UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2023

or

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

For the transition period from _____________ to _____________

Commission file number 1-4174

THE WILLIAMS COMPANIES, INC.

(Exact name of registrant as specified in its charter)

Delaware	73-0569878
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
One Williams Center Tulsa, Oklahoma	74172-0172
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: 800-945-5426 (800-WILLIAMS)

NO CHANGE

(Former name, former address and former fiscal year, if changed since last report)

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, $1.00 par value	WMB	New York Stock Exchange

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. 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.

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 Exchange Act.) Yes ☐ No ☑

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	**Shares Outstanding at October 30, 2023**
Common Stock, $1.00 par value	1,216,498,672

The Williams Companies, Inc.
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The reports, filings, and other public announcements of The Williams Companies, Inc. (Williams) may contain or incorporate by reference statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements" within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. These forward-looking statements relate to anticipated financial performance, management's plans and objectives for future operations, business prospects, outcomes of regulatory proceedings, market conditions, and other matters. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995.

All statements, other than statements of historical facts, included in this report that address activities, events, or developments that we expect, believe, or anticipate will exist or may occur in the future are forward-looking statements. Forward-looking statements can be identified by various forms of words such as "anticipates," "believes," "seeks," "could," "may," "should," "continues," "estimates," "expects," "forecasts," "intends," "might," "goals," "objectives," "targets," "planned," "potential," "projects," "scheduled," "will," "assumes," "guidance," "outlook," "in-service date," or other similar expressions. These forward-looking statements are based on management's beliefs and assumptions and on information currently available to management and include, among others, statements regarding:

- Levels of dividends to Williams stockholders;
- Future credit ratings of Williams and its affiliates;
- Amounts and nature of future capital expenditures;
- Expansion and growth of our business and operations;
- Expected in-service dates for capital projects;
- Financial condition and liquidity;
- Business strategy;
- Cash flow from operations or results of operations;
- Seasonality of certain business components;
- Natural gas, natural gas liquids, and crude oil prices, supply, and demand;
- Demand for our services.

Forward-looking statements are based on numerous assumptions, uncertainties, and risks that could cause future events or results to be materially different from those stated or implied in this report. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors that could cause actual results to differ from results contemplated by the forward-looking statements include, among others, the following:

- Availability of supplies, market demand, and volatility of prices;
- Development and rate of adoption of alternative energy sources;
- The impact of existing and future laws and regulations, the regulatory environment, environmental matters, and litigation, as well as our ability to obtain necessary permits and approvals, and achieve favorable rate proceeding outcomes;
- Our exposure to the credit risk of our customers and counterparties;
- Our ability to acquire new businesses and assets and successfully integrate those operations and assets into existing businesses as well as successfully expand our facilities and consummate asset sales on acceptable terms;
- Whether we are able to successfully identify, evaluate, and timely execute our capital projects and investment opportunities;
- The strength and financial resources of our competitors and the effects of competition;
- The amount of cash distributions from and capital requirements of our investments and joint ventures in which we participate;
- Whether we will be able to effectively execute our financing plan;
- Increasing scrutiny and changing expectations from stakeholders with respect to our environmental, social, and governance practices;

- The physical and financial risks associated with climate change;
- The impacts of operational and developmental hazards and unforeseen interruptions;
- The risks resulting from outbreaks or other public health crises, including COVID-19;
- Risks associated with weather and natural phenomena, including climate conditions and physical damage to our facilities;
- Acts of terrorism, cybersecurity incidents, and related disruptions;
- Our costs and funding obligations for defined benefit pension plans and other postretirement benefit plans;
- Changes in maintenance and construction costs, as well as our ability to obtain sufficient construction-related inputs, including skilled labor;
- Inflation, interest rates, and general economic conditions (including future disruptions and volatility in the global credit markets and the impact of these events on customers and suppliers);
- Risks related to financing, including restrictions stemming from debt agreements, future changes in credit ratings as determined by nationally recognized credit rating agencies, and the availability and cost of capital;
- The ability of the members of the Organization of Petroleum Exporting Countries (OPEC) and other oil exporting nations to agree to and maintain oil price and production controls and the impact on domestic production;
- Changes in the current geopolitical situation, including the Russian invasion of Ukraine and the developing conflict between Israel and Hamas;
- Changes in U.S. governmental administration and policies;
- Whether we are able to pay current and expected levels of dividends;
- Additional risks described in our filings with the SEC.

Given the uncertainties and risk factors that could cause our actual results to differ materially from those contained in any forward-looking statement, we caution investors not to unduly rely on our forward-looking statements. We disclaim any obligations to, and do not intend to, update the above list or announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

In addition to causing our actual results to differ, the factors listed above and referred to below may cause our intentions to change from those statements of intention set forth in this report. Such changes in our intentions may also cause our results to differ. We may change our intentions, at any time and without notice, based upon changes in such factors, our assumptions, or otherwise.

Because forward-looking statements involve risks and uncertainties, we caution that there are important factors, in addition to those listed above, that may cause actual results to differ materially from those contained in the forward-looking statements. For a detailed discussion of those factors, see Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2022, as filed with the SEC on February 27, 2023, as may be supplemented by disclosures in Part II, Item 1A. Risk Factors in subsequent Quarterly Reports on Form 10-Q.

DEFINITIONS

The following is a listing of certain abbreviations, acronyms, and other industry terminology that may be used throughout this Form 10-Q.

Measurements:

Barrel or Bbl: One barrel of petroleum products that equals 42 U.S. gallons
Mbbls/d: One thousand barrels per day

Bcf: One billion cubic feet of natural gas
Bcf/d: One billion cubic feet of natural gas per day
MMcf/d: One million cubic feet of natural gas per day

British Thermal Unit (Btu): A unit of energy needed to raise the temperature of one pound of water by one degree Fahrenheit
MMbtu: One million British thermal units

Dekatherms (Dth): A unit of energy equal to one million British thermal units
Mdth/d: One thousand dekatherms per day
MMdth: One million dekatherms or approximately one trillion British thermal units
MMdth/d: One million dekatherms per day

Consolidated Entities: Entities in which we either own 100 percent ownership interest or for which we do not own 100 percent ownership interest but which we control and therefore consolidate, including the following:

Cardinal: Cardinal Gas Services, L.L.C.

Gulfstar One: Gulfstar One LLC

Northeast JV: Ohio Valley Midstream LLC

Northwest Pipeline: Northwest Pipeline LLC

Transco: Transcontinental Gas Pipe Line Company, LLC

Nonconsolidated Entities: Entities in which we do not own a 100 percent ownership interest and which, as of September 30, 2023, we account for as equity-method investments, including principally the following:

Blue Racer: Blue Racer Midstream LLC

Brazos Permian II: Brazos Permian II, LLC

Discovery: Discovery Producer Services LLC

Gulfstream: Gulfstream Natural Gas System, L.L.C.

Laurel Mountain: Laurel Mountain Midstream, LLC

OPPL: Overland Pass Pipeline Company LLC

RMM: Rocky Mountain Midstream Holdings LLC

Targa Train 7: Targa Train 7 LLC

Government and Regulatory:

EPA: Environmental Protection Agency

Exchange Act, the: Securities and Exchange Act of 1934, as amended

FERC: Federal Energy Regulatory Commission

IRS: Internal Revenue Service

SEC: Securities and Exchange Commission

Securities Act, the: Securities Act of 1933, as amended

Other:

EBITDA: Earnings before interest, taxes, depreciation, and amortization

Fractionation: The process by which a mixed stream of natural gas liquids is separated into constituent products, such as ethane, propane, and butane

GAAP: U.S. generally accepted accounting principles

LNG: Liquefied natural gas; natural gas which has been liquefied at cryogenic temperatures

MVC: Minimum volume commitments

NGLs: Natural gas liquids; natural gas liquids result from natural gas processing and crude oil refining and are used as petrochemical feedstocks, heating fuels, and gasoline additives, among other applications

Appalachia Midstream Investments: Our equity-method investments with an approximate average 66 percent interest in multiple gas gathering systems in the Marcellus Shale region

Sequent Acquisition: The July 1, 2021, acquisition of 100 percent of Sequent Energy Management, L.P. and Sequent Energy Canada, Corp.

Trace Acquisition: The April 29, 2022, acquisition of 100 percent of Gemini Arklatex, LLC, through which we acquired the Haynesville Shale region gas gathering and related assets of Trace Midstream (Trace)

NorTex Asset Purchase: The August 31, 2022, purchase of a group of assets in north Texas, primarily natural gas storage facilities and pipelines, from NorTex Midstream Holdings, LLC

MountainWest Acquisition: The February 14, 2023, acquisition of 100 percent of MountainWest Pipelines Holding Company (MountainWest), which includes FERC-regulated interstate natural gas pipeline systems and natural gas storage capacity

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements

The Williams Companies, Inc.
Consolidated Statement of Income
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
	(Millions, except per-share amounts)			
Revenues:				
Service revenues	$ 1,770	$ 1,685	$ 5,212	$ 4,828
Service revenues – commodity consideration	45	60	108	223
Product sales	720	1,260	2,158	3,475
Net gain (loss) on commodity derivatives	24	16	645	(491)
Total revenues	2,559	3,021	8,123	8,035
Costs and expenses:				
Product costs	484	990	1,458	2,650
Net processing commodity expenses	31	29	129	99
Operating and maintenance expenses	522	486	1,466	1,345
Depreciation and amortization expenses	521	500	1,542	1,504
Selling, general, and administrative expenses	146	163	483	477
Gain on sale of business (Note 3)	(130)	—	(130)	—
Other (income) expense – net	(9)	33	(49)	14
Total costs and expenses	1,565	2,201	4,899	6,089
Operating income (loss)	994	820	3,224	1,946
Equity earnings (losses)	127	193	434	492
Other investing income (loss) – net	24	1	45	4
Interest incurred	(330)	(296)	(953)	(871)
Interest capitalized	16	5	39	13
Other income (expense) – net	30	(6)	69	5
Income (loss) before income taxes	861	717	2,858	1,589
Less: Provision (benefit) for income taxes	176	96	635	169
Income (loss) from continuing operations	685	621	2,223	1,420
Income (loss) from discontinued operations (Note 9)	(1)	—	(88)	—
Net income (loss)	684	621	2,135	1,420
Less: Net income (loss) attributable to noncontrolling interests	30	21	94	40
Net income (loss) attributable to The Williams Companies, Inc.	654	600	2,041	1,380
Less: Preferred stock dividends	1	1	2	2
Net income (loss) available to common stockholders	$ 653	$ 599	$ 2,039	$ 1,378
Amounts attributable to The Williams Companies, Inc. available to common stockholders:				
Income (loss) from continuing operations	$ 654	$ 599	$ 2,127	$ 1,378
Income (loss) from discontinued operations	(1)	—	(88)	—
Net income (loss) available to common stockholders	$ 653	$ 599	$ 2,039	$ 1,378
Basic earnings (loss) per common share:				
Income (loss) from continuing operations	$ .54	$ .49	$ 1.74	$ 1.13
Income (loss) from discontinued operations	—	—	(.07)	—
Net income (loss) available to common stockholders	$ .54	$ .49	$ 1.67	$ 1.13
Weighted-average shares (thousands)	1,216,951	1,218,964	1,218,021	1,218,202
Diluted earnings (loss) per common share:				
Income (loss) from continuing operations	$ .54	$ .49	$ 1.74	$ 1.13
Income (loss) from discontinued operations	—	—	(.07)	—
Net income (loss) available to common stockholders	$ .54	$ .49	$ 1.67	$ 1.13
Weighted-average shares (thousands)	1,220,073	1,222,472	1,222,650	1,222,153

See accompanying notes.

The Williams Companies, Inc.
Consolidated Statement of Comprehensive Income (Loss)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
	(Millions)			
Net income (loss)	$ 684	$ 621	$ 2,135	$ 1,420
Other comprehensive income (loss):				
Designated interest rate cash flow hedging activities:				
Net unrealized gain (loss) from derivative instruments, net of taxes of $(12) and $(23) in 2023 and $3 and $1 in 2022	36	(8)	72	(3)
Reclassifications into earnings of net derivative instruments (gain) loss, net of taxes of $— and $— in 2023 and $— and $— in 2022	(1)	—	(2)	—
Pension and other postretirement benefits:				
Net actuarial gain (loss) arising during the year, net of taxes of $— and $— in 2023 and ($1) and ($1) in 2022	—	2	—	2
Amortization of actuarial (gain) loss and net actuarial loss from settlements included in net periodic benefit cost (credit), net of taxes of $— and $(1) in 2023 and $(1) and ($2) in 2022	1	2	2	7
Other comprehensive income (loss)	36	(4)	72	6
Comprehensive income (loss)	720	617	2,207	1,426
Less: Comprehensive income (loss) attributable to noncontrolling interests	30	21	94	40
Comprehensive income (loss) attributable to The Williams Companies, Inc.	$ 690	$ 596	$ 2,113	$ 1,386

See accompanying notes.

The Williams Companies, Inc.
Consolidated Balance Sheet
(Unaudited)

	September 30, 2023	December 31, 2022
	(Millions, except per-share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,074	$ 152
Trade accounts and other receivables (net of allowance of $3 at September 30, 2023 and $6 at December 31, 2022)	1,419	2,723
Inventories	266	320
Derivative assets	243	323
Other current assets and deferred charges	254	279
Total current assets	4,256	3,797
Investments	4,998	5,065
Property, plant, and equipment	50,805	47,057
Accumulated depreciation and amortization	(18,177)	(16,168)
Property, plant, and equipment – net	32,628	30,889
Intangible assets – net of accumulated amortization	7,459	7,363
Regulatory assets, deferred charges, and other	1,447	1,319
Total assets	$ 50,788	$ 48,433
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 1,358	$ 2,327
Derivative liabilities	123	316
Accrued and other current liabilities	1,166	1,270
Commercial paper	—	350
Long-term debt due within one year	2,879	627
Total current liabilities	5,526	4,890
Long-term debt	22,772	21,927
Deferred income tax liabilities	3,496	2,887
Regulatory liabilities, deferred income, and other	4,651	4,684
Contingent liabilities and commitments (Note 9)		
Equity:		
Stockholders’ equity:		
Preferred stock ($1 par value; 30 million shares authorized at September 30, 2023 and December 31, 2022; 35,000 shares issued at September 30, 2023 and December 31, 2022)	35	35
Common stock ($1 par value; 1,470 million shares authorized at September 30, 2023 and December 31, 2022; 1,256 million shares issued at September 30, 2023 and 1,253 million shares issued at December 31, 2022)	1,256	1,253
Capital in excess of par value	24,562	24,542
Retained deficit	(12,876)	(13,271)
Accumulated other comprehensive income (loss)	48	(24)
Treasury stock, at cost (39 million shares at September 30, 2023 and 35 million shares at December 31, 2022 of common stock)	(1,180)	(1,050)
Total stockholders’ equity	11,845	11,485
Noncontrolling interests in consolidated subsidiaries	2,498	2,560
Total equity	14,343	14,045
Total liabilities and equity	$ 50,788	$ 48,433

See accompanying notes.

The Williams Companies, Inc.
Consolidated Statement of Changes in Equity
(Unaudited)

	The Williams Companies, Inc. Stockholders								
	Preferred Stock	Common Stock	Capital in Excess of Par Value	Retained Deficit	AOCI*	Treasury Stock	Total Stockholders' Equity	Noncontrolling Interests	Total Equity
	(Millions)								
Balance – June 30, 2023	$ 35	$ 1,256	$ 24,538	$ (12,982)	$ 12	$ (1,180)	$ 11,679	$ 2,530	$ 14,209
Net income (loss)	—	—	—	654	—	—	654	30	684
Other comprehensive income (loss)	—	—	—	—	36	—	36	—	36
Cash dividends – common stock ($0.4475 per share)	—	—	—	(544)	—	—	(544)	—	(544)
Dividends and distributions to noncontrolling interests	—	—	—	—	—	—	—	(62)	(62)
Stock-based compensation and related common stock issuances, net of tax	—	—	23	—	—	—	23	—	23
Other	—	—	1	(4)	—	—	(3)	—	(3)
Net increase (decrease) in equity	—	—	24	106	36	—	166	(32)	134
Balance – September 30, 2023	$ 35	$ 1,256	$ 24,562	$ (12,876)	$ 48	$ (1,180)	$ 11,845	$ 2,498	$ 14,343
Balance – June 30, 2022	$ 35	$ 1,253	$ 24,500	$ (13,498)	$ (23)	$ (1,041)	$ 11,226	$ 2,610	$ 13,836
Net income (loss)	—	—	—	600	—	—	600	21	621
Other comprehensive income (loss)	—	—	—	—	(4)	—	(4)	—	(4)
Cash dividends – common stock ($0.425 per share)	—	—	—	(518)	—	—	(518)	—	(518)
Dividends and distributions to noncontrolling interests	—	—	—	—	—	—	—	(46)	(46)
Stock-based compensation and related common stock issuances, net of tax	—	—	28	—	—	—	28	—	28
Contributions from noncontrolling interests	—	—	—	—	—	—	—	7	7
Purchases of treasury stock	—	—	—	—	—	(9)	(9)	—	(9)
Other	—	—	(1)	(3)	—	—	(4)	(1)	(5)
Net increase (decrease) in equity	—	—	27	79	(4)	(9)	93	(19)	74
Balance – September 30, 2022	$ 35	$ 1,253	$ 24,527	$ (13,419)	$ (27)	$ (1,050)	$ 11,319	$ 2,591	$ 13,910

* Accumulated Other Comprehensive Income (Loss)

See accompanying notes.

The Williams Companies, Inc.
Consolidated Statement of Changes in Equity (Continued)
(Unaudited)

	The Williams Companies, Inc. Stockholders								
	Preferred Stock	**Common Stock**	**Capital in Excess of Par Value**	**Retained Deficit**	**AOCI***	**Treasury Stock**	**Total Stockholders' Equity**	**Noncontrolling Interests**	**Total Equity**
					(Millions)				
Balance – December 31, 2022	$ 35	$ 1,253	$ 24,542	$ (13,271)	$ (24)	$ (1,050)	$ 11,485	$ 2,560	$ 14,045
Net income (loss)	—	—	—	2,041	—	—	2,041	94	2,135
Other comprehensive income (loss)	—	—	—	—	72	—	72	—	72
Cash dividends – common stock ($1.3425 per share)	—	—	—	(1,635)	—	—	(1,635)	—	(1,635)
Dividends and distributions to noncontrolling interests	—	—	—	—	—	—	—	(174)	(174)
Stock-based compensation and related common stock issuances, net of tax	—	3	19	—	—	—	22	—	22
Contributions from noncontrolling interests	—	—	—	—	—	—	—	18	18
Purchases of treasury stock	—	—	—	—	—	(130)	(130)	—	(130)
Other	—	—	1	(11)	—	—	(10)	—	(10)
Net increase (decrease) in equity	—	3	20	395	72	(130)	360	(62)	298
Balance – September 30, 2023	$ 35	$ 1,256	$ 24,562	$ (12,876)	$ 48	$ (1,180)	$ 11,845	$ 2,498	$ 14,343
Balance – December 31, 2021	$ 35	$ 1,250	$ 24,449	$ (13,237)	$ (33)	$ (1,041)	$ 11,423	$ 2,678	$ 14,101
Net income (loss)	—	—	—	1,380	—	—	1,380	40	1,420
Other comprehensive income (loss)	—	—	—	—	6	—	6	—	6
Cash dividends – common stock ($1.275 per share)	—	—	—	(1,553)	—	—	(1,553)	—	(1,553)
Dividends and distributions to noncontrolling interests	—	—	—	—	—	—	—	(141)	(141)
Stock-based compensation and related common stock issuances, net of tax	—	3	79	—	—	—	82	—	82
Contributions from noncontrolling interests	—	—	—	—	—	—	—	15	15
Purchases of treasury stock	—	—	—	—	—	(9)	(9)	—	(9)
Other	—	—	(1)	(9)	—	—	(10)	(1)	(11)
Net increase (decrease) in equity	—	3	78	(182)	6	(9)	(104)	(87)	(191)
Balance – September 30, 2022	$ 35	$ 1,253	$ 24,527	$ (13,419)	$ (27)	$ (1,050)	$ 11,319	$ 2,591	$ 13,910

* Accumulated Other Comprehensive Income (Loss)

See accompanying notes.

The Williams Companies, Inc.
Consolidated Statement of Cash Flows
(Unaudited)

	Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022
	(Millions)	
OPERATING ACTIVITIES:		
Net income (loss)	$ 2,135	$ 1,420
Adjustments to reconcile to net cash provided (used) by operating activities:		
Depreciation and amortization	1,542	1,504
Provision (benefit) for deferred income taxes	586	182
Equity (earnings) losses	(434)	(492)
Distributions from equity-method investees	607	688
Net unrealized (gain) loss from derivative instruments	(433)	329
Gain on sale of business (Note 3)	(130)	—
Inventory write-downs	28	76
Amortization of stock-based awards	59	58
Cash provided (used) by changes in current assets and liabilities:		
Accounts receivable	1,295	(672)
Inventories	29	(152)
Other current assets and deferred charges	(5)	(62)
Accounts payable	(1,072)	743
Accrued and other current liabilities	(114)	167
Changes in current and noncurrent derivative assets and liabilities	172	86
Other, including changes in noncurrent assets and liabilities	(140)	(205)
Net cash provided (used) by operating activities	4,125	3,670
FINANCING ACTIVITIES:		
Proceeds from (payments of) commercial paper – net	(352)	—
Proceeds from long-term debt	2,754	1,752
Payments of long-term debt	(21)	(2,019)
Proceeds from issuance of common stock	8	53
Purchases of treasury stock	(130)	(9)
Common dividends paid	(1,635)	(1,553)
Dividends and distributions paid to noncontrolling interests	(174)	(141)
Contributions from noncontrolling interests	18	15
Payments for debt issuance costs	(21)	(14)
Other – net	(19)	(40)
Net cash provided (used) by financing activities	428	(1,956)
INVESTING ACTIVITIES:		
Property, plant, and equipment:		
Capital expenditures (1)	(1,845)	(1,447)
Dispositions – net	(33)	(19)
Contributions in aid of construction	20	8
Proceeds from sale of business (Note 3)	348	—
Purchases of businesses, net of cash acquired (Note 3)	(1,024)	(933)
Purchases of and contributions to equity-method investments	(80)	(140)
Other – net	(17)	(4)
Net cash provided (used) by investing activities	(2,631)	(2,535)
Increase (decrease) in cash and cash equivalents	1,922	(821)
Cash and cash equivalents at beginning of year	152	1,680
Cash and cash equivalents at end of period	$ 2,074	$ 859

(1) Increases to property, plant, and equipment	$ (1,960)	$ (1,549)
Changes in related accounts payable and accrued liabilities	115	102
Capital expenditures	$ (1,845)	$ (1,447)

See accompanying notes.

The Williams Companies, Inc.
Notes to Consolidated Financial Statements
(Unaudited)

Note 1 – General, Description of Business, and Basis of Presentation

General

Our accompanying interim consolidated financial statements do not include all the notes in our annual financial statements and, therefore, should be read in conjunction with our consolidated financial statements and notes thereto for the year ended December 31, 2022, in our Annual Report on Form 10-K. The accompanying unaudited financial statements include all normal recurring adjustments and others that, in the opinion of management, are necessary to present fairly our interim financial statements.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in our consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

Unless the context clearly indicates otherwise, references in this report to "Williams," "we," "our," "us," or like terms refer to The Williams Companies, Inc. and its subsidiaries. Unless the context clearly indicates otherwise, references to "Williams," "we," "our," and "us" include the operations in which we own interests accounted for as equity-method investments that are not consolidated in our financial statements. When we refer to our equity investees by name, we are referring exclusively to their businesses and operations.

Share Repurchase Program

In September 2021, our Board of Directors authorized a share repurchase program with a maximum dollar limit of $1.5 billion. Repurchases may be made from time to time in the open market, by block purchases, in privately negotiated transactions, or in such other manner as determined by our management. Our management will also determine the timing and amount of any repurchases based on market conditions and other factors. The share repurchase program does not obligate us to acquire any particular amount of common stock, and it may be suspended or discontinued at any time. This share repurchase program does not have an expiration date. During the nine months ended September 30, 2023, there have been $130 million in repurchases under the program which are included in our Consolidated Statement of Changes in Equity. Cumulative repurchases to date under the program total $139 million.

Description of Business

We are a Delaware corporation whose common stock is listed and traded on the New York Stock Exchange. Our operations are located in the United States and are presented within the following reportable segments: Transmission & Gulf of Mexico, Northeast G&P, West, and Gas & NGL Marketing Services, consistent with the manner in which our chief operating decision maker evaluates performance and allocates resources. All remaining business activities, including our upstream operations and corporate activities, are included in Other.

Transmission & Gulf of Mexico is comprised of our interstate natural gas pipelines, Transco, Northwest Pipeline, and MountainWest (see Note 3 – Acquisitions and Divestitures), and their related natural gas storage facilities, as well as natural gas gathering and processing and crude oil production handling and transportation assets in the Gulf Coast region, including a 51 percent interest in Gulfstar One (a consolidated variable interest entity, or VIE), a 50 percent equity-method investment in Gulfstream, and a 60 percent equity-method investment in Discovery. Transmission & Gulf of Mexico also includes natural gas storage facilities and pipelines providing services in north Texas.

Northeast G&P is comprised of our midstream gathering, processing, and fractionation businesses in the Marcellus Shale region primarily in Pennsylvania and New York, and the Utica Shale region of eastern Ohio, as well as a 65 percent interest in Northeast JV (a consolidated VIE) which operates in West Virginia, Ohio, and Pennsylvania, a 66 percent interest in Cardinal (a consolidated VIE) which operates in Ohio, a 69 percent equity-method investment in Laurel Mountain, a 50 percent equity-method investment in Blue Racer, and Appalachia Midstream Investments.

West is comprised of our gas gathering, processing, and treating operations in the Rocky Mountain region of Colorado and Wyoming, the Barnett Shale region of north-central Texas, the Eagle Ford Shale region of south Texas, the Haynesville Shale region of east Texas and northwest Louisiana, and the Mid-Continent region which includes the Anadarko and Permian basins. This segment also includes our NGL storage facilities, an undivided 50 percent interest in an NGL fractionator near Conway, Kansas, a 50 percent equity-method investment in OPPL, a 50 percent equity-method investment in RMM, a 20 percent equity-method investment in Targa Train 7 (a nonconsolidated VIE), and a 15 percent equity-method investment in Brazos Permian II (a nonconsolidated VIE).

Gas & NGL Marketing Services is comprised of our NGL and natural gas marketing and trading operations, which includes risk management and transactions related to the storage and transportation of natural gas and NGLs on strategically positioned assets.

Basis of Presentation

Significant risks and uncertainties

We believe that the carrying value of certain of our property, plant, and equipment and intangible assets, notably certain acquired assets accounted for as business combinations between 2012 and 2014, may be in excess of current fair value. However, the carrying value of these assets, in our judgment, continues to be recoverable. It is reasonably possible that future strategic decisions, including transactions such as monetizing assets or contributing assets to new ventures with third parties, as well as unfavorable changes in expected producer activities, could impact our assumptions and ultimately result in impairments of these assets. Such transactions or developments may also indicate that certain of our equity-method investments have experienced other-than-temporary declines in value, which could result in impairment.

Note 2 – Variable Interest Entities

Consolidated VIEs

As of September 30, 2023, we consolidated the following VIEs:

Northeast JV

We own a 65 percent interest in the Northeast JV, a subsidiary that is a VIE due to certain of our voting rights being disproportionate to our obligation to absorb losses and substantially all of the Northeast JV’s activities being performed on our behalf. We are the primary beneficiary because we have the power to direct the activities that most significantly impact the Northeast JV’s economic performance. The Northeast JV provides midstream services for producers in the Marcellus Shale and Utica Shale regions. Future expansion activity is expected to be funded with capital contributions from us and the other equity partner on a proportional basis.

Gulfstar One

We own a 51 percent interest in Gulfstar One, a subsidiary that, due to certain risk-sharing provisions in its customer contracts, is a VIE. Gulfstar One includes a proprietary floating production system, Gulfstar FPS, and associated pipelines that provide production handling and gathering services in the eastern deepwater Gulf of Mexico. We are the primary beneficiary because we have the power to direct the activities that most significantly impact Gulfstar One’s economic performance.

Cardinal

We own a 66 percent interest in Cardinal, a subsidiary that provides gathering services for the Utica Shale region and is a VIE due to certain risks shared with customers. We are the primary beneficiary because we have the power to direct the activities that most significantly impact Cardinal's economic performance. In order to meet contractual gas gathering commitments, we may fund more than our proportional share of future expansion activity, which could ultimately impact relative ownership.

The following table presents amounts included in our Consolidated Balance Sheet that are only for the use or obligation of our consolidated VIEs:

	September 30, 2023	December 31, 2022
	(Millions)	
Assets (liabilities):		
Cash and cash equivalents	$ 29	$ 49
Trade accounts and other receivables – net	195	136
Inventories	6	4
Other current assets and deferred charges	6	7
Property, plant, and equipment – net	5,090	5,154
Intangible assets – net of accumulated amortization	2,077	2,158
Regulatory assets, deferred charges, and other	31	29
Accounts payable	(97)	(76)
Accrued and other current liabilities	(23)	(34)
Regulatory liabilities, deferred income, and other	(273)	(275)

Nonconsolidated VIEs

Targa Train 7

We own a 20 percent interest in Targa Train 7, which provides fractionation services at Mont Belvieu, Texas, and is a VIE due primarily to our limited participating rights as the minority equity holder. At September 30, 2023, the carrying value of our investment in Targa Train 7 was $44 million. Our maximum exposure to loss is limited to the carrying value of our investment.

Brazos Permian II

We own a 15 percent interest in Brazos Permian II, which provides gathering and processing services in the Delaware basin and is a VIE due primarily to our limited participating rights as the minority equity holder. At September 30, 2023, the carrying value of our investment in Brazos Permian II was $23 million. Our maximum exposure to loss is limited to the carrying value of our investment.

Note 3 – Acquisitions and Divestitures

Sale of Certain Gulf Coast Liquids Pipelines

On September 29, 2023, we completed the sale of various petrochemical and feedstock pipelines and associated contracts in the Gulf Coast region for $348 million. As a result of this sale, we recorded a gain of $130 million in the third quarter of 2023 in our Transmission & Gulf of Mexico segment. The gain is included in *Gain on sale of business* in our Consolidated Statement of Income. The results of operations for this disposal group, excluding the gain noted, were not significant for the reporting periods.

MountainWest Acquisition

On February 14, 2023, we closed on the acquisition of 100 percent of MountainWest, which includes FERC-regulated interstate natural gas pipeline systems and natural gas storage capacity, for $1.08 billion of cash, funded with available sources of short-term liquidity, and retaining $430 million outstanding principal amount of MountainWest long-term debt. The $1.024 billion *Purchases of businesses, net of cash acquired* in our Consolidated Statement of Cash Flows includes the cash purchase price reduced for post-closing adjustments and the cash acquired as presented in the preliminary purchase price allocation. The purpose of the MountainWest Acquisition was to expand our existing transmission and storage infrastructure footprint into major markets in Utah, Wyoming, and Colorado.

During the period from the acquisition date of February 14, 2023 to September 30, 2023, the operations acquired in the MountainWest Acquisition contributed *Revenues* of $156 million and *Modified EBITDA* (as defined in Note 10 – Segment Disclosures) of $78 million, which includes $20 million of transition-related costs.

Acquisition-related costs for the MountainWest Acquisition of $15 million are reported within our Transmission & Gulf of Mexico segment and included in *Selling, general, and administrative expenses* in our Consolidated Statement of Income during 2023.

We accounted for the MountainWest Acquisition as a business combination, which requires, among other things, that identifiable assets acquired and liabilities assumed be recognized at their acquisition date fair values. The valuation techniques used consisted of depreciated replacement costs for non-regulated property, plant, and equipment, as well as the market approach for the assumed long-term debt consistent with the valuation technique discussed in Note 7 – Fair Value Measurements and Guarantees. MountainWest's regulated operations are accounted for pursuant to Accounting Standards Codification 980, Regulated Operations. The fair value of assets and liabilities subject to rate making and cost recovery provisions were determined utilizing the income approach. MountainWest's expected return on rate base is consistent with expected returns of similarly situated assets, resulting in carryover basis of these assets and liabilities equaling their fair value.

The following table presents the preliminary allocation of the acquisition date fair value of the major classes of the assets acquired, which are included in our Transmission & Gulf of Mexico segment, and liabilities assumed at February 14, 2023. The allocation is considered preliminary because the valuation work has not been completed due to the ongoing review of the valuation results and validation of significant inputs and assumptions. Preliminary fair value measurements were made for certain acquired assets and liabilities, primarily property, plant, and equipment and long-term debt; however, adjustments to those measurements may be made in subsequent periods, up to one year from the acquisition date, as new information related to facts and circumstances as of the acquisition date may be identified. The fair value of accounts receivable acquired equals contractual amounts receivable. After the March 31, 2023, financial statements were issued, we identified adjustments to the preliminary purchase price allocation, primarily resulting in an increase of $19 million in trade accounts and other receivables and decreases of $72 million in property, plant, and equipment and $60 million in other noncurrent liabilities.

		(Millions)
Cash and cash equivalents	$	23
Trade accounts and other receivables		33
Other current assets		26
Investments		22
Property, plant, and equipment – net		1,020
Other noncurrent assets		32
Total identifiable assets acquired	$	1,156
Current liabilities	$	(47)
Long-term debt (see Note 6)		(365)
Other noncurrent liabilities		(95)
Total liabilities assumed	$	(507)
Net identifiable assets acquired	$	649
Goodwill included in *Intangible assets – net of accumulated amortization*		398
Net assets acquired	$	1,047

Goodwill recognized in the MountainWest Acquisition relates primarily to enhancing and diversifying our basin positions and the long-term value associated with rate regulated businesses and is reported within our Transmission & Gulf of Mexico segment. Substantially all of the goodwill is deductible for tax purposes. Goodwill is included within *Intangible assets – net of accumulated amortization* in our Consolidated Balance Sheet and represents the excess of the consideration over the fair value of the net assets acquired. It is not subject to amortization but is evaluated annually as of October 1 for impairment or more frequently if impairment indicators are present that would indicate it is more likely than not that the fair value of the reporting unit is less than its carrying amount. As part of the evaluation, we compare our estimate of the fair value of the reporting unit with its carrying value, including goodwill. If the carrying value of the reporting unit exceeds its fair value, an impairment charge is recorded for the difference (not to exceed the carrying value of goodwill). Judgments and assumptions are inherent in our management's estimates of fair value.

Trace Acquisition

On April 29, 2022, we closed on the acquisition of 100 percent of Gemini Arklatex, LLC through which we acquired the Haynesville Shale region gas gathering and related assets of Trace for $972 million of cash funded with cash on hand and proceeds from issuance of commercial paper. The purpose of the Trace Acquisition was to expand our footprint into the east Texas area of the Haynesville Shale region, increasing in-basin scale in one of the largest growth basins in the country.

During the period from the acquisition date of April 29, 2022 to December 31, 2022, the operations acquired in the Trace Acquisition contributed *Revenues* of $148 million and *Modified EBITDA* of $73 million.

Acquisition-related costs for the Trace Acquisition of $8 million are reported within our West segment and were included in *Selling, general, and administrative expenses* in our Consolidated Statement of Income during 2022.

We accounted for the Trace Acquisition as a business combination. The following table presents the allocation of the acquisition date fair value of the major classes of the assets acquired, which are included in our West segment, and liabilities assumed at April 29, 2022. The fair value of accounts receivable acquired equals contractual amounts receivable. The valuation techniques used consisted of the income approach (excess earnings method) for valuation of intangible assets and depreciated replacement costs for property, plant, and equipment.

		(Millions)
Cash and cash equivalents	$	39
Trade accounts and other receivables		18
Property, plant, and equipment – net		448
Intangible assets – net of accumulated amortization		472
Other noncurrent assets		20
Total assets acquired	$	997
Accounts payable	$	(12)
Accrued and other current liabilities		(5)
Other noncurrent liabilities		(8)
Total liabilities assumed	$	(25)
Net assets acquired	$	972

Other intangible assets

Other intangible assets recognized in the Trace Acquisition are related to contractual customer relationships from gas gathering agreements with our customers. The basis for determining the value of these intangible assets is estimated future net cash flows to be derived from acquired contractual customer relationships discounted using a risk-adjusted discount rate. These intangible assets are being amortized on a straight-line basis over an initial period of 20 years which represents the term over which the contractual customer relationships are expected to contribute to our cash flows. Approximately 2 percent of the expected future revenues from these contractual customer relationships are impacted by our ability and intent to renew or renegotiate existing customer contracts. We expense costs incurred to renew or extend the terms of our gas gathering contracts with customers. Based on the estimated future revenues during the current contract periods (as estimated at the time of the acquisition), the weighted-average period prior to the next renewal or extension of the existing contractual customer relationships is approximately 19 years.

Supplemental Pro Forma

The following pro forma *Revenues* and *Net income (loss) attributable to The Williams Companies, Inc.* for the three months ended September 30, 2022, and nine months ended September 30, 2023 and 2022, are presented as if the MountainWest Acquisition had been completed on January 1, 2022, and the Trace Acquisition had been completed on January 1, 2021. These pro forma amounts are not necessarily indicative of what the actual results would have been if the MountainWest Acquisition and Trace Acquisition had in fact occurred on the dates or for the periods indicated, nor do they purport to project *Revenues* or *Net income (loss) attributable to The Williams Companies, Inc.* for any future periods or as of any date. These amounts do not give effect to any potential cost savings, operating synergies, or revenue enhancements to result from the transaction or the potential costs to achieve these cost savings, operating synergies, and revenue enhancements.

	Three Months Ended September 30, 2022		
	As Reported	Pro Forma MountainWest	Pro Forma Combined
	(Millions)		
Revenues	$ 3,021	$ 63	$ 3,084
Net income (loss) attributable to The Williams Companies, Inc.	600	12	612

	Nine Months Ended September 30, 2023		
	As Reported	Pro Forma MountainWest (1)	Pro Forma Combined
	(Millions)		
Revenues	$ 8,123	$ 35	$ 8,158
Net income (loss) attributable to The Williams Companies, Inc.	2,041	6	2,047

	Nine Months Ended September 30, 2022			
	As Reported	Pro Forma MountainWest	Pro Forma Trace (2)	Pro Forma Combined
	(Millions)			
Revenues	$ 8,035	$ 192	$ 45	$ 8,272
Net income (loss) attributable to The Williams Companies, Inc.	1,380	43	18	1,441

(1) Excludes results from operations acquired in the MountainWest Acquisition for the period beginning on the acquisition date of February 14, 2023, as these results are included in the amounts as reported.

(2) Excludes results from operations acquired in the Trace Acquisition for the period beginning on the acquisition date of April 29, 2022, as these results are included in the amounts as reported.

NorTex Asset Purchase

On August 31, 2022, we purchased a group of assets in north Texas, primarily natural gas storage facilities and pipelines, from NorTex Midstream Holdings, LLC for approximately $424 million. These assets are included in our Transmission & Gulf of Mexico segment.

Note 4 – Revenue Recognition

Revenue by Category

The following table presents our revenue disaggregated by major service line:

	Regulated Interstate Transportation & Storage	Gulf of Mexico Midstream & Storage	Northeast Midstream	West Midstream	Gas & NGL Marketing Services	Other	Eliminations	Total
				(Millions)				
Three Months Ended September 30, 2023								
Revenues from contracts with customers:								
Service revenues:								
Regulated interstate natural gas transportation and storage	$ 841	$ —	$ —	$ —	$ —	$ —	$ (18)	$ 823
Gathering, processing, transportation, fractionation, and storage:								
Monetary consideration	—	121	450	368	—	—	(41)	898
Commodity consideration	—	11	—	34	—	—	—	45
Other	5	2	22	2	—	—	(3)	28
Total service revenues	846	134	472	404	—	—	(62)	1,794
Product sales	35	31	27	112	1,189	117	(244)	1,267
Total revenues from contracts with customers	881	165	499	516	1,189	117	(306)	3,061
Other revenues (1)	5	4	6	17	697	13	(2)	740
Other adjustments (2)	—	—	—	—	(1,328)	—	86	(1,242)
Total revenues	$ 886	$ 169	$ 505	$ 533	$ 558	$ 130	$ (222)	$ 2,559
Three Months Ended September 30, 2022								
Revenues from contracts with customers:								
Service revenues:								
Regulated interstate natural gas transportation and storage	$ 794	$ —	$ —	$ —	$ —	$ —	$ (18)	$ 776
Gathering, processing, transportation, fractionation, and storage:								
Monetary consideration (3)	—	104	391	420	—	—	(51)	864
Commodity consideration	—	11	2	47	—	—	—	60
Other (3)	3	4	20	2	1	—	(4)	26
Total service revenues	797	119	413	469	1	—	(73)	1,726
Product sales	81	51	40	245	3,109	238	(523)	3,241
Total revenues from contracts with customers	878	170	453	714	3,110	238	(596)	4,967
Other revenues (1)	3	3	6	(6)	2,607	(23)	(1)	2,589
Other adjustments (2)	—	—	—	—	(4,779)	—	244	(4,535)
Total revenues	$ 881	$ 173	$ 459	$ 708	$ 938	$ 215	$ (353)	$ 3,021

	Regulated Interstate Transportation & Storage	Gulf of Mexico Midstream & Storage	Northeast Midstream	West Midstream	Gas & NGL Marketing Services	Other	Eliminations	Total
				(Millions)				
Nine Months Ended September 30, 2023								
Revenues from contracts with customers:								
Service revenues:								
Regulated interstate natural gas transportation and storage	$ 2,480	$ —	$ —	$ —	$ —	$ —	$ (41)	$ 2,439
Gathering, processing, transportation, fractionation, and storage:								
Monetary consideration	—	334	1,334	1,070	—	—	(130)	2,608
Commodity consideration	—	29	3	76	—	—	—	108
Other	14	10	67	8	1	—	(11)	89
Total service revenues	2,494	373	1,404	1,154	1	—	(182)	5,244
Product sales	114	91	104	287	3,519	302	(686)	3,731
Total revenues from contracts with customers	2,608	464	1,508	1,441	3,520	302	(868)	8,975
Other revenues (1)	26	11	20	95	3,240	36	(2)	3,426
Other adjustments (2)	—	—	—	—	(4,566)	—	288	(4,278)
Total revenues	$ 2,634	$ 475	$ 1,528	$ 1,536	$ 2,194	$ 338	$ (582)	$ 8,123
Nine Months Ended September 30, 2022								
Revenues from contracts with customers:								
Service revenues:								
Regulated interstate natural gas transportation and storage	$ 2,343	$ —	$ —	$ —	$ —	$ —	$ (54)	$ 2,289
Gathering, processing, transportation, fractionation, and storage:								
Monetary consideration (3)	—	277	1,127	1,122	—	—	(117)	2,409
Commodity consideration	—	54	12	157	—	—	—	223
Other (3)	8	9	62	8	2	—	(13)	76
Total service revenues	2,351	340	1,201	1,287	2	—	(184)	4,997
Product sales	140	215	110	684	8,422	522	(1,442)	8,651
Total revenues from contracts with customers	2,491	555	1,311	1,971	8,424	522	(1,626)	13,648
Other revenues (1)	8	7	19	(14)	5,838	(72)	(10)	5,776
Other adjustments (2)	—	—	—	—	(11,911)	—	522	(11,389)
Total revenues	$ 2,499	$ 562	$ 1,330	$ 1,957	$ 2,351	$ 450	$ (1,114)	$ 8,035

(1) Revenues not derived from contracts with customers primarily consist of physical product sales related to derivative contracts, realized and unrealized gains and losses associated with our derivative contracts, which are reported in *Net gain (loss) on commodity derivatives* in the Consolidated Statement of Income, management fees that we receive for certain services we provide to operated equity-method investments, and leasing revenues associated with our headquarters building.

(2) Other adjustments reflect certain costs of Gas & NGL Marketing Services' risk management activities. As we are acting as agent for natural gas marketing customers or engage in energy trading activities, the resulting revenues are presented net of the related costs of those activities in our Consolidated Statement of Income.

(3) Certain contractual reimbursements of operating and maintenance costs previously included in *Other* are now presented in *Monetary consideration* as they were received in exchange for providing gas gathering and processing services.

Contract Assets

The following table presents a reconciliation of our contract assets:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
	(Millions)			
Balance at beginning of period	$ 56	$ 48	$ 29	$ 22
Revenue recognized in excess of amounts invoiced	45	54	133	158
Minimum volume commitments invoiced	(28)	(41)	(89)	(119)
Balance at end of period	$ 73	$ 61	$ 73	$ 61

Contract Liabilities

The following table presents a reconciliation of our contract liabilities:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
	(Millions)			
Balance at beginning of period	$ 1,039	$ 1,115	$ 1,043	$ 1,126
Payments received and deferred	40	34	164	144
Significant financing component	3	2	7	7
Contract liability acquired (disposed) – net	(2)	2	3	2
Recognized in revenue	(68)	(71)	(205)	(197)
Balance at end of period	$ 1,012	$ 1,082	$ 1,012	$ 1,082

Remaining Performance Obligations

Remaining performance obligations primarily include reservation charges on contracted capacity for our gas pipeline firm transportation contracts with customers, storage capacity contracts, long-term contracts containing MVC associated with our midstream businesses, and fixed payments associated with offshore production handling. For our interstate natural gas pipeline businesses, remaining performance obligations reflect the rates for such services in our current FERC tariffs for the life of the related contracts; however, these rates may change based on future tariffs approved by the FERC and the amount and timing of these changes are not currently known.

Our remaining performance obligations exclude variable consideration, including contracts with variable consideration for which we have elected the practical expedient for consideration recognized in revenue as billed. Certain of our contracts contain evergreen and other renewal provisions for periods beyond the initial term of the contract. The remaining performance obligation amounts as of September 30, 2023, do not consider potential future performance obligations for which the renewal has not been exercised and exclude contracts with customers for which the underlying facilities have not received FERC authorization to be placed into service. Consideration received prior to September 30, 2023, that will be recognized in future periods is also excluded from our remaining performance obligations and is instead reflected in contract liabilities.

The following table presents the amount of the contract liabilities balance expected to be recognized as revenue when performance obligations are satisfied and the transaction price allocated to the remaining performance obligations under certain contracts as of September 30, 2023.

	Contract Liabilities	Remaining Performance Obligations
	(Millions)	
2023 (three months)	$ 95	$ 950
2024 (one year)	144	3,746
2025 (one year)	123	3,413
2026 (one year)	119	3,105
2027 (one year)	109	2,579
Thereafter	422	15,300
Total	$ 1,012	$ 29,093

Accounts Receivable

The following is a summary of our *Trade accounts and other receivables – net*:

	September 30, 2023	December 31, 2022
	(Millions)	
Accounts receivable related to revenues from contracts with customers	$ 1,145	$ 1,771
Receivables from derivatives	207	889
Other accounts receivable	67	63
Trade accounts and other receivables – net	$ 1,419	$ 2,723

Note 5 – Provision (Benefit) for Income Taxes

The *Provision (benefit) for income taxes* from continuing operations includes:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
	(Millions)			
Current:				
Federal	$ 10	$ —	$ 10	$ (27)
State	7	4	11	14
	17	4	21	(13)
Deferred:				
Federal	169	163	555	247
State	(10)	(71)	59	(65)
	159	92	614	182
Provision (benefit) for income taxes	$ 176	$ 96	$ 635	$ 169

The effective income tax rate for the total provision (benefit) for the three months ended September 30, 2023, is less than the federal statutory rate primarily due to a decrease in our estimate of the deferred state income tax rate.

The effective income tax rate for the total provision (benefit) for the nine months ended September 30, 2023, is greater than the federal statutory rate primarily due to the effect of state income taxes.

The effective income tax rate for the total provision (benefit) for the three months ended September 30, 2022, is less than the federal statutory rate primarily due to the effect of state income taxes, including a $92 million state income tax benefit related to a decrease in our estimate of the deferred state income tax rate (net of federal effect) driven primarily by the enacted decline in the Pennsylvania state income tax rate over the next several years, partially offset by a $23 million unfavorable revision to a state net operating loss carryforward (net of federal benefit).

The effective income tax rate for the total provision (benefit) for the nine months ended September 30, 2022, is less than the federal statutory rate primarily due to the release of a valuation allowance on foreign tax credits, the effect of state income taxes, including a $92 million state income tax benefit related to a decrease in our estimate of the deferred state income tax rate (net of federal effect), and federal settlements.

We have a valuation allowance on certain deferred income tax assets that serves to reduce those assets to amounts that will, more likely than not, be realized. We must evaluate whether we will ultimately realize these tax benefits considering all available positive and negative evidence, which incorporates management's assessment of available tax planning strategies, future reversals of existing taxable temporary differences, and the availability and character of future taxable income. In the second quarter of 2022, we released $88 million of valuation allowance upon determining we expect to utilize an additional $70 million of foreign tax credits and $18 million related to various state net operating loss carryforwards and state credits.

During the second quarter of 2022, we finalized settlements for 2011 through 2014 on certain contested matters with the IRS. This settlement resulted in decreasing our uncertain tax positions of approximately $46 million, which favorably impacted the *Provision (benefit) for income taxes*.

Note 6 – Debt and Banking Arrangements

Long-Term Debt

Our senior unsecured public debt issuances for 2023 are as follows:

Issue Date	Maturity Date	Amount		Rate
		(Millions)		
March 2, 2023	March 2, 2026	$	750	5.40%
March 2, 2023	March 15, 2033	$	750	5.65%
August 10, 2023*	March 2, 2026	$	350	5.40%
August 10, 2023	August 15, 2028	$	900	5.30%

*Additional issuance of the 5.40 percent senior notes due 2026 issued on March 2, 2023, and will trade interchangeably with such notes.

As a result of the MountainWest Acquisition on February 14, 2023, our Consolidated Balance Sheet now includes $100 million of 3.53 percent senior unsecured notes due January 31, 2028, $150 million of 3.91 percent senior unsecured notes due January 31, 2038, and $180 million of 4.875 percent senior unsecured notes due December 1, 2041. The acquisition date fair value reflects a $65 million reduction to the aggregate principal amount. (See Note 3 – Acquisitions and Divestitures.)

Commercial Paper Program

At September 30, 2023, no commercial paper was outstanding under our $3.5 billion commercial paper program.

Credit Facility

In the second quarter of 2023, the maturity date of our October 2021 amended and restated credit agreement (Credit Agreement) was extended one year and now expires October 8, 2027. One participating lender, Credit Suisse AG, New York Branch, with a commitment of approximately $194 million did not extend their commitment beyond October 8, 2026. The amended Credit Agreement allows the co-borrowers to request up to two extensions of the maturity date each for an additional one-year period to allow a maturity date as late as October 8, 2029, under certain circumstances. Additionally, the amended Credit Agreement replaces the London Interbank Offered Rate with the Term Secured Overnight Financing Rate as the benchmark interest rate index.

	September 30, 2023	
	Stated Capacity	Outstanding
	(Millions)	
Long-term credit facility (1)	$ 3,750	$ —
Letters of credit under certain bilateral bank agreements		10

(1) In managing our available liquidity, we do not expect a maximum outstanding amount in excess of the capacity of our credit facility inclusive of any outstanding amounts under our commercial paper program.

Note 7 – Fair Value Measurements and Guarantees

The following table presents, by level within the fair value hierarchy, certain of our significant financial assets and liabilities. The carrying values of cash and cash equivalents, accounts receivable, accounts payable, and commercial paper approximate fair value because of the short-term nature of these instruments. Therefore, these assets and liabilities are not presented in the following table.

			Fair Value Measurements Using		
	Carrying Amount	Fair Value	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			(Millions)		
Assets (liabilities) at September 30, 2023:					
Measured on a recurring basis:					
ARO Trust investments	$ 247	$ 247	$ 247	$ —	$ —
Commodity derivative assets (1)	170	170	90	75	5
Commodity derivative liabilities (1)	(373)	(373)	—	(347)	(26)
Interest rate derivatives	66	66	—	66	—
Other financial assets (liabilities) – net	4	4	—	4	—
Additional disclosures:					
Long-term debt, including current portion	(25,651)	(23,895)	—	(23,895)	—
Guarantees	(37)	(29)	—	(13)	(16)
Assets (liabilities) at December 31, 2022:					
Measured on a recurring basis:					
ARO Trust investments	$ 230	$ 230	$ 230	$ —	$ —
Commodity derivative assets (2)	166	166	20	132	14
Commodity derivative liabilities (2)	(810)	(810)	(22)	(718)	(70)
Other financial assets (liabilities) – net	(5)	(5)	—	(5)	—
Additional disclosures:					
Long-term debt, including current portion	(22,554)	(21,569)	—	(21,569)	—
Guarantees	(38)	(25)	—	(9)	(16)

(1) Commodity derivative assets and liabilities exclude $30 million of net cash collateral in Level 1.

(2) Commodity derivative assets and liabilities exclude $202 million of net cash collateral in Level 1.

Fair Value Methods

We use the following methods and assumptions in estimating the fair value of our financial instruments:

Assets measured at fair value on a recurring basis

ARO Trust investments*:* Transco deposits a portion of its collected rates, pursuant to its rate case settlement, into an external trust (ARO Trust) that is specifically designated to fund future asset retirement obligations (ARO). The ARO Trust invests in a portfolio of actively traded mutual funds that are measured at fair value on a recurring basis based on quoted prices in an active market and is reported in *Regulatory assets, deferred charges, and other* in our Consolidated Balance Sheet. Both realized and unrealized gains and losses are ultimately recorded as regulatory assets or liabilities.

Commodity derivatives: Commodity derivatives include exchange-traded contracts and over-the-counter (OTC) contracts, which consist of physical forwards, futures, and swaps that are measured at fair value on a recurring basis. We also have other derivatives related to asset management agreements and other contracts that require physical delivery. Derivatives classified as Level 1 are valued using New York Mercantile Exchange (NYMEX) futures prices. Derivatives classified as Level 2 are valued using basis transactions that represent the cost to transport natural gas from a NYMEX delivery point to the contract delivery point. These transactions are based on quotes obtained either through electronic trading platforms or directly from brokers. Derivatives classified as Level 3 are valued using a combination of observable and unobservable inputs. The fair value amounts are presented on a net basis and reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements and cash held on deposit in margin accounts that we have received or remitted to collateralize certain derivative positions. Commodity derivative assets are reported in *Derivative assets* and *Regulatory assets, deferred charges, and other* in our Consolidated Balance Sheet. Commodity derivative liabilities are reported in *Derivative liabilities* and *Regulatory liabilities, deferred income, and other* in our Consolidated Balance Sheet. Changes in the fair value of our derivative assets and liabilities are recorded in *Net gain (loss) on commodity derivatives* and *Net processing commodity expenses* in our Consolidated Statement of Income. See Note 8 – Commodity Derivatives for additional information on our derivatives.

Interest rate derivatives: During 2023, we entered into forward starting interest rate swap agreements with notional amounts totaling $750 million. The fair value of these derivatives is determined using discounted cash flows considering forward interest rates and the terms of the agreements, corroborated by counterparty valuations, and is classified as a Level 2 measurement. We designated these derivatives as cash flow hedges to reduce interest rate exposure on future debt issuances. Gains and losses on these derivative instruments are reflected as a component of AOCI and will be amortized to earnings as a component of *Interest incurred* in our Consolidated Statement of Income. These forward starting interest rate swaps are reported in *Derivative assets* in our Consolidated Balance Sheet**.**

Additional fair value disclosures

Long-term debt, including current portion*:* The disclosed fair value of our long-term debt is determined primarily by a market approach using broker quoted indicative period-end bond prices. The quoted prices are based on observable transactions in less active markets for our debt or similar instruments. The fair values of the financing obligations associated with our Dalton, Leidy South, and Atlantic Sunrise projects, which are included within long-term debt, were determined using an income approach.

Guarantees: Guarantees primarily consist of a guarantee we have provided in the event of nonpayment by our previously owned communications subsidiary, Williams Communications Group, Inc., (WilTel), on a lease performance obligation that extends through 2042. Guarantees also include an indemnification related to a disposed operation.

To estimate the fair value of the WilTel guarantee, an estimated default rate is applied to the sum of the future contractual lease payments using an income approach. The estimated default rate is determined by obtaining the average cumulative issuer-weighted default rate based on the credit rating of WilTel's current owner and the term of the underlying obligation. The default rate is published by Moody’s Investors Service. The carrying value of the WilTel guarantee is reported in *Accrued and other current liabilities* in our Consolidated Balance Sheet. The maximum potential undiscounted liquidity exposure is approximately $23 million at September 30, 2023. Our exposure declines systematically through the remaining term of WilTel’s obligation.

The fair value of the guarantee associated with the indemnification related to a disposed operation was estimated using an income approach that considered probability-weighted scenarios of potential levels of future performance. The terms of the indemnification do not limit the maximum potential future payments associated with the guarantee. The carrying value of this guarantee is reported in *Regulatory liabilities, deferred income, and other* in our Consolidated Balance Sheet.

We are required by our revolving credit agreement to indemnify lenders for certain taxes required to be withheld from payments due to the lenders and for certain tax payments made by the lenders. The maximum potential amount of future payments under these indemnifications is based on the related borrowings and such future payments cannot currently be determined. These indemnifications generally continue indefinitely unless limited by the underlying tax regulations and have no carrying value. We have never been called upon to perform under these indemnifications and have no current expectation of a future claim.

Note 8 – Commodity Derivatives

We are exposed to commodity price risk. To manage this volatility, we use various contracts in our marketing and trading activities that generally meet the definition of derivatives. Derivative positions are monitored using techniques including, but not limited to value at risk. Derivative instruments are recognized at fair value in our Consolidated Balance Sheet as either assets or liabilities and are presented on a net basis by counterparty, net of margin deposits. See Note 7 – Fair Value Measurements and Guarantees for additional fair value information. In our Consolidated Statement of Cash Flows, any cash impacts of settled commodity derivatives are recorded as operating activities.

We enter into commodity derivatives to economically hedge exposures to natural gas, NGLs, and crude oil and retain exposure to price changes that can, in a volatile energy market, be material and can adversely affect our results of operations.

At September 30, 2023, the notional volume of the net long (short) positions for our commodity derivative contracts were as follows:

	Commodity	Unit of Measure	Net Long (Short) Position
Index Risk	Natural Gas	MMBtu	848,556,144
Central Hub Risk - Henry Hub	Natural Gas	MMBtu	(68,125,793)
Basis Risk	Natural Gas	MMBtu	(29,104,256)
Central Hub Risk - Mont Belvieu	Natural Gas Liquids	Barrels	(669,952)
Basis Risk	Natural Gas Liquids	Barrels	(605,000)
Central Hub Risk - WTI	Crude Oil	Barrels	(234,600)

Derivative Financial Statement Presentation

The fair value of commodity derivatives, which are not designated as hedging instruments for accounting purposes, was reflected as follows:

Derivative Category	September 30, 2023 Assets	September 30, 2023 (Liabilities)	December 31, 2022 Assets	December 31, 2022 (Liabilities)
	(Millions)			
Current	$ 457	$ (434)	$ 1,099	$ (1,278)
Noncurrent	172	(398)	269	(734)
Total derivatives	$ 629	$ (832)	$ 1,368	$ (2,012)
Counterparty and collateral netting offset	(428)	458	(1,034)	1,236
Amounts recognized in our Consolidated Balance Sheet	$ 201	$ (374)	$ 334	$ (776)

The pre-tax effects of commodity derivative instruments in our Consolidated Statement of Income were as follows:

	Gain (Loss)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
	(Millions)			
Net gain (loss) on commodity derivatives within *Total revenues*:				
Realized commodity derivatives not designated as hedging instruments	$ (8)	$ (13)	$ 169	$ (145)
Unrealized commodity derivatives not designated as hedging instruments	32	29	476	(346)
	$ 24	$ 16	$ 645	$ (491)
Net gain (loss) on commodity derivatives within *Net processing commodity expenses*:				
Realized commodity derivatives not designated as hedging instruments	$ —	$ 6	$ (3)	$ 12
Unrealized commodity derivatives not designated as hedging instruments	(9)	6	(43)	17
	$ (9)	$ 12	$ (46)	$ 29
Total net gain (loss) on commodity derivatives	$ 15	$ 28	$ 599	$ (462)

Contingent Features

Generally, collateral may be provided in the form of a parent guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are offset against fair value amounts recognized for derivatives executed with the same counterparty.

We have specific trade and credit contracts that contain minimum credit rating requirements. These credit rating requirements typically give counterparties the right to suspend or terminate credit if our credit ratings are downgraded to non-investment grade status. Under such circumstances, we would need to post collateral to continue transacting business with these counterparties. At September 30, 2023, the contractually required collateral in the event of a credit rating downgrade to non-investment grade status was $9 million.

We maintain accounts with brokers or the clearing houses of certain exchanges to facilitate financial derivative transactions. Based on the value of the positions in these accounts and the associated margin requirements, we may be required to deposit cash into these accounts. At September 30, 2023, net cash collateral held on deposit in broker margin accounts was $30 million.

Note 9 – Contingencies

Alaska Refinery Contamination Litigation

We are involved in litigation arising from our ownership and operation of the North Pole Refinery in North Pole, Alaska, from 1980 until 2004, through our wholly owned subsidiaries Williams Alaska Petroleum Inc. (WAPI) and MAPCO Inc. We sold the refinery to Flint Hills Resources Alaska, LLC (FHRA), a subsidiary of Koch Industries, Inc., in 2004. The litigation involves three cases, with filing dates ranging from 2010 to 2014. The actions primarily arise from sulfolane contamination allegedly emanating from the refinery. A putative class action lawsuit was filed by James West in 2010 naming us, WAPI, and FHRA as defendants. We and FHRA filed claims against each other seeking, among other things, contractual indemnification alleging that the other party caused the sulfolane contamination. In 2011, we and FHRA settled the claim with James West. Certain claims by FHRA against us were resolved by the Alaska Supreme Court in our favor. FHRA's claims against us for contractual indemnification and statutory claims for damages related to off-site sulfolane were remanded to the Alaska Superior Court. The State of Alaska filed its action in March 2014, seeking damages. The City of North Pole (North Pole) filed its lawsuit in November 2014, seeking past and future damages, as well as punitive damages. Both we and WAPI asserted counterclaims against the State of Alaska and North Pole, and cross-claims against FHRA. FHRA has also filed cross-claims against us.

The underlying factual basis and claims in the cases are similar and may duplicate exposure. As such, in February 2017, the three cases were consolidated into one action in state court containing the remaining claims from the James West case and those of the State of Alaska and North Pole. The State of Alaska later announced the discovery of additional contaminants per- and polyfluoralkyl (PFOS and PFOA) offsite of the refinery, and the court permitted the State of Alaska to amend its complaint to add a claim for offsite PFOS/PFOA contamination. The court subsequently remanded the offsite PFOS/PFOA claims to the Alaska Department of Environmental Conservation for investigation and stayed the claims pending their potential resolution at the administrative agency. Several trial dates encompassing all three cases have been scheduled and stricken. In the summer of 2019, the court deconsolidated the cases for purposes of trial. A bench trial on all claims except North Pole's claims began in October 2019.

In January 2020, the Alaska Superior Court issued its Memorandum of Decision finding in favor of the State of Alaska and FHRA, with the total incurred and potential future damages estimated to be $86 million, plus fees and interest. The court found that FHRA is not entitled to contractual indemnification from us because FHRA contributed to the sulfolane contamination. On March 23, 2020, the court entered final judgment in the case. Filing deadlines were stayed until May 1, 2020. However, on April 21, 2020, we filed a Notice of Appeal. We also filed post-judgment motions including a Motion for New Trial and a Motion to Alter or Amend the Judgment. These post-trial motions were resolved with the court's denial of the last motion on June 11, 2020. Our Statement of Points on Appeal was filed on July 13, 2020. On June 22, 2020, the court stayed the North Pole's case pending resolution of the appeal in the State of Alaska and FHRA case. On December 23, 2020, we filed our opening brief on appeal. Oral argument was held on December 15, 2021. On May 26, 2023, the Alaska Supreme Court issued its Opinion substantially affirming the Superior Court's decision. On July 18, 2023, the Superior Court granted our stay of execution of the monetary judgment portions of the judgment while we seek review before the United States Supreme Court. On September 25, 2023, we filed a Petition for a Writ of Certiorari with the United States Supreme Court. During the second quarter of 2023, as a result of the Alaska Supreme Court's Opinion, we recorded a pre-tax charge of $115 million to *Income (loss) from discontinued operations* to fully accrue for the judgment, plus the related fees and interest. An additional $1 million of pre-tax interest expense was recorded in the third quarter of 2023.

Royalty Matters

Certain of our customers, including Chesapeake Energy Corporation (Chesapeake), have been named in various lawsuits alleging underpayment of royalties and claiming, among other things, violations of anti-trust laws and the

Racketeer Influenced and Corrupt Organizations Act. We have also been named as a defendant in certain of these cases filed in Pennsylvania based on allegations that we improperly participated with Chesapeake in causing the alleged royalty underpayments. We believe that the claims asserted are subject to indemnity obligations owed to us by Chesapeake, which obligations survived Chesapeake's bankruptcy proceedings. Prior to its bankruptcy, Chesapeake reached a settlement to resolve substantially all Pennsylvania royalty cases pending. During the pendency of the bankruptcy, that settlement was renegotiated. The settlement applies to both Chesapeake and us and does not require any contribution from us. On August 23, 2021, after referral to the United States District Court for the Southern District of Texas by the bankruptcy court, the court approved the settlement. Two objectors filed an appeal with the United States Court of Appeals for the Fifth Circuit. On June 8, 2023, the Court of Appeals vacated the settlement approval and remanded to the United States District Court for the Southern District of Texas with instructions to dismiss the settlement proceedings for lack of jurisdiction. On August 31, 2023, the bankruptcy court entered an order finding the settlement agreements to be null and void. Certain plaintiffs have filed a notice of dismissal of their claims against Chesapeake that arose prior to February 8, 2021 in the United States District Court for the Middle District of Pennsylvania lawsuits. The notice states that plaintiffs are not releasing their claims against the other defendants, including us, or claims against Chesapeake that arose after February 9, 2021. We continue to believe the claims against us are subject to indemnity obligations owed to us by Chesapeake.

Litigation Against Energy Transfer and Related Parties

On April 6, 2016, we filed suit in Delaware Chancery Court against Energy Transfer Equity, L.P. (Energy Transfer) and LE GP, LLC (the general partner for Energy Transfer) alleging willful and material breaches of the Agreement and Plan of Merger (ETE Merger Agreement) with Energy Transfer resulting from the private offering by Energy Transfer on March 8, 2016, of Series A Convertible Preferred Units (Special Offering) to certain Energy Transfer insiders and other accredited investors. The suit seeks, among other things, an injunction ordering the defendants to unwind the Special Offering and to specifically perform their obligations under the ETE Merger Agreement. On April 19, 2016, we filed an amended complaint seeking the same relief. On May 3, 2016, Energy Transfer and LE GP, LLC filed an answer and counterclaims.

On May 13, 2016, we filed a separate complaint in Delaware Chancery Court against Energy Transfer, LE GP, LLC and the other Energy Transfer affiliates that are parties to the ETE Merger Agreement, alleging material breaches of the ETE Merger Agreement for failing to cooperate and use necessary efforts to obtain a tax opinion required under the ETE Merger Agreement (Tax Opinion) and for otherwise failing to use necessary efforts to consummate the merger under the ETE Merger Agreement wherein we would be merged with and into the newly formed Energy Transfer Corp LP (ETC) (ETC Merger). The suit sought, among other things, a declaratory judgment and injunction preventing Energy Transfer from terminating or otherwise avoiding its obligations under the ETE Merger Agreement due to any failure to obtain the Tax Opinion.

The Court of Chancery coordinated the Special Offering and Tax Opinion suits. On May 20, 2016, the Energy Transfer defendants filed amended affirmative defenses and verified counterclaims in the Special Offering and Tax Opinion suits, alleging certain breaches of the ETE Merger Agreement by us and seeking, among other things, a declaration that we were not entitled to specific performance, that Energy Transfer could terminate the ETC Merger, and that Energy Transfer is entitled to a $1.48 billion termination fee. On June 24, 2016, following a two-day trial, the court issued a Memorandum Opinion and Order denying our requested relief in the Tax Opinion suit. The court did not rule on the substance of our claims related to the Special Offering or on the substance of Energy Transfer's counterclaims. On June 27, 2016, we filed an appeal of the court's decision with the Supreme Court of Delaware, seeking reversal and remand to pursue damages. On March 23, 2017, the Supreme Court of Delaware affirmed the Court of Chancery's ruling. On March 30, 2017, we filed a motion for reargument with the Supreme Court of Delaware, which was denied on April 5, 2017.

On September 16, 2016, we filed an amended complaint with the Court of Chancery seeking damages for breaches of the ETE Merger Agreement by defendants. On September 23, 2016, Energy Transfer filed a second amended and supplemental affirmative defenses and verified counterclaim with the Court of Chancery seeking, among other things, payment of the $1.48 billion termination fee due to our alleged breaches of the ETE Merger Agreement. On December 1, 2017, the court granted our motion to dismiss certain of Energy Transfer's counterclaims, including its claim seeking payment of the $1.48 billion termination fee. On December 8, 2017, Energy Transfer filed a motion for reargument, which the Court of Chancery denied on April 16, 2018. Trial was held May 10 through May 17, 2021. On December 29, 2021, the court entered judgment in our favor in the amount of $410 million, plus interest at the contractual rate, and our reasonable attorneys' fees and expenses. On September 21, 2022, the court entered a final order and judgment awarding us the termination fee, attorney's fees, expenses, and interest in the amount of $602 million plus additional interest starting September 17, 2022. Attorney fees of approximately $90 million will be payable upon receipt of the judgment amount. Energy Transfer appealed to the Delaware Supreme Court. The Delaware Supreme Court held oral argument en banc on July 12, 2023. On October 10, 2023, the Delaware Supreme Court issued an opinion affirming the Court of Chancery's ruling. On October 25, 2023, Energy Transfer filed a motion for reargument with the Delaware Supreme Court.

Environmental Matters

We are a participant in certain environmental activities in various stages including assessment studies, cleanup operations, and/or remedial processes at certain sites, some of which we currently do not own. We are monitoring these sites in a coordinated effort with other potentially responsible parties, the U.S. Environmental Protection Agency (EPA), or other governmental authorities. We are jointly and severally liable along with unrelated third parties in some of these activities and solely responsible in others. Certain of our subsidiaries have been identified as potentially responsible parties at various Superfund and state waste disposal sites. In addition, these subsidiaries have incurred, or are alleged to have incurred, various other hazardous materials removal or remediation obligations under environmental laws. As of September 30, 2023, we have accrued liabilities totaling $51 million for these matters, as discussed below. Estimates of the most likely costs of cleanup are generally based on completed assessment studies, preliminary results of studies, or our experience with other similar cleanup operations. At September 30, 2023, certain assessment studies were still in process for which the ultimate outcome may yield different estimates of most likely costs. Therefore, the actual costs incurred will depend on the final amount, type, and extent of contamination discovered at these sites, the final cleanup standards mandated by the EPA or other governmental authorities, and other factors.

The EPA and various state regulatory agencies routinely propose and promulgate new rules and issue updated guidance to existing rules. These rulemakings include, but are not limited to, rules for reciprocating internal combustion engine and combustion turbine maximum achievable control technology, reviews and updates to the National Ambient Air Quality Standards, and rules for new and existing source performance standards for volatile organic compound and methane. We continuously monitor these regulatory changes and how they may impact our operations. Implementation of new or modified regulations may result in impacts to our operations and increase the cost of additions to *Property, plant, and equipment – net* in our Consolidated Balance Sheet for both new and existing facilities in affected areas; however, due to regulatory uncertainty on final rule content and applicability timeframes, we are unable to reasonably estimate the cost of these regulatory impacts at this time.

Continuing operations

Our interstate gas pipelines are involved in remediation and monitoring activities related to certain facilities and locations for polychlorinated biphenyls, mercury, and other hazardous substances. These activities have involved the EPA and various state environmental authorities, resulting in our identification as a potentially responsible party at various Superfund waste sites. At September 30, 2023, we have accrued liabilities of $13 million for these costs and expect to recover approximately $4 million through rates.

We also accrue environmental remediation costs for natural gas underground storage facilities, primarily related to soil and groundwater contamination. At September 30, 2023, we have accrued liabilities totaling $10 million for these costs.

Former operations

We have potential obligations in connection with assets and businesses we no longer operate. These potential obligations include remediation activities at the direction of federal and state environmental authorities and the indemnification of the purchasers of certain of these assets and businesses for environmental and other liabilities existing at the time the sale was consummated. Our responsibilities relate to the operations of the assets and businesses described below.

- Former agricultural fertilizer and chemical operations and former retail petroleum and refining operations;
- Former petroleum products and natural gas pipelines;
- Former petroleum refining facilities;
- Former exploration and production and mining operations;
- Former electricity and natural gas marketing and trading operations.

At September 30, 2023, we have accrued environmental liabilities of $28 million related to these matters.

Other Divestiture Indemnifications

Pursuant to various purchase and sale agreements relating to divested businesses and assets, we have indemnified certain purchasers against liabilities that they may incur with respect to the businesses and assets acquired from us. The indemnities provided to the purchasers are customary in sale transactions and are contingent upon the purchasers incurring liabilities that are not otherwise recoverable from third parties. The indemnities generally relate to breach of warranties, tax, historic litigation, personal injury, property damage, environmental matters, right of way, and other representations that we have provided.

At September 30, 2023, other than as previously disclosed, we are not aware of any material claims against us involving the above-described indemnities; thus, we do not expect any of the indemnities provided pursuant to the sales agreements to have a material impact on our future financial position. Any claim for indemnity brought against us in the future may have a material adverse effect on our results of operations in the period in which the claim is made.

In addition to the foregoing, various other proceedings are pending against us that are incidental to our operations, none of which are expected to be material to our expected future annual results of operations, liquidity, and financial position.

Summary

We have disclosed our estimated range of reasonably possible losses for certain matters above, as well as all significant matters for which we are unable to reasonably estimate a range of possible loss. We estimate that for all other matters for which we are able to reasonably estimate a range of loss, our aggregate reasonably possible losses beyond amounts accrued are immaterial to our expected future annual results of operations, liquidity, and financial position. These calculations have been made without consideration of any potential recovery from third parties.

Note 10 – Segment Disclosures

Our reportable segments are Transmission & Gulf of Mexico, Northeast G&P, West, and Gas & NGL Marketing Services. All remaining business activities are included in Other. (See Note 1 – General, Description of Business, and Basis of Presentation.)

Performance Measurement

We evaluate segment operating performance based upon *Modified EBITDA*. This measure represents the basis of our internal financial reporting and is the primary performance measure used by our chief operating decision maker in measuring performance and allocating resources among our reportable segments. Intersegment *Service revenues* primarily represent transportation services provided to our marketing business and gathering services provided to our oil and gas properties. Intersegment *Product sales* primarily represent the sale of natural gas and NGLs from our natural gas processing plants and our oil and gas properties to our marketing business.

We define *Modified EBITDA* as follows:

- Net income (loss) before:
  - Income (loss) from discontinued operations;
  - Provision (benefit) for income taxes;
  - Interest incurred, net of interest capitalized;
  - Equity earnings (losses);
  - Other investing income (loss) – net;
  - Depreciation and amortization expenses;
  - Accretion expense associated with asset retirement obligations for nonregulated operations.
- This measure is further adjusted to include our proportionate share (based on ownership interest) of *Modified EBITDA* from our equity-method investments calculated consistently with the definition described above.

Significant noncash items which are components of *Modified EBITDA* may include unrealized net gain (loss) on commodity derivatives within *Total revenues*, unrealized net gain (loss) on commodity derivatives within *Net processing commodity expenses* for our Gas & NGL Marketing segment, and charges associated with lower of cost or net realizable value adjustments to our Gas & NGL Marketing segment inventory. These charges are reflected in *Product sales* and *Product costs* in our Consolidated Statement of Income.

The following table reflects the reconciliation of *Modified EBITDA* to *Net income (loss)* as reported in our Consolidated Statement of Income.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
	(Millions)			
Modified EBITDA by segment:				
Transmission & Gulf of Mexico	$ 881	$ 638	$ 2,327	$ 1,987
Northeast G&P	454	464	1,439	1,332
West	315	337	931	885
Gas & NGL Marketing Services	43	20	678	(249)
Other	81	140	196	284
	1,774	1,599	5,571	4,239
Accretion expense associated with asset retirement obligations for nonregulated operations	(14)	(12)	(43)	(36)
Depreciation and amortization expenses	(521)	(500)	(1,542)	(1,504)
Equity earnings (losses)	127	193	434	492
Other investing income (loss) – net	24	1	45	4
Proportional Modified EBITDA of equity-method investments	(215)	(273)	(693)	(748)
Interest expense	(314)	(291)	(914)	(858)
(Provision) benefit for income taxes	(176)	(96)	(635)	(169)
Income (loss) from discontinued operations	(1)	—	(88)	—
Net income (loss)	$ 684	$ 621	$ 2,135	$ 1,420

The following table reflects the reconciliation of *Segment revenues* to *Total revenues* as reported in our Consolidated Statement of Income.

	Transmission &Gulf of Mexico	Northeast G&P	West	Gas & NGL Marketing Services (1)	Other	Eliminations	Total
				(Millions)			
Three Months Ended September 30, 2023							
Segment revenues:							
Service revenues							
External	$ 953	$ 473	$ 340	$ —	$ 4	$ —	$ 1,770
Internal	25	5	34	—	—	(64)	—
Total service revenues	978	478	374	—	4	(64)	1,770
Total service revenues – commodity consideration	11	—	34	—	—	—	45
Product sales							
External	35	13	14	619	39	—	720
Internal	28	14	98	(63)	79	(156)	—
Total product sales	63	27	112	556	118	(156)	720
Net gain (loss) on commodity derivatives							
Realized	1	—	13	(31)	9	—	(8)
Unrealized	—	—	—	33	(1)	—	32
Total net gain (loss) on commodity derivatives (2)	1	—	13	2	8	—	24
Total revenues	$ 1,053	$ 505	$ 533	$ 558	$ 130	$ (220)	$ 2,559
Three Months Ended September 30, 2022							
Segment revenues:							
Service revenues							
External	$ 880	$ 408	$ 393	$ 1	$ 3	$ —	$ 1,685
Internal	30	9	32	—	3	(74)	—
Total service revenues	910	417	425	1	6	(74)	1,685
Total service revenues – commodity consideration	11	2	47	—	—	—	60
Product sales							
External	78	11	61	1,079	31	—	1,260
Internal	43	29	184	(195)	207	(268)	—
Total product sales	121	40	245	884	238	(268)	1,260
Net gain (loss) on commodity derivatives							
Realized	—	—	(9)	54	(58)	—	(13)
Unrealized	1	—	—	(1)	29	—	29
Total net gain (loss) on commodity derivatives (2)	1	—	(9)	53	(29)	—	16
Total revenues	$ 1,043	$ 459	$ 708	$ 938	$ 215	$ (342)	$ 3,021

	Transmission & Gulf of Mexico	Northeast G&P	West	Gas & NGL Marketing Services (1)	Other	Eliminations	Total
				(Millions)			
Nine Months Ended September 30, 2023							
Segment revenues:							
Service revenues							
External	$ 2,801	$ 1,396	$ 1,002	$ 1	$ 12	$ —	$ 5,212
Internal	73	25	86	—	—	(184)	—
Total service revenues	2,874	1,421	1,088	1	12	(184)	5,212
Total service revenues – commodity consideration	29	3	76	—	—	—	108
Product sales							
External	116	32	43	1,882	85	—	2,158
Internal	81	72	244	(224)	218	(391)	—
Total product sales	197	104	287	1,658	303	(391)	2,158
Net gain (loss) on commodity derivatives							
Realized	2	—	85	41	41	—	169
Unrealized	—	—	—	494	(18)	—	476
Total net gain (loss) on commodity derivatives (2)	2	—	85	535	23	—	645
Total revenues	$ 3,102	$ 1,528	$ 1,536	$ 2,194	$ 338	$ (575)	$ 8,123
Nine Months Ended September 30, 2022							
Segment revenues:							
Service revenues							
External	$ 2,563	$ 1,178	$ 1,073	$ 2	$ 12	$ —	$ 4,828
Internal	88	30	66	—	10	(194)	—
Total service revenues	2,651	1,208	1,139	2	22	(194)	4,828
Total service revenues – commodity consideration	54	12	157	—	—	—	223
Product sales							
External	187	24	111	3,073	80	—	3,475
Internal	147	86	573	(349)	442	(899)	—
Total product sales	334	110	684	2,724	522	(899)	3,475
Net gain (loss) on commodity derivatives							
Realized	—	—	(23)	(18)	(104)	—	(145)
Unrealized	1	—	—	(357)	10	—	(346)
Total net gain (loss) on commodity derivatives (2)	1	—	(23)	(375)	(94)	—	(491)
Total revenues	$ 3,040	$ 1,330	$ 1,957	$ 2,351	$ 450	$ (1,093)	$ 8,035

(1) As we are acting as agent for natural gas marketing customers or engage in energy trading activities, the resulting revenues are presented net of the related costs of those activities.

(2) We record transactions that qualify as derivatives at fair value with changes in fair value recognized in earnings in the period of change and characterized as unrealized gains or losses. Gains and losses on derivatives held for energy trading purposes are presented on a net basis in revenue.

Note 11 – Subsequent Events

DJ Basin Acquisitions

In October 2023, we agreed to acquire Cureton Front Range, LLC, whose operations are located in the Denver-Julesberg Basin (DJ Basin), for $560 million, subject to working capital and post-closing adjustments. Concurrently, we entered into an agreement to purchase an additional 50 percent interest in our equity-method investment RMM for $714 million. Upon closing, we will own 100 percent of and will consolidate RMM. These acquisitions are expected to close in the fourth quarter of 2023 and will expand our gathering and processing footprint in the DJ Basin. The Cureton Front Range, LLC acquisition is expected to be funded with available sources of short-term liquidity. Substantially all of the RMM purchase price is not due to the seller and does not accrue interest until the fourth quarter of 2024. These businesses will be reported within the West segment.

Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations

General

We are an energy company committed to being the leader in providing infrastructure that safely delivers natural gas products to reliably fuel the clean energy economy. Our operations are located in the United States.

Our interstate natural gas pipeline strategy is to create value by maximizing the utilization of our pipeline capacity by providing high-quality, low-cost transportation of natural gas to large and growing markets. Our gas pipeline businesses’ interstate transmission and storage activities are subject to regulation by the FERC and as such, our rates and charges for the transportation of natural gas in interstate commerce, and the extension, expansion or abandonment of jurisdictional facilities and accounting, among other things, are subject to regulation. The rates are established primarily through the FERC’s ratemaking process, but we also may negotiate rates with our customers pursuant to the terms of our tariffs and FERC policy. Changes in commodity prices and volumes transported have limited near-term impact on these revenues because the majority of cost of service is recovered through firm capacity reservation charges in transportation rates.

The ongoing strategy of our midstream operations is to safely and reliably operate large-scale midstream infrastructure where our assets can be fully utilized and drive low per-unit costs. We focus on consistently attracting new business by providing highly reliable service to our customers. These services include natural gas gathering, processing, treating, compression, and storage, NGL fractionation, transportation and storage, crude oil production handling and transportation, as well as marketing services for NGL, crude oil, and natural gas.

Consistent with the manner in which our chief operating decision maker evaluates performance and allocates resources, our operations are conducted, managed, and presented within the following reportable segments: Transmission & Gulf of Mexico, Northeast G&P, West, and Gas & NGL Marketing Services. All remaining business activities, including our upstream operations and corporate activities, are included in Other. Our reportable segments are comprised of the following business activities:

- Transmission & Gulf of Mexico is comprised of our interstate natural gas pipelines, Transco, Northwest Pipeline, and MountainWest, and their related natural gas storage facilities, as well as natural gas gathering and processing and crude oil production handling and transportation assets in the Gulf Coast region, including a 51 percent interest in Gulfstar One, a 50 percent equity-method investment in Gulfstream, and a 60 percent equity-method investment in Discovery. Transmission & Gulf of Mexico also includes natural gas storage facilities and pipelines providing services in north Texas.

- Northeast G&P is comprised of our midstream gathering, processing, and fractionation businesses in the Marcellus Shale region primarily in Pennsylvania and New York, and the Utica Shale region of eastern Ohio, as well as a 65 percent interest in Northeast JV which operates in West Virginia, Ohio, and Pennsylvania, a 66 percent interest in Cardinal which operates in Ohio, a 69 percent equity-method investment in Laurel Mountain, a 50 percent equity-method investment in Blue Racer, and Appalachia Midstream Investments.

- West is comprised of our gas gathering, processing, and treating operations in the Rocky Mountain region of Colorado and Wyoming, the Barnett Shale region of north-central Texas, the Eagle Ford Shale region of south Texas, the Haynesville Shale region of east Texas and northwest Louisiana, and the Mid-Continent region which includes the Anadarko and Permian basins. This segment also includes our NGL storage facilities, an undivided 50 percent interest in an NGL fractionator near Conway, Kansas, a 50 percent equity-method investment in OPPL, a 50 percent equity-method investment in RMM, a 20 percent equity-method investment in Targa Train 7, and a 15 percent equity-method investment in Brazos Permian II.

- Gas & NGL Marketing Services is comprised of our NGL and natural gas marketing and trading operations, which includes risk management and transactions related to the storage and transportation of natural gas and NGLs on strategically positioned assets.

Unless indicated otherwise, the following discussion and analysis of results of operations and financial condition and liquidity relates to our current continuing operations and should be read in conjunction with the consolidated financial statements and notes thereto of this Form 10-Q and our Annual Report on Form 10-K for the year ended December 31, 2022 dated February 27, 2023.

Dividends

In September 2023, we paid a regular quarterly dividend of $0.4475 per share.

Overview of Nine Months Ended September 30, 2023

Net income (loss) attributable to The Williams Companies, Inc., for the nine months ended September 30, 2023, increased $661 million compared to the nine months ended September 30, 2022. Further discussion of our results is found in this report in the Results of Operations.

Recent Developments

Favorable Judgment Against Energy Transfer

On September 21, 2022, the Delaware Court of Chancery entered a final order and judgment awarding us the termination fee, attorney's fees, expenses, and interest in the amount of $602 million plus additional interest starting September 17, 2022. Attorney fees of approximately $90 million will be payable upon receipt of the judgment amount. Energy Transfer appealed to the Delaware Supreme Court. On October 10, 2023, the Delaware Supreme Court issued an opinion affirming the Court of Chancery's ruling. On October 25, 2023, Energy Transfer filed a motion for reargument with the Delaware Supreme Court. (See Note 9 – Contingencies of our Notes to Consolidated Financial Statements.)

DJ Basin Acquisitions

In October 2023, we agreed to acquire Cureton Front Range, LLC, whose operations are located in the Denver-Julesberg Basin (DJ Basin), for $560 million, subject to working capital and post-closing adjustments. Concurrently, we entered into an agreement to purchase an additional 50 percent interest in our equity-method investment RMM for $714 million. Upon closing, we will own 100 percent of and will consolidate RMM. These acquisitions are expected to close in the fourth quarter of 2023 and will expand our gathering and processing footprint in the DJ Basin. The Cureton Front Range, LLC acquisition is expected to be funded with available sources of short-term liquidity. Substantially all of the RMM purchase price is not due to the seller and does not accrue interest until the fourth quarter of 2024. These businesses will be reported within the West segment.

Sale of Certain Gulf Coast Liquids Pipelines

On September 29, 2023, we completed the sale of various petrochemical and feedstock pipelines and associated contracts in the Gulf Coast region for $348 million. As a result of this sale, we recorded a gain of $130 million in the third quarter of 2023 in our Transmission & Gulf of Mexico segment.

MountainWest Acquisition

On February 14, 2023, we closed on the acquisition of 100 percent of MountainWest, which includes FERC-regulated interstate natural gas pipeline systems and natural gas storage capacity, for $1.08 billion of cash, funded with available sources of short-term liquidity, and retaining $430 million outstanding principal amount of MountainWest long-term debt (see Note 3 – Acquisitions and Divestitures of Notes to Consolidated Financial Statements). The MountainWest Acquisition expands our existing transmission and storage infrastructure footprint into major markets in Utah, Wyoming, and Colorado.

Northwest Pipeline FERC Rate Case Settlement

On November 15, 2022, Northwest Pipeline received approval from the FERC for a stipulation and settlement agreement which generally reduces rates effective January 1, 2023, resolves other rate issues, establishes a Modernization and Emission Reduction Program, and satisfies its rate case filing obligation. Provisions were included in the settlement that establish a moratorium on any proceedings that would seek to place new rates in effect any earlier than January 1, 2026, and that a general rate case filing will be made for rates to become effective not later than April 1, 2028, unless we have entered into a pre-filing settlement prior to that date.

Company Outlook

Our strategy is to provide a large-scale, reliable, and clean energy infrastructure designed to maximize the opportunities created by the vast supply of natural gas and natural gas products that exists in the United States. We accomplish this by connecting the growing demand for cleaner fuels and feedstocks with our major positions in the premier natural gas and natural gas products supply basins. We continue to maintain a strong commitment to safety, environmental stewardship, including seeking opportunities for renewable energy ventures, operational excellence, and customer satisfaction. We believe that accomplishing these goals will position us to deliver safe, reliable, clean energy services to our customers and an attractive return to our shareholders. Our business plan for 2023 includes a continued focus on earnings and cash flow growth.

In 2023, our operating results are expected to benefit from the MountainWest Acquisition, volume growth in the Haynesville and Northeast G&P areas, annual inflation-based rate increases across our gathering and processing business, and partial in-service of the Regional Energy Access project. We also anticipate increases resulting from a full year of contribution from recently acquired Trace and NorTex assets. These increases are partially offset by a lower expected commodity price environment.

We seek to maintain a strong financial position and liquidity, as well as manage a diversified portfolio of safe, clean, and reliable energy infrastructure assets that continue to serve key growth markets and supply basins in the United States. Our growth capital and investment expenditures in 2023 are expected to be in a range from $1.6 billion to $1.9 billion, excluding acquisitions. Growth capital spending in 2023 primarily includes Transco expansions, all of which are fully contracted with firm transportation agreements, projects supporting the Northeast G&P business and projects supporting growth in the Haynesville basin, including the Louisiana Energy Gateway project. We also expect to invest capital in the development of our upstream oil and gas properties. In addition to growth capital and investment expenditures, we also remain committed to projects that maintain our assets for safe and reliable operations, as well as projects that reduce emissions, and meet legal, regulatory, and/or contractual commitments.

Potential risks and obstacles that could impact the execution of our plan include:

- A global recession, which could result in downturns in financial markets and commodity prices, as well as impact demand for natural gas and related products;
- Opposition to, and regulations affecting, our infrastructure projects, including the risk of delay or denial in permits and approvals needed for our projects;
- Counterparty credit and performance risk;
- Unexpected significant increases in capital expenditures or delays in capital project execution, including increases from inflation or delays caused by supply chain disruptions;
- Unexpected changes in customer drilling and production activities, which could negatively impact gathering and processing volumes;
- Lower than anticipated demand for natural gas and natural gas products which could result in lower-than-expected volumes, energy commodity prices, and margins;

- General economic, financial markets, or industry downturns, including increased inflation and interest rates;
- Physical damages to facilities, including damage to offshore facilities by weather-related events;
- Other risks set forth under Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2022, as filed with the SEC on February 27, 2023, as may be supplemented by disclosures in Part II, Item 1A. Risk Factors in subsequent Quarterly Reports on Form 10-Q.

Expansion Projects

Our ongoing major expansion projects include the following:

Transmission & Gulf of Mexico

Deepwater Shenandoah Project

In June 2021, we reached an agreement with two third-parties to provide offshore natural gas gathering and transportation services as well as onshore natural gas processing services. The project expands our existing Gulf of Mexico offshore infrastructure via a 5-mile offshore lateral pipeline from the Shenandoah platform to Discovery’s existing Keathley Canyon Connector pipeline, adds onshore processing facilities at Larose, Louisiana to handle the expected rich Shenandoah production, and the natural gas liquids will be fractionated and marketed at Discovery’s Paradis plant in Louisiana. We plan to place the project into service in the fourth quarter of 2024.

Deepwater Whale Project

In August 2021, we reached an agreement with two third-parties to provide offshore natural gas gathering and crude oil transportation services as well as onshore natural gas processing services. The project expands our existing Western Gulf of Mexico offshore infrastructure via a 26-mile gas lateral pipeline from the Whale platform to the existing Perdido gas pipeline and adds a new 125-mile oil pipeline from the Whale platform to our existing junction platform. We plan to place the project into service in the fourth quarter of 2024.

Regional Energy Access

In January 2023, we received approval from the FERC for the project to expand Transco’s existing natural gas transmission system to provide incremental firm transportation capacity from receipt points in northeastern Pennsylvania to multiple delivery points in Pennsylvania, New Jersey, and Maryland. We placed a portion of the project into service in October 2023 and plan to place the remainder of the project into service as early as the fourth quarter of 2024, assuming timely receipt of all necessary regulatory approvals. The project is expected to increase capacity by 829 Mdth/d.

Southside Reliability Enhancement

In July 2023, we received approval from the FERC for the project, which involves an expansion of Transco’s existing natural gas transmission system to provide incremental firm transportation capacity from receipt points in Virginia and North Carolina to delivery points in North Carolina. We plan to place the project into service as early as the fourth quarter of 2024, assuming timely receipt of all necessary regulatory approvals. The project is expected to increase capacity by 423 Mdth/d.

Texas to Louisiana Energy Pathway

In August 2022, we filed an application with the FERC for the project, which involves an expansion of Transco’s existing natural gas transmission system to provide firm transportation capacity from receipt points in south Texas to delivery points in Texas and Louisiana. We plan to place the project into service as early as the first quarter of 2025, assuming timely receipt of all necessary regulatory approvals. The project is expected to provide 364 Mdth/d of new firm transportation service through a combination of increasing capacity, converting interruptible capacity to firm, and utilizing existing capacity.

Southeast Energy Connector

In August 2022, we filed an application with the FERC for the project, which involves an expansion of Transco's existing natural gas transmission system to provide incremental firm transportation capacity from receipt points in Mississippi and Alabama to a delivery point in Alabama. We plan to place the project into service in the second quarter of 2025, assuming timely receipt of all necessary regulatory approvals. The project is expected to increase capacity by 150 Mdth/d.

Commonwealth Energy Connector

In August 2022, we filed an application with the FERC for the project, which involves an expansion of Transco's existing natural gas transmission system to provide incremental firm transportation capacity in Virginia. We plan to place the project into service as early as the fourth quarter of 2025, assuming timely receipt of all necessary regulatory approvals. The project is expected to increase capacity by 105 Mdth/d.

Alabama Georgia Connector

In April 2023, we filed an application with the FERC for the project, which involves an expansion of Transco's existing natural gas transmission system to provide incremental firm transportation capacity from our Station 85 pooling point in Alabama to customers in Georgia. We plan to place the project into service as early as the fourth quarter of 2025, assuming timely receipt of all necessary regulatory approvals. The project is expected to increase capacity by approximately 64 Mdth/d.

West

Louisiana Energy Gateway

In June 2022, we announced our intention to construct new natural gas gathering assets which are expected to gather 1.8 Bcf/d of natural gas produced in the Haynesville Shale basin for delivery to premium markets, including Transco, industrial markets, and growing LNG export demand along the Gulf Coast. This project is expected to go into service in the fourth quarter of 2024.

Haynesville Gathering Expansion

In February 2023, we announced our agreement with a third party to facilitate natural gas production growth in the Haynesville basin. We plan to construct a greenfield gathering system in support of the third party's 26,000-acre dedication. The system, once constructed, will provide natural gas gathering services to the third party. The third party has also agreed to a long-term capacity commitment on our Louisiana Energy Gateway project. This project is expected to go into service in the second half of 2025.

Northeast G&P

Susquehanna Supply Hub Gathering Expansion

We have an agreement in place with a third party to facilitate natural gas production growth in the Susquehanna region. We plan to construct approximately 22 miles of gathering pipeline and associated incremental compression. The system, once constructed, will add incremental capacity of 320 MMcf/d and will provide natural gas gathering services to the third party. The project is expected to go into service in the fourth quarter of 2023.

Utica Shale Gathering Expansion

We have an agreement in place with a third party to facilitate natural gas production growth in the Utica region on our Cardinal gathering system. We are constructing approximately 30 miles of gathering pipeline and associated incremental compression. The system, once constructed, will add incremental capacity of 125 MMcf/d and will provide natural gas gathering services to the third party. Phase 1 of this project was placed into service in the third quarter of 2023. Phase 2 of this project is expected to go into service in the fourth quarter of 2023.

Results of Operations

The following table and discussion is a summary of our consolidated results of operations for the three and nine months ended September 30, 2023, compared to the three and nine months ended September 30, 2022. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2023	2022	$ Change*	% Change*	2023	2022	$ Change*	% Change*
	(Millions)				(Millions)			
Revenues:								
Service revenues	$ 1,770	$ 1,685	+85	+5 %	$ 5,212	$ 4,828	+384	+8 %
Service revenues – commodity consideration	45	60	-15	-25 %	108	223	-115	-52 %
Product sales	720	1,260	-540	-43 %	2,158	3,475	-1,317	-38 %
Net gain (loss) on commodity derivatives	24	16	+8	+50 %	645	(491)	+1,136	NM
Total revenues	2,559	3,021			8,123	8,035		
Costs and expenses:								
Product costs	484	990	+506	+51 %	1,458	2,650	+1,192	+45 %
Net processing commodity expenses	31	29	-2	-7 %	129	99	-30	-30 %
Operating and maintenance expenses	522	486	-36	-7 %	1,466	1,345	-121	-9 %
Depreciation and amortization expenses	521	500	-21	-4 %	1,542	1,504	-38	-3 %
Selling, general, and administrative expenses	146	163	+17	+10 %	483	477	-6	-1 %
Gain on sale of business	(130)	—	+130	NM	(130)	—	+130	NM
Other (income) expense – net	(9)	33	+42	NM	(49)	14	+63	NM
Total costs and expenses	1,565	2,201			4,899	6,089		
Operating income (loss)	994	820			3,224	1,946		
Equity earnings (losses)	127	193	-66	-34 %	434	492	-58	-12 %
Other investing income (loss) – net	24	1	+23	NM	45	4	+41	NM
Interest expense	(314)	(291)	-23	-8 %	(914)	(858)	-56	-7 %
Other income (expense) – net	30	(6)	+36	NM	69	5	+64	NM
Income (loss) before income taxes	861	717			2,858	1,589		
Less: Provision (benefit) for income taxes	176	96	-80	-83 %	635	169	-466	NM
Income (loss) from continuing operations	685	621			2,223	1,420		
Income (loss) from discontinued operations	(1)	—	-1	NM	(88)	—	-88	NM
Net income (loss)	684	621			2,135	1,420		
Less: Net income (loss) attributable to noncontrolling interests	30	21	-9	-43 %	94	40	-54	-135 %
Net income (loss) attributable to The Williams Companies, Inc.	$ 654	$ 600	+54	+9 %	$ 2,041	$ 1,380	+661	+48 %

* + = Favorable change; - = Unfavorable change; NM = A percentage calculation is not meaningful due to a change in signs, a zero-value denominator, or a percentage change greater than 200.

Three months ended September 30, 2023 vs. three months ended September 30, 2022

Service revenues increased primarily due to higher volumes from the MountainWest Acquisition and higher gathering and processing volumes, as well as higher rates due to rate escalations and annual cost of service rate redetermination for certain of our Northeast G&P operations, partially offset by lower rates driven by unfavorable commodity pricing at our West operations.

Service revenues – commodity consideration decreased primarily due to lower NGL prices, partially offset by higher volumes. These revenues represent consideration we receive in the form of commodities as full or partial payment for processing services provided. Most of these NGL volumes are sold during the month processed and therefore are offset within *Product costs* below.

Product sales associated with our marketing sales activities decreased primarily due to lower commodity prices, partially offset by higher natural gas volumes. This decrease was substantially offset by lower natural gas marketing costs driven by lower prices as well as the benefit related to less significant lower of cost or net realizable value adjustments to our natural gas inventory in 2023 compared to 2022, partially offset by higher volumes. As we are acting as agent for natural gas marketing customers of our Gas & NGL Marketing Services segment, our natural gas marketing product sales are presented net of the related costs of those activities. *Product sales* from our upstream operations decreased primarily due to lower commodity prices, partially offset by higher commodity production volumes. *Product sales* also decreased due to lower system management gas sales, and lower equity NGL sales due to lower prices partially offset by higher volumes.

Net gain (loss) on commodity derivatives includes realized and unrealized gains and losses from derivative instruments reflected within *Total revenues* primarily in our Gas & NGL Marketing Services, West, and Other segments (see Note 8 – Commodity Derivatives of Notes to Consolidated Financial Statements). We experience significant earnings volatility from the fair value accounting required for the derivatives used to hedge a portion of the economic value of the underlying transportation and storage portfolio, upstream-related production, and natural gas and NGLs associated with exposure to commodity-based gathering and processing contracts. However, the unrealized fair value measurement gains and losses are generally offset by valuation changes in the economic value of the underlying production or transportation and storage contracts, which is not recognized until the underlying transaction occurs.

Product costs decreased primarily due to lower prices and volumes associated with our NGL marketing activities and lower system management gas purchases, as well as lower costs associated with NGLs acquired as commodity consideration related to our equity NGL production activities.

Net processing commodity expenses increased primarily due to the unfavorable changes related to gains and losses on commodity derivatives for processing plant shrink gas purchases (see Note 8 – Commodity Derivatives of Notes to Consolidated Financial Statements). This increase was partially offset by lower natural gas purchases associated with our equity NGL production activities primarily due to lower prices.

The sum of *Service revenues – commodity consideration, Product sales*, *Product costs,* net realized gains and losses on commodity derivatives related to sales of product, and net realized processing commodity expenses comprise our *Commodity margins*. However, *Product sales* and net realized gains and losses on commodity derivatives at our Other segment reflecting sales related to our oil and gas producing properties comprise *Net realized product sales* and are excluded from our *Commodity margins*. See Results of Operations— Period-Over-Period Operating Results - Segments for additional discussion of *Commodity margins* and *Net realized product sales* on a segment basis.

Operating and maintenance expenses increased primarily due to higher operating costs, including increased costs associated with the 2023 MountainWest Acquisition and the timing and scope of maintenance activities.

Depreciation and amortization expenses increased primarily related to our upstream assets, assets acquired in the 2023 MountainWest Acquisition, and higher depreciation at Transco. The increase is partially offset by lower amortization of intangibles related to our 2021 Sequent Acquisition.

Selling, general, and administrative expenses decreased primarily due to lower employee-related costs.

Gain on sale of business reflects a gain from the sale of various Gulf Coast petrochemical and feedstock pipelines in our Transmission & Gulf of Mexico segment in 2023 (see Note 3 – Acquisitions and Divestitures of Notes to Consolidated Financial Statements).

Other (income) expense – net within *Operating income (loss)* changed favorably primarily due to the absences of 2022 losses related to Eminence storage cavern abandonments and regulatory charges associated with a decrease in Transco’s estimated deferred state income tax rate.

The change in *Equity earnings (losses)* resulted from our share of a loss contingency accrual related to our 14 percent ownership in Aux Sable Liquid Products LP and a decrease at Laurel Mountain.

Other investing income (loss) – net changed favorably due to higher interest income earned on higher cash and cash equivalent balances.

Interest expense changed unfavorably primarily due to our 2023 debt issuances and MountainWest’s long-term debt (see Note 6 – Debt and Banking Arrangements of Notes to Consolidated Financial Statements), partially offset by an increase in *Interest capitalized* related to ongoing expansion projects.

The favorable change in *Other income (expense) – net* below *Operating income (loss)* includes an increase in allowance for equity funds used during construction (equity AFUDC).

Provision (benefit) for income taxes changed unfavorably primarily due to a lower benefit associated with decreases in our estimate of the state deferred income tax rate in both periods and higher pre-tax income, partially offset by the absence of an unfavorable revision to a state net operating loss carryforward in 2022. See Note 5 – Provision (Benefit) for Income Taxes of Notes to Consolidated Financial Statements for a discussion of the effective tax rate compared to the federal statutory rate for both periods.

Nine months ended September 30, 2023 vs. nine months ended September 30, 2022

Service revenues increased primarily due to higher volumes from the MountainWest and Trace Acquisitions, and the NorTex Asset Purchase, and higher gathering, processing, and transportation & fractionation volumes, and higher rates due to rate escalations and annual cost of service rate redetermination for certain Northeast G&P operations, as well as higher volumes at Transmission & Gulf of Mexico’s Eastern Gulf Coast region. An increase in the Haynesville Shale region, primarily associated with higher gathering volumes, was partially offset by lower rates driven by unfavorable commodity pricing at our West operations.

Service revenues – commodity consideration decreased primarily due to lower NGL prices and volumes. These revenues represent consideration we receive in the form of commodities as full or partial payment for processing services provided. Most of these NGL volumes are sold during the month processed and therefore are offset within *Product costs* below.

Product sales associated with our marketing sales activities decreased primarily due to lower natural gas and NGL prices and volumes. This decrease was substantially offset by lower natural gas marketing costs driven by lower prices and lower volumes, as well as a benefit related to less significant lower of cost or net realizable value adjustments to our natural gas inventory in 2023 compared to 2022. *Product sales* from our upstream operations decreased due to lower commodity prices, offset by higher commodity production volumes. *Product sales* also decreased due to lower prices and volumes related to our equity NGL sales and lower system management gas sales.

Net gain (loss) on commodity derivatives includes realized and unrealized gains and losses from derivative instruments reflected within *Total revenues* primarily in our Gas & NGL Marketing Services, West, and Other segments (see Note 8 – Commodity Derivatives of Notes to Consolidated Financial Statements).

Product costs decreased primarily due to lower prices and volumes associated with our NGL marketing activities, lower prices associated with NGLs acquired as commodity consideration related to our equity NGL production activities, and lower system management gas purchases.

Net processing commodity expenses increased primarily due to the unfavorable changes related to gains and losses on commodity derivatives for processing plant shrink gas purchases (see Note 8 – Commodity Derivatives of Notes to Consolidated Financial Statements), partially offset by lower prices and volumes for natural gas purchases associated with our equity NGL production activities.

Operating and maintenance expenses increased primarily due to higher operating costs, including increased costs associated with the 2023 MountainWest Acquisition, the 2022 Trace Acquisition, and the 2022 NorTex Asset Purchase, and increased scope and timing of operating and maintenance activities.

Depreciation and amortization expenses increased primarily related to our upstream assets, and assets acquired in the 2023 MountainWest Acquisition, the 2022 Trace Acquisition, and the NorTex Asset Purchase. The increase is partially offset by lower amortization of intangibles related to our 2021 Sequent Acquisition and a decrease in ARO-related depreciation at Transco (offset in *Other (income) expense – net* within *Operating income (loss)* resulting in no net impact on our results of operations).

Selling, general, and administrative expenses increased primarily due to acquisition and transition-related costs associated with the MountainWest Acquisition, partially offset by lower employee-related costs.

Gain on sale of business reflects a gain from the sale of various Gulf Coast petrochemical and feedstock pipelines in our Transmission & Gulf of Mexico segment, as previously discussed.

Other (income) expense – net within *Operating income (loss)* changed favorably primarily due to the absence of a 2022 loss related to Eminence storage cavern abandonments, a favorable change associated with regulatory liabilities established for the impacts of deferred income taxes at Northwest Pipeline and the absence of 2022 regulatory charges associated with a decrease in Transco’s estimated deferred state income tax rate, as well as a 2023 gain related to a contract settlement. These favorable changes were partially offset by a decrease in the deferral of ARO-related depreciation (offset in *Depreciation and amortization expenses*, resulting in no net impact on our results of operations).

The change in *Equity earnings (losses)* resulted primarily from a decrease at Laurel Mountain and our share of a loss contingency accrual related to our 14 percent ownership in Aux Sable Liquid Products LP, partially offset by increases at RMM, OPPL, and Blue Racer.

Other investing income (loss) – net changed favorably due to higher interest income earned on higher cash and cash equivalent balances.

Interest expense changed unfavorably primarily due to our 2023 debt issuances and MountainWest's long-term debt (see Note 6 – Debt and Banking Arrangements of Notes to Consolidated Financial Statements), partially offset by an increase in *Interest capitalized* related to ongoing expansion projects.

The favorable change in *Other income (expense) – net* below *Operating income (loss)* includes an increase in equity AFUDC.

Provision (benefit) for income taxes changed unfavorably primarily due to higher pre-tax income, the absence of a benefit related to the release of valuation allowances on deferred income tax assets in 2022, a lower benefit associated with decreases in our estimate of the state deferred income tax rate in both periods, and the absence of 2022 federal income tax settlements. See Note 5 – Provision (Benefit) for Income Taxes of Notes to Consolidated Financial Statements for a discussion of the effective tax rate compared to the federal statutory rate for both periods.

Income (loss) from discontinued operations in 2023 includes a pre-tax charge of $116 million to increase the related accrued liability associated with our Alaska refinery contamination litigation, partially offset by the related income tax effect (see Note 9 – Contingencies of Notes to Consolidated Financial Statements).

The unfavorable change in *Net income (loss) attributable to noncontrolling interests* is primarily due to higher results at Cardinal and the Northeast JV.

Period-Over-Period Operating Results - Segments

We evaluate segment operating performance based upon *Modified EBITDA*. Note 10 – Segment Disclosures of Notes to Consolidated Financial Statements includes a reconciliation of this non-GAAP measure to *Net income (loss)*. Management uses *Modified EBITDA* because it is an accepted financial indicator used by investors to compare company performance. In addition, management believes that this measure provides investors an enhanced perspective of the operating performance of our assets. *Modified EBITDA* should not be considered in isolation or as a substitute for a measure of performance prepared in accordance with GAAP.

Transmission & Gulf of Mexico

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
	(Millions)			
Service revenues	$ 978	$ 910	$ 2,874	$ 2,651
Service revenues – commodity consideration (1)	11	11	29	54
Product sales (1)	63	121	197	334
Net realized gain (loss) on commodity derivatives (1)	1	—	2	—
Net unrealized gain (loss) on commodity derivatives	—	1	—	1
Net gain (loss) on commodity derivatives	1	1	2	1
Segment revenues	1,053	1,043	3,102	3,040
Product costs (1)	(64)	(120)	(193)	(329)
Net processing commodity expenses (1)	(4)	(2)	(10)	(23)
Other segment costs and expenses	(286)	(333)	(855)	(844)
Gain on sale of business	130	—	130	—
Proportional Modified EBITDA of equity-method investments	52	50	153	143
Transmission & Gulf of Mexico Modified EBITDA	$ 881	$ 638	$ 2,327	$ 1,987
Commodity margins	$ 7	$ 10	$ 25	$ 36

(1) Included as a component of *Commodity margins*.

Three months ended September 30, 2023 vs. three months ended September 30, 2022

Transmission & Gulf of Mexico Modified EBITDA increased primarily due to a *Gain on sale of business,* higher *Service revenues* and lower *Other segment costs and expenses.*

Service revenues increased primarily due to:

- A $62 million increase due to the acquisition of MountainWest in February 2023 primarily in transportation and storage revenues;
- An $11 million increase due to the NorTex Asset Purchase in August 2022 primarily in storage and transportation revenues;

- A $5 million increase in the Eastern Gulf Coast region primarily due to higher production handling volumes from new wells at Devils Tower; partially offset by

- An $8 million decrease in reimbursable electric power costs, offset by similar changes in electricity charges, reflected in *Other segment costs and expenses.*

Other segment costs and expenses decreased primarily due to:

- Favorable changes associated with the absence of 2022 regulatory charges associated with decreases in Transco's estimated deferred state income tax rates and regulatory liabilities established for the impacts of deferred income taxes at Northwest Pipeline;

- The absence of losses related to Eminence storage cavern abandonments in 2022;

- A favorable change in equity AFUDC as a result of increased capital expenditures at Transco; partially offset by

- Higher operating and administrative costs including higher operating, acquisition, and transition costs related to our MountainWest Acquisition and NorTex Asset Purchase; and higher costs related to timing and scope of general maintenance activities primarily at Transco and Northwest Pipeline, partially offset by lower reimbursable electric power costs, which is offset by a similar change in electricity reimbursements reflected in *Service revenues*; and lower employee related costs;

- Higher project feasibility costs.

Gain on sale of business includes a gain recognized on the sale of various petrochemical and feedstock pipelines and associated contracts in the Gulf Coast region in September 2023.

Nine months ended September 30, 2023 vs. nine months ended September 30, 2022

Transmission & Gulf of Mexico Modified EBITDA increased primarily due to higher *Service revenues* and a *Gain on sale of business*, partially offset by higher *Other segment costs and expenses* and lower *Commodity margins.*

Service revenues increased primarily due to:

- A $155 million increase due to the acquisition of MountainWest primarily in transportation and storage revenues;

- A $39 million increase due to the NorTex Asset Purchase primarily in storage and transportation revenues;

- A $23 million increase in the Eastern Gulf Coast region primarily due to higher production handling volumes from new wells at Devils Tower;

- A $17 million increase in Transco's and Northwest Pipeline's revenues associated with park and loan services;

- A $13 million increase in Transco's and Northwest Pipeline's revenues associated with short term firm transportation; partially offset by

- A $10 million decrease in reimbursable electric power costs, offset by similar changes in electricity charges, reflected in *Other segment costs and expenses;*

- A $11 million decrease due to lower rates from the FERC rate case settlement effective January 1, 2023, at Northwest Pipeline.

Commodity margins decreased primarily due to a $14 million decrease from our equity NGLs, driven by unfavorable net realized pricing for equity NGL sales.

Other segment costs and expenses increased primarily due to:

- Higher operating and administrative costs including higher operating, acquisition, and transition costs related to our MountainWest Acquisition and NorTex Asset Purchase; and higher costs related to timing and scope of general maintenance activities primarily at Transco, partially offset by lower reimbursable electric power costs, which is offset by a similar change in electricity reimbursements reflected in *Service revenues*; and lower employee-related costs;

- Higher project feasibility costs;

- An unfavorable change in the deferral of ARO-related depreciation at Transco; partially offset by

- Favorable changes associated with regulatory liabilities established for the impacts of deferred income taxes at Northwest Pipeline and the absence of 2022 regulatory charges associated with decreases in Transco's estimated deferred state income tax rate;

- A favorable change in equity AFUDC as a result of increased capital expenditures at Transco;

- The absence of losses related to Eminence storage cavern abandonments in 2022.

Gain on sale of business includes a gain recognized on the sale of various petrochemical and feedstock pipelines and associated contracts in the Gulf Coast region in September 2023.

Northeast G&P

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
	(Millions)			
Service revenues	$ 478	$ 417	$ 1,421	$ 1,208
Service revenues – commodity consideration (1)	—	2	3	12
Product sales (1)	27	40	104	110
Segment revenues	505	459	1,528	1,330
Product costs (1)	(19)	(39)	(96)	(110)
Net processing commodity expenses (1)	(1)	—	—	(2)
Other segment costs and expenses	(150)	(138)	(414)	(392)
Proportional Modified EBITDA of equity-method investments	119	182	421	506
Northeast G&P Modified EBITDA	$ 454	$ 464	$ 1,439	$ 1,332
Commodity margins	$ 7	$ 3	$ 11	$ 10

(1) Included as a component of *Commodity margins*.

Three months ended September 30, 2023 vs. three months ended September 30, 2022

Northeast G&P Modified EBITDA decreased primarily due to lower *Proportional Modified EBITDA of equity-method investments* and higher *Other segment costs and expenses*, partially offset by higher *Service revenues*.

Service revenues increased primarily due to:

- A $25 million increase in gathering revenues in the Utica Shale region primarily related to higher rates resulting from annual cost of service rate redetermination as well as higher volumes;

- A $20 million increase in revenues at the Northeast JV primarily related to higher transportation & fractionation and processing volumes as well as higher processing rates;
- A $17 million increase in gathering revenues at Susquehanna Supply Hub primarily related to escalated rates as well as higher volumes.

Other segment costs and expenses increased primarily due to increased scope of operations and higher operating taxes.

Proportional Modified EBITDA of equity-method investments decreased due to our $31 million share of a loss contingency accrual related to our 14 percent ownership in Aux Sable Liquid Products LP, as well as a decrease at Laurel Mountain primarily due to lower commodity-based rates, MVC, and volumes. Additionally, for Appalachia Midstream Investments, lower gathering rates resulting from annual cost of service rate redetermination and lower volumes at the Bradford Supply Hub were substantially offset by higher volumes and annual rate escalation at Marcellus South.

Nine months ended September 30, 2023 vs. nine months ended September 30, 2022

Northeast G&P Modified EBITDA increased primarily due to higher *Service revenues*, partially offset by lower *Proportional Modified EBITDA of equity-method investments* and higher *Other segment costs and expenses*.

Service revenues increased primarily due to:

- A $90 million increase in revenues at the Northeast JV primarily related to higher transportation & fractionation, processing, and gathering volumes as well as higher processing rates;
- An $84 million increase in gathering revenues in the Utica Shale region primarily related to higher rates resulting from annual cost of service rate redetermination as well as higher volumes;
- A $40 million increase in gathering revenues at Susquehanna Supply Hub primarily related to escalated rates as well as higher volumes.

Other segment costs and expenses increased primarily due to increased scope of operations and higher operating taxes.

Proportional Modified EBITDA of equity-method investments decreased due to lower commodity-based rates, MVC, and volumes at Laurel Mountain, as well as our $31 million share of a loss contingency accrual related to our 14 percent ownership in Aux Sable Liquid Products LP. The decrease was partially offset by an increase at Blue Racer primarily driven by higher volumes. Additionally, Appalachia Midstream Investments increased primarily driven by higher volumes and annual rate escalation at Marcellus South, partially offset by lower gathering rates resulting from annual cost of service rate redetermination and lower volumes at the Bradford Supply Hub.

West

	Three Months Ended September 30, 2023	Three Months Ended September 30, 2022	Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022
	(Millions)			
Service revenues	$ 374	$ 425	$ 1,088	$ 1,139
Service revenues – commodity consideration (1)	34	47	76	157
Product sales (1)	112	245	287	684
Net realized gain (loss) on commodity derivatives – service revenues	12	(10)	80	(15)
Net realized gain (loss) on commodity derivatives – product sales (1)	1	1	5	(8)
Net realized gain (loss) on commodity derivatives	13	(9)	85	(23)
Segment revenues	533	708	1,536	1,957
Product costs (1)	(108)	(238)	(277)	(667)
Net processing commodity expenses (1)	(18)	(28)	(76)	(91)
Other segment costs and expenses	(137)	(146)	(373)	(413)
Proportional Modified EBITDA of equity-method investments	45	41	121	99
West Modified EBITDA	$ 315	$ 337	$ 931	$ 885
Commodity margins	$ 21	$ 27	$ 15	$ 75

(1) Included as a component of *Commodity margins.*

Three months ended September 30, 2023 vs. three months ended September 30, 2022

West Modified EBITDA decreased primarily due to lower *Service revenues,* partially offset by favorable *Net realized gain (loss) on commodity derivatives – service revenues.*

Service revenues decreased primarily due to:

- A $48 million decrease in the Barnett Shale region primarily due to lower gathering rates driven by unfavorable commodity pricing; partially offset by
- A $5 million increase in the Haynesville Shale region primarily due to higher gathering volumes associated with increased producer activity, substantially offset by lower gathering rates driven by unfavorable commodity pricing.

Net realized gain (loss) on commodity derivatives – service revenues reflects a favorable change in settled commodity prices relative to our natural gas hedge positions.

Nine months ended September 30, 2023 vs. nine months ended September 30, 2022

West Modified EBITDA increased primarily due to favorable *Net realized gain (loss) on commodity derivatives – service revenues*, lower *Other segment costs and expenses*, and higher *Proportional Modified EBITDA of equity-method investments,* partially offset by lower *Commodity margins* and lower *Service revenues*.

Service revenues decreased primarily due to:

- A $92 million decrease in the Barnett Shale region primarily due to lower gathering rates driven by unfavorable commodity pricing, partially offset by higher gathering volumes from increased producer activity;
- A $10 million decrease in the Eagle Ford Shale region primarily due to lower MVC revenues, partially offset by higher gathering volumes;
- An $8 million decrease in the Piceance region primarily due to lower gathering and processing volumes driven by natural production rate declines;
- A $7 million decrease associated with reimbursable compressor power and fuel purchases primarily due to lower prices, which are offset by similar changes in *Other segment costs and expenses*; partially offset by
- A $70 million increase in the Haynesville Shale region primarily associated with higher gathering volumes including from increased producer activity and the Trace Acquisition in April 2022, partially offset by lower rates driven by unfavorable commodity pricing.

Net realized gain (loss) on commodity derivatives – service revenues reflects a favorable change in settled commodity prices relative to our natural gas hedge positions.

Commodity margins decreased primarily due to a $44 million decrease from our equity NGLs and a $16 million decrease from other sales activities, both primarily due to lower net realized commodity pricing.

Other segment costs and expenses decreased primarily due to favorable contract settlements in first-quarter 2023, a favorable change in our net imbalance liability due to changes in pricing, lower employee-related costs, the absence of acquisition-related costs associated with the Trace Acquisition in 2022, and lower reimbursable compressor power and fuel purchases which are offset in *Service revenues*, partially offset by higher operating expenses related to operations acquired in the Trace Acquisition and unfavorable changes in system gains and losses.

Proportional Modified EBITDA of equity-method investments increased primarily due to higher volumes at OPPL and RMM.

Gas & NGL Marketing Services

	Three Months Ended September 30, 2023	Three Months Ended September 30, 2022	Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022
	(Millions)			
Service revenues	$ —	$ 1	$ 1	$ 2
Product sales (1)	556	884	1,658	2,724
Net realized gain (loss) from derivative instruments (1)	(31)	54	41	(18)
Net unrealized gain (loss) from derivative instruments	33	(1)	494	(357)
Net gain (loss) on commodity derivatives	2	53	535	(375)
Segment revenues	558	938	2,194	2,351
Net unrealized gain (loss) from derivative instruments within Net processing commodity expenses	(9)	6	(43)	17
Product costs (1)	(487)	(899)	(1,398)	(2,544)
Other segment costs and expenses	(19)	(25)	(75)	(73)
Gas & NGL Marketing Services Modified EBITDA	$ 43	$ 20	$ 678	$ (249)
Commodity margins	$ 38	$ 39	$ 301	$ 162

(1) Included as a component of *Commodity margins*.

Three months ended September 30, 2023 vs. three months ended September 30, 2022

Gas & NGL Marketing Services Modified EBITDA increased primarily due to a favorable change in *Net unrealized gain (loss) from derivative instruments* within *Segment revenues* and *Net processing commodity expenses*.

Commodity margins reflect:

- A $47 million decrease from our natural gas marketing operations including $69 million of lower natural gas transportation capacity marketing margins due to an unfavorable change in net realized pricing spreads, partially offset by $22 million of higher natural gas storage marketing margins primarily due to a $41 million favorable change in lower of cost or net realizable value adjustment, partially offset by an unfavorable change in realized derivative gains (losses); substantially offset by

- A $46 million increase in our NGL marketing margins including a favorable change in net realized gains and losses on sale of inventory in 2023 compared to 2022 driven by a favorable change in NGL prices and an $18 million favorable change in lower of cost or net realizable value inventory adjustment.

Net unrealized gain (loss) from derivative instruments within *Segment revenues* and *Net processing commodity expenses* relates to derivative contracts that are not designated as hedges for accounting purposes. The change from 2022 is primarily due to a change in forward commodity prices relative to our hedge positions in 2023 compared to 2022.

Nine months ended September 30, 2023 vs. nine months ended September 30, 2022

Gas & NGL Marketing Services Modified EBITDA increased primarily due to a favorable change in *Net unrealized gain (loss) from derivative instruments* within *Segment revenues* and *Net processing commodity expenses* and higher *Commodity margins*.

Commodity margins increased $139 million primarily due to:

- A $135 million increase from our natural gas marketing operations including $121 million of higher natural gas storage marketing margins primarily driven by lower cost of storage inventory in the first quarter of 2023 resulting from a fourth-quarter 2022 lower of cost or net realizable value inventory adjustment; a favorable change of $35 million lower of cost or net realizable value adjustment; and the absence of a $15 million charge related to the remaining recognition of a purchase accounting inventory fair value adjustment in 2022. The increase in our natural gas marketing margins also includes $14 million of higher natural gas transportation capacity marketing margins due to favorable net realized pricing spreads.

- A $4 million increase in our NGL marketing margins including a $13 million favorable change in lower of cost or net realizable value inventory adjustments, partially offset by an unfavorable change in ethane prices and higher transportation and fractionation fees.

Net unrealized gain (loss) from derivative instruments within *Segment revenues* and *Net processing commodity expenses* relates to derivative contracts that are not designated as hedges for accounting purposes. The change from 2022 is primarily due to a change in forward commodity prices relative to our hedge positions in 2023 compared to 2022.

Other

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
	(Millions)			
Service revenues	$ 4	$ 6	$ 12	$ 22
Product sales (1)	118	238	303	522
Net realized gain (loss) from derivative instruments (1)	9	(58)	41	(104)
Net unrealized gain (loss) from derivative instruments	(1)	29	(18)	10
Net gain (loss) on commodity derivatives	8	(29)	23	(94)
Segment revenues	130	215	338	450
Other segment costs and expenses	(48)	(75)	(140)	(166)
Proportional Modified EBITDA of equity-method investments	(1)	—	(2)	—
Other Modified EBITDA	$ 81	$ 140	$ 196	$ 284
Net realized product sales	$ 127	$ 180	$ 344	$ 418

(1) Included as a component of *Net realized product sales*.

Three months ended September 30, 2023 vs. three months ended September 30, 2022

Other Modified EBITDA decreased primarily due to lower results from our upstream operations, which included the following, partially offset by lower *Other segment costs and expenses*:

- A $53 million decrease in *Net realized product sales* primarily due to lower net realized commodity prices, partially offset by higher sales associated with increased production volumes from new wells in our Wamsutter and Haynesville Shale regions;

- A $30 million unfavorable change in *Net unrealized gain (loss) from derivative instruments* due to a change in forward commodity prices relative to our hedge positions in 2023 compared to 2022.

Other segment costs and expenses decreased primarily due to the absence of an $11 million charge related to an accrual for loss contingency in the third quarter of 2022 and a $9 million favorable change associated with regulatory assets related to the effects of deferred taxes on equity funds used during construction.

Nine months ended September 30, 2023 vs. nine months ended September 30, 2022

Other Modified EBITDA decreased primarily due to lower results from our upstream operations, which included the following, partially offset by lower *Other segment costs and expenses*:

- A $74 million decrease in *Net realized product sales* primarily due to lower net realized commodity prices, partially offset by higher sales associated with increased production volumes. Higher natural gas production volumes from new wells in our Haynesville Shale region and higher crude oil production volumes from new wells in our Wamsutter region were partially offset by lower natural gas and NGL production volumes in our Wamsutter region driven by the impact of severe winter weather in 2023;

- A $28 million unfavorable change in *Net unrealized gain (loss) from derivative instruments* due to a change in forward commodity prices relative to our hedge positions in 2023 compared to 2022;

- An increase in *Other segment costs and expenses* associated with our upstream operations primarily due to increased production volumes and expenses related to severe winter weather in 2023, partially offset by lower associated ad valorem and production taxes which were impacted by lower commodity prices and lower natural gas and NGL production volumes in our Wamsutter region.

Other segment costs and expenses not associated with our upstream operations decreased primarily due to the absence of an $11 million charge related to an accrual for loss contingency in the third quarter of 2022 and a $15 million favorable change associated with regulatory assets related to the effects of deferred taxes on equity funds used during construction.

Management's Discussion and Analysis of Financial Condition and Liquidity

Outlook

Our growth capital and investment expenditures in 2023 are currently expected to be in a range from $1.6 billion to $1.9 billion, excluding acquisitions discussed below. Growth capital spending in 2023 primarily includes Transco expansions, all of which are fully contracted with firm transportation agreements, projects supporting the Northeast G&P business and projects supporting growth in the Haynesville basin, including the Louisiana Energy Gateway project. We also expect to invest capital in the development of our upstream oil and gas properties. In addition to growth capital and investment expenditures, we also remain committed to projects that maintain our assets for safe and reliable operations, as well as projects that reduce emissions, and meet legal, regulatory, and/or contractual commitments. We intend to fund substantially all planned 2023 capital spending with cash available after paying dividends. We retain the flexibility to adjust planned levels of growth capital and investment expenditures in response to changes in economic conditions or business opportunities including the repurchase of our common stock.

In October 2023, we agreed to acquire Cureton Front Range, LLC, whose operations are located in the DJ Basin, for $560 million, subject to working capital and post-closing adjustments. Concurrently, we entered into an agreement to purchase an additional 50 percent interest in our equity-method investment RMM for $714 million. Upon closing, we will own 100 percent of and will consolidate RMM. These acquisitions are expected to close in the fourth quarter of 2023 and will expand our gathering and processing footprint in the DJ Basin. The Cureton Front Range, LLC acquisition is expected to be funded with available sources of short-term liquidity. Substantially all of the RMM purchase price is not due to the seller and does not accrue interest until the fourth quarter of 2024.

On September 29, 2023, we completed the sale of various petrochemical and feedstock pipelines and associated contracts in the Gulf Coast region for $348 million (see Note 3 – Acquisitions and Divestitures of Notes to Consolidated Financial Statements).

On February 14, 2023, we closed on the acquisition of 100 percent of MountainWest which includes FERC-regulated interstate natural gas pipeline systems and natural gas storage capacity, for $1.08 billion of cash, funded with available sources of short-term liquidity, and retaining $430 million outstanding principal amount of MountainWest long-term debt (see Note 3 – Acquisitions and Divestitures of Notes to Consolidated Financial Statements).

During the first quarter of 2023, we issued $1.5 billion of long-term debt, a portion of which we used to pay down our commercial paper outstanding. During the third quarter of 2023, we issued $1.25 billion of long-term debt. We intend to use the net proceeds from this issuance for general corporate purposes, which may include the repayment of our near-term debt maturities. As of September 30, 2023, we have approximately $2.88 billion of long-term debt due within one year. Our potential sources of liquidity available to address these maturities include cash on hand, proceeds from refinancing, our credit facility, or our commercial paper program, as well as proceeds from asset monetizations.

Liquidity

Based on our forecasted levels of cash flow from operations and other sources of liquidity, we expect to have sufficient liquidity to manage our businesses in 2023. Our potential material internal and external sources and uses of liquidity are as follows:

Sources:	
	Cash and cash equivalents on hand
	Cash generated from operations
	Distributions from our equity-method investees
	Utilization of our credit facility and/or commercial paper program
	Cash proceeds from issuance of debt and/or equity securities
	Proceeds from asset monetizations

Uses:	
	Working capital requirements
	Capital and investment expenditures
	Product costs
	Gas & NGL Marketing Services payments for transportation and storage capacity and gas supply
	Other operating costs including human capital expenses
	Quarterly dividends to our shareholders
	Repayments of borrowings under our credit facility and/or commercial paper program
	Debt service payments, including payments of long-term debt
	Distributions to noncontrolling interests
	Share repurchase program

As of September 30, 2023, we have $22.8 billion of long-term debt due after one year. Our potential sources of liquidity available to address these maturities include cash generated from operations, proceeds from refinancing, our credit facility, or our commercial paper program, as well as proceeds from asset monetizations.

Potential risks associated with our planned levels of liquidity discussed above include those previously discussed in Company Outlook.

As of September 30, 2023, we had a working capital deficit of $1.3 billion, including cash and cash equivalents and long-term debt due within one year. Our available liquidity is as follows:

Available Liquidity		**September 30, 2023**
		(Millions)
Cash and cash equivalents	$	2,074
Capacity available under our $3.75 billion credit facility, less amounts outstanding under our $3.5 billion commercial paper program (1)		3,750
	$	5,824

(1) In managing our available liquidity, we do not expect a maximum outstanding amount in excess of the capacity of our credit facility inclusive of any outstanding amounts under our commercial paper program. We had no commercial paper outstanding as of September 30, 2023. Through September 30, 2023, the highest amount outstanding under our commercial paper program and credit facility during 2023 was $730 million. At September 30, 2023, we were in compliance with the financial covenants associated with our credit facility.

Dividends

We increased our regular quarterly cash dividend to common stockholders by approximately 5.3 percent from the $0.425 per share paid in each quarter of 2022, to $0.4475 per share paid in March, June, and September 2023.

Distributions from Equity-Method Investees

The organizational documents of entities in which we have an equity-method investment generally require periodic distributions of their available cash to their members. In each case, available cash is reduced, in part, by reserves appropriate for operating their respective businesses.

Credit Ratings

The interest rates at which we are able to borrow money are impacted by our credit ratings. The current ratings are as follows:

Rating Agency	Outlook	Senior Unsecured Debt Rating
S&P Global Ratings	Stable	BBB
Moody's Investors Service	Stable	Baa2
Fitch Ratings	Stable	BBB

These credit ratings are included for informational purposes and are not recommendations to buy, sell, or hold our securities, and each rating should be evaluated independently of any other rating. No assurance can be given that the credit rating agencies will continue to assign us investment-grade ratings even if we meet or exceed their current criteria for investment-grade ratios. A downgrade of our credit ratings might increase our future cost of borrowing and, if ratings were to fall below investment grade, could require us to provide additional collateral to third parties, negatively impacting our available liquidity.

Sources (Uses) of Cash

The following table summarizes the sources (uses) of cash and cash equivalents for each of the periods presented in the Consolidated Statement of Cash Flows (see Notes to Consolidated Financial Statements for the Notes referenced in the table):

	Cash Flow Category	Nine Months Ended September 30, 2023	2022
		(Millions)	
Sources of cash and cash equivalents:			
Net cash provided (used) by operating activities	Operating	$ 4,125	$ 3,670
Proceeds from long-term debt	Financing	2,754	1,752
Proceeds from sale of business (see Note 3)	Investing	348	—
Uses of cash and cash equivalents:			
Capital expenditures	Investing	(1,845)	(1,447)
Common dividends paid	Financing	(1,635)	(1,553)
Purchases of businesses, net of cash acquired (see Note 3)	Investing	(1,024)	(933)
Proceeds from (payments of) commercial paper - net	Financing	(352)	—
Purchases of treasury stock	Financing	(130)	(9)
Dividends and distributions paid to noncontrolling interests	Financing	(174)	(141)
Purchases of and contributions to equity-method investments	Investing	(80)	(140)
Payments of long-term debt	Financing	(21)	(2,019)
Other sources / (uses) – net	Financing and Investing	(44)	(1)
Increase (decrease) in cash and cash equivalents		$ 1,922	$ (821)

Operating activities

The factors that determine operating activities are largely the same as those that affect *Net income (loss)*, with the exception of noncash items such as *Depreciation and amortization*, *Provision (benefit) for deferred income taxes*, *Equity (earnings) losses*, *Net unrealized (gain) loss from derivative instruments*, *Gain on sale of business*, *Inventory write-downs,* and *Amortization of stock-based awards.*

Our *Net cash provided (used) by operating activities* for the nine months ended September 30, 2023, increased from the same period in 2022 primarily due to higher operating income (excluding noncash items as previously discussed), net favorable changes in operating working capital, and improved derivative margin requirements, partially offset by lower *Distributions from equity-method investees*.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

Our current interest rate risk exposure is related primarily to our debt portfolio. Our debt portfolio is primarily comprised of fixed rate debt, which mitigates the impact of fluctuations in interest rates. We may utilize interest rate derivative instruments to hedge interest rate risk associated with future debt issuances (see Note 7 – Fair Value Measurements and Guarantees of Notes to Consolidated Financial Statements).

Commodity Price Risk

We are exposed to commodity price risk through our natural gas and NGL marketing activities, including contracts to purchase, sell, transport, and store product. We routinely manage this risk with a variety of exchange-traded and OTC energy contracts such as forward contracts, futures contracts, and basis swaps, as well as physical transactions. Although many of the contracts used to manage commodity exposure are derivative instruments, these economic hedges are not designated or do not qualify for hedge accounting treatment.

We are also exposed to commodity prices through our upstream business and certain gathering and processing contracts. We use derivative instruments to lock in forward sales prices on a portion of our expected future production. These economic hedges are not designated for hedge accounting treatment.

The maturities of our commodity derivative contracts at September 30, 2023 were as follows:

Fair Value Measurements of Assets (Liabilities) Using (1)	Total Fair Value	Maturity 2023	Maturity 2024 - 2025	Maturity 2026 - 2027+
		(Millions)		
Level 1 (2)	$ 90	$ 41	$ 54	$ (5)
Level 2	(272)	(11)	(100)	(161)
Level 3	(21)	—	5	(26)
Fair value of contracts outstanding at end of period	$ (203)	$ 30	$ (41)	$ (192)

(1) See Note 7 – Fair Value Measurements and Guarantees of Notes to Consolidated Financial Statements for discussion of valuation techniques by level within the fair value hierarchy. See Note 8 – Commodity Derivatives of Notes to Consolidated Financial Statements for the amount of change in fair value recognized in our Consolidated Statement of Income.

(2) Commodity derivative assets and liabilities exclude $30 million of net cash collateral in Level 1.

Value at Risk (VaR)

VaR is the maximum predicted loss in portfolio value over a specified time period that is not expected to be exceeded within a given degree of probability. Our VaR may not be comparable to that of other companies due to differences in the factors used to calculate VaR. Our VaR is determined using parametric models with 95 percent confidence intervals and one-day holding periods, which means that 95 percent of the time, the risk of loss in a day from a portfolio of positions is expected to be less than or equal to the amount of VaR calculated. Our open exposure is managed in accordance with established policies that limit market risk and require daily reporting of predicted financial loss to management. Because we generally manage physical gas assets and economically protect our positions by hedging in the futures markets, our open exposure is generally mitigated. We employ daily risk testing, using both VaR and stress testing, to evaluate the risk of our positions.

We actively monitor open commodity marketing positions and the resulting VaR and maintain a relatively small risk exposure as total buy volume is close to sell volume, with minimal open natural gas price risk.

The VaR associated with our integrated natural gas trading operations activity was $4 million at September 30, 2023 and $10 million at December 31, 2022. We had the following VaRs for the period shown:

	Nine Months Ended September 30, 2023
	(Millions)
Average	$ 7
High	$ 13
Low	$ 4

Our non-trading portfolio primarily consists of derivatives that hedge our upstream business and certain gathering and processing contracts. The VaR associated with these derivatives was $3 million at September 30, 2023 and $8 million at December 31, 2022. We had the following VaRs for the period shown:

	Nine Months Ended September 30, 2023
	(Millions)
Average	$ 4
High	$ 8
Low	$ 2

Item 4. Controls and Procedures

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a - 15(e) and 15d - 15(e) of the Exchange Act) (Disclosure Controls) or our internal control over financial reporting (Internal Controls) will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and Internal Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls and Internal Controls will be modified as systems change and conditions warrant.

Evaluation of Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that these Disclosure Controls are effective at a reasonable assurance level.

As disclosed in Note 3 – Acquisitions and Divestitures of Notes to Consolidated Financial Statements, we acquired MountainWest on February 14, 2023, and its total revenues constituted approximately 2 percent of total revenues as shown on our consolidated financial statements for the nine months ended September 30, 2023. MountainWest's total assets constituted approximately 3 percent of total assets as shown on our consolidated financial statements as of September 30, 2023. We excluded MountainWest's disclosure controls and procedures that are subsumed by its internal control over financial reporting from the scope of management's assessment of the effectiveness of our disclosure controls and procedures. This exclusion is in accordance with the guidance issued by the Staff of the Securities and Exchange Commission that an assessment of recent business combinations may be omitted from management's assessment of internal control over financial reporting for one year following the acquisition.

Changes in Internal Control Over Financial Reporting

As noted above, we acquired MountainWest on February 14, 2023. We are currently integrating MountainWest into our operations and internal control processes. The scope of our assessment of our internal control over financial reporting as of December 31, 2023, will exclude MountainWest's internal control over financial reporting.

Other than as set forth above, there have been no changes during the third quarter of 2023 that have materially affected, or are reasonably likely to materially affect, our Internal Control over Financial Reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Environmental

Certain reportable legal proceedings involving governmental authorities under federal, state, and local laws regulating the discharge of materials into the environment are described below. While it is not possible for us to predict the final outcome of the proceedings that are still pending, we do not anticipate a material effect on our consolidated financial position if we receive an unfavorable outcome in any one or more of such proceedings. Our threshold for disclosing material environmental legal proceedings involving a governmental authority where potential monetary sanctions are involved is $1 million.

On January 19, 2016, we received a Notice of Noncompliance with certain Leak Detection and Repair (LDAR) regulations under the Clean Air Act at our Moundsville Fractionator Facility from the EPA, Region 3. Subsequently, the EPA alleged similar violations of certain LDAR regulations at our Oak Grove Gas Plant. On March 19, 2018, we received a Notice of Violation of certain LDAR regulations at our former Ignacio Gas Plant from the EPA, Region 8, following an on-site inspection of the facility. On March 20, 2018, we also received a Notice of Violation of certain LDAR regulations at our Parachute Creek Gas Plant from the EPA, Region 8. All such notices were subsequently referred to a common attorney at the Department of Justice (DOJ). We have executed a consent decree with the DOJ and other agencies resolving the claims at these facilities, as well as alleged violations at certain other facilities. The consent decree which will become effective upon final entry by the United States District Court for the District of Colorado, requires both payment of a civil penalty in the amount of $3.75 million and injunctive relief.

Other environmental matters called for by this Item are described under the caption "*Environmental Matters*" in Note 9 – Contingencies of Notes to Consolidated Financial Statements included under Part I, Item 1. Financial Statements of this report, which information is incorporated by reference into this Item.

Other litigation

The additional information called for by this Item is provided in Note 9 – Contingencies of Notes to Consolidated Financial Statements included under Part I, Item 1. Financial Statements of this report, which information is incorporated by reference into this Item.

Item 1A. Risk Factors

Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2022, as filed with the SEC on February 27, 2023, includes risk factors that could materially affect our business, financial condition, or future results. Those Risk Factors have not materially changed.

Item 2. Unregistered Sales of Equity Securities, Use of Proceeds, and Issuer Purchases of Equity Securities

ISSUER PURCHASES OF EQUITY SECURITIES

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs(1)	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
July 1 - July 31, 2023	—	$ —	—	$ 1,360,938,325
August 1 - August 31, 2023	—	$ —	—	$ 1,360,938,325
September 1 - September 30, 2023	—	$ —	—	$ 1,360,938,325
Total	—		—	

(1) In September 2021, our Board of Directors authorized a share repurchase program with a maximum dollar limit of $1.5 billion. Repurchases may be made from time to time in the open market, by block purchases, in privately negotiated transactions, or in such other manner as determined by our management. Our management will also determine the timing and amount of any repurchases based on market conditions and other factors. The share repurchase program does not obligate us to acquire any particular amount of common stock, and it may be suspended or discontinued at any time. This share repurchase program does not have an expiration date.

Item 5. Other Information

During the three months ended September 30, 2023, no director or officer of the Company adopted or terminated a “Rule 10b5-1 trading arrangement” or “non-Rule 10b5-1 trading arrangement,” as each term is defined in Item 408(a) of Regulation S-K.

Item 6. Exhibits

Exhibit No.		Description
2.1	—	Agreement and Plan of Merger dated as of May 16, 2018, by and among The Williams Companies, Inc., SCMS LLC, Williams Partners L.P., and WPZ GP LLC (filed on May 17, 2018 as Exhibit 2.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
2.2	—	Amendment No 1. to Agreement and Plan of Merger dated as of May 1, 2016, by and among The Williams Companies, Inc., Energy Transfer Corp LP, Energy Transfer Corp GP, LLC, Energy Transfer Equity, L.P., LE GP, LLC, and Energy Transfer Equity GP, LLC (filed on May 3, 2016 as Exhibit 2.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
2.3	—	Agreement and Plan of Merger dated as of September 28, 2015, by and among The Williams Companies, Inc., Energy Transfer Corp LP, Energy Transfer Corp GP, LLC, Energy Transfer Equity, L.P., LE GP, LLC, and Energy Transfer Equity GP, LLC (filed on October 1, 2015 as Exhibit 2.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
3.1	—	Amended and Restated Certificate of Incorporation as supplemented (filed on May 26, 2010, as Exhibit 3.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
3.2	—	Certificate of Designations of Series B Preferred Stock of The Williams Companies, Inc. (filed on July 17, 2018 as Exhibit 3.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
3.3	—	Certificate of Amendment dated August 10, 2018 (filed on August 10, 2018 as Exhibit 3.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
3.4	—	By-Laws of The Williams Companies, Inc., as last amended effective October 25, 2022 (filed on October 31, 2022, as Exhibit 3.4 to The Williams Companies, Inc.'s current report on Form 10-Q (File No. 001-04174) and incorporated herein by reference).
31.1*	—	Certification of Chief Executive Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	—	Certification of Chief Financial Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32**	—	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	—	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*	—	XBRL Taxonomy Extension Schema.
101.CAL*	—	XBRL Taxonomy Extension Calculation Linkbase.
101.DEF*	—	XBRL Taxonomy Extension Definition Linkbase.
101.LAB*	—	XBRL Taxonomy Extension Label Linkbase.

Exhibit No.		Description
101.PRE*	—	XBRL Taxonomy Extension Presentation Linkbase.
104*	—	Cover Page Interactive Data File. The cover page interactive data file does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document (contained in Exhibit 101).

* Filed herewith.

** Furnished herewith.

SIGNATURE

Pursuant to the 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.

THE WILLIAMS COMPANIES, INC.
(Registrant)

/s/ Mary A. Hausman

Mary A. Hausman
Vice President, Chief Accounting Officer and Controller (Duly Authorized Officer and Principal Accounting Officer)

November 1, 2023

Exhibit 31.1

CERTIFICATIONS

I, Alan S. Armstrong, certify that:

1. I have reviewed this quarterly report on Form 10-Q of The Williams Companies, Inc.;

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(s) 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(s) 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.

Date: November 1, 2023

/s/ Alan S. Armstrong

Alan S. Armstrong
President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATIONS

I, John D. Porter, certify that:

1. I have reviewed this quarterly report on Form 10-Q of The Williams Companies, Inc.;

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(s) 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(s) 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.

Date: November 1, 2023

/s/ John D. Porter

John D. Porter
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of The Williams Companies, Inc. (the "Company") on Form 10-Q for the period ending September 30, 2023, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned hereby certifies, in his capacity as an officer of the Company, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Alan S. Armstrong
Alan S. Armstrong
President and Chief Executive Officer
November 1, 2023

/s/ John D. Porter
John D. Porter
Senior Vice President and Chief Financial Officer
November 1, 2023

A signed original of this written statement required by Section 906 has been provided to, and will be retained by, the Company and furnished to the Securities and Exchange Commission or its staff upon request.

The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Report and shall not be considered filed as part of the Report.