,926	(3,845)	4,081	—	—	—
Total reportable segments	24,728	(12,190)	12,538	16,614	(8,489)	8,125
Other[b]	3,448	(2,585)	863	2,845	(2,594)	251
Total consolidated results	$ 28,176	$ (14,775)	$ 13,401	$ 19,459	$ (11,083)	$ 8,376

(a) Represents activities not allocated to a segment. See text above for a description of included activities. Operating revenues include unrealized losses of $362 million and losses of $156 million for the three months ended September 30, 2026 and 2025, respectively. Purchased power and fuel expenses include unrealized gains of $482 million and gains of $25 million for the three months ended September 30, 2026 and 2025, respectively.

(b) Represents activities not allocated to a segment. See text above for a description of included activities. Operating revenues include unrealized gains of $633 million and losses of $356 million for the nine months ended September 30, 2026 and 2025, respectively. Purchased power and fuel expenses include unrealized gains of $109 million and gains of $70 million for the nine months ended September 30, 2026 and 2025, respectively.

6. Government Assistance

Beginning in 2024, our nuclear units are eligible for a PTC extending through 2032. See Note 1 — Basis of Presentation and Note 6 — Government Assistance of our 2025 Form 10-K for additional information on nuclear PTCs.

For the three and nine months ended September 30, 2026, we did not record a material nuclear PTC benefit as the estimate of full year gross receipts exceeded the phase-out for annual gross receipts per MWh for most units. For the three and nine months ended September 30, 2025, our Consolidated Statements of Operations and Comprehensive Income included an estimated nuclear PTC benefit in Operating revenues of approximately $175 million and $220 million, respectively. As of September 30, 2026 and December 31, 2025, our Consolidated Balance Sheets reflect approximately $195 million and $120 million, respectively, of nuclear PTCs within Other deferred debits and other assets. For the nine months ended September 30, 2026, we did not utilize any estimated nuclear PTCs as a credit against our current federal income taxes payable. For the year ended December 31, 2025, we recognized a reduction to Accounts payable and accrued expenses in our Consolidated Balance Sheets of $375 million for estimated nuclear PTCs that we have utilized as a credit against our current federal income taxes payable.

Many of the state-sponsored programs providing compensation for the emissions-free attributes of generation from certain of our nuclear units include contractual or other provisions that require us to refund that compensation up to the amount of the nuclear PTC received or pass through the entirety of the nuclear PTC received. As of September 30, 2026 and December 31, 2025, we have recognized approximately $155 million and $1,190 million, respectively, of estimated payables within Other deferred credits and other liabilities, Accounts payable and accrued expenses or as offsets to Accounts receivable, net in our Consolidated Balance Sheets associated with programs requiring refunds or pass through of the nuclear PTC. In general, we expect to remit refunds or pass-throughs of state-sponsored program compensation related to nuclear PTCs in the year following the filing of the related tax return. During the nine months ended September 30, 2026, we refunded or offset against outstanding receivables approximately $1,030 million associated with state-sponsored program compensation relating to the nuclear PTCs recorded in 2024. During the three and nine months ended September 30, 2026, we recognized a reduction to net operating revenue (pre-tax) of approximately $280 million and $555 million, respectively, associated with these programs in our Consolidated Statements of Operations and Comprehensive Income, compared to a reduction to net operating revenue (pre-tax) of approximately $220 million and $30 million during the three and nine months ended September 30, 2025, respectively.

7. Accounts Receivable

The following table provides information on the disaggregation of Accounts receivable, net:

	Accounts receivable, net	
September 30, 2026	**CEG Parent**	**Constellation**
Customer accounts receivable (net of allowance for credit losses of $154 for CEG Parent and Constellation)	$ 3,833	$ 3,833
Other accounts receivable (net of allowance for credit losses of $— for CEG Parent and Constellation)	704	686
Total	$ 4,537	$ 4,519
December 31, 2025		
Customer accounts receivable (net of allowance for credit losses of $158 for CEG Parent and Constellation)	$ 3,577	$ 3,577
Other accounts receivable (net of allowance for credit losses of $9 for CEG Parent and Constellation)	689	674
Total	$ 4,266	$ 4,251

Allowance for Credit Losses on Accounts Receivable

The following table presents the rollforward of allowance for credit losses on customer accounts receivable from January 1, 2026 to September 30, 2026.

Balance as of January 1, 2026	$	158
Current period provision for expected credit losses		45
Write-offs, net of recoveries[(a)]		(49)
Balance as of September 30, 2026	$	154

(a) Recoveries were not material.

The allowance for credit losses on other accounts receivable was not material as of the balance sheet dates, therefore, a rollforward is not presented.

Unbilled Customer Revenue

We recorded $1,694 million and $1,305 million of unbilled customer revenues in Accounts receivable, net in the Consolidated Balance Sheets as of September 30, 2026 and December 31, 2025, respectively.

Calpine Accounts Receivable Sales Program

Following the acquisition of Calpine on January 7, 2026, the Company has assumed Calpine's Accounts Receivable Sales Program (Calpine AR Facility). The Calpine AR Facility was established by Calpine in December 2016 and was last renewed in November 2025 with a current expiration of November 2026. The Calpine AR Facility is a receivables purchase agreement between Calpine Energy Solutions, LLC and Calpine Receivables, LLC, a wholly-owned subsidiary that is accounted for as an unconsolidated VIE, along with an additional purchase and sale agreement between Calpine Receivables, LLC, and unaffiliated financial institutions, the combination of which allows for the revolving sale of up to $500 million in certain trade accounts receivables of Calpine Energy Solutions, LLC to third parties at a nominal discount.

Receivables sold under the Calpine AR Facility are accounted for as sales and excluded from Accounts receivable, net in the Consolidated Balance Sheets and reflected as Cash provided by operating activities in the Consolidated Statements of Cash Flows. Any portion of the purchase price for the sold receivables which is not paid in cash is recorded as a short-term note receivable within Accounts receivable, net. Our risk of loss following the transfer of accounts receivable is limited to the short-term note receivable outstanding and our investment in Calpine Receivables, LLC, neither of which are material as of September 30, 2026.

The Company has guaranteed the performance of Calpine Energy Solutions, LLC to Calpine Receivables, LLC under the Calpine AR Facility, see Note 15 — Commitments and Contingencies for additional information. Additionally, see Note 17 — Variable Interest Entities for additional information on Calpine Receivables, LLC and its status as an unconsolidated VIE.

There was $530 million in gross accounts receivable outstanding that were sold at a nominal discount under the Calpine AR Facility as of September 30, 2026, and $491 million of the $500 million facility amount was utilized. The following table summarizes certain activity for the period under the Calpine AR Facility:

		Nine Months Ended September 30, 2026
Aggregate receivables sold during the period	$	3,176
Proceeds collected on sold receivables		3,131

Other Sales of Customer Accounts Receivable

We are required, under supplier tariffs, to sell customer receivables to certain utility companies at a nominal discount. The total gross receivables sold were $2,745 million and $3,207 million for the nine months ended September 30, 2026 and 2025, respectively. Of the total gross receivables sold, only $342 million and $289 million were sold with recourse for the nine months ended September 30, 2026 and 2025, respectively. Our

allowance for credit losses is not materially impacted by our sale of receivables under supplier tariffs with recourse.

8. Property, Plant, and Equipment

The following table presents a summary of property, plant, and equipment balances by asset category as of September 30, 2026 and December 31, 2025:

Asset Category	September 30, 2026	December 31, 2025
Electric[(a)]	$ 51,380	$ 33,253
Nuclear fuel	6,811	6,298
CWIP[(a)]	3,743	1,995
Total property, plant, and equipment	61,934	41,546
Less: accumulated depreciation	20,196	19,072
Property, plant, and equipment, net[(b)]	$ 41,738	$ 22,474

(a) Includes Electric and CWIP assets acquired as a result of the Calpine acquisition of $17,256 million and $1,234 million, respectively, as of September 30, 2026.
(b) Excludes assets held for sale related to regulatory requirements of the acquisition of Calpine. See Note 2 — Mergers, Acquisitions, and Dispositions for additional information.

The estimated useful lives of our generating facilities are based on a combination of depreciation studies, historical retirements, site licenses and management estimates of operating costs and expected energy market conditions. As a result of the acquisition of Calpine, we added a fleet of natural gas, oil, geothermal, battery storage and solar assets. There were no material changes in the estimated useful lives of our combined oil and gas, battery storage, wind and solar facilities as a result. Geothermal facility depreciation provisions are based on an estimated useful life through 2066. For additional information about the useful lives of our generating facilities and depreciation provisions, see Note 8 — Property, Plant, and Equipment of our 2025 Form 10-K.

9. Asset Retirement Obligations

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 2025 Form 10-K for additional information regarding AROs and the financial statement impact of changes in estimates.

The following table provides a rollforward of the nuclear decommissioning AROs reflected in the Consolidated Balance Sheets from December 31, 2025 to September 30, 2026:

Balance as of December 31, 2025	$ 12,908
Accretion expense	474
Net decrease due to changes in, and timing of, estimated future cash flows	(1,150)
Costs incurred related to decommissioning plants	(9)
Balance as of September 30, 2026	$ 12,223

During the nine months ended September 30, 2026, the net $1,150 million decrease in the ARO for the changes in, and timing of, estimated future cash flows was driven by multiple adjustments, including the following:

- Decrease of $1,277 million due primarily to changes in assumed retirement dates for various plants, including Calvert Cliffs, FitzPatrick, Limerick, and Nine Mile Point.
- Increase of $127 million due primarily to higher escalation rates partially offset by higher discount rates and SNF shipment timing.

The 2026 ARO updates resulted in a decrease of $292 million in Operating and maintenance expense for the nine months ended September 30, 2026 in the Consolidated Statements of Operations and Comprehensive Income.

NDT Funds

We had NDT funds totaling $20,447 million and $19,396 million as of September 30, 2026 and December 31, 2025, respectively. The current portions of the NDT funds, which are included in Other current assets in our Consolidated Balance Sheets, were not material as of September 30, 2026 and December 31, 2025. See Note 18 — 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 2025 Form 10-K for additional information on the Regulatory Agreement Units.

The following table presents our noncurrent payables to ComEd, PECO, CenterPoint, and AEP Texas reflected as Payables related to Regulatory Agreement Units in the Consolidated Balance Sheets as of September 30, 2026 and December 31, 2025:

	September 30, 2026	December 31, 2025
ComEd	$ 4,598	$ 4,313
PECO	598	442
CenterPoint	501	430
AEP Texas	129	149
Payables related to Regulatory Agreement Units	$ 5,826	$ 5,334

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 annual decommissioning funding status report with the NRC for our shutdown units, and any units within five years of shutdown in March 2026. The status report demonstrated adequate decommissioning funding assurance as of December 31, 2025 for all units included in the report. See Note 10 — Asset Retirement Obligations of our 2025 Form 10-K for additional information.

Non-Nuclear Asset Retirement Obligations

We have AROs for plant closure costs associated with our natural gas, oil, battery storage, and renewable generating facilities, including geothermal. The obligations include asbestos abatement, removal of certain storage tanks, restoring leased land to the condition it was in prior to construction of renewable generating stations, disposal of hazardous materials, plug and abandonment of wells, and other decommissioning-related activities. See Note 1 — Basis of Presentation of our 2025 Form 10-K for additional information on the accounting policy for AROs.

The following table provides a rollforward of the non-nuclear AROs reflected in the Consolidated Balance Sheets from December 31, 2025 to September 30, 2026:

Balance as of December 31, 2025	$ 317
Acquisition of Calpine[(a)]	359
Accretion expense	28
Development projects	10
Costs incurred related to decommissioning plants	(6)
Net decrease due to changes in, and timing of, estimated future cash flows	(8)
Balance as of September 30, 2026	$ 700

(a) Reflects our decommissioning obligations for Calpine plants acquired on January 7, 2026, which are recorded at estimated fair value. See Note 2 — Mergers, Acquisitions, and Dispositions for additional information. Many of the facilities acquired from Calpine do not have AROs given the absence of legal requirements to perform retirement related activities.

10. Income Taxes

Rate Reconciliation

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

	Three Months Ended September 30,			
	2026		2025	
U.S. federal statutory income tax	21.0 %	$ 469	21.0 %	$ 293
Increase (decrease) due to:				
State income taxes, net of federal income tax benefit[a]	(1.4)	(31)	5.1	71
Foreign tax effects	—	—	0.1	1
Tax credits				
PTC	(0.5)	(11)	(2.8)	(40)
Amortization of ITC, including deferred taxes on basis differences	(0.5)	(11)	(0.3)	(4)
Other	(0.3)	(8)	(0.2)	(3)
Nontaxable or nondeductible items				
Excess officers compensation	—	—	1.0	14
Other	—	—	0.9	12
Other adjustments				
Qualified NDT fund income and losses	(0.1)	(3)	8.6	122
Effective income tax[b]	18.2 %	$ 405	33.4 %	$ 466

	Nine Months Ended September 30,			
	2026		2025	
U.S. federal statutory income tax	21.0 %	$ 1,104	21.0 %	$ 592
Increase (decrease) due to:				
State income taxes, net of federal income tax benefit[a]	1.2	64	4.2	118
Foreign tax effects	—	—	0.1	2
Tax credits				
PTC	(0.4)	(20)	(1.9)	(53)
Amortization of ITC, including deferred taxes on basis differences	(0.4)	(19)	(0.4)	(10)
Other	(0.2)	(12)	(0.3)	(8)
Nontaxable or nondeductible items				
Share-based payment awards	(0.3)	(15)	(1.4)	(40)
Excess officers compensation	0.1	3	1.1	30
Other	0.5	25	0.4	13
Other adjustments				
Qualified NDT fund income and losses	3.9	203	10.1	284
Effective income tax[b]	25.4 %	$ 1,333	32.9 %	$ 928

(a) In 2026, state taxes in Pennsylvania, Maryland, California, and Illinois made up the majority (greater than 50%) of the tax effect in this category. In 2025, state taxes in Illinois, Maryland, Massachusetts, California, Pennsylvania, and New Jersey made up the majority (greater than 50%) of the tax effect in this category.
(b) Amounts may not recalculate due to rounding.

Other Tax Matters

Tax Matters Agreement

In connection with the corporate separation transaction, 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 the taxable periods in which we were included in joint federal and state filings. However, the TMA specifies the portion of this tax liability for which we will bear contractual responsibility, and we and Exelon agreed to indemnify each other against any amounts for which such indemnified party is not responsible. Specifically, we will be liable for taxes due and payable in connection with tax returns that we are required to file. We will also be liable for our share of certain taxes required to be paid by Exelon with respect to taxable years or periods (or portions thereof) ending on or prior to the separation to the extent that we would have been responsible for such taxes under the Exelon tax sharing agreement then existing. As of September 30, 2026 and December 31, 2025, respectively, our Consolidated Balance Sheets reflect $34 million and $43 million in Other deferred credits and other liabilities, for tax liabilities where we maintain contractual responsibility to Exelon.

Tax Refunds and Attributes. The TMA provides for the allocation of certain pre-closing tax attributes between us and Exelon. Tax attributes will be allocated in accordance with the principles set forth in the existing Exelon tax sharing agreement, unless otherwise required by law. Under the TMA, we will be entitled to refunds for taxes for which we are responsible. In addition, it is expected that Exelon will have tax attributes that may be used to offset Exelon's future tax liabilities. A significant portion of such attributes were generated by our business. In March 2026, we adjusted our receivable under the TMA as a result of IRS Notice 2026-7, as discussed below. During the second quarter of 2026 and 2025, we received payments for tax attributes utilized by Exelon related to the 2025 and 2024 tax years of $53 million and $128 million, respectively. As of September 30, 2026 and December 31, 2025, respectively, we had $98 million and $175 million in Accounts receivable, net and $279 million and $21 million in Other deferred debits and other assets for the reclassified tax attributes expected to be utilized by Exelon after separation in accordance with the terms of the TMA.

IRS Notice 2026-7. In February 2026, the IRS issued Notice 2026-7 (the Notice), which provides guidance on the implementation of the corporate alternative minimum tax (CAMT). The Notice permits taxpayers to deduct repair and maintenance costs under tax law principles in determining adjusted financial statement income and applies retroactively to previously filed tax returns. As a result of this Notice, Exelon amended its 2023 and 2024 tax returns to reflect less CAMT and thus lower utilization of previously refunded tax attributes.

We received a demand letter from Exelon in February 2026, and as a result, in March 2026 we remitted $235 million to Exelon under the TMA related to prior periods. We increased our receivable for the $235 million in the first quarter of 2026, as reflected above, as we expect Exelon to pay us as it utilizes these tax attributes in future periods.

11. Retirement Benefits

Components of Net Periodic Benefit (Credits) Costs

See Note 1 — Basis of Presentation of our 2025 Form 10-K for additional information on where we report the service cost and other non-service cost (credit) components for all plans.

The following tables present the components of our net periodic benefit (credit) cost for the three and nine months ended September 30, 2026 and 2025. The amounts below are shown prior to capitalization and co-owner allocations, the effects of which were not material for any of the periods presented.

	Pension Benefits		OPEB		Total Pension Benefits and OPEB	
	2026	2025	2026	2025	2026	2025
Three Months Ended September 30,						
Components of net periodic benefit (credit) cost:						
Service cost	$ 22	$ 21	$ 5	$ 4	$ 27	$ 25
Non-service components of pension benefits & OPEB (credit) cost:						
Interest cost	99	101	19	19	118	120
Expected return on assets	(119)	(122)	(8)	(9)	(127)	(131)
Amortization of:						
Prior service (credit) cost	1	1	(1)	(2)	—	(1)
Actuarial (gain) loss	37	26	—	(2)	37	24
Settlement charges	6	1	—	—	6	1
Non-service components of pension benefits & OPEB (credit) cost	24	7	10	6	34	13
Net periodic benefit (credit) cost	$ 46	$ 28	$ 15	$ 10	$ 61	$ 38
Nine Months Ended September 30,						
Components of net periodic benefit (credit) cost:						
Service cost	$ 65	$ 63	$ 15	$ 13	$ 80	$ 76
Non-service components of pension benefits & OPEB (credit) cost:						
Interest cost	298	306	59	58	357	364
Expected return on assets	(357)	(367)	(23)	(25)	(380)	(392)
Amortization of:						
Prior service (credit) cost	1	1	(4)	(5)	(3)	(4)
Actuarial (gain) loss	113	77	(2)	(6)	111	71
Settlement charges	6	1	—	—	6	1
Non-service components of pension benefits & OPEB (credit) cost	61	18	30	22	91	40
Net periodic benefit (credit) cost	$ 126	$ 81	$ 45	$ 35	$ 171	$ 116

12. Derivative Financial Instruments

We use derivative instruments to manage commodity price risk and interest rate 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, including NPNS, are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. All derivative instruments, excluding NPNS, 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 delivered.

Authoritative guidance for the offsetting of 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 commodity economic hedges are shown gross. The impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, including margin on exchange positions, is aggregated in the collateral and netting columns.

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

Commodity Price Risk

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

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on owned and contracted generation positions that have not been hedged. Beginning in 2024, our existing nuclear fleet is eligible for a nuclear PTC, an important tool in managing commodity price risk for each nuclear unit not already receiving state support. The nuclear PTC provides increasing levels of support as unit revenues decline below levels established in the IRA and is further adjusted for inflation annually through the duration of the program based on the GDP price deflator for the preceding calendar year. See Note 6 — Government Assistance for additional information.

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

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 commodity sales and purchases 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.

The following tables provide a summary of the commodity derivative fair value balances recorded as of September 30, 2026 and December 31, 2025:

September 30, 2026	Economic Hedges	Collateral[(a)]	Netting[(a)]	Total
Derivative assets (current)	$ 17,604	$ 526	$ (16,032)	$ 2,098
Derivative assets (noncurrent)	9,688	243	(7,910)	2,021
Total derivative assets	27,292	769	(23,942)	4,119
Derivative liabilities (current)	(17,766)	766	16,032	(968)
Derivative liabilities (noncurrent)	(9,003)	371	7,910	(722)
Total derivative liabilities	(26,769)	1,137	23,942	(1,690)
Total derivative net assets (liabilities)	$ 523	$ 1,906	$ —	$ 2,429
December 31, 2025				
Derivative assets (current)	$ 7,349	$ 375	$ (6,791)	$ 933
Derivative assets (noncurrent)	5,030	272	(4,853)	449
Total derivative assets	12,379	647	(11,644)	1,382
Derivative liabilities (current)	(7,642)	386	6,791	(465)
Derivative liabilities (noncurrent)	(5,585)	319	4,853	(413)
Total derivative liabilities	(13,227)	705	11,644	(878)
Total derivative net assets (liabilities)	$ (848)	$ 1,352	$ —	$ 504

(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.

The following table summarizes the net buy/(sell) notional position of commodity derivative transactions, excluding our NPNS derivatives that are not recorded at fair value, as of September 30, 2026 and December 31, 2025:

	Total Net Position (In Millions)		
Commodity Type	September 30, 2026	December 31, 2025	Unit of Measure
Electricity[(a)]	(651)	(260)	MWh
Natural Gas[(a)]	1,312	33	MMBtu
Emissions	(18)	(35)	Short Ton

(a) The increase in our net notional position as of September 30, 2026 compared to December 31, 2025 is primarily driven by derivatives acquired from Calpine. See Note 2 — Mergers, Acquisitions, and Dispositions for additional information.

Economic Hedges (Commodity Price Risk)

For the three and nine months ended September 30, 2026 and 2025, we recognized the following net pre-tax commodity unrealized gains (losses), which are also included 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,	
Income Statement Location	2026	2025	2026	2025
Operating revenues	$ (361)	$ (158)	$ 632	$ (354)
Purchased power and fuel	480	28	111	67
Total	$ 119	$ (130)	$ 743	$ (287)

Interest Rate Risk

We utilize interest rate swaps to manage our interest rate exposure, which are treated as economic hedges. The notional amounts for interest rate swaps were approximately $4.3 billion and $1.4 billion as of September 30, 2026 and December 31, 2025, respectively.

The derivative assets and liabilities as of September 30, 2026 and December 31, 2025 and the gains and losses associated with management of interest rate risk for the three and nine months ended September 30, 2026 and 2025 were not material. The gains and losses associated with management of interest rate risk are included in the Net fair value changes related to derivatives line in the Consolidated Statements of Cash Flows.

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 right of offset language in the enabling agreement, our credit department establishes credit limits, margining thresholds and collateral requirements for each counterparty, which are defined in the derivative contracts. Counterparty credit limits are based on an internal credit review process that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings by credit rating agencies, and other risk management criteria. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with us, as specified in each enabling agreement. Our credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

The following tables provide information on the credit exposure for derivative instruments, inclusive of payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of September 30, 2026. The amounts in the tables below exclude credit risk exposure from individual retail counterparties, NPNS contracts, forward values on non-derivative contracts and exposure through RTOs, ISOs, as well as commodity exchanges. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties.

Rating as of September 30, 2026	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	$ 1,799	$ 226	$ 1,573	1	$ 300
Non-investment grade	87	30	57	—	—
No external ratings					
Internally rated — investment grade	196	7	189	—	—
Internally rated — non-investment grade	454	164	290	—	—
Total	$ 2,536	$ 427	$ 2,109	1	$ 300

(a) As of September 30, 2026, credit collateral held from counterparties where we had credit exposure included $133 million of cash and $294 million of letters of credit.

Net Credit Exposure by Type of Counterparty	As of September 30, 2026
Investor-owned utilities, marketers, power producers	$ 992
Financial Institutions	487
Energy cooperatives and municipalities	273
Other	357
Total	$ 2,109

Credit-Risk-Related Contingent Features

As part of the normal course of business, we routinely enter into physically and financially settled contracts for the purchase and sale of capacity, electricity, fuels, emissions allowances, and other energy-related products. Certain of our derivative instruments contain provisions that require us to post collateral. We also enter into commodity transactions on exchanges where the exchanges act as the counterparty to each trade. Transactions on the exchanges must adhere to comprehensive collateral and margining requirements. This collateral may be posted in the form of cash or credit support with thresholds contingent upon our credit ratings from S&P and Moody's. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk-related contingent features stipulate that if we were to be downgraded or lose our investment grade credit ratings (based on our senior unsecured debt rating), we would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In such cases, we believe an amount of several months of future payments (e.g., capacity payments) rather than a calculation of fair value is a reasonable 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, 2026	December 31, 2025
Gross fair value of derivative contracts containing this feature	$ (3,127)	$ (1,307)
Offsetting fair value of derivative contracts under master netting arrangements	1,672	554
Net fair value of derivative contracts containing this feature	$ (1,455)	$ (753)

As of September 30, 2026 and December 31, 2025, 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.

	September 30, 2026	December 31, 2025
Cash collateral posted	$ 2,306	$ 1,399
Letters of credit posted	1,457	718
Cash collateral held	400	47
Letters of credit held	338	115
Additional collateral required in the event of a credit downgrade below investment grade (at BB+/Ba1)[a][b][c]	3,649	2,670

(a) 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.
(b) The downgrade collateral is inclusive of all contracts in a liability position regardless of accounting treatment and excludes any contracts with individual retail counterparties.
(c) A loss of investment grade credit rating would require a three-notch downgrade from current levels of BBB+ and Baa1 at S&P and Moody's, respectively.

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

13. Debt and Credit Agreements

Long-Term Debt

Calpine Acquisition

Upon completion of the acquisition of Calpine in January 2026, we assumed approximately $12.6 billion of debt inclusive of approximately $7.6 billion of corporate long-term debt, including senior unsecured and secured notes and corporate term loans in addition to approximately $5.0 billion of various project financing arrangements. Pursuant to the Exchange Offers discussed below, we issued new notes in January 2026 effectively replacing $2.3 billion of Calpine's senior unsecured and secured notes with Constellation senior unsecured notes. Using the proceeds from our January 2026 bond issuance, as discussed below, along with cash on hand and short-term debt, we repaid $2.5 billion of Calpine corporate term loans immediately after the acquisition closing, $1.25 billion of Calpine senior secured first lien notes in February 2026, and $1.4 billion of Calpine senior unsecured notes in March 2026.

As discussed above, the following project financing arrangements were assumed as part of the acquisition:

Geysers Power Company, LLC. We acquired the GPC first lien senior secured term loan facility, which includes a term loan and $250 million letter of credit facility, up to $50 million of which may be used for loans to finance energy storage projects (the sub-facility). At acquisition, outstanding borrowings under the term loan and sub-facility were approximately $1.35 billion and $45 million, respectively. The GPC facility is secured by substantially all of the real and personal property of GPC and subsidiaries, primarily consisting of the Geysers Assets. The facility matures May 2029 and bears interest at SOFR plus 1.625%. As of September 30, 2026, there were $1.2 billion and $42 million of borrowings outstanding under the term loan and sub-facility, respectively.

Calpine Construction Finance Company, L.P. We acquired the CCFC first lien senior secured term loan facility with $2.1 billion outstanding borrowings at acquisition. The CCFC term loan facility is secured by certain real and personal property of CCFC, primarily six natural gas-fired power plants. Brazos Valley Energy Center (Brazos), f/k/a Jack A. Fusco Energy Center secured the facility prior to its release following the plant's sale in October 2026. See Note 2 — Mergers, Acquisitions, and Dispositions for additional information regarding the sale. The term loan matures July 2030 and bears interest at SOFR plus 1.75%. As of September 30, 2026, there was $2.1 billion of borrowings outstanding under the term loan.

CDHI Intermediate Holdco, LLC. We acquired the CDHI facility (CDHI Revolver), a $1.2 billion letter of credit facility, up to $400 million of which can be used for revolving loans to finance construction of renewable energy projects. At acquisition, outstanding borrowings under the CDHI Revolver were $319 million. The CDHI Revolver was secured by substantially all of the assets of CDHI's subsidiaries in accordance with the terms of the agreement. In March 2026 and April 2026, the capacity of the CDHI Revolver was reduced by an aggregate $818 million. In June 2026, in connection with the capacity reductions, the lenders consented to the release of four plants from the collateral securing the facility; the two York Energy Centers, Sutter Energy Center, and South Point Energy Center. The two York Energy Centers which partially secured the CDHI Revolver are being sold. See Note 2 — Mergers, Acquisitions, and Dispositions for additional information regarding the sale. Redemptions prior to March 2026 were based on SOFR plus 2.25%. Effective March 2026 through the termination of the facility, redemptions were based on SOFR plus 2.375%. As of September 30, 2026, there was $269 million of borrowings outstanding under the credit facility. In October 2026, we repaid all outstanding borrowings under the CDHI Revolver, cancelled any outstanding letters of credit, and terminated all commitments which effectively terminated the facility.

Nova Power, LLC. We acquired the Nova Power, LLC credit agreement, which is comprised of a term loan, with $591 million of outstanding borrowings at acquisition, and an $80 million letter of credit facility. The agreement financed a portion of the cost of the development, construction, maintenance, and operation of the Nova Power battery storage project, and is secured by Nova Power's real and personal property. The credit agreement matures September 2031 and bears interest at SOFR plus 1.75%. As of September 30, 2026, there was $560 million of borrowings outstanding under the credit agreement.

Greenfield L.P. We acquired the Greenfield L.P. credit facility, which includes a term loan, with $342 million of outstanding borrowings at acquisition, and several letters of credit facilities, with issuing capacity of approximately $75 million. The Greenfield L.P. credit facility is secured by certain real and personal property, primarily the Greenfield Energy Center in Ontario, Canada. The credit facility matures November 2030 and bears interest at CORRA plus 1.875%. As of September 30, 2026, there was $311 million of borrowings outstanding under the facility.

Pin Oak Creek Energy Center LLC. We acquired Pin Oak Creek Energy Center's obligations under a credit agreement with Texas Energy Fund (TEF), as lender, as administered by the Public Utility Commission of Texas (PUCT). The loan proceeds were used to finance eligible costs for the development (as defined in the agreement), construction, and installation of Pin Oak Creek Energy Center in Fairfield, Texas. The loan had outstanding borrowings of $230 million at acquisition. The loan matures October 2045 and bears interest at 3%. As of September 30, 2026, there was $277 million of borrowings outstanding under the loan.

Calpine Credit Agreements

As a result of the acquisition, we assumed Calpine's corporate secured and unsecured letters of credit facilities with capacity totaling $525 million and $200 million, respectively, at the time of acquisition.

The total capacity of assumed project and corporate credit facilities discussed above was approximately $2.3 billion at the time of acquisition, which was reduced by outstanding borrowings under the GPC facility and CDHI Revolver. At the time of acquisition, there were outstanding letters of credit on the assumed facilities of approximately $1.7 billion. See the Credit Facilities table below for additional information on credit facilities associated with these project financing arrangements.

Debt Exchange Offering

In December 2025, in connection with the planned acquisition of Calpine, we commenced private exchange offers and related consent solicitations for certain outstanding debt of Calpine (the Exchange Offers). We solicited consents from holders of the Calpine debt to amend the notes and the related indentures under which they were issued to eliminate substantially all of the restrictive covenants, restrictive provisions and events of default, other than payment-related and bankruptcy-related events of default. In January 2026, we completed the Exchange Offers, pursuant to which $2.3 billion of Calpine senior secured and unsecured notes were exchanged for Constellation senior unsecured notes.

The terms of the debt issued under the exchange are as follows:

Note	Interest Rate	Maturity	Issued Amount
2029 Senior Unsecured Notes	4.625%	February 2029	$ 647
2031 Senior Unsecured Notes	5.000%	February 2031	848
2031 Senior Unsecured Notes	3.750%	March 2031	795
Total			$ 2,290

Senior Note Issuance

In January 2026, we issued senior unsecured notes totaling $2.75 billion, the proceeds from which were used to pay down Calpine debt assumed. In May 2026, we issued senior unsecured notes totaling $2.2 billion and used the net proceeds (i) to repay short-term borrowings, including commercial paper obligations and (ii) for general corporate purposes. The terms of the debt issuances are reflected in the Debt Issuances and Redemptions table below.

Long-term Debt Summary

The following table presents the outstanding long-term debt, as of September 30, 2026 and December 31, 2025:

	Rates	Maturity Date	September 30, 2026	December 31, 2025
Long-term debt				
Senior unsecured notes[(a)]	3.75% - 6.50%	2028 - 2066	$ 13,033	$ 5,688
Tax-exempt notes[(b)]	4.10% - 4.45%	2029 - 2053	412	412
Notes payable and other[(a)]	1.71% - 8.18%	2026 - 2046	111	53
Project finance:[(a)]				
Variable rates	4.13% - 6.11%	2027 - 2031	5,090	597
Fixed rates	2.29% - 8.64%	2031 - 2048	878	653
Total long-term debt			19,524	7,403
Unamortized debt discount and premium, net			(19)	(1)
Unamortized fair value of debt			(16)	—
Unamortized debt issuance costs			(91)	(60)
Long-term debt due within one year			(359)	(92)
Long-term debt			$ 19,039	$ 7,250

(a) Includes debt assumed in acquisition of Calpine.
(b) The Tax-exempt notes have a maturity date of June 2029 to April 2053, and a mandatory purchase date that ranges from April 2028 to June 2029.

Debt Issuances and Redemptions

During the nine months ended September 30, 2026, the following long-term debt was issued (redeemed):

Type[a]	Interest Rate	Maturity	Amount
2028 Senior Unsecured Notes[b]	3.90 %	January 2028	$ 900
2036 Senior Unsecured Notes	5.30 %	June 2036	850
2066 Senior Unsecured Notes[b]	5.88 %	January 2066	800
2031 Senior Unsecured Notes[b]	4.40 %	January 2031	750
2029 Senior Unsecured Notes	4.55 %	June 2029	750
2032 Senior Unsecured Notes	4.80 %	January 2032	600
2028 Floating Rate Senior Notes[b]	SOFR + 0.60 %	January 2028	300
Other issuances			51
Other redemptions			(300)
Calpine Term Loan	SOFR + 1.75 %	February 2032	(860)
Calpine 2028 Senior Secured Notes	4.50 %	February 2028	(1,250)
Calpine 2028 Senior Unsecured Notes	5.125 %	March 2028	(1,400)
Calpine Term Loan	SOFR + 1.75 %	January 2031	(1,650)
Total long-term debt issued (redeemed)			$ (459)

(a) Does not include debt exchange activity discussed above.
(b) Relates to January 2026 debt issuance used to pay down Calpine corporate debt assumed.

DOE Loan Guarantees

Crane Clean Energy Center

In November 2025, the DOE Office of Energy Dominance Financing issued a guarantee for up to $1.0 billion for an unsecured loan from the Federal Financing Bank to support the restart of the Crane Clean Energy Center. The loan matures November 2055. Interest rates on the loan are fixed upon each advance at a spread of 0.375% above U.S. Treasuries of comparable maturity. There have been no borrowings on this loan as of the date of this filing.

Nuclear Uprates

In October 2026, we signed a conditional loan commitment with the DOE Office of Energy Dominance Financing. Subject to the execution of a loan agreement, the DOE would issue a guarantee for up to $5.0 billion for an unsecured loan from the Federal Financing Bank to support uprates at various nuclear facilities. The loan would have a 30-year term. Interest rates would be fixed upon each advance at a spread of 0.375% above U.S. Treasuries of comparable maturity.

Short-Term Borrowings

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

Credit Agreements

In September 2025, we amended our existing revolving credit facility (RCF) to increase the available aggregate commitment from $4.5 billion to $7.0 billion, which included incremental revolving credit commitments of $2.5 billion and extension of the maturity date to September 2030. The incremental commitments became available upon the closing of the Calpine acquisition in January 2026. The RCF may be drawn down in the form of loans and/or to support commercial paper and letter of credit issuances.

The RCF fixed facility fee rate is 0.175% and borrowings under the RCF bear interest at a rate based upon either the Daily Simple SOFR rate or a Term SOFR rate, plus an adder based upon our credit rating. The adders for the Daily Simple SOFR-based borrowings and Term SOFR borrowings are 0.075% and 1.075%, respectively. The letters of credit bear interest at a rate of 1.075%.

If we were to lose our investment grade credit rating, the maximum adders for Daily Simple SOFR rate borrowings and Term SOFR rate borrowings would be 1.00% and 2.00%, respectively. The credit agreements also require us to pay facility fees based upon the aggregate commitments. The fees vary depending upon our credit rating.

Accounts Receivable Facility

The Accounts Receivable Facility (the Facility) provides NER access to revolving loans from a number of financial institutions (Lenders) secured by certain customer accounts receivable. The maximum funding limit of the Facility is $1.5 billion and matures December 2027. Draws and repayments related to the Facility will be reflected as Proceeds from short-term borrowings and Repayments of short-term borrowings, respectively, in the Consolidated Statements of Cash Flows. Draws on the Facility bear interest at a commercial paper rate or a Daily One Month Term SOFR or Term SOFR rate, plus an adder of 0.10% per annum. In the first quarter of 2026, we drew on the Facility in full. Subsequently, in the second quarter of 2026, we used the proceeds of the term loan and senior notes issued to repay $1.1 billion of the Facility. As of September 30, 2026, $400 million of the Facility was drawn on and outstanding.

The Facility requires the balance of eligible receivables to be maintained at or above the balance of cash proceeds received from the Lenders. To the extent the eligible receivables decrease below such balance, we are required to repay cash to the Lenders. When eligible receivables exceed cash proceeds, we have the ability to increase the cash proceeds received up to the maximum funding limit. As of September 30, 2026, the balance of our eligible receivables exceeded the cash proceeds outstanding from the Lenders.

Credit Facilities Summary

As of September 30, 2026 and December 31, 2025, we had the following aggregate capacity, credit facility borrowings and available capacity under our respective credit facilities:

Facility Type	Aggregate Capacity	Facility Draws	Outstanding Letters of Credit[a]	Outstanding Commercial Paper[b]	Total Available Capacity
September 30, 2026					
Revolving Credit Facility	$ 7,000	$ —	$ 121	$ 2,092	$ 4,787
Bilateral and letter of credit facilities[c][d]	4,100	—	3,139	—	961
Accounts Receivable Facility	1,500	400	—	—	1,100
CDHI Revolver[d][e]	340	269	—	—	71
Liquidity Facility	971	—	774	—	191 [f]
Project Finance[d]	571	42	445	—	84
Total	$ 14,482	$ 711	$ 4,479	$ 2,092	$ 7,194

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

Facility Type	Aggregate Capacity	Facility Draws	Outstanding Letters of Credit[a]	Outstanding Commercial Paper[b]	Total Available Capacity
December 31, 2025					
Revolving Credit Facility	$ 4,500	$ —	$ 40	$ —	$ 4,460
Bilateral and letter of credit facilities	2,350	—	1,276	—	1,074
Accounts Receivable Facility	1,500	—	—	—	1,500
Liquidity Facility	971	—	647	—	312 [f]
Project Finance	137	—	122	—	15
Total	$ 9,458	$ —	$ 2,085	$ —	$ 7,361

(a) Excludes an additional outstanding letter of credit which was not issued under these facilities of $15 million as of September 30, 2026 and December 31, 2025. See Note 15 — Commitments and Contingencies for additional information.
(b) Our commercial paper program is supported by the revolving credit agreement. In order to maintain our commercial paper program in the amounts indicated above, we must have a credit facility in place, at least equal to the amount of our commercial paper program. As of September 30, 2026 and December 31, 2025, the maximum program size of our commercial paper program was $7.0 billion and $4.5 billion, respectively. We do not issue commercial paper in an aggregate amount exceeding the then available capacity under our credit facility. The weighted average interest rate on commercial paper borrowings was 4.28% as of September 30, 2026. There were no commercial paper borrowings outstanding as of December 31, 2025.
(c) In 2026, we entered into or amended bilateral credit facilities, increasing aggregate letter of credit capacity by $1,025 million, converting certain facilities to uncommitted status and extending certain maturities. As of September 30, 2026, uncommitted facilities totaled $3,450 million. Such facilities are subject to issuer discretion, have no stated maturity and may be terminated by either party upon notice.
(d) Includes corporate and project-related facilities assumed in connection with Calpine acquisition in January 2026.
(e) In October 2026, we cancelled any outstanding letters of credit and terminated all commitments under the CDHI Revolver as part of the facility termination.
(f) 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, 2026 and December 31, 2025, without posting additional collateral, the actual availability of facility, prior to outstanding letters of credit was $966 million and $959 million, respectively.

Short-Term Loan Agreements

As of September 30, 2026 and December 31, 2025, we had the following short-term loan agreements, which are unsecured and reflected in Short-term borrowings in the Consolidated Balance Sheets:

Month Initiated	Interest Rate	Maturity	September 30, 2026	December 31, 2025
April 2026	1-month SOFR + 0.70%	April 2027	$ 1,500	$ —
May 2025	1-month SOFR + 0.90%	May 2026	—	900
September 2025	1-month SOFR + 0.90%	September 2026	—	750

Debt Covenants

As of September 30, 2026, we are in compliance with all debt covenants.

14. Fair Value of Financial Assets and Liabilities

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

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

Fair Value of Financial Liabilities Recorded at Amortized Cost

The following table presents the carrying amounts and fair values of our long-term debt and SNF obligation as of September 30, 2026 and December 31, 2025. 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, 2026				December 31, 2025			
	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	$ 19,398	$ 15,489	$ 3,302	$ 18,791	$ 7,342	$ 6,995	$ 666	$ 7,661
SNF Obligation[(a)]	1,468	1,339	—	1,339	1,426	1,406	—	1,406

(a) SNF Obligation is included in Other deferred credits and other liabilities in the Consolidated Balance Sheets.

Valuation Techniques Used to Determine Fair Value and Net Asset Value

Our valuation techniques used to measure the fair value and net asset value of the assets and liabilities are in accordance with the policies discussed in Note 17 — Fair Value of Financial Assets and Liabilities of our 2025 Form 10-K except for certain assumed variable rate project financings which are valued using a model that estimates pricing using an internal rate of return calculation and benchmark indices, which may be adjusted for company or security specific risks, resulting in these being classified as Level 3.

Recurring Fair Value Measurements

The following table presents 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, 2026 and December 31, 2025:

	September 30, 2026				December 31, 2025			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Cash equivalents[a]	$ 437	$ —	$ —	$ 437	$ 42	$ —	$ —	$ 42
NDT fund investments								
Cash equivalents[b]	220	200	—	420	72	165	—	237
Equities	6,575	1,079	—	7,654	6,245	1,426	—	7,671
Fixed income	2,373	1,530	401	4,304	2,201	1,566	395	4,162
Private credit	—	—	133	133	—	—	132	132
Assets measured at NAV	—	—	—	7,936	—	—	—	7,194
NDT fund investments subtotal[c]	9,168	2,809	534	20,447	8,518	3,157	527	19,396
Rabbi trust investments	73	49	2	124	66	45	1	112
Investments in equities	56	—	—	56	87	—	—	87
Derivative assets								
Economic hedges	1,970	14,165	11,299	27,434	1,114	7,449	3,830	12,393
Effect of netting and allocation of collateral	(1,908)	(12,530)	(8,736)	(23,174)	(889)	(6,853)	(3,256)	(10,998)
Derivative assets subtotal	62	1,635	2,563	4,260	225	596	574	1,395
Total assets measured at fair value	9,796	4,493	3,099	25,324	8,938	3,798	1,102	21,032
Liabilities								
Derivative liabilities								
Economic hedges	(2,271)	(14,476)	(10,026)	(26,773)	(1,148)	(8,021)	(4,062)	(13,231)
Effect of netting and allocation of collateral	2,138	13,667	9,275	25,080	1,065	7,657	3,628	12,350
Derivative liabilities subtotal	(133)	(809)	(751)	(1,693)	(83)	(364)	(434)	(881)
Deferred compensation obligation	—	(110)	—	(110)	—	(124)	—	(124)
Total liabilities measured at fair value	(133)	(919)	(751)	(1,803)	(83)	(488)	(434)	(1,005)
Total net assets	$ 9,663	$ 3,574	$ 2,348	$ 23,521	$ 8,855	$ 3,310	$ 668	$ 20,027

(a) CEG Parent has $460 million and $70 million of Level 1 cash equivalents as of September 30, 2026 and December 31, 2025, respectively. We exclude cash of $496 million and $3,621 million, and restricted cash of $52 million and $57 million as of September 30, 2026 and December 31, 2025, respectively. CEG Parent has excluded an additional $1 million of cash as of September 30, 2026 and no additional cash exclusions as of December 31, 2025.

(b) Includes net liabilities of $218 million and $166 million as of September 30, 2026 and December 31, 2025, respectively, which consist of receivables related to pending securities sales, interest and dividend receivables, repurchase agreement obligations, and payables related to pending securities purchases. The repurchase agreements are generally short-term in nature with durations generally of 30 days or less.

(c) Includes total NDT derivative assets and liabilities that are not material, which have notional amounts of $971 million and $810 million as of September 30, 2026 and December 31, 2025, respectively. The notional principal amounts provide one measure of the transaction volume outstanding as of the periods ended and do not represent the amount of our exposure to credit or market loss.

As of September 30, 2026, our NDTs have outstanding commitments to invest in private credit, private equity, and real assets of $629 million, $466 million, and $534 million, respectively. These commitments will be funded by our existing NDT funds.

Equity Security Investments without Readily Determinable Fair Values. We hold investments without readily determinable fair values with carrying amounts of $141 million and $109 million as of September 30, 2026 and December 31, 2025, respectively. Changes in fair value, cumulative adjustments, and impairments were not material for the three and nine months ended September 30, 2026 and the year ended December 31, 2025.

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, 2026 and 2025:

	Three Months Ended September 30, 2026			
	NDT Fund Investments	Derivatives	Rabbi Trust Investments	Total
Balance as of July 1, 2026	$ 531	$ 1,663	$ 2	$ 2,196
Total realized / unrealized gains (losses)				
Included in net income (loss)	1	259 [b]	—	260
Included in Payables related to Regulatory Agreement Units	2	—	—	2
Change in collateral	—	(146)	—	(146)
Purchases	—	26	—	26
Sales	—	(14)	—	(14)
Transfers into Level 3	—	7	—	7
Transfers out of Level 3	—	34	—	34
Contract amortization	—	(17)	—	(17)
Balance as of September 30, 2026	$ 534	$ 1,812	$ 2	$ 2,348
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of September 30, 2026	$ 1	$ 591	$ —	$ 592

	Three Months Ended September 30, 2025			
	NDT Fund Investments	Derivatives	Rabbi Trust Investments	Total
Balance as of July 1, 2025	$ 504	$ 137	$ 1	$ 642
Total realized / unrealized gains (losses)				
Included in net income (loss)	4	(211) [b]	—	(207)
Included in Payables related to Regulatory Agreement Units	9	—	—	9
Change in collateral	—	58	—	58
Purchases	—	17	—	17
Transfers into Level 3	—	(1) [c]	—	(1)
Transfers out of Level 3	—	(55) [c]	—	(55)
Balance as of September 30, 2025	$ 517	$ (55)	$ 1	$ 463
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of September 30, 2025	$ 4	$ (114)	$ —	$ (110)

	Nine Months Ended September 30, 2026			
	NDT Fund Investments	Derivatives	Rabbi Trust Investments	Total
Balance as of January 1, 2026	$ 527	$ 140	$ 1	$ 668
Contracts acquired at acquisition date	—	1,290 [(a)]	—	1,290
Total realized / unrealized gains (losses)				
Included in net income (loss)	2	593 [(b)]	1	596
Included in Payables related to Regulatory Agreement Units	5	—	—	5
Change in collateral	—	(44)	—	(44)
Purchases	—	70	—	70
Sales	—	(20)	—	(20)
Transfers into Level 3	—	(1) [(c)]	—	(1)
Transfers out of Level 3	—	203 [(c)]	—	203
Contract amortization	—	(419)	—	(419)
Balance as of September 30, 2026	$ 534	$ 1,812	$ 2	$ 2,348
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of September 30, 2026	$ 2	$ 882	$ 1	$ 885

	Nine Months Ended September 30, 2025			
	NDT Fund Investments	Derivatives	Rabbi Trust Investments	Total
Balance as of January 1, 2025	$ 502	$ (1)	$ 1	$ 502
Total realized / unrealized gains (losses)				
Included in net income (loss)	6	(248) [(b)]	—	(242)
Included in Payables related to Regulatory Agreement Units	12	—	—	12
Change in collateral	—	205	—	205
Purchases	—	68	—	68
Sales	—	(5)	—	(5)
Settlements	(4)	—	—	(4)
Transfers into Level 3	1	(44) [(c)]	—	(43)
Transfers out of Level 3	—	(30) [(c)]	—	(30)
Balance as of September 30, 2025	$ 517	$ (55)	$ 1	$ 463
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of September 30, 2025	$ 6	$ (4)	$ —	$ 2

(a) Represents contracts acquired as part of the Calpine acquisition in January 2026. See Note 2 — Mergers, Acquisitions, and Dispositions for additional information.
(b) Includes a reduction of $349 million and $708 million for realized gains due to the settlement of derivative contracts for the three and nine months ended September 30, 2026, respectively. Includes a reduction of $97 million and $244 million for realized gains due to the settlement of derivative contracts for the three and nine months ended September 30, 2025.
(c) Transfers into and out of Level 3 generally occur when the contract tenor becomes less and more observable, respectively, primarily due to changes in market liquidity or assumptions for certain commodity contracts.

The following table presents 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, 2026 and 2025:

	Three Months Ended September 30,					
	Operating revenues		Purchased power and fuel		Other, net	
	2026	2025	2026	2025	2026	2025
Total gains (losses) included in net income	$ (96)	$ (272)	$ 338	$ 61	$ 1	$ 4
Total unrealized gains (losses)	60	(186)	531	72	1	4

	Nine Months Ended September 30,					
	Operating revenues		Purchased power and fuel		Other, net	
	2026	2025	2026	2025	2026	2025
Total gains (losses) included in net income	$ 29	$ (271)	$ 145	$ 23	$ 3	$ 6
Total unrealized gains (losses)	591	(120)	291	116	3	6

Derivatives

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

Type of trade	Fair Value as of September 30, 2026	Fair Value as of December 31, 2025	Valuation Technique	Unobservable Input	2026 Range & Arithmetic Average		2025 Range & Arithmetic Average	
Level 3 Derivatives —Economic hedges[(a)(b)]	$ 1,273	$ (232)	Discounted Cash Flow	Forward power price (Non-congestion)	$0.32 - $251	$53	$4.77 - $154	$54
				Forward power price (Congestion)	$2 - $186	$55	$3.14 - $154	$50
				Forward gas price	$0.83 - $21	$3.55	($0.46) - $15	$3.52
			Option Model	Volatility percentage	6% - 171%	79%	14% - 197%	59%

(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 (received) on Level 3 positions of $539 million and $372 million as of September 30, 2026 and December 31, 2025, respectively.

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

15. Commitments and Contingencies

Commitments

Commercial Commitments. Commercial commitments as of September 30, 2026, representing commitments potentially triggered by future events, were as follows:

	Expiration within						
	2026	2027	2028	2029	2030	2031 and thereafter	Total
Letters of credit	$ 2,844	$ 1,521	$ 128	$ —	$ 1	$ —	$ 4,494
Surety bonds[(a)]	409	523	118	—	—	557	1,607
Guarantee under the Calpine AR Facility[(b)]	530	—	—	—	—	—	530
Total commercial commitments	$ 3,783	$ 2,044	$ 246	$ —	$ 1	$ 557	$ 6,631

(a) Surety bonds — Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(b) We have guaranteed the performance of Calpine Energy Solutions, LLC to Calpine Receivables, LLC under the Calpine AR Facility. The commitment represents the gross amount of sold receivables that are currently outstanding, limited to $550 million per the guarantee agreement. Refer to Note 7 — Accounts Receivable for additional information.

First Priority Liens for Commodity Procurement and Risk Management Activities

Following the acquisition of Calpine in January 2026, the Company assumed additional first-priority liens on Calpine assets, which are currently subject to first priority liens under various debt agreements, as collateral under certain of our power and natural gas agreements and certain of the interest rate swaps in order to reduce the cash collateral and letters of credit that would otherwise be provided to the counterparties under such agreements. The counterparties under such agreements share the benefits of the collateral subject to such first priority liens pro rata with the lenders under various debt agreements. As of September 30, 2026, the exposure was $96 million under these first priority liens for power and natural gas agreements and no exposure for the interest rate swaps.

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

As of September 30, 2026 and December 31, 2025, we had accrued undiscounted amounts for environmental liabilities of $14 million and $9 million, respectively, in Accounts payable and accrued expenses and $171 million and $169 million, respectively, in Other deferred credits and other liabilities in the Consolidated Balance Sheets. See Note 18 — Commitments and Contingencies of our 2025 Form 10-K for additional information on environmental remediation matters. As of September 30, 2026, and through the date of filing, there have been no material changes in amounts recognized for the matters discussed in our 2025 Form 10-K.

Litigation

We are involved in various 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.

As of September 30, 2026 and December 31, 2025, we had accrued $37 million and $15 million, respectively, in Accounts payable and accrued expenses and $120 million and $113 million, respectively, in Other deferred credits and other liabilities in the Consolidated Balance Sheets for liabilities related to litigation matters, including asbestos personal injury claims. See Note 18 — Commitments and Contingencies of our 2025 Form 10-K for additional information on asbestos personal injury claims. As of September 30, 2026, and through the date of filing, there have been no material changes in amounts recognized for the matters discussed in our 2025 Form 10-K.

Impacts of the February 2021 Extreme Cold Weather Event and Texas-based Generating Assets Outages. Calpine was acquired on January 7, 2026, and is party to the same ongoing litigation proceedings as Constellation. See Note 18 — Commitments and Contingencies of our 2025 Form 10-K for additional information on this matter, which is likewise representative of the ongoing proceedings as it pertains to Calpine.

In March 2026, the Supreme Court of Texas denied plaintiffs' petitions for a writ of mandamus in all five bellwether appeals. In July 2026, the Court denied plaintiffs' motions for rehearing. The parties have returned to the Multi-District-Litigation court to effect dismissal of all remaining Winter Storm Uri tort claims pending against the power generator defendants.

16. Shareholders' Equity

Share Repurchase Program (CEG Parent)

During 2026, our Board of Directors approved a $4.4 billion increase relative to the remaining $0.6 billion authorization under our share repurchase program. No other repurchase plans or programs have been authorized. As of the date of this filing, we have approximately $2.0 billion of remaining authority for repurchases. See Note 19 — Shareholders' Equity of our 2025 Form 10-K for additional information on our share repurchase program.

During the three and nine months ended September 30, 2026, we repurchased approximately 3.8 million and 10.9 million shares of our common stock in the open market for approximately $1.0 billion and $3.0 billion, respectively, inclusive of open market repurchases and the secondary public offering discussed further in Note 2 — Mergers, Acquisitions, and Dispositions. During the three and nine months ended September 30, 2025, there were no open market repurchases.

ASR Agreements. In June 2025, we entered into an ASR agreement with a financial institution to initiate share repurchases of our common stock. Under the ASR agreement, we paid a specified amount to the financial institution and received an initial delivery of shares of common stock based on 80% of the ASR agreement's cost, which resulted in an immediate reduction in the number of our shares outstanding, with incremental shares delivered upon settlement of the ASR.

The following table summarizes the ASR agreement for the nine months ended September 30, 2025:

(in millions, except average price paid per share)

ASR Agreement Initiation	Total Cost	Initial Shares Received	ASR Agreement Settlement	Additional Shares Received	Total Number of Shares Purchased	Average Price Paid per Share
June 2025	$ 404	1.1	August 2025	0.2	1.3	$ 311.84

Capped Call Options. During the first quarter of 2025, we entered into two structured share repurchase agreements. Under these agreements, we made up-front cash payments of $150 million in the first quarter of 2025 in exchange for the right to receive a predetermined amount of shares of our common stock or cash at expiration. Neither option was exercised during the second or third quarters of 2025, therefore we did not receive any shares at expiration. As a result, we received our initial up-front cash payments of $150 million plus a nominal cash premium during the second and third quarters of 2025. The cash received restored the remaining authority available for repurchases.

Changes in Accumulated Other Comprehensive Income (Loss) (All Registrants)

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

Three Months Ended September 30, 2026	Gains (losses) on Cash Flow Hedges	Pension and OPEB Items[a]	Foreign Currency Items	Total
Beginning balance	$ 4	$ (2,385)	$ (17)	$ (2,398)
OCI before reclassifications	—	—	—	—
Amounts reclassified from AOCI	1	31	—	32
Net current-period OCI	1	31	—	32
Ending balance	$ 5	$ (2,354)	$ (17)	$ (2,366)
Three Months Ended September 30, 2025				
Beginning balance	$ (3)	$ (2,263)	$ (6)	$ (2,272)
OCI before reclassifications	—	—	(8)	(8)
Amounts reclassified from AOCI	2	18	—	20
Net current-period OCI	2	18	(8)	12
Ending balance	$ (1)	$ (2,245)	$ (14)	$ (2,260)
Nine Months Ended September 30, 2026				
Beginning balance	$ 1	$ (2,413)	$ (13)	$ (2,425)
OCI before reclassifications	—	(25)	(4)	(29)
Amounts reclassified from AOCI	4	84	—	88
Net current-period OCI	4	59	(4)	59
Ending balance	$ 5	$ (2,354)	$ (17)	$ (2,366)
Nine Months Ended September 30, 2025				
Beginning balance	$ (6)	$ (2,262)	$ (34)	$ (2,302)
OCI before reclassifications	—	(34)	20	(14)
Amounts reclassified from AOCI	5	51	—	56
Net current-period OCI	5	17	20	42
Ending balance	$ (1)	$ (2,245)	$ (14)	$ (2,260)

(a) AOCI amounts are included in the computation of net periodic pension and OPEB cost. See Note 11 — Retirement Benefits for additional information. See our Consolidated Statements of Operations and Comprehensive Income for individual components of AOCI.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
Pension and OPEB plans:				
Actuarial loss reclassified to periodic benefit cost	$ (11)	$ (5)	$ (29)	$ (18)
Pension and OPEB plans valuation adjustment	—	—	8	12

17. Variable Interest Entities

At September 30, 2026 and December 31, 2025, 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, 2026 and December 31, 2025. 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, 2026	December 31, 2025
Cash and cash equivalents	$ 79	$ 52
Restricted cash and cash equivalents	49	48
Accounts receivable, net	2,337	2,477
Inventories, net	25	13
Other current assets	34	29
Total current assets	2,524	2,619
Property, plant, and equipment, net	2,196	1,942
Other deferred debits and other assets	111	123
Total assets[(a)]	$ 4,831	$ 4,684
Short-term borrowings	$ 427	$ —
Long-term debt due within one year	70	66
Accounts payable and accrued expenses	53	34
Derivative liabilities	2	—
Other current liabilities	31	3
Total current liabilities	583	103
Long-term debt	806	578
Asset retirement obligations	254	231
Other deferred credits and other liabilities	34	2
Total deferred credits and other liabilities	288	233
Total liabilities	$ 1,677	$ 914

(a) Our balances include unrestricted assets for current UEC assets of $17 million and $17 million, disclosed within other current assets in the table above, and noncurrent UEC assets of $103 million and $116 million, disclosed within other noncurrent assets in the table above, as of September 30, 2026 and December 31, 2025, respectively.

As of September 30, 2026 and December 31, 2025, 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 Note 21 - Variable Interest Entities of our 2025 Form 10-K for additional information.	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.
Generating facilities, which are 100% owned by us, and have a significant PPA with a singular counterparty.	The PPAs absorb 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 and gas. NER's assets will be available first and foremost to satisfy the claims of the creditors of NER. Refer to Note 7 — Accounts Receivable of our 2025 Form 10-K for additional information on the sale of receivables.	Equity capitalization is insufficient to support its operations.	We conduct all activities.

Unconsolidated VIEs

Our variable interests in unconsolidated VIEs generally include an equity method investment and energy purchase and sale contracts. For the equity investment, the carrying amount of the investment is reflected in the Consolidated Balance Sheets in Other deferred debits and other assets, see Note 18 — Supplemental Financial Information for additional information. For the energy purchase and sale contracts (commercial agreements), the carrying amount of assets and liabilities in the Consolidated Balance Sheets that relate to our involvement with the VIEs are predominantly related to working capital accounts and generally represent the amounts owed by, or owed to, us for the deliveries associated with the current billing cycles under the commercial agreements.

As of September 30, 2026 and December 31, 2025, we had significant unconsolidated variable interests in several VIEs for which we were not the primary beneficiary. These interests include certain commercial and securitization agreements.

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

	September 30, 2026			December 31, 2025		
	Commercial Agreement VIEs	Equity Investment VIEs	Total	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[(a)]	$ 708	$ 541	$ 1,249	$ 711	$ —	$ 711
Total liabilities[(a)]	91	501	592	95	—	95
Other ownership interests in VIE[(a)]	617	40	657	616	—	616

(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.

As of September 30, 2026 and December 31, 2025, the unconsolidated VIEs consist of:

Unconsolidated VIE or VIE groups:	Reason entity is a VIE:	Reason we are not the primary beneficiary:
Energy Purchase and Sale agreements - We have several energy purchase and sale agreements with generating facilities.	PPAs that absorb variability through fixed pricing.	We do not conduct the operational activities.
Calpine Receivables, LLC[(a)] - A bankruptcy remote entity created for the special purpose of purchasing trade accounts receivable from Calpine Energy Solutions, LLC under the Accounts Receivable Sales Program. Refer to Note 7 — Accounts Receivable for additional information.	Equity capitalization is insufficient to support its operations.	We do not have the power to direct activities nor affect its financial performance.

(a) Calpine Receivables, LLC became an unconsolidated VIE in January 2026 as a result of the Calpine acquisition. As such, it was not an unconsolidated VIE as of December 31, 2025.

18. Supplemental Financial Information

Supplemental Consolidated Statements of Operations and Comprehensive Income Information

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
Operating revenues	2026	2025	2026	2025
Variable lease income	$ 109	$ 65	$ 291	$ 181

	Three Months Ended September 30,		Nine Months Ended September 30,	
Taxes other than income taxes	2026	2025	2026	2025
Property	$ 102	$ 74	$ 295	$ 216
Gross receipts[(a)]	64	46	180	123
Payroll	54	44	172	128
Other	5	1	14	5
Total	$ 225	$ 165	$ 661	$ 472

(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.

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

Note 18 — Supplemental Financial Information

Other, net	Three Months Ended September 30, 2026	Three Months Ended September 30, 2025	Nine Months Ended September 30, 2026	Nine Months Ended September 30, 2025
Decommissioning-related activities:				
Net realized income on NDT funds[a]				
Regulatory Agreement Units	$ 272	$ 165	$ 827	$ 540
Non-Regulatory Agreement Units	126	78	450	245
Net unrealized gains (losses) on NDT funds				
Regulatory Agreement Units	(318)	313	(25)	624
Non-Regulatory Agreement Units	(130)	200	31	430
Regulatory offset to NDT fund-related activities[b]	34	(383)	(643)	(935)
Total Decommissioning-related activities	(16)	373	640	904
Net unrealized gains (losses) from equity investments[c]	(8)	19	(32)	(256)
Other	(20)	51	(3)	81
Total	$ (44)	$ 443	$ 605	$ 729

(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) Includes unrealized gains (losses) resulting from an equity investment in a publicly traded company. We record the fair value of this investment in Other deferred debits and other assets in the Consolidated Balance Sheets based on quoted market price of the stock.

Supplemental Cash Flow Information

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

Depreciation, amortization, and accretion	Income statement location	Nine Months Ended September 30, 2026	Nine Months Ended September 30, 2025
PP&E	Depreciation and amortization	$ 1,317	$ 729
Nuclear fuel	Purchased power and fuel	765	712
ARO accretion	Operating and maintenance	503	480
Amortization of acquired derivative contracts[a]	Operating revenues or Purchased power and fuel	223	—
Amortization of UECs	Operating revenues or Purchased power and fuel	80	10
Amortization of intangible assets, net[b]	Depreciation and amortization	23	14
Other amortization	Purchased power and fuel, or Interest expense, net	(13)	—
Total		$ 2,898	$ 1,945

(a) Related to the amortization of acquired derivative contracts from the acquisition of Calpine.
(b) Primarily related to the amortization of customer relationships and trade names.

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

Note 18 — Supplemental Financial Information

	CEG Parent		Constellation	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
Other non-cash operating activities	**2026**	**2025**	**2026**	**2025**
Other decommissioning-related activity[(a)]	$ (574)	$ (366)	$ (574)	$ (366)
Pension and non-pension postretirement benefit costs	151	115	151	115
Other	330	177	242	112
Total	$ (93)	$ (74)	$ (181)	$ (139)

(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.

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.

September 30, 2026	**CEG Parent**	**Constellation**
Cash and cash equivalents	$ 603	$ 601
Restricted cash and cash equivalents	406	384
Total cash, restricted cash, and cash equivalents	$ 1,009	$ 985
December 31, 2025		
Cash and cash equivalents	$ 3,641	$ 3,641
Restricted cash and cash equivalents	107	79
Total cash, restricted cash, and cash equivalents	$ 3,748	$ 3,720
September 30, 2025		
Cash and cash equivalents	$ 3,959	$ 3,949
Restricted cash and cash equivalents	132	88
Total cash, restricted cash, and cash equivalents	$ 4,091	$ 4,037

For additional information on restricted cash, see Note 1 — Basis of Presentation of our 2025 Form 10-K. Calpine's restricted cash balances, included in our balances as of September 30, 2026, align with our current policy or represent other agreements that require us to establish and maintain segregated cash accounts, the use of which is restricted, making these cash funds unavailable for general use.

Supplemental Balance Sheet Information

The following tables provide additional information about material items recorded in the Consolidated Balance Sheets.

Inventories, net	September 30, 2026	December 31, 2025
Materials and supplies	$ 2,280	$ 1,485
Natural gas, oil, and emission allowances	1,106	251
Total	$ 3,386	$ 1,736

	CEG Parent		Constellation	
Accounts payable and accrued expenses	September 30, 2026	December 31, 2025	September 30, 2026	December 31, 2025
Accounts payable	$ 2,597	$ 2,813	$ 2,578	$ 2,801
Compensation-related accruals[(a)]	946	920	840	672
Taxes accrued[(b)]	510	246	510	245
Other accrued expenses	847	315	847	315
Total	$ 4,900	$ 4,294	$ 4,775	$ 4,033

(a) Primarily includes accrued payroll, bonuses and other incentives, vacation, and benefits.
(b) Includes $375 million as of December 31, 2025, related to estimated nuclear PTCs that were used to offset our current tax liability. No credits were utilized during the nine months ended September 30, 2026. See Note 6 — Government Assistance for additional information on the nuclear PTC.

The following table provides additional information about investments included in Other deferred debits and other assets in the Consolidated Balance Sheets.

Investments	September 30, 2026	December 31, 2025
Equity method investments	$ 56	$ 3
Other investments:		
Employee benefit trusts and investments[(a)]	124	112
Equity investments with readily determinable fair values[(b)]	54	82
Equity investments without readily determinable fair values	141	109
Other available for sale debt security investments	2	1
Total	$ 377	$ 307

(a) Debt and equity security investments are recorded at fair market value.
(b) Does not include the equity investments with readily determinable fair values that are recorded in Other current assets in the Consolidated Balance Sheets. See Note 14 — Fair Value of Financial Assets and Liabilities for additional information on investments in equities.

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

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

Executive Overview

Constellation Energy Corporation, a Fortune 200 company headquartered in Baltimore, is the largest private-sector power producer in the world and the nation's largest producer of clean and reliable energy. With 55 gigawatts of capacity from nuclear, natural gas, oil, geothermal, hydro, wind and solar facilities, our fleet has the generating capacity to power the equivalent of 27 million homes, providing about 10% of the nation's clean energy and delivering the around-the-clock reliability needed to power America's growing economy. We are also the largest nuclear energy company in the U.S. and a leading competitive retail supplier, serving approximately 2.5 million customer accounts nationwide, including 80% of the Fortune 100. We are committed to investing in innovation and new technologies to drive the transition to a reliable, sustainable and secure energy future.

Significant Transactions and Developments

Acquisition of Calpine Corporation

On January 7, 2026, we acquired 100% of the outstanding equity of Calpine for a purchase price of approximately $21.8 billion. The merger consideration consisted of 50 million newly issued shares of our common stock, no par value, and approximately $4.5 billion in cash on hand. After considering divestitures connected with certain regulatory approvals, Calpine owns and operates a generation fleet of predominantly natural gas, geothermal, battery storage, and solar assets with approximately 23 GWs of generation capacity, in addition to a competitive retail electric supplier platform serving approximately 62 TWhs of load annually.

This acquisition is complementary to, and aligns strategically with, our existing business operations and provides both increased scale and meaningful market diversification. The merger couples the largest producer of clean, emissions-free energy with the reliable, dispatchable natural gas assets of Calpine, and also creates the nation's leading competitive retail electric supplier, providing increased scale, diversification and complementary capabilities that enable us to meet growing demand with a broader array of energy and sustainability products. The addition of Calpine strengthens our essential role in providing clean, reliable energy as the nation seeks to transition to a more sustainable future, and will better position us to pursue investments in new and existing technologies to meet growing demand.

In March 2026, we entered into an agreement with LS Power Equity Advisors, LLC to sell five natural gas-fired generating facilities with approximately 4.4 GWs of capacity from Calpine's portfolio of generation assets located in PJM to satisfy regulatory commitments related to our acquisition of Calpine. The transaction is valued at $5.0 billion before closing adjustments. Completion of the transaction is subject to customary closing conditions and receipt of applicable regulatory approvals, and is expected to close by the end of this year.

In October 2026, we completed the divestiture of the Brazos Valley Energy Center (f/k/a Jack A. Fusco Energy Center), a 606 MW natural gas-fired plant in ERCOT, to LS Power for $860 million before closing adjustments.

See Note 2 — Mergers, Acquisitions, and Dispositions and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

New Data Center Facility at Freestone Energy Center

In the first quarter of 2026, we signed a new 380 MW agreement with Dallas-based CyrusOne, a leading global data center developer and operator, to connect and serve a new data center adjacent to the Freestone Energy Center, in Freestone County, Texas. The agreement provides CyrusOne with access to power, grid connectivity and site infrastructure needed to support development of the new facility, while ensuring electricity continues to flow to the regional grid and ensuring reliability for all customers and communities. We have also entered into an exclusive agreement to provide power, grid connectivity and site infrastructure for Phase 2, which will be an additional 380 MWs. These agreements are in addition to the 400 MW agreements announced in the second half of last year between Calpine and CyrusOne for the Thad Hill Energy Center in Bosque County, Texas.

Pastoria Solar Project

In April 2026, we celebrated the commissioning of the 105 MW Pastoria Solar Project, the largest renewable energy project contracted by the California Department of Water Resources to date in its mission to fully decarbonize its operations by 2035. The Pastoria Solar Project connects to the grid through the interconnection facilities at our highly efficient 750 MW natural gas-fired Pastoria facility. Also, co-located with the Pastoria Solar Project is the Pastoria Power Bank, an 80 MW/320 MWh Battery Energy Storage System, which came online in July 2026. The Pastoria Power Bank is contracted and supported by a 15-year power purchase agreement with Pacific Gas and Electric Company.

Pin Oak Creek Energy Center

In April 2026, our Pin Oak Creek Energy Center achieved commercial operation. Pin Oak Creek is a 460 MW, state-of-the-art natural gas facility designed to provide reliable, dispatchable power to the ERCOT grid. As a peaking facility, it is built to operate when demand is highest and reliability matters most, while also maintaining the flexibility to run longer if system conditions require it. The project is a direct response to Texas' continued growth and increasing electricity demand across homes, businesses, and industry. Pin Oak Creek will play a critical role in strengthening grid reliability and supporting the state's economic momentum.

Long-term Nuclear PPAs

In the second quarter of 2026, we signed long-term PPAs with a diverse group of investment-grade customers covering 920 MW of clean, reliable nuclear generation, primarily from our existing fleet. The agreements have terms of 15 to 20 years and are expected to commence between 2029 and 2032. This total includes a 176 MW PPA with Walmart that will support a 30 MW capacity expansion at our Dresden Clean Energy Center in Illinois, as well as additional investments in the facility, its workforce, and the local community.

In September 2026, we announced a 20-year, 690 MW PPA with Amazon and a related retail supply agreement supporting Amazon's operations in PJM. The agreements will enable more than $3 billion of investment in our Calvert Cliffs Clean Energy Center, including facility improvements and a 190 MW capacity expansion expected to come online between 2030 and 2032, while supporting the facility's continued operation and future relicensing.

In October 2026, we announced a 20-year PPA with Google that will enable more than $4.3 billion of investment across 11 of our nuclear units in Illinois, Pennsylvania, and New Jersey to add approximately 890 MW of incremental generation capacity to the PJM grid, with the first uprate expected in 2028. We also entered into a 15-year financial energy load following agreement with Google for 2,700 MW in PJM.

These agreements reflect continued demand from large-load customers for reliable, clean energy. Realization of the anticipated investments and capacity expansions remains subject to regulatory approvals, successful completion of the planned uprates, continued operation and relicensing of the applicable facilities, and other conditions.

Agreement to Acquire Rhode Island State Energy Center

In September 2026, we entered into an agreement to acquire all of the equity interests in RISEC Holdings, LLC, the owner of the Rhode Island State Energy Center, from Shell Energy North America (US), L.P. for $715 million, subject to customary purchase price adjustments. The Rhode Island State Energy Center is a natural gas-fired combined-cycle electric generation facility with a generating capacity of 609 MW. The facility sells electricity and capacity into the competitive ISO New England wholesale power market and is expected to become part of our merchant generation portfolio. Completion of the transaction is subject to receipt of required regulatory approvals and other customary closing conditions.

Conditional DOE Loan Commitment Supporting Nuclear Uprates

In October 2026, we signed a conditional loan commitment with the DOE Office of Energy Dominance Financing. Subject to the execution of a loan agreement, the DOE would issue a guarantee for up to $5.0 billion for an unsecured loan from the Federal Financing Bank to support uprates at various nuclear facilities. The loan would have a 30-year term. Interest rates would be fixed upon each advance at a spread of 0.375% above U.S. Treasuries of comparable maturity.

Other Key Business Drivers

PJM Market Reform

In January 2026, the National Energy Dominance Council, supported by governors in the PJM territory, urged PJM to propose certain tariff revisions with respect to its capacity auction. PJM subsequently initiated stakeholder discussions regarding potential market reforms, including a reliability backstop auction mechanism, enhancements to large load forecasting and measures to accelerate generator interconnection studies. In February 2026, PJM proposed extending the existing RPM capacity market price collar—approximately $325/MW-day and $175/MW-day—for the 2028/2029 and 2029/2030 Base Residual Auctions. FERC accepted the extension in April 2026, citing reliability concerns, significant demand growth, including from data centers, and anticipated market reforms.

In July 2026, PJM proposed a one-time reliability backstop procurement. In September 2026, FERC accepted the proposal and suspended it to become effective February 28, 2027, subject to refund and subject to the outcome of a paper hearing. FERC also encouraged PJM to re-file an updated proposal within 30 days rather than proceeding with the paper hearing. PJM submitted an updated auction filing on October 29, 2026 and proposed that the one-time procurement open March 1, 2027 and close on March 28, 2027, with results announced on May 10, 2027. Many of the proposed auction parameters are the same, with the exception that the load forecast that is used to clear the auction will not be finalized until April 28, 2027. Separately, in August 2026, PJM filed its Interim Resource Adequacy Service proposal, which would have imposed curtailment risk on new large loads over 50 MW coming online after June 1, 2027 that did not contract for new capacity. FERC largely rejected the proposal, finding that it improperly intruded on state jurisdiction over retail rates and that PJM had not established the lawfulness of certain provisions. PJM has indicated that they will make a subsequent filing, but no details are available at this time.

FERC Issues Order in PJM Show Cause Proceeding

In December 2025, FERC issued an order finding the existing PJM Tariff to be unjust and unreasonable and directing PJM to take a number of actions. FERC ordered three new transmission services: an interim interruptible network integration transmission service (IT NITS), which will allow load to take service on an interruptible basis while waiting for the network upgrades required for traditional NITS, and two other services. The IT NITS service allows the load to elect to connect promptly and receive some service from the grid, while avoiding PJM purchases of capacity to serve it, as it will be interruptible. The other services include a firm and non-firm contract demand service for co-located load. FERC also directed several PJM compliance filings and a paper hearing.

In June 2026, FERC ruled on a number of issues presented in the co-location paper hearing and on several PJM compliance filings implementing directives from the December 2025 order. Importantly, FERC pressed PJM to implement changes to accommodate co-located load prior to PJM's proposed June 2029 effective date. In August 2026, PJM submitted its compliance filing and we are awaiting a FERC order on the filing.

FERC also issued a series of orders in the various RTOs in response to the Advance Notice of Proposed Rulemaking (ANOPR) published by DOE last fall. The orders direct filings by RTOs and their transmission owners that are designed to expedite service to large load (regardless of whether it is co-located) and avoid the expense and delay associated with network upgrades to provide service to these loads. Constellation's Load Dependent Capacity at Existing Plants (LCEP) proposal, which would expedite connection of new generation when paired with a large load at an existing plant, was flagged in several RTO orders as a proposal to be considered.

Russia and Ukraine Conflict

We are closely monitoring developments of the ongoing Russia and Ukraine conflict, including United States, United Kingdom, European Union, and Canadian sanctions, and legislation that may impact exports and imports of Russian nuclear fuel supply and enrichment activities, as well as the potential for Russia to limit fuel deliveries. The U.S. "Prohibiting Russian Uranium Imports Act" became effective in August 2024, banning the import of low-enriched uranium into the U.S. that is produced in Russia or by Russian entities, absent a waiver from the DOE. Under a corollary bill, in 2026, the DOE began the process of distributing billions of dollars to support expansion of the domestic nuclear fuel cycle within the United States to improve emissions-free energy security. The

Lindsay O. Graham Sanctioning Russia and Iran Act of 2026 (Graham Act) that continued the uranium import waivers but appeared to increase difficulties for shipping fuel from Russia was signed in September 2026. In October 2026, the President issued an Executive Order that waived the application of all the sanctions, restrictions, and tariffs in the Graham Act. 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 to support our refueling needs and mitigate the risk of exposure to Russian nuclear fuel supply. 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. Our fuel procurement activities comply with all U.S. and international trade laws and we continue to take advantage of all available avenues to maintain continuity in our nuclear fuel supply, including working with the U.S. Government and our diverse set of suppliers to secure the nuclear fuel needed to continue to operate our nuclear fleet long-term.

Environmental Regulation

California Assembly Bill 32, as amended by Senate Bill 32 in 2016, directed the California Air Resources Board (CARB) to adopt regulations to achieve the maximum technologically feasible and cost-effective reductions in GHG emissions, targeting statewide GHG emissions at 1990 levels by 2020 and to at least 40% below 1990 levels by 2030. The California Climate Crisis Act was enacted in 2022 and further establishes the state's policy to achieve net zero GHG emissions as soon as possible, but no later than 2045, and to reduce statewide anthropogenic GHG emissions to 85% below 1990 levels by 2045. To achieve these targets, CARB has promulgated complementary regulatory measures, including the Cap-and-Trade Program and Mandatory Greenhouse Gas Emissions Reporting Regulation. Covered entities, such as our power plants, must surrender compliance instruments, which include both allowances and offset credits, in an amount equivalent to their GHG emissions. Assembly Bill 398, enacted in 2017, authorized the extension of the Cap-and-Trade Program through 2030 and required several changes to the program, including establishing a price ceiling and other price mitigative mechanisms and limiting the amount of offsets allowed to comply with the regulation. In September 2025, California Governor Gavin Newsom signed AB 1207 and SB 840 into law, extending the state’s Cap-and-Trade Program through January 1, 2046, and renaming it the “Cap and Invest" Program.

In September 2021, Illinois Governor JB Pritzker signed into law the Climate and Equitable Jobs Act, which, among other things, establishes a schedule for eliminating CO_2 emissions by EGUs. Under that schedule, privately owned natural gas units that exceed an established level of NOx or SO_2 emissions and are located within three miles of an environmental justice community, or an equity investment-eligible community must permanently eliminate CO_2 and co-pollutant emissions by January 1, 2030, subject to certain reliability exceptions, such as a determination by PJM that the unit is needed for reliability. PJM made such a finding with respect to our natural gas generation facility, Zion Energy Center, acquired as part of Calpine, and accordingly Zion plans to operate past January 2030.

Regulation of GHGs from Power Plants under the Clean Air Act. In February 2026, EPA issued a final rule to repeal the 2009 Endangerment Finding underpinning all GHG regulation by EPA. In September 2026, EPA issued a final rule to repeal its 2024 GHG power plant standards, except for efficiency-based standards that apply to new gas power plants. With the repeal, new baseload gas plants will no longer face compliance obligations based on carbon capture and sequestration/storage beginning in 2032. Both the February 2026 and September 2026 rules have been challenged in the D.C. Circuit. EPA also issued a supplemental proposal in September 2026 to repeal its full suite of power plant GHG regulations, including the efficiency-based standards for new gas power plants, based on its reinterpretation of section 111 of the Clean Air Act. EPA recently accepted comments on the proposal. EPA's approach in the supplemental proposal, if finalized and upheld in court, would limit and/or delay options for future action on climate for the power sector by EPA.

See ITEM 1. BUSINESS, Environmental Matters and Regulation of our 2025 Form 10-K for additional information on environmental legislation and regulation we are subject to.

Critical Accounting Policies and Estimates

Management makes a number of significant estimates, assumptions, and judgments in the preparation of our financial statements. At September 30, 2026, our critical accounting policies and estimates had not changed significantly from December 31, 2025. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF

FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Critical Accounting Policies and Estimates of our 2025 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, 2026 compared to the same period in 2025. For additional information regarding the financial results for the three and nine months ended September 30, 2026 and 2025, see the discussion of Results of Operations below.

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2026	2025	$ Change	2026	2025	$ Change
GAAP Net Income (Loss) Attributable to Common Shareholders	$ 1,835	$ 930	$ 905	$ 3,938	$ 1,887	$ 2,051

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

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

Unless otherwise noted, the income tax impact of each reconciling adjustment between GAAP Net Income (Loss) Attributable to Common Shareholders and Adjusted (non-GAAP) Operating Earnings is based on the marginal statutory federal and state income tax rates, taking into account whether the income or expense item is taxable or deductible, respectively, in whole or in part, which may result in an effective tax rate that differs from the marginal rate. The marginal statutory income tax rate was 25.4% and 25.6% for the three and nine months ended September 30, 2026 and 2025, respectively. The following table provides a reconciliation between GAAP Net Income (Loss) Attributable to Common Shareholders and Adjusted (non-GAAP) Operating Earnings for the three and nine months ended September 30, 2026 compared to the same period in 2025.

	Three Months Ended September 30,			
	2026		2025	
(In millions, except per share data)		Earnings Per Share[a]		Earnings Per Share[a]
GAAP Net Income (Loss) Attributable to Common Shareholders	$ 1,835	$ 5.19	$ 930	$ 2.97
Unrealized (Gain) Loss on Fair Value Adjustments (net of taxes of $44 and $32, respectively)[b]	(127)	(0.36)	94	0.30
Decommissioning-Related Activities (net of taxes of $23 and $187, respectively)[c]	56	0.16	(117)	(0.37)
Amortization of Acquired Commodity Contracts (net of taxes of $13 and $—, respectively)[d]	39	0.11	—	—
Calpine Merger and Integration Costs (net of taxes of $30 and $10, respectively)[e]	73	0.20	28	0.09
Plant Retirements and Divestitures (net of taxes of $3 and $2, respectively)	(9)	(0.03)	(5)	(0.02)
Pension & OPEB Non-Service (Credits) Costs (net of taxes of $8 and $3, respectively)	25	0.07	9	0.03
Change in Legal and Environmental Liabilities (net of taxes of $3 and $—, respectively)	9	0.02	1	—
Income Tax-Related Adjustments[f]	(108)	(0.30)	13	0.04

Noncontrolling Interests[g]	(1)	—	(1)	—
Adjusted (non-GAAP) Operating Earnings	$ 1,792	$ 5.06	$ 952	$ 3.04

	Nine Months Ended September 30,			
	2026		2025	
(In millions, except per share data)		**Earnings Per Share[a]**		**Earnings Per Share[a]**
GAAP Net Income (Loss) Attributable to Common Shareholders	$ 3,938	$ 11.06	$ 1,887	$ 6.02
Unrealized (Gain) Loss on Fair Value Adjustments (net of taxes of $175 and $163, respectively)[b]	(508)	(1.43)	478	1.52
Decommissioning-Related Activities (net of taxes of $354 and $426, respectively)[c]	(339)	(0.95)	(242)	(0.77)
Amortization of Acquired Commodity Contracts (net of taxes of $117 and $—, respectively)[d]	342	0.96	—	—
Calpine Merger and Integration Costs (net of taxes of $69 and $17, respectively)[e]	276	0.77	50	0.16
Plant Retirements and Divestitures (net of taxes of $3 and $4, respectively)	(9)	(0.03)	13	0.04
Pension & OPEB Non-Service (Credits) Costs (net of taxes of $22 and $9, respectively)	65	0.18	27	0.09
Change in Legal and Environmental Liabilities (net of taxes of $15 and $1, respectively)	44	0.12	2	0.01
Income Tax-Related Adjustments[f]	(121)	(0.34)	13	0.04
Noncontrolling Interests[g]	(4)	(0.01)	(4)	(0.01)
Adjusted (non-GAAP) Operating Earnings	$ 3,684	$ 10.34	$ 2,224	$ 7.09

(a) Amounts may not sum due to rounding. Earnings per share amount is based on average diluted common shares outstanding of 354 million and 313 million for the three months ended September 30, 2026 and 2025, respectively, and 356 million and 314 million for the nine months ended September 30, 2026 and 2025, respectively.
(b) Includes unrealized gains and losses on economic hedges, interest rate swaps, and fair value adjustments related to gas imbalances and equity investments.
(c) Reflects all gains and losses associated with NDTs, ARO accretion, ARC depreciation, ARO remeasurement, and impacts of contractual offset for Regulatory Agreement Units. The tax effects of Regulatory Agreement Units result in a 100% effective tax rate under contractual offset accounting. Additionally, the tax effects of NDT investment returns result in different effective tax rates depending on whether the underlying funds are held within qualified or non-qualified trusts.
(d) In 2026, reflects the non-cash impacts of the amortization of certain commodity contracts recorded at fair value associated with the Calpine acquisition.
(e) Reflects costs associated with the completion of the Calpine merger and subsequent integration of its operations. Certain of these transaction-related expenses are not tax deductible.
(f) Adjustment to deferred income taxes due to changes in forecasted apportionment.
(g) Represents elimination of the noncontrolling interest portion of certain adjustments included above.

Results of Operations

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2026	2025	$ Change	2026	2025	$ Change
Operating revenues	$ 9,550	$ 6,570	$ 2,980	$ 28,176	$ 19,459	$ 8,717
Operating expenses						
Purchased power and fuel	4,400	3,567	833	14,775	11,083	3,692
Operating and maintenance	1,991	1,511	480	6,024	4,673	1,351
Depreciation and amortization	454	241	213	1,340	743	597
Taxes other than income taxes	225	165	60	661	472	189
Total operating expenses	7,070	5,484	1,586	22,800	16,971	5,829
Gain (loss) on sales of assets	12	—	12	28	—	28
Operating income (loss)	2,492	1,086	1,406	5,404	2,488	2,916
Other income and (deductions)						
Interest expense, net	(217)	(134)	(83)	(753)	(398)	(355)
Other, net	(44)	443	(487)	605	729	(124)
Total other income and (deductions)	(261)	309	(570)	(148)	331	(479)
Income (loss) before income taxes	2,231	1,395	836	5,256	2,819	2,437
Income tax (benefit) expense	405	466	(61)	1,333	928	405
Equity in income (losses) of unconsolidated affiliates	9	—	9	23	—	23
Net income (loss)	1,835	929	906	3,946	1,891	2,055
Net income (loss) attributable to noncontrolling interests	—	(1)	1	8	4	4
Net income (loss) attributable to common shareholders	$ 1,835	$ 930	$ 905	$ 3,938	$ 1,887	$ 2,051

Three Months Ended September 30, 2026 Compared to Three Months Ended September 30, 2025. The variance in Net income (loss) attributable to common shareholders was favorable by $905 million primarily due to:

- Addition of Calpine operations acquired in January 2026, inclusive of the impacts of purchase accounting. See Note 2 — Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information; and
- Favorable net adjustments to deferred income taxes due to changes in forecasted apportionment.

The favorable items were partially offset by:

- Unfavorable decommissioning-related activities; and
- Lower Nuclear PTC revenues in 2026. See Note 6 — Government Assistance of the Combined Notes to Consolidated Financial Statements for additional information.

Nine Months Ended September 30, 2026 Compared to Nine Months Ended September 30, 2025. The variance in Net income (loss) attributable to common shareholders was favorable by $2,051 million primarily due to:

- Addition of Calpine operations acquired in January 2026, inclusive of the impacts of purchase accounting. See Note 2 — Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information;
- Favorable net market and portfolio conditions primarily driven by higher capacity revenues;
- Lower net unrealized loss on equity investments;

- Favorable net adjustments to deferred income taxes due to changes in forecasted apportionment; and
- Favorable decommissioning-related activities primarily driven by the 2026 nuclear ARO updates. See Note 9 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information.

The favorable items were partially offset by:

- Unfavorable Calpine merger and integration costs;
- Unfavorable interest expense primarily driven by increased long-term debt outstanding; and
- Unfavorable impacts from nuclear outages.

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

With the exception of Calpine's natural gas sales, which are included in the Calpine segment, wholesale and retail sales of natural gas, as well as sales of other energy-related products and sustainable solutions and other miscellaneous business activities that are not significant to overall results of operations, are reported under Other and not allocated to a segment.

For the three and nine months ended September 30, 2026 compared to 2025, Operating revenues were as follows:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2026	2025	$ Change	% Change	2026	2025	$ Change	% Change
Mid-Atlantic	$ 1,877	$ 1,763	$ 114	6.5 %	$ 5,279	$ 4,876	$ 403	8.3 %
Midwest	1,562	1,390	172	12.4 %	4,862	4,317	545	12.6 %
New York	569	558	11	2.0 %	1,702	1,655	47	2.8 %
ERCOT	592	628	(36)	(5.7)%	1,408	1,489	(81)	(5.4)%
Other Power Regions	1,099	1,543	(444)	(28.8)%	3,551	4,277	(726)	(17.0)%
Calpine	3,384	—	3,384	100.0 %	7,926	—	7,926	100.0 %
Total reportable segment revenues	9,083	5,882	3,201	54.4 %	24,728	16,614	8,114	48.8 %
Other	829	844	(15)	(1.8)%	2,815	3,201	(386)	(12.1)%
Unrealized gains (losses)[(a)]	(362)	(156)	(206)	(a)	633	(356)	989	(a)
Total Operating revenues	$ 9,550	$ 6,570	$ 2,980	45.4 %	$ 28,176	$ 19,459	$ 8,717	44.8 %

(a) % Change in unrealized gains (losses) is not a meaningful measure.

Sales and Supply Sources. Our sales and supply volumes (GWhs) by segment are summarized below:

	Three Months Ended September 30,				Nine Months Ended September 30,			
(GWhs)	2026	2025	Change	% Change	2026	2025	Change	% Change
Nuclear Generation[(a)]								
Mid-Atlantic	13,659	13,665	(6)	— %	39,661	39,105	556	1.4 %
Midwest	24,333	23,644	689	2.9 %	70,420	71,000	(580)	(0.8)%
New York	6,177	6,671	(494)	(7.4)%	18,528	19,585	(1,057)	(5.4)%
ERCOT	2,508	2,497	11	0.4 %	6,896	7,541	(645)	(8.6)%
Total Nuclear Generation	46,677	46,477	200	0.4 %	135,505	137,231	(1,726)	(1.3)%
Natural Gas, Oil, and Renewables[(a)]								
Mid-Atlantic	377	242	135	55.8 %	1,728	1,683	45	2.7 %
Midwest	156	141	15	10.6 %	773	785	(12)	(1.5)%
ERCOT	4,626	4,325	301	7.0 %	11,106	10,615	491	4.6 %
Other Power Regions	1,436	1,466	(30)	(2.0)%	4,287	4,556	(269)	(5.9)%
Calpine	38,387	—	38,387	100.0 %	89,797	—	89,797	100.0 %
Total Natural Gas, Oil, and Renewables	44,982	6,174	38,808	628.6 %	107,691	17,639	90,052	510.5 %
Purchased Power								
Mid-Atlantic	4,953	5,416	(463)	(8.5)%	12,110	13,960	(1,850)	(13.3)%
Midwest	326	403	(77)	(19.1)%	1,137	1,366	(229)	(16.8)%
ERCOT	673	714	(41)	(5.7)%	1,999	2,209	(210)	(9.5)%
Other Power Regions	9,173	11,451	(2,278)	(19.9)%	26,669	32,295	(5,626)	(17.4)%
Calpine	1,890	—	1,890	100.0 %	6,707	—	6,707	100.0 %
Total Purchased Power	17,015	17,984	(969)	(5.4)%	48,622	49,830	(1,208)	(2.4)%
Total Supply/Sales by Segment								
Mid-Atlantic	18,989	19,323	(334)	(1.7)%	53,499	54,748	(1,249)	(2.3)%
Midwest	24,815	24,188	627	2.6 %	72,330	73,151	(821)	(1.1)%
New York	6,177	6,671	(494)	(7.4)%	18,528	19,585	(1,057)	(5.4)%
ERCOT	7,807	7,536	271	3.6 %	20,001	20,365	(364)	(1.8)%
Other Power Regions	10,609	12,917	(2,308)	(17.9)%	30,956	36,851	(5,895)	(16.0)%
Calpine	40,277	—	40,277	100.0 %	96,504	—	96,504	100.0 %
Total Supply/Sales by Segment	108,674	70,635	38,039	53.9 %	291,818	204,700	87,118	42.6 %

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
Nuclear fleet capacity factor	97.2 %	96.8 %	94.2 %	95.3 %
Refueling outage days	20	23	205	152
Non-refueling outage days	6	5	26	27

Equivalent Forced Outage Factor (Natural Gas, Oil, and Pumped-storage Hydro). As a result of our expanded fleet following the acquisition of Calpine in January 2026, we now consider EFOF to be a key operational metric beginning in 2026. EFOF represents the percentage for which a generating unit is not available due to forced outages and forced deratings in a given period. We consider EFOF to be a useful measure in analyzing the reliability and performance of our natural gas, oil, and pumped-storage hydro fleet. The EFOF for the three and nine months ended September 30, 2026 was 5.9%. This operational metric is being included as a complement to the financial information provided in accordance with GAAP. However, as an operational metric, it may not be calculated or presented in a manner comparable to similar metrics used by other companies.

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 based on our net hourly position. We assess the net position by ISO/RTO across segments and, where applicable, by segment within the ISO/RTO. The price of electricity is impacted by several variables, including but not limited to, the price of fuels, generation resources in the geographic region, weather, ongoing 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 zones/hubs in each ISO/RTO where we have significant activity. This does not reflect prices we ultimately realized.

	Three Months Ended September 30,				Nine Months Ended September 30,			
ISO/RTO	2026	2025	$ Change	% Change	2026	2025	$ Change	% Change
PJM - PJM West	$ 69.97	$ 46.77	$ 23.20	49.6 %	$ 72.84	$ 47.63	$ 25.21	52.9 %
PJM - ComEd	51.44	42.72	8.72	20.4 %	43.82	36.37	7.45	20.5 %
NYISO - Central	51.07	49.51	1.56	3.2 %	67.94	54.07	13.87	25.7 %
ERCOT - North	34.41	35.05	(0.64)	(1.8)%	34.88	33.06	1.82	5.5 %
ERCOT - Houston	36.05	35.90	0.15	0.4 %	35.74	34.86	0.88	2.5 %
ISO-NE - Southeast Massachusetts	54.05	50.43	3.62	7.2 %	73.68	65.16	8.52	13.1 %
CAISO - NP15	43.18	41.35	1.83	4.4 %	29.82	36.31	(6.49)	(17.9)%

Capacity Prices. We participate in capacity auctions in each ISO/RTO where we have qualifying generating assets. We also incur capacity costs associated with load served, which are factored into customer sales prices. Capacity prices have a material impact on our operating revenues and purchased power and fuel expense. We report capacity on a net monthly basis in either Operating revenues or Purchased power and fuel expense. We assess the net position by ISO/RTO across segments and, where applicable, by segment within the ISO/RTO. The following table presents the average capacity prices ($/MW Day) for each ISO/RTO in which we have

significant activity. Prices reflect the weighted average prices for the various auction periods within the three and nine months ended September 30, 2026 and 2025.

We also enter into bilateral capacity contracts at negotiated contract prices. These contracts primarily relate to resource adequacy in CAISO and have a material impact on our operating revenues. Negotiated contract prices from these bilateral contracts are not included in the table below.

	Three Months Ended September 30,				Nine Months Ended September 30,			
ISO/RTO	2026	2025	$ Change	% Change	2026	2025	$ Change	% Change
PJM - Eastern Mid-Atlantic Area Council	$ 329.17	$ 269.92	$ 59.25	22.0 %	$ 296.25	$ 149.74	$ 146.51	97.8 %
PJM - ComEd	329.17	269.92	59.25	22.0 %	296.25	136.03	160.22	117.8 %
NYISO - Rest of State	162.67	193.33	(30.66)	(15.9)%	156.89	137.52	19.37	14.1 %
ISO-NE - Rest of Pool[a]	86.24	84.37	1.87	2.2 %	85.20	83.37	1.83	2.2 %

(a) We did not have significant activity at this zone for the three months ended September 30, 2025.

ZEC Prices. We are compensated through state programs for the emissions-free attributes of our nuclear generation. The following table includes the average ZEC reference prices ($/MWh) for each state and associated segment in which state programs have been enacted. Gross prices reflect the weighted average price for the various delivery periods within the three and nine months ended September 30, 2026 and 2025 and may not necessarily reflect prices we ultimately realized as a result of interaction with the nuclear PTC discussed below.

	Three Months Ended September 30,				Nine Months Ended September 30,			
State (Segment)[a]	2026	2025	$ Change	% Change	2026	2025	$ Change	% Change
New Jersey (Mid-Atlantic)[b]	$ —	$ —	$ —	— %	$ —	$ 10.00	$ (10.00)	(100.0)%
Illinois (Midwest)	1.02	1.17	(0.15)	(12.8)%	1.10	5.73	(4.63)	(80.8)%
New York (New York)	14.76	14.76	—	— %	14.76	15.93	(1.17)	(7.3)%

(a) See ITEM 1. BUSINESS, Environmental Matters and Regulation of our 2025 Form 10-K for additional information on the plants receiving payments through state programs.
(b) The New Jersey ZEC program concluded in May 2025.

Illinois CMC Price. The price received (paid) for each CMC is determined by the IPA monthly by subtracting energy and capacity index prices from the bid price, which resulted in $33.43 per MWh for the period June 2024 through May 2025, $33.50 per MWh for the period June 2025 through May 2026, and $34.50 per MWh for the period June 2026 through May 2027. 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 ($26.54) and ($17.11) for the three months ended September 30, 2026 and 2025, respectively, and ($19.54) and ($6.53) for the nine months ended September 30, 2026 and 2025, respectively. The average CMC prices may not necessarily reflect prices we ultimately realized as a result of interaction with the nuclear PTC discussed below.

Nuclear PTC. Beginning in 2024, our nuclear units are eligible for a PTC extending through 2032. The nuclear PTC provides a transferable credit up to $15 per MWh and is subject to phase-out when annual gross receipts are between $26.00 per MWh and $44.75 per MWh for 2025 and 2026. Both the amount of the PTC and the gross receipts thresholds adjust for inflation annually through the duration of the program based on the GDP price deflator for the preceding calendar year.

Many of the state-sponsored programs (e.g., ZECs and CMCs) providing compensation for the emissions-free attributes of generation from certain of our nuclear units include contractual or other provisions that require us to refund that compensation up to the amount of the nuclear PTC received or pass through the entirety of the nuclear PTC received. See Note 6 — Government Assistance of the Combined Notes to Consolidated Financial Statements for additional information on the nuclear PTC.

The following table summarizes the impacts to Operating revenues related to the benefits of nuclear PTC and state-sponsored programs subject to refund or pass through as described above for the three and nine months ended September 30, 2026 compared to 2025:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2026	2025	$ Change	% Change	2026	2025	$ Change	% Change
Nuclear PTC revenue[(a)]	$ 44	$ 175	$ (131)	(74.9)%	$ 69	$ 220	$ (151)	(68.6)%
State-sponsored programs net revenue[(b)]	(280)	(220)	(60)	(27.3)%	(555)	(30)	(525)	(1750.0)%

(a) Our estimate required the exercise of judgment in determining the amount of nuclear PTC expected for each of our nuclear units. Refer to Note 6 — Government Assistance of the Combined Notes to Consolidated Financial Statements for additional information.

(b) Includes only state-sponsored programs that have contractual or other provisions that require us to refund that compensation up to the amount of the nuclear PTC received or pass through the entirety of the nuclear PTC received.

For the three and nine months ended September 30, 2026 compared to 2025, changes in **Operating revenues** by segment were approximately as follows:

	Three Months Ended September 30		
	$ Change	% Change	Description
Mid-Atlantic	$ 114	6.5 %	• favorable retail load revenue of $160 primarily due to higher contracted energy prices; partially offset by • unfavorable realized economic hedges of $70 due to settled prices relative to hedged prices
Midwest	172	12.4 %	• favorable net generation and wholesale load revenue of $175 primarily due to higher energy prices • favorable retail load revenue of $130 primarily due to higher contracted energy prices; partially offset by • unfavorable nuclear PTC revenue of $105 due to higher energy and capacity prices • unfavorable CMC program revenue of $55 primarily due to higher energy and capacity prices
New York	11	2.0 %	• no individually significant drivers
ERCOT	(36)	(5.7)%	• no individually significant drivers
Other Power Regions	(444)	(28.8)%	• unfavorable retail load revenue of $185 primarily due to lower energy prices in the West and lower load volumes in New England • unfavorable wholesale load revenue of $165 primarily due to lower load volumes in New England • unfavorable revenues of $90 in the West due to the impacts of ISO hourly energy netting
Calpine	3,384	100.0 %	• represents the operating revenues associated with our Calpine segment
Other	(15)	(1.8)%	• current year includes unfavorable amortization of $55 associated with certain commodity contracts related to the Calpine acquisition
Unrealized gains or losses[(a)(b)]	(206)	(a)	• losses on economic hedging activities of $362 in 2026 compared to losses of $156 in 2025, inclusive of Calpine
Total	$ 2,980	45.4 %	

	Nine Months Ended September 30		
	$ Change	% Change	Description
Mid-Atlantic	$ 403	8.3 %	• favorable retail load revenue of $630 primarily due to higher contracted energy prices • favorable wholesale load revenue of $165 primarily due to higher contracted energy prices, partially offset by lower load volumes; partially offset by • unfavorable realized economic hedges of $370 due to settled prices relative to hedged prices
Midwest	545	12.6 %	• favorable net generation and wholesale load revenue of $580 primarily due to higher energy prices, partially offset by lower generation volumes • favorable retail load revenue of $455 primarily due to higher contracted energy prices and higher load volumes • favorable net capacity revenue of $185 primarily due to higher prices • favorable realized economic hedges of $80 due to settled prices relative to hedged prices; partially offset by • unfavorable CMC program revenue of $450 primarily due to higher energy and capacity prices • unfavorable ZEC program revenue of $180 primarily due to lower revenue recognized for Illinois ZECs delivered in prior planning years and decrease in ZEC price • unfavorable nuclear PTC revenue of $145 due to higher energy and capacity prices
New York	47	2.8 %	• favorable net generation revenue of $155 associated with the sale of generation volumes relative to purchased power to supply load primarily due to higher energy prices; partially offset by • unfavorable realized economic hedges of $75 due to settled prices relative to hedged prices
ERCOT	(81)	(5.4)%	• unfavorable realized economic hedges of $65 due to settled prices relative to hedged prices
Other Power Regions	(726)	(17.0)%	• unfavorable wholesale load revenue of $370 primarily due to lower load volumes in New England • unfavorable retail load revenue of $285 primarily due to lower load volumes in New England and lower energy prices in the West • unfavorable revenues of $115 in the West due to the impacts of ISO hourly energy netting
Calpine	7,926	100.0 %	• represents the operating revenues associated with our Calpine segment since the date of acquisition
Other	(386)	(12.1)%	• current year includes unfavorable amortization of $475 associated with certain commodity contracts related to the Calpine acquisition • unfavorable revenues in the United Kingdom, inclusive of realized economic hedges, of $55 primarily due to lower energy prices; partially offset by • favorable retail gas revenue of $105 primarily due to higher gas prices
Unrealized gains or losses[a][b]	989	(a)	• gains on economic hedging activities of $633 in 2026 compared to losses of $356 in 2025, inclusive of Calpine
Total	$ 8,717	44.8 %	

(a) % Change in unrealized gains or losses is not a meaningful measure.
(b) See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on unrealized 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 sales and supply sources by segment, nuclear fleet capacity factor, EFOF, capacity prices, and electricity prices.

With the exception of Calpine's natural gas activity, which is included in the Calpine segment, wholesale and retail natural gas activity, energy-related activity in the United Kingdom, as well as other miscellaneous business activities that are not significant to overall results of operations are reported under Other and are not allocated to a segment.

For the three and nine months ended September 30, 2026 compared to 2025, Purchased power and fuel expense were as follows:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2026	2025	$ Change	% Change	2026	2025	$ Change	% Change
Mid-Atlantic	$ 850	$ 871	$ (21)	(2.4)%	$ 2,451	$ 2,393	$ 58	2.4 %
Midwest	630	447	183	40.9 %	2,098	1,489	609	40.9 %
New York	157	159	(2)	(1.3)%	491	458	33	7.2 %
ERCOT	247	213	34	16.0 %	571	589	(18)	(3.1)%
Other Power Regions	839	1,200	(361)	(30.1)%	2,734	3,560	(826)	(23.2)%
Calpine	1,457	—	1,457	100.0 %	3,845	—	3,845	100.0 %
Total segment purchased power and fuel	4,180	2,890	1,290	44.6 %	12,190	8,489	3,701	43.6 %
Other	702	702	—	— %	2,694	2,664	30	1.1 %
Unrealized losses (gains)[a]	(482)	(25)	(457)	(a)	(109)	(70)	(39)	(a)
Total purchased power and fuel	$ 4,400	$ 3,567	$ 833	23.4 %	$ 14,775	$ 11,083	$ 3,692	33.3 %

(a) % Change in unrealized losses (gains) is not a meaningful measure.

Natural Gas Prices. As an owner-operator of a large fleet of natural gas-fired generation facilities, the cost of our natural gas supply has a significant impact on our Purchased power and fuel expense. The following table summarizes the average daily reference price ($/MMBtu) for the periods presented in each geographic region where we have significant activity. This does not reflect prices we ultimately realized.

	Three Months Ended September 30,				Nine Months Ended September 30,			
Location	2026	2025	$ Change	% Change	2026	2025	$ Change	% Change
Henry Hub	$ 2.87	$ 3.03	$ (0.16)	(5.3)%	$ 3.56	$ 3.48	$ 0.08	2.3 %
Transco Zone 6[a]	1.85	2.23	(0.38)	(17.0)%	4.46	3.55	0.91	25.6 %
Houston Ship Channel[b]	2.46	2.69	(0.23)	(8.6)%	2.72	2.96	(0.24)	(8.1)%
PG&E Citygate[c]	3.09	3.47	(0.38)	(11.0)%	2.24	3.33	(1.09)	(32.7)%
Algonquin Citygate[d]	2.24	2.96	(0.72)	(24.3)%	6.19	5.85	0.34	5.8 %

(a) Transcontinental Gas pipeline located in Mid-Atlantic region.
(b) Houston-area pipeline and industrial network located in ERCOT region.
(c) Pacific Gas & Electric Company virtual trading point located in West region.
(d) Algonquin Gas Transmission physical delivery point located in New England region.

For the three and nine months ended September 30, 2026 compared to 2025, changes in **Purchased power and fuel** expense by segment were approximately as follows:

	Three Months Ended September 30		
	$ Change	% Change	Description
Mid-Atlantic	$ (21)	(2.4)%	• favorable realized economic hedges of $75 due to settled prices relative to hedged prices • unfavorable $70 associated with purchased power to supply load, net of generation, primarily due to higher energy prices
Midwest	183	40.9 %	• unfavorable $175 associated with purchased power to supply load, net of generation, primarily due to higher net transmission costs
New York	(2)	(1.3)%	• no individually significant drivers
ERCOT	34	16.0 %	• no individually significant drivers
Other Power Regions	(361)	(30.1)%	• favorable $210 associated with purchased power to supply load primarily due to lower load volumes in New England • favorable cost of $90 in the West due to the impacts of ISO hourly energy netting
Calpine	1,457	100.0 %	• represents the purchased power and fuel associated with our Calpine segment
Other	—	— %	• no individually significant drivers
Unrealized gains or losses[a][b]	(457)	(a)	• gains on economic hedging activities of $482 in 2026 compared to gains of $25 in 2025, inclusive of Calpine
Total	$ 833	23.4 %	

	Nine Months Ended September 30		
	$ Change	% Change	Description
Mid-Atlantic	$ 58	2.4 %	• unfavorable $475 associated with purchased power to supply load, net of generation, primarily due to higher energy prices, higher prices associated with net capacity costs, and higher costs related to an extreme weather event in January 2026; partially offset by • favorable realized economic hedges of $390 due to settled prices relative to hedged prices • favorable $65 due to financial transmission rights overfunding in 2026
Midwest	609	40.9 %	• unfavorable $565 associated with purchased power to supply load, net of generation, primarily due to higher costs related to a significant weather event in January 2026 and net transmission costs
New York	33	7.2 %	• no individually significant drivers
ERCOT	(18)	(3.1)%	• no individually significant drivers
Other Power Regions	(826)	(23.2)%	• favorable $405 associated with purchased power to supply load primarily due to lower load volumes in New England, and lower energy prices in the West • favorable $185 associated with environmental product sales and lower environmental obligations • favorable cost of $115 in the West due to the impacts of ISO hourly energy netting • favorable realized economic power hedges of $105 due to settled prices relative to hedged prices
Calpine	3,845	100.0 %	• represents the purchased power and fuel associated with our Calpine segment since the date of acquisition
Other	30	1.1 %	• unfavorable net wholesale gas purchases of $105, inclusive of realized economic hedges, primarily due to higher gas prices • favorable purchases in the United Kingdom, inclusive of realized economic hedges, of $60 primarily due to lower energy prices

	Nine Months Ended September 30		
	$ Change	% Change	Description
Unrealized gains or losses[a][b]	(39)	(a)	• gains on economic hedging activities of $109 in 2026 compared to gains of $70 in 2025, inclusive of Calpine
Total	$ 3,692	33.3 %	

(a) % Change in unrealized gains or losses is not a meaningful measure.
(b) See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on unrealized gains and losses.

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

	2026 vs. 2025	
	Three Months Ended September 30,	Nine Months Ended September 30,
	Increase (Decrease)	Increase (Decrease)
Labor, contracting, and materials[a]	$ 261	$ 666
Calpine merger and integration costs	62	273
Nuclear refueling outage costs[b]	—	119
Changes in legal and environmental liabilities	10	57
Decommissioning-related activities	(16)	(284)
Other[c]	163	520
Total increase	$ 480	$ 1,351

(a) Primarily reflects increased employee-related costs, including labor and other incentives, as well as higher contracting expense, driven in large part by the addition of Calpine's operations beginning in January 2026.
(b) Includes the co-owned Salem and STP generating units.
(c) Primarily includes administrative expenses such as information technology, regulatory fees, facilities and rentals, and insurance. The increase is driven primarily by the addition of Calpine's operations beginning in January 2026.

Depreciation and amortization expense increased by $213 million for the three months ended September 30, 2026 compared to the same period in 2025, and increased by $597 million for the nine months ended September 30, 2026 compared to the same period in 2025, primarily due to the additional depreciation and amortization associated with assets acquired from Calpine beginning in January 2026. See Note 2 — Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

Interest expense, net increased by $83 million for the three months ended September 30, 2026 compared to the same period in 2025, and increased by $355 million for the nine months ended September 30, 2026 compared to the same period in 2025, primarily due to a net increase in outstanding debt as a result of the debt assumed and related financing transactions following the acquisition of Calpine in January 2026. See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

Other, net was unfavorable for the three and nine months ended September 30, 2026 compared to the same period in 2025, due to activity described in the table below:

	Income (Deductions)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
Decommissioning-related activities[a]	$ (16)	$ 373	$ 640	$ 904
Net unrealized gains (losses) from equity investments[b]	(8)	19	(32)	(256)
Other	(20)	51	(3)	81
Other, net	$ (44)	$ 443	$ 605	$ 729

(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 9 — Asset Retirement Obligations and Note 18 — Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements for additional information.

(b) Includes unrealized gains (losses) resulting from an equity investment in a publicly traded company. We record the fair value of this investment in Other deferred debits and other assets in the Consolidated Balance Sheets based on quoted market price of the stock.

Effective income tax rates were 18.2% and 33.4% for the three months ended September 30, 2026 and 2025, respectively, and 25.4% and 32.9% for the nine months ended September 30, 2026 and 2025, respectively. The decrease in effective tax rate for the three months ended was primarily driven by the long-term rate change and lower qualified NDT fund income in the third quarter of 2026 which is taxed at a higher rate. The decrease in effective tax rate for the nine months ended was primarily due to proportionally lower qualified NDT fund income in 2026 which is taxed at a higher rate as well as long-term rate change. See Note 10 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Liquidity and Capital Resources

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

Our operating and capital expenditures requirements are provided by internally generated cash flows from operations 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. Annually, we 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, such as our planned restart of Crane and nuclear uprate projects. 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., issuing equity, 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 approximately $14.5 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 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

Cash Flow Activities

The following table summarizes our cash flow activities for the nine months ended September 30, 2026 and 2025, respectively:

	Nine Months Ended September 30,		
	2026	2025	$ Change
Cash, restricted cash, and cash equivalents at beginning of period	$ 3,748	$ 3,129	$ 619
Net cash provided by (used in):			
Operating activities	4,979	3,432	1,547
Investing activities	(6,064)	(2,221)	(3,843)
Financing activities	(1,654)	(249)	(1,405)
Net increase (decrease) in cash, restricted cash, and cash equivalents	(2,739)	962	(3,701)
Cash, restricted cash, and cash equivalents at end of period	$ 1,009	$ 4,091	$ (3,082)

Net Cash Provided By (Used In) Operating Activities

Cash provided by operating activities was $4,979 million and $3,432 million for the nine months ended September 30, 2026 and 2025, respectively. Changes in our cash flows from operations were generally consistent with changes in results of operations, as adjusted for changes in working capital in the normal course of business. Included in net cash provided by operating activities for the nine months ended September 30, 2026, are refunds to state programs associated with nuclear PTCs. See Note 6 — Government Assistance of the Combined Notes to Consolidated Financial Statements for additional information.

Net Cash Provided By (Used In) Investing Activities

Cash used in investing activities was ($6,064) million and ($2,221) million for the nine months ended September 30, 2026 and 2025, respectively. The change is primarily related to cash paid, net of cash acquired, for the Calpine acquisition and an increase in capital expenditures related to the planned restart of Crane, inclusion of Calpine, nuclear uprate projects, and co-location infrastructure. See Note 2 — Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

Net Cash Provided By (Used In) Financing Activities

Cash used in financing activities was ($1,654) million and ($249) million for the nine months ended September 30, 2026 and 2025, respectively. The change primarily relates to long-term debt and changes in short-term borrowings. Debt issuances and redemptions or repayments vary each year. For the nine months ended September 30, 2026, these activities reflect the impact of debt transactions associated with the acquisition of Calpine. The remaining change is related to repurchases of common stock. See Note 13 — Debt and Credit Agreements and Note 16 — Shareholders' Equity of the Combined Notes to Consolidated Financial Statements for additional information.

Quarterly dividends declared by our Board of Directors during 2026 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share
First Quarter of 2026	February 20, 2026	March 9, 2026	March 20, 2026	$ 0.4265
Second Quarter of 2026	April 28, 2026	May 15, 2026	June 5, 2026	0.4265
Third Quarter of 2026	August 4, 2026	August 18, 2026	September 4, 2026	0.4265
Fourth Quarter of 2026	October 30, 2026	November 16, 2026	December 4, 2026	0.4265

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, 2026, we have access to facilities with aggregate bank commitments of approximately $14.5 billion. See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

We had access to the commercial paper markets and had availability under our revolving credit facilities during the third quarter of 2026 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 2025 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.

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. A loss of investment grade credit rating would have required a three-notch downgrade by S&P or Moody's from their current levels as of September 30, 2026 of BBB+ and Baa1, to BB+ and Ba1 or below, respectively. As of September 30, 2026, we had approximately $7.2 billion of available capacity under our credit facilities and $0.6 billion of cash on hand. In the event of a credit downgrade below investment grade and a resulting requirement to provide incremental collateral exceeding available capacity under our credit facilities and cash on hand, we would be required to access additional liquidity through the capital markets. 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. Our credit ratings were affirmed by Moody’s and S&P in January 2026 following the completion of the acquisition of Calpine.

If we had lost our investment grade credit ratings as of September 30, 2026, we would have been required to provide incremental collateral estimated to be approximately $3.6 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.

See Note 12 — Derivative Financial Instruments and Note 13 — 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 qualified pension funding decisions, including actuarially-determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act, and management of the pension obligation. The Pension Protection Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively) and at-risk status (which triggers higher minimum contribution requirements and participant notification). The contributions below reflect a funding strategy to make annual contributions to offset the growth of the liability. Based on this funding strategy and current market conditions, which are both subject to change, our annual qualified pension contribution was made in February 2026 for $161 million. Unlike the qualified pension plans, our non-qualified plans are not subject to statutory minimum contribution requirements.

OPEB plans are also not subject to statutory minimum contribution requirements, though we have funded a portion of our plans. Annually, we evaluate whether additional funding for those plans is needed. 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 2026 are approximately $25 million and the planned contributions to the OPEB plans, including estimated benefit payments to unfunded plans, are $64 million. Expected contributions in 2026 or future years could be affected by adjustments in our pension and OPEB funding strategy, market conditions, or pension regulation changes. Refer to ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - Liquidity and Capital Resources of our 2025 Form 10-K for additional information on pension and other postretirement benefits.

Cash Requirements for Other Financial Commitments

In connection with the acquisition of Calpine in January 2026, we assumed approximately $3 billion of projected cash payments under existing financial commitments with fixed or minimum payments required. These commitments exclude future cash payments for debt service on assumed debt as much of the debt was refinanced or paid off following the acquisition. See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information. Other than as described above and elsewhere in this Quarterly Report on Form 10-Q, there have been no material changes to the cash requirements from contractual and other obligations disclosed in our 2025 Annual Report on Form 10-K. Refer to ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - Liquidity and Capital Resources of our 2025 Form 10-K for additional information on our cash requirements for financial commitments.

Accounts Receivable Facilities

We maintain multiple accounts receivable financing arrangements, including a revolving facility secured by certain accounts receivable and an accounts receivable sales program assumed in connection with our January 2026 acquisition of Calpine. See Note 7 — Accounts Receivable and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

Project Financing

Project financing is based upon a 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. 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. As a result of our acquisition of Calpine in January 2026, we assumed various project financing arrangements. See Note 16 — Debt and Credit Agreements of our 2025 Form 10-K and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements 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. We assumed various credit facilities as part of the acquisition of Calpine. See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on our credit facilities.

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 9 — Asset Retirement

Obligations 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, 2026, the Crane NDT is fully funded under the SAFSTOR scenario that is the planned decommissioning option, as described in the Crane PSDAR filed with the NRC in April 2019. We will continue to file Crane's decommissioning funding status with the NRC annually until restart, at which point we will file decommissioning funding status reports in accordance with applicable NRC requirements. Additionally, as of September 30, 2026, we have adequate NDT funds for the remaining radiological decommissioning costs at Zion Nuclear Station related to the Independent Spent Fuel Storage Installation. Decommissioning costs other than radiological may require funding from us. See Liquidity and Capital Resources — NRC Minimum Funding Requirements of our 2025 Form 10-K for information regarding the risk of additional financial assurance for shutdown units.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

(Dollars in millions, unless otherwise noted)

We are exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates, and equity prices. We manage these risks through risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The Executive Committee and the Audit and Risk Committee of the Board of Directors have oversight responsibilities for risk management. The following discussion serves as an update to ITEM 7A — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK of our 2025 Annual Report on Form 10-K incorporated herein by reference.

Commodity Price Risk

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

Electricity available from our owned or contracted generation supply in excess of our obligations to customers is sold into the wholesale markets. To reduce commodity price risk caused by market fluctuations, we enter into non-derivative contracts as well as derivative contracts, including swaps, futures, forwards, and options, with approved counterparties to hedge anticipated exposures in locations and periods where our load serving activities do not naturally offset existing generation portfolio risk. Portfolio hedging activities are generally concentrated in the prompt three years, when customer demand and market liquidity enable effective price risk mitigation. We expect the settlement of the majority of our economic hedges will occur during 2026 through 2028. We also enter into transactions that further optimize the economic benefits of our overall portfolio.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on owned and contracted generation positions that have not been hedged. Beginning in 2024, our existing nuclear fleet is eligible for a nuclear PTC, an important tool in managing commodity price risk for each nuclear unit not already receiving state support. The nuclear PTC provides increasing levels of support as unit revenues decline below levels established in the IRA and is further adjusted for inflation annually through the duration of the program based on the GDP price deflator for the preceding calendar year. See Note 6 — Government Assistance of the Combined Notes to Consolidated Financial Statements for additional information.

The forecasted market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure as of September 30, 2026 for our portfolio associated with a hypothetical $10/MWh reduction in the annual average around-the-clock energy price and $5/MWh reduction in around-the-clock spark spread results in an impact to earnings that is not material for 2026 and 2027. See Note 12 — 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. We also enter into natural gas transportation and storage contracts that allow us to source reliable and cost-effective natural gas for our fleet and to take advantage of favorable market pricing, regardless of when the gas is used in our operations. Fuel oil inventories are managed so that, in the winter months, sufficient volumes of fuel are available in the event of extreme weather conditions and during the remaining months to take advantage of favorable market pricing.

Nuclear fuel is obtained predominantly through long-term contracts for uranium concentrates, conversion services, enrichment services, (or a combination thereof) and fabrication services, including contracts sourced from Russia. 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 secure the nuclear fuel needed to continue to operate our nuclear fleet long-term. Approximately 35% of our uranium concentrate requirements for the remainder of 2026 through 2031 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. See ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Other Key Business Drivers for additional information on the Russia and Ukraine conflict.

Commodity Derivative Activity

The following table provides detail on changes in our commodity derivative contract net assets (liabilities) balance sheet position from December 31, 2025 to September 30, 2026. This table incorporates the unrealized gains and losses that are immediately recorded in earnings. This table excludes all NPNS contracts. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on the balance sheet classification of the commodity derivative contract net assets (liabilities) recorded as of September 30, 2026 and December 31, 2025.

Balance as of December 31, 2025[(a)]	$	504
Net change in fair value of contracts recorded in results of operations		1,395
Reclassification to realized at settlement of contracts recorded in results of operations		(652)
Changes in allocated collateral		(43)
Contracts acquired at acquisition date[(b)]		1,403
Amortization of acquired contracts[(b)]		(223)
Net option premium paid (received)		36
Option premium amortization		23
Upfront payments and amortizations[(c)]		(15)
Foreign currency translation		1
Balance as of September 30, 2026[(a)]	$	2,429

(a) Amounts are shown net of collateral paid to and received from counterparties.
(b) Includes amounts related to contracts acquired as part of the Calpine acquisition in January 2026. See Note 2 — Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.
(c) 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 commodity derivative contract net assets (liabilities). See Note 14 — 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						
	2026	2027	2028	2029	2030	2031 and Beyond	Total Fair Value
Commodity derivative contracts[(a)]:							
Actively quoted prices (Level 1)	$ 124	$ (194)	$ (16)	$ 1	$ 8	$ 6	$ (71)
Prices provided by external sources (Level 2)	197	510	35	(51)	(2)	(1)	688
Prices based on model or other valuation methods (Level 3)	(125)	814	505	245	120	253	1,812
Total	$ 196	$ 1,130	$ 524	$ 195	$ 126	$ 258	$ 2,429

(a) Amounts are shown net of collateral paid to and received from counterparties (and offset against derivative assets and liabilities) of $1,906 million at September 30, 2026.

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 12 — 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 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 12 — Derivative Financial Instruments and Note 15 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding the letters of credit supporting the cash collateral.

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

RTOs and ISOs

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

Exchange Traded Transactions

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

Interest Rate 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, including derivatives to lock in rate levels in anticipation of future financings. A hypothetical 50 basis points change in interest rates associated with unhedged variable-rate long-term debt and interest rate swaps would not have resulted in a material impact to our earnings for the nine months ended September 30, 2026. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Equity Price Risk

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

A hypothetical 25 basis points increase in interest rates and 10% decrease in equity prices would have resulted in a $1,155 million reduction in the fair value of our NDT trust assets as of September 30, 2026. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See Note 9 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements and Liquidity and Capital Resources section of ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information.

Our employee benefit plan trusts also hold investments in equity and debt securities. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Critical Accounting Policies and Estimates of our 2025 Form 10-K for further information.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

During the third quarter of 2026, 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, 2026, 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 2026 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 15 — 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, 2026, our risk factors were consistent with the risk factors described in our 2025 Form 10-K in ITEM 1A. RISK FACTORS which was inclusive of the risks related to the Calpine acquisition and its operations.

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

Issuer Purchases of Equity Securities (CEG Parent)

During 2026, our Board of Directors approved a $4.4 billion increase relative to the remaining $0.6 billion authorization under our share repurchase program. No other repurchase plans or programs have been authorized. As of the date of this filing, we have approximately $2.0 billion of remaining authority for repurchases. See Note 16 — Shareholders' Equity of the Combined Notes to Consolidated Financial Statements for additional information regarding our share repurchase program.

The following table provides information regarding our share repurchases under the program during the three months ended September 30, 2026.

Period	Total Number of Shares Purchased[a]	Average Price Paid per Share	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Programs[b]
July 1, 2026 to July 31, 2026[c]	1,006,731	$ 248.33	$ 2,772
August 1, 2026 to August 31, 2026[c]	2,065,963	277.09	2,200
September 1, 2026 to September 30, 2026[c]	719,314	288.52	1,992
Total	3,792,008	$ 271.62	$ 1,992

(a) We have not made any purchases of shares other than in connection with the publicly announced share repurchase program described above.
(b) Approximate dollar value of shares that may yet be purchased under the program includes taxes and commissions.
(c) Represents repurchases under open market repurchase agreements. See Note 16 — Shareholders' Equity of the Combined Notes to Consolidated Financial Statements for additional information.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

ITEM 5. OTHER INFORMATION

Rule 10b5-1 Trading Plans

During the three months ended September 30, 2026, none of our directors or executive officers (as defined in Rule 16a-1 under the Exchange Act) adopted or terminated any contract, instruction or written plan for the purchase or sale of our securities that was intended to satisfy the affirmative defense conditions of Rule 10b5-1(c) or any "non-Rule 10b5-1 trading arrangement" (as defined in Item 408 under Regulation S-K of the Exchange Act).

ITEM 6. EXHIBITS

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, 2026 filed by the following officers for the following registrants:

Exhibit No.	Description
31.1	Filed by Joseph Dominguez for Constellation Energy Corporation
31.2	Filed by Shane P. Smith for Constellation Energy Corporation
31.3	Filed by Joseph Dominguez for Constellation Energy Generation, LLC
31.4	Filed by Shane P. Smith for Constellation Energy Generation, LLC

Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code as to the Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2026 filed by the following officers for the following registrants:

Exhibit No.	Description
32.1	Filed by Joseph Dominguez for Constellation Energy Corporation
32.2	Filed by Shane P. Smith for Constellation Energy Corporation
32.3	Filed by Joseph Dominguez for Constellation Energy Generation, LLC
32.4	Filed by Shane P. Smith for Constellation Energy Generation, LLC

Exhibit No.	Description
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)

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
Joseph Dominguez
President and Chief Executive Officer
(Principal Executive Officer)

/s/ SHANE P. SMITH
Shane P. Smith
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 9, 2026

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
Joseph Dominguez
President and Chief Executive Officer
(Principal Executive Officer)

/s/ SHANE P. SMITH
Shane P. Smith
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 9, 2026

Exhibit 31.1

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Joseph Dominguez, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Constellation Energy Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ JOSEPH DOMINGUEZ
President and Chief Executive Officer
(Principal Executive Officer)

Date: November 9, 2026

Exhibit 31.2

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Shane P. Smith, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Constellation Energy Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ SHANE P. SMITH
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: November 9, 2026

Exhibit 31.3

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Joseph Dominguez, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Constellation Energy Generation, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ JOSEPH DOMINGUEZ
President and Chief Executive Officer
(Principal Executive Officer)

Date: November 9, 2026

Exhibit 31.4

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Shane P. Smith, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Constellation Energy Generation, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ SHANE P. SMITH
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: November 9, 2026

Exhibit 32.1

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Constellation Energy Corporation for the quarterly period ended September 30, 2026, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Constellation Energy Corporation.

/s/ JOSEPH DOMINGUEZ
Joseph Dominguez
President and Chief Executive Officer

Date: November 9, 2026

Exhibit 32.2

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Constellation Energy Corporation for the quarterly period ended September 30, 2026, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Constellation Energy Corporation.

/s/ SHANE P. SMITH

Shane P. Smith
Executive Vice President and Chief Financial Officer

Date: November 9, 2026

Exhibit 32.3

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Constellation Energy Generation, LLC for the quarterly period ended September 30, 2026, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Constellation Energy Generation, LLC.

/s/ JOSEPH DOMINGUEZ
Joseph Dominguez
President and Chief Executive Officer

Date: November 9, 2026

Exhibit 32.4

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Constellation Energy Generation, LLC for the quarterly period ended September 30, 2026, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Constellation Energy Generation, LLC.

/s/ SHANE P. SMITH

Shane P. Smith
Executive Vice President and Chief Financial Officer

Date: November 9, 2026