Enterprise Products Partners L.P.

Third Quarter 2025 Earnings Support Slides

October 30, 2025

NYSE: EPD

Forward-Looking Statements

This presentation contains forward-looking statements based on the beliefs of the company, as well as assumptions made by, and information currently available to our management team (including information published by third parties). When used in this presentation, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "estimate," "forecast," "intend," "could," "should," "would," "will," "believe," "may," "scheduled," "pending," "potential" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements.

Although management believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will prove to be correct. You should not put undue reliance on any forward-looking statements, which speak only as of their dates. Forward-looking statements are subject to risks and uncertainties that may cause actual results to differ materially from those expected, including insufficient cash from operations, adverse market conditions, governmental regulations, the possibility that tax or other costs or difficulties related thereto will be greater than expected, the impact of competition and other risk factors discussed in our latest filings with the Securities and Exchange Commission.

All forward-looking statements attributable to Enterprise or any person acting on our behalf are expressly qualified in their entirety by the cautionary statements contained herein, in such filings and in our future periodic reports filed with the Securities and Exchange Commission. Except as required by law, we do not intend to update or revise our forward-looking statements, whether as a result of new information, future events or otherwise.

Qualifying Statements

This supplemental package contains earnings support slides highlighting major variances for the quarter.

This data should be read in conjunction with the information contained in the earnings release for the third quarter of 2025 and our SEC Form 10-Q (when filed), which provide a more comprehensive description of the variances between certain periods.

Enterprise Allocation of Capital

"All of the Above" Approach

Responsibly Returning Capital to Investors

- $61 Billion ("B") of capital returned to equity investors via LP distributions and common unit buybacks, since IPO
- Distributions: $0.545/unit for 3Q 2025, a 3.8% increase over 3Q 2024
- Buybacks: $80 million ("MM"), 2.5MM common units, of repurchases in 3Q 2025
  - $250MM, 8MM common units, of repurchases for the 9 months ended September 30, 2025 ("9 Mo 2025")
  - Unitholder Reinvestment & Employee Support: our DRIP[1] and EUPP[2] programs purchased a combined 1.2MM and 3.5MM common units in 3Q 2025 and 9 Mo 2025 respectively, on the open market
- Adjusted CFFO Payout Ratio[3]: 58% TTM 3Q 2025

Capital Expenditures

- Growth Capital Expenditures Range: ≈$4.5B in 2025; $2.2B to $2.5B in 2026
- Sustaining Capital Expenditures: ≈$525MM in 2025

Maintain and Protect Balance Sheet

- Leverage Ratio[3]: 3.3x as of September 30, 2025
- Liquidity: $3.6B comprised of available credit capacity and unrestricted cash as of September 30, 2025

(1) Distribution Reinvestment Plan ("DRIP")
(2) Employee Unit Purchase Plan ("EUPP")
(3) See definitions

EPD's Role in Building a Resilient Portfolio

Recession Resistant

- Businesses have a high degree of inelastic demand from providing integral infrastructure services to producers and consumers of energy and energy products

Inflation Protection

- Approximately 90% of long-term contracts have escalation provisions to mitigate impacts of inflation to cash flow and distributions

Assets Underwritten by Conservative, Long-Term Financing

- Only A- rated midstream energy infrastructure company
- Debt portfolio has a 17-year average maturity(1), 96% of portfolio is fixed rate(1), weighted-average interest rate of 4.7%(1)

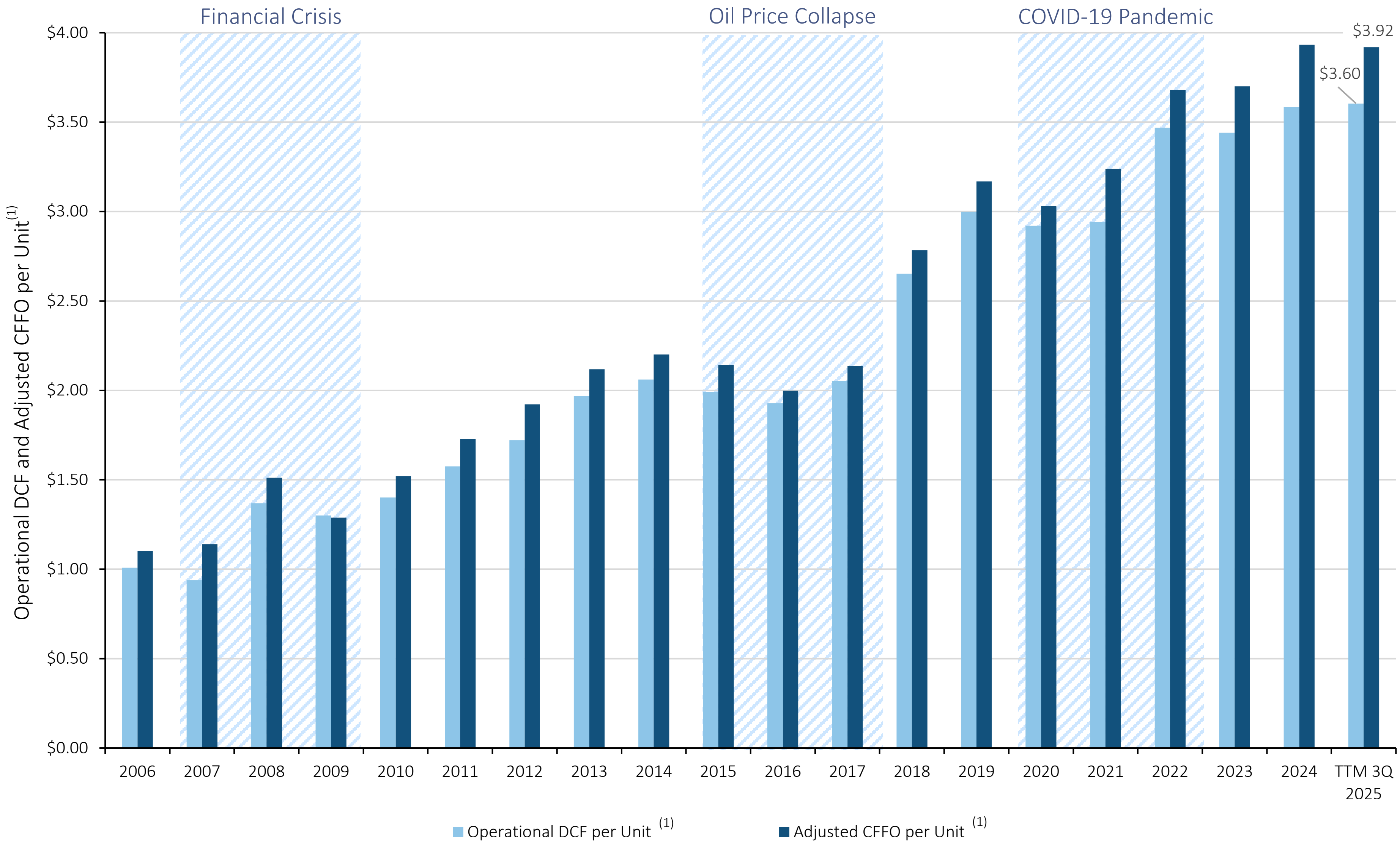
Stable Cash Flow Yields and Consistent Distribution Income Growth

- 27 consecutive years of distribution growth throughout business cycles

(1) As of September 30, 2025

History of Cash Flow per Unit Durability

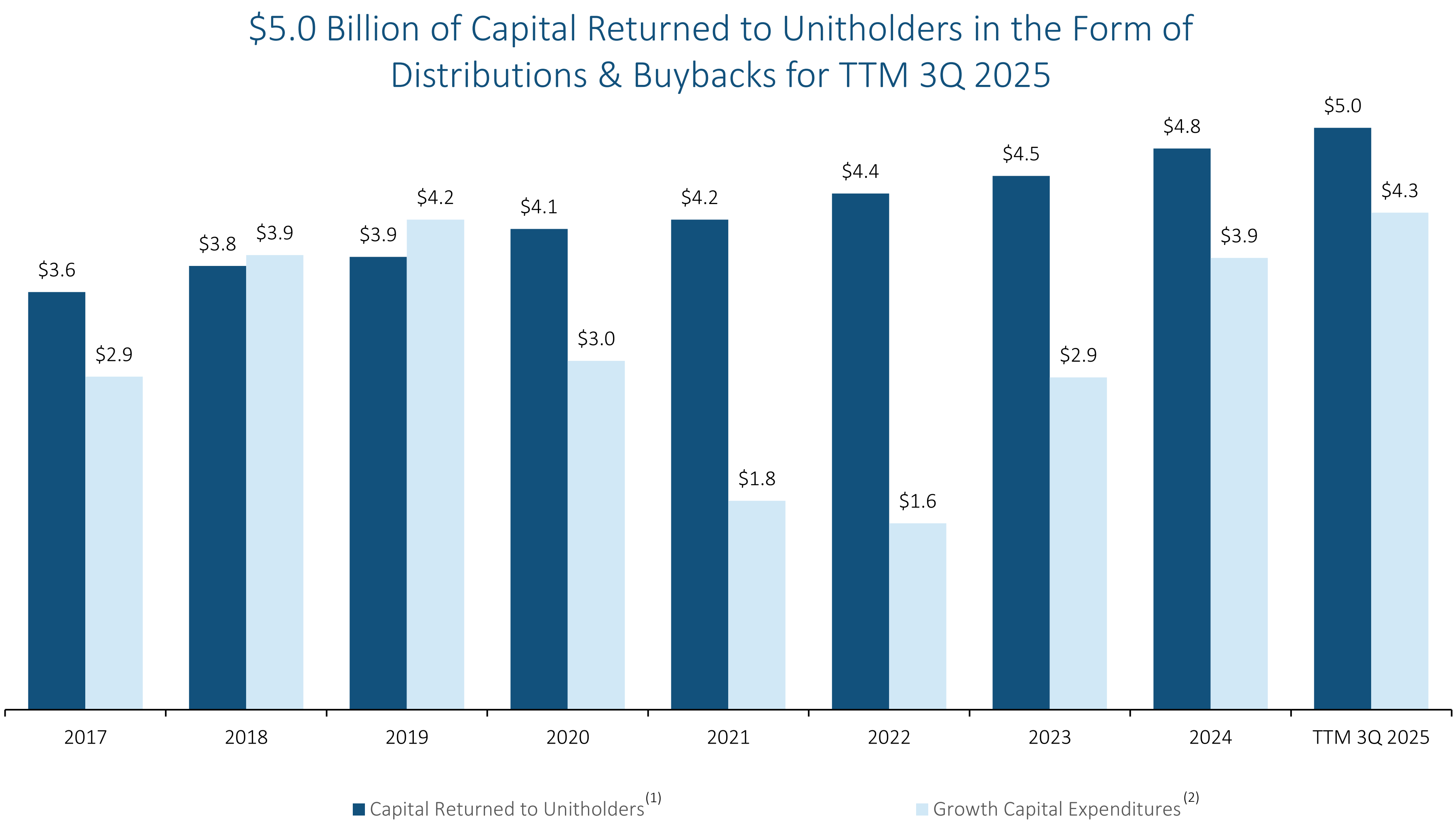
A Track Record of Resilience



Source: EPD
(1) For a definition, please see Appendix.

Responsible, Strategic Growth

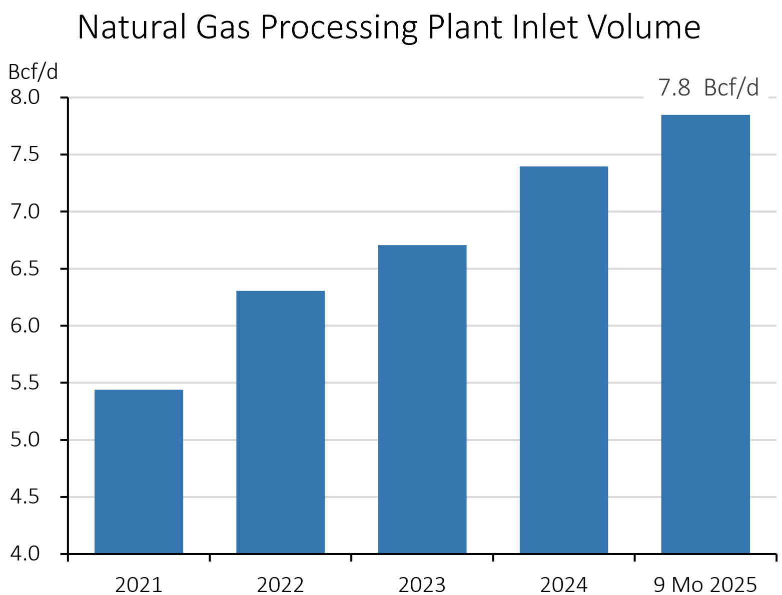
Returning Capital & Reinvesting in the Business

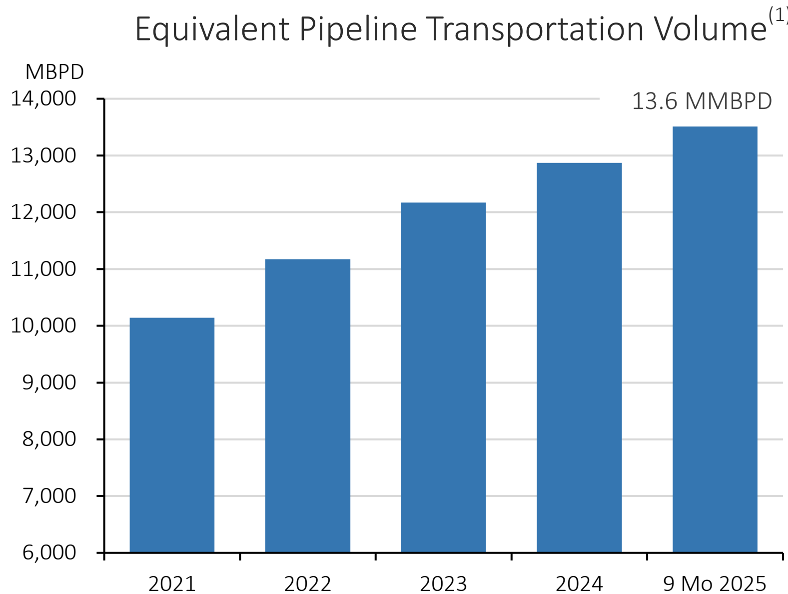


(1) Capital Returned to Unitholders represents cash distributions to common unitholders and distribution equivalent rights and common unit repurchases for the applicable period.
(2) Represents organic capital spending, excludes acquisitions

Strategic Investment Drives Value Chain Growth

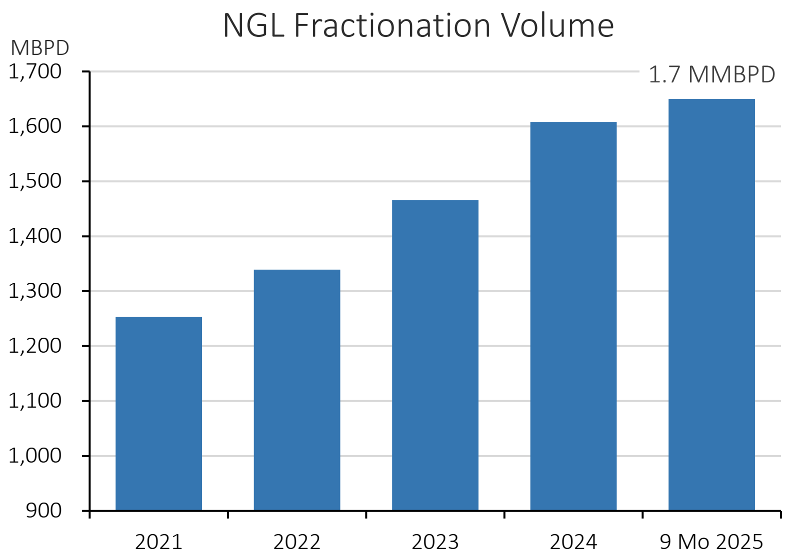
10% CAGR

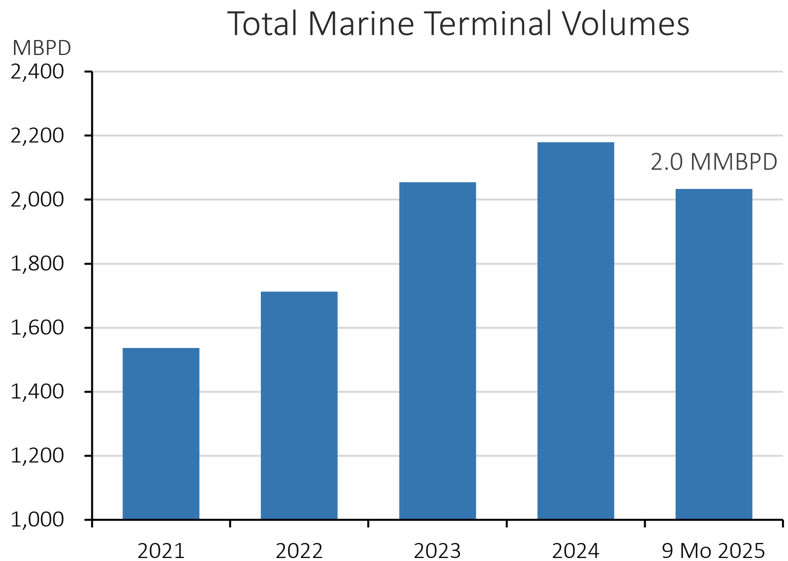




8% CAGR

8% CAGR





8% CAGR

Note: These selected volume statistics reflect volumes owned by consolidated entities on a 100% basis and volumes for assets owned by unconsolidated affiliates net to Enterprise's interest.

(1) Represents total NGL, crude oil, refined products and petrochemical transportation volumes plus equivalent energy volumes where 3.8 million British thermal units ("MMBtus") of natural gas transportation volumes are equivalent to one barrel of NGLs transported.

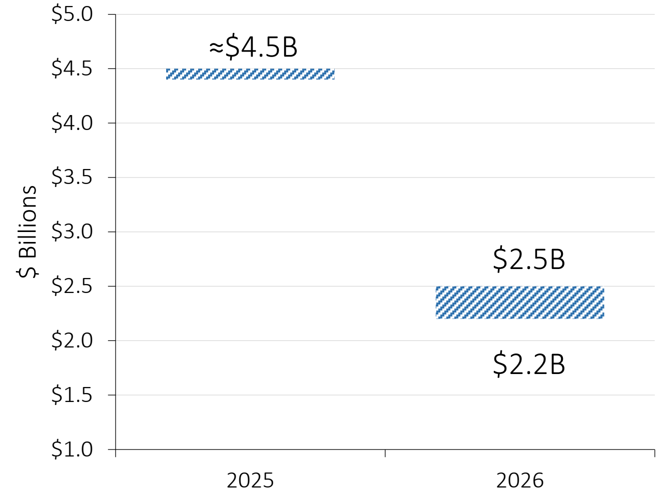
Growth Capital Expenditures

$5.1B of Major Capital Projects Under Construction[(1)]

Highlighted Major Capital Projects[(1)]

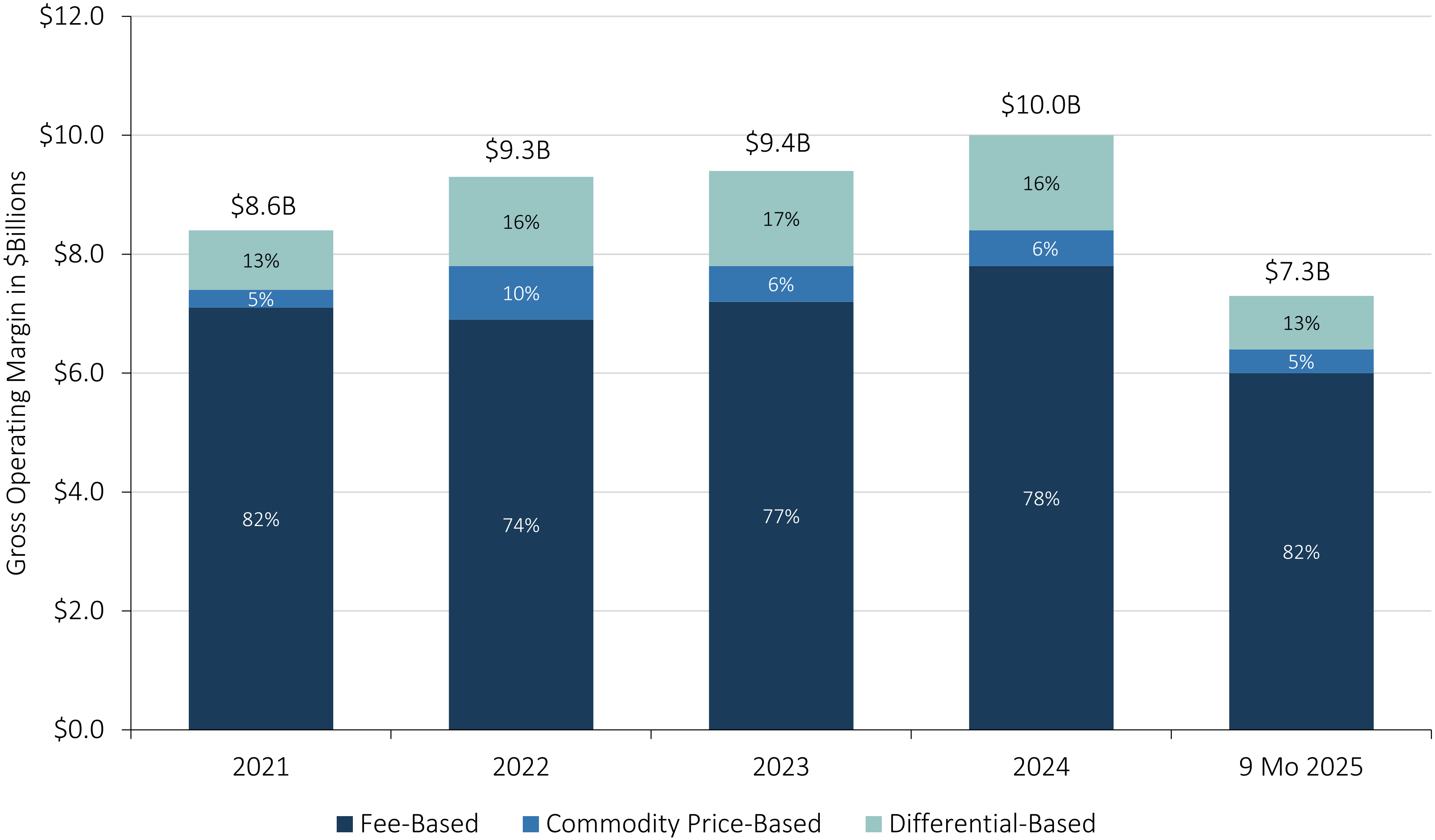
		Forecast In-service
Permian Basin Gathering & Treating	Delaware Basin & Midland Basin Natural Gas Gathering, Compression & Treating	2025 & 2026
Orion	300 MMcf/d Gas Processing Plant in Permian (Midland)	In-service
Mentone West	300 MMcf/d Gas Processing Plant in Permian (Delaware)	In-service
Mentone West 2	300 MMcf/d Gas Processing Plant in Permian (Delaware)	1H 26
Athena	300 MMcf/d Gas Processing Plant in Permian (Midland)	4Q 26
Bahia Pipeline	600 MBPD Mixed NGL ("Y-Grade") Pipeline	4Q 25
Fractionator 14	150 MBPD Nameplate Capacity Fractionator in Mont Belvieu	In-service
Neches River Terminal ("NRT")	New Build Ethane & Propane Export Terminal in Orange County, TX	P1: In-service P2: 1H 26
EHT LPG Expansion	+300 MBPD Expansion of LPG (Propane & Butane) Loading Capacity at Enterprise Hydrocarbons Terminal ("EHT")	YE 2026
Morgan's Point Enhancements	900 MBbl Refrigerated Ethane Tank Enabling Higher Loading Rates at Morgan's Point Ethane Terminal	4Q 25

Forecasted Annual Growth Capex Range



(1) Major Capital Projects Under Construction: $5.1 billion represents the total project value of major projects under construction (those that are not yet in-service) and includes growth projects of significance in terms of relative capital cost or commercial strategy. The table above includes a selection of highlighted projects.

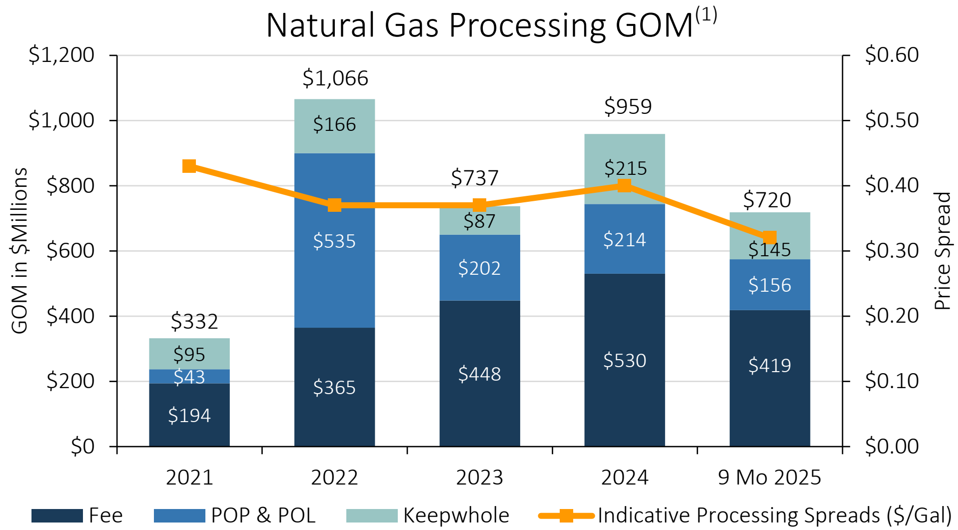
Indicative Attribution of Total GOM

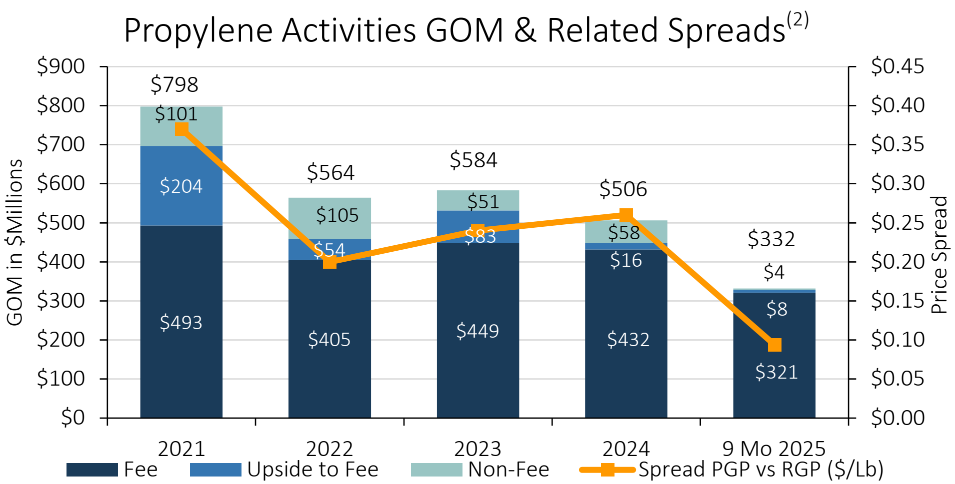


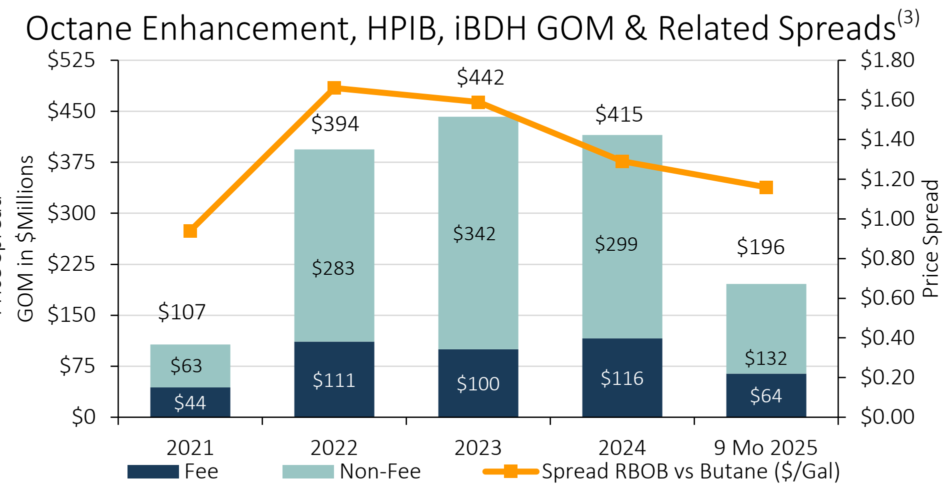
Total gross operating margin is a Non-GAAP measure. For a reconciliation of these amounts to their nearest GAAP counterparts, see "Non-GAAP Financial Measures" on our website.
The amounts above are adjusted to exclude MTM results for the respective periods.

Indicative Attribution of Segment GOM

Select Businesses as of 9 Mo 2025







The above figures exclude MTM results for the segments.

(1) Contracts and commercial arrangements in Natural Gas Processing are structured as either fee-based, commodity-based or a combination of the two. Our commodity-based contracts include keepwhole, margin-band, percent-of-liquids (POL), percent-of-proceeds (POP) and contracts featuring a combination of commodity and fee-based terms. In February 2022, we completed the acquisition of Navitas Midstream (thereafter referred to as our "Midland Basin" assets).

(2) Contracts and commercial arrangements in Propylene Activities are primarily structured as fee-based tolling contracts. The majority of our legacy margin-based contracts at our propylene splitters, which contained exposure to the Refinery Grade Propylene – Polymer Grade Propylene spread were converted to fee-based processing agreements by the end of the first quarter of 2025. Reactor-based assets are subject to scheduled turnarounds and plant maintenance.

(3) Contracts and commercial arrangements in octane enhancement, HPIB, and iBDH are structured as fee-based tolling contracts and product sales with price spread based margins. Octane enhancement capacity is approx. 20 MBPD with relevant price spreads being Normal Butane to RBOB and RBOB to MTBE. Reactor-based assets are subject to scheduled turnarounds and plant maintenance.

Segment Gross Operating Margin Variance
3Q 2025 vs. 3Q 2024

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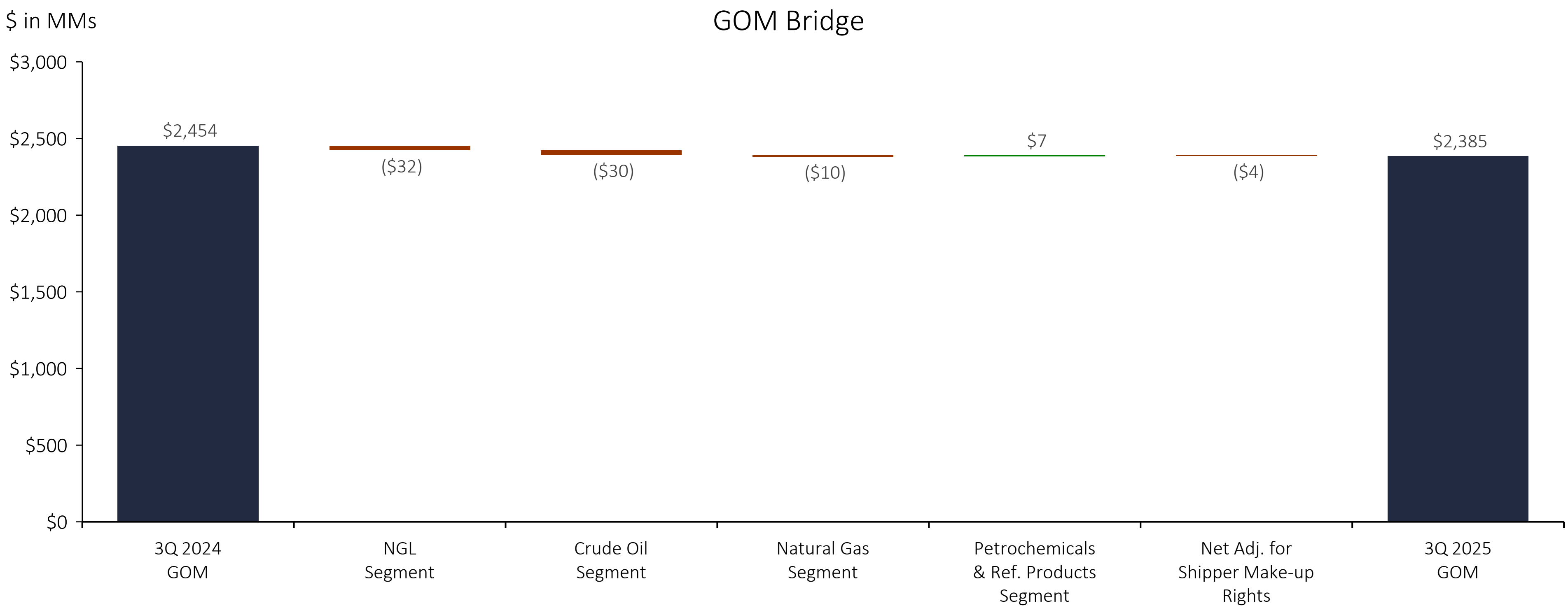
Total GOM Bridge by Segment

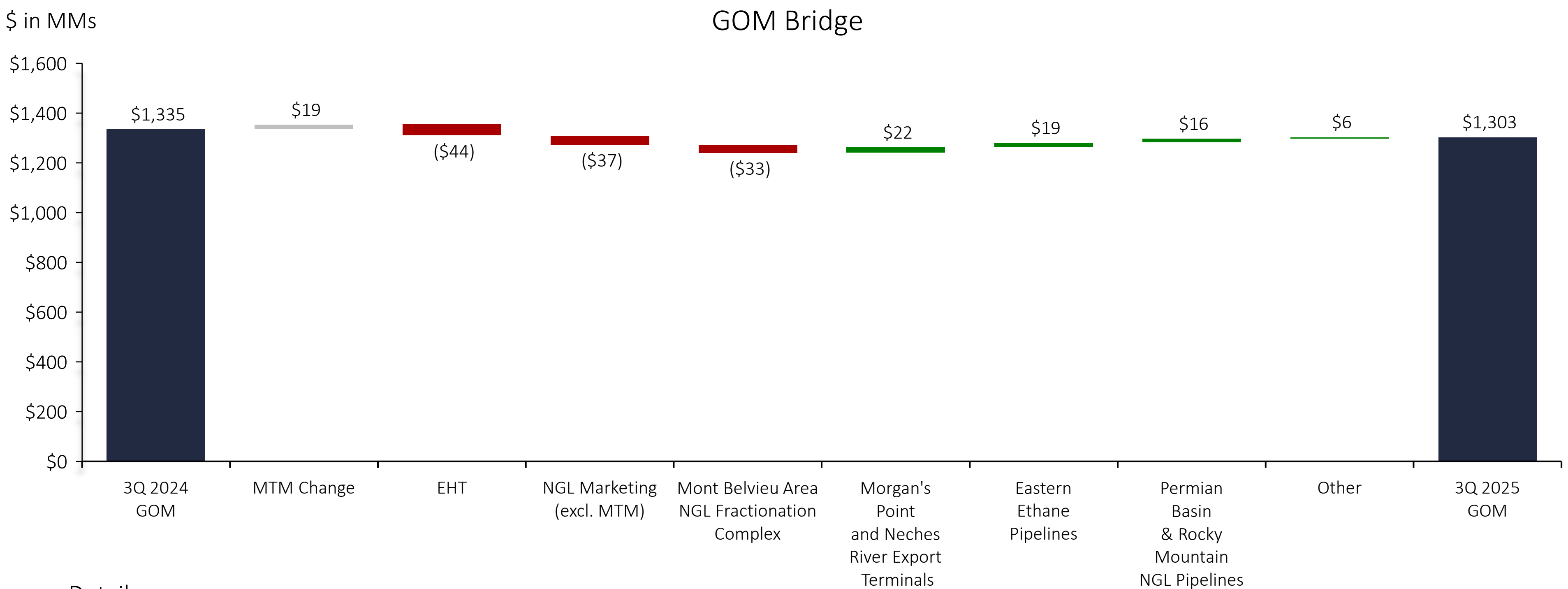
3Q 2025 vs. 3Q 2024



The following slides summarize the primary drivers for changes in gross operating margin for each segment between 3Q 2025 and 3Q 2024. Total gross operating margin is a Non-GAAP measure. For a reconciliation of these amounts to their nearest GAAP counterparts, see "Non-GAAP Financial Measures" on our website

NGL Segment

3Q 2025 vs. 3Q 2024

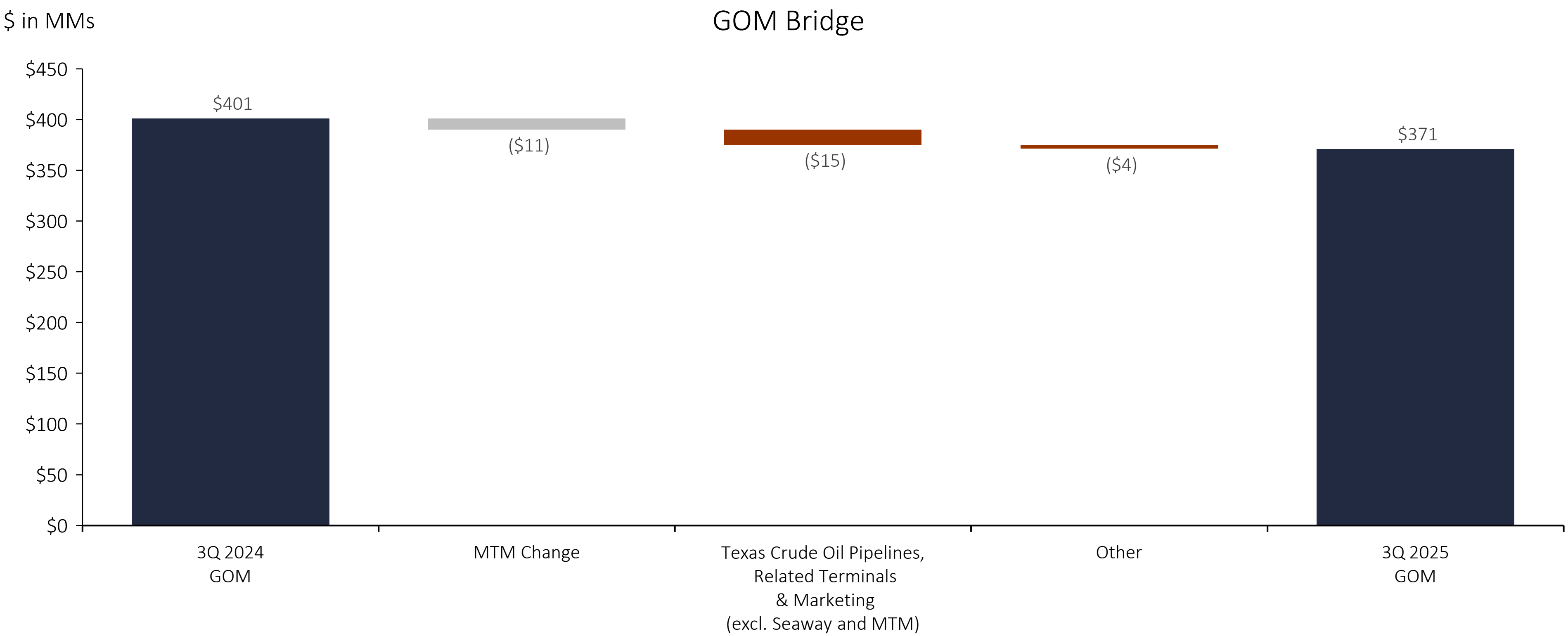


Details:

- MTM activity resulted in a gain of $16MM in 3Q 2025 compared to a loss of $3MM in 3Q 2024
- EHT GOM decreased primarily due to lower average loading fees largely due to the re-contracting of a legacy agreement at lower rates in the first half of 2025
- NGL marketing activities (excluding MTM) GOM decreased primarily due to lower average sales margins
- Mont Belvieu area NGL Fractionation Complex GOM decreased primarily due to higher operating costs, lower ancillary revenues and a 21 MBPD decrease in fractionation volumes stemming from plant maintenance and fractionator turnarounds
- Morgan's Point and Neches River Terminals GOM increased primarily due to a combined 63 MBPD increase in ethane export volumes. The first phase of the Neches River Terminal was placed in service in July 2025
- Eastern Ethane Pipelines GOM increased primarily due to higher average transportation fees and a 109 MBPD increase in transportation volumes
- Permian Basin and Rocky Mountain NGL pipelines (MAPL, Seminole, Chaparral and Shin Oak) GOM increased primarily due to a 138 MBPD increase in transportation volumes

Crude Oil Segment

3Q 2025 vs. 3Q 2024

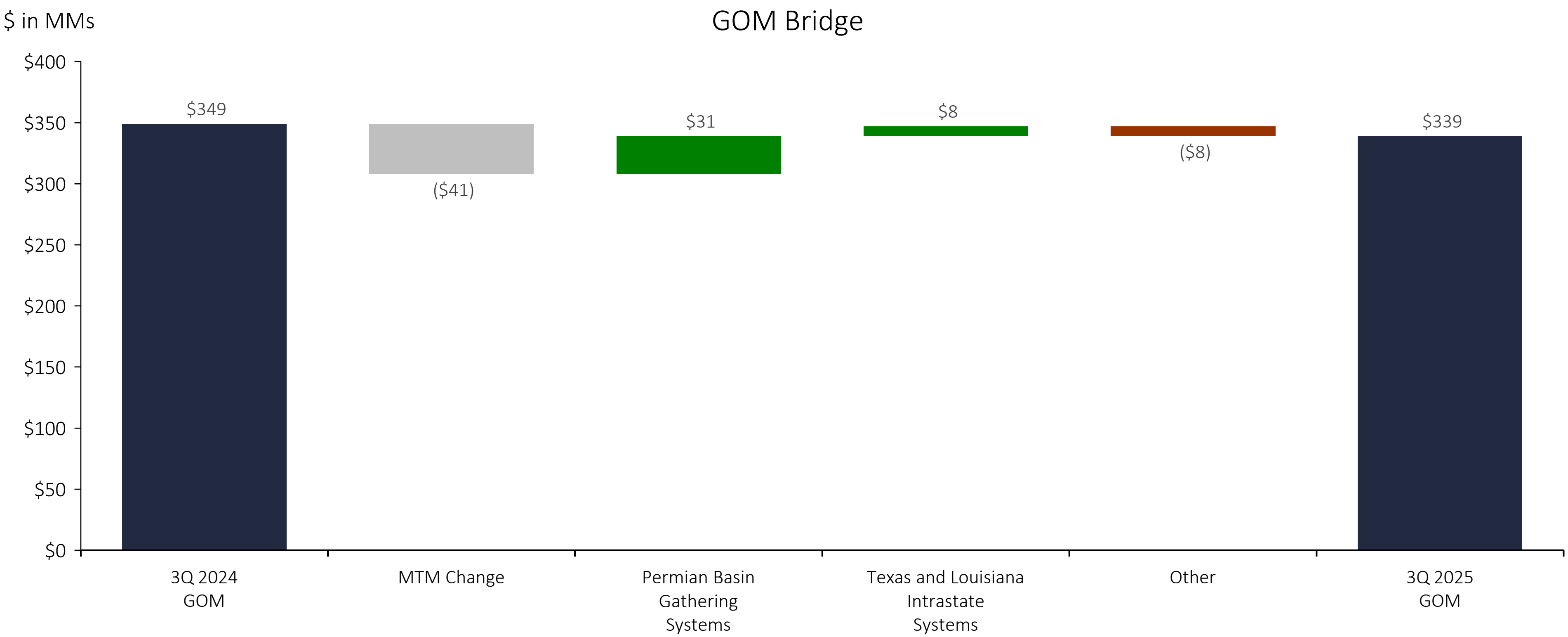


Details:

- MTM activity resulted in a loss of $6MM in 3Q 2025 compared to a gain of $5MM in 3Q 2024
- Texas crude oil pipelines, related terminals and marketing activities (excluding Seaway and MTM) GOM decreased primarily due to lower average sales margins from marketing activities

Natural Gas Segment

3Q 2025 vs. 3Q 2024

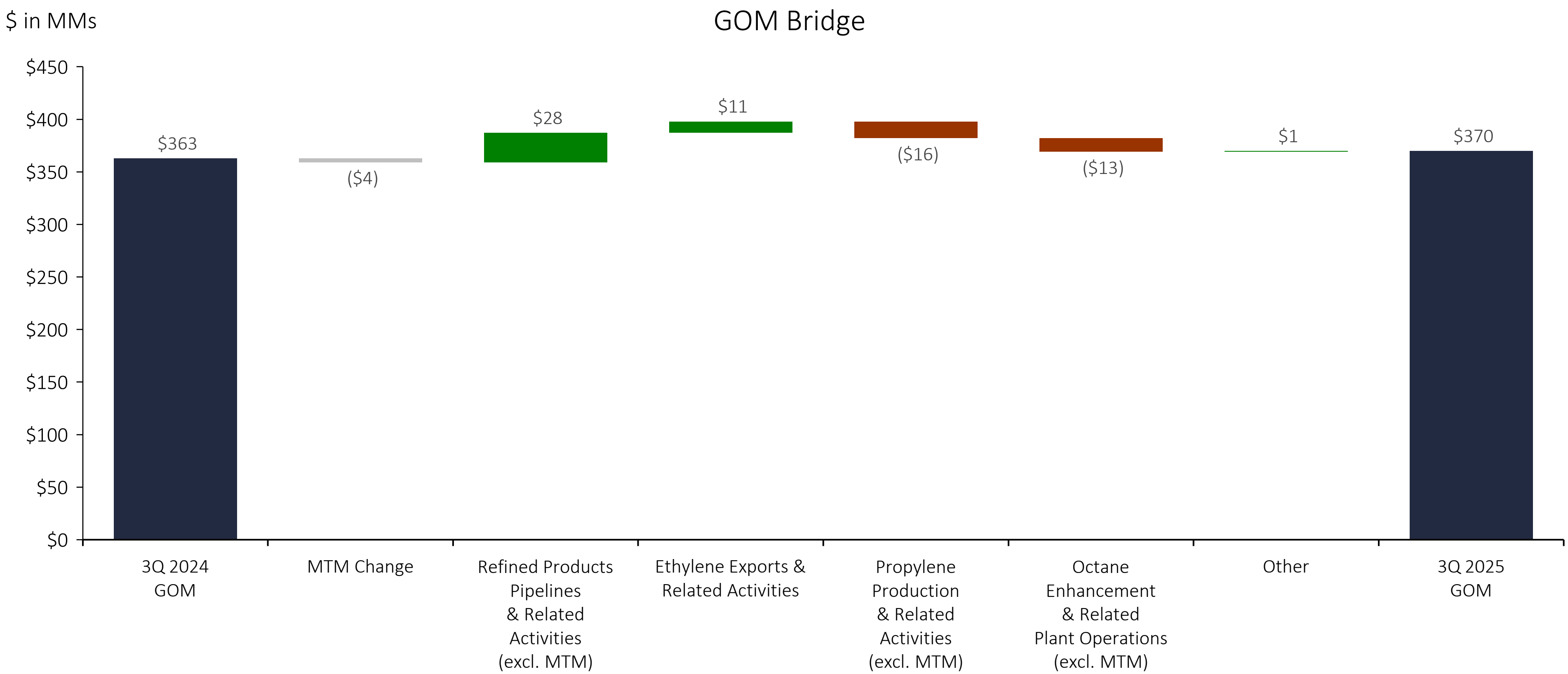


Details:

- MTM activity resulted in a loss of $40MM in 3Q 2025 compared to a gain of $1MM in 3Q 2024
- Permian Basin Gathering Systems (Delaware Basin and Midland Basin) GOM increased primarily due to a combined 937 BBtus/d increase in gathering volumes
- Texas and Louisiana Intrastate Systems (Texas Intrastate and Acadian Gas System) GOM increased primarily due to a combined 645 BBtus/d increase in transportation volumes

Petrochemical & Refined Products Segment

3Q 2025 vs. 3Q 2024



Details:

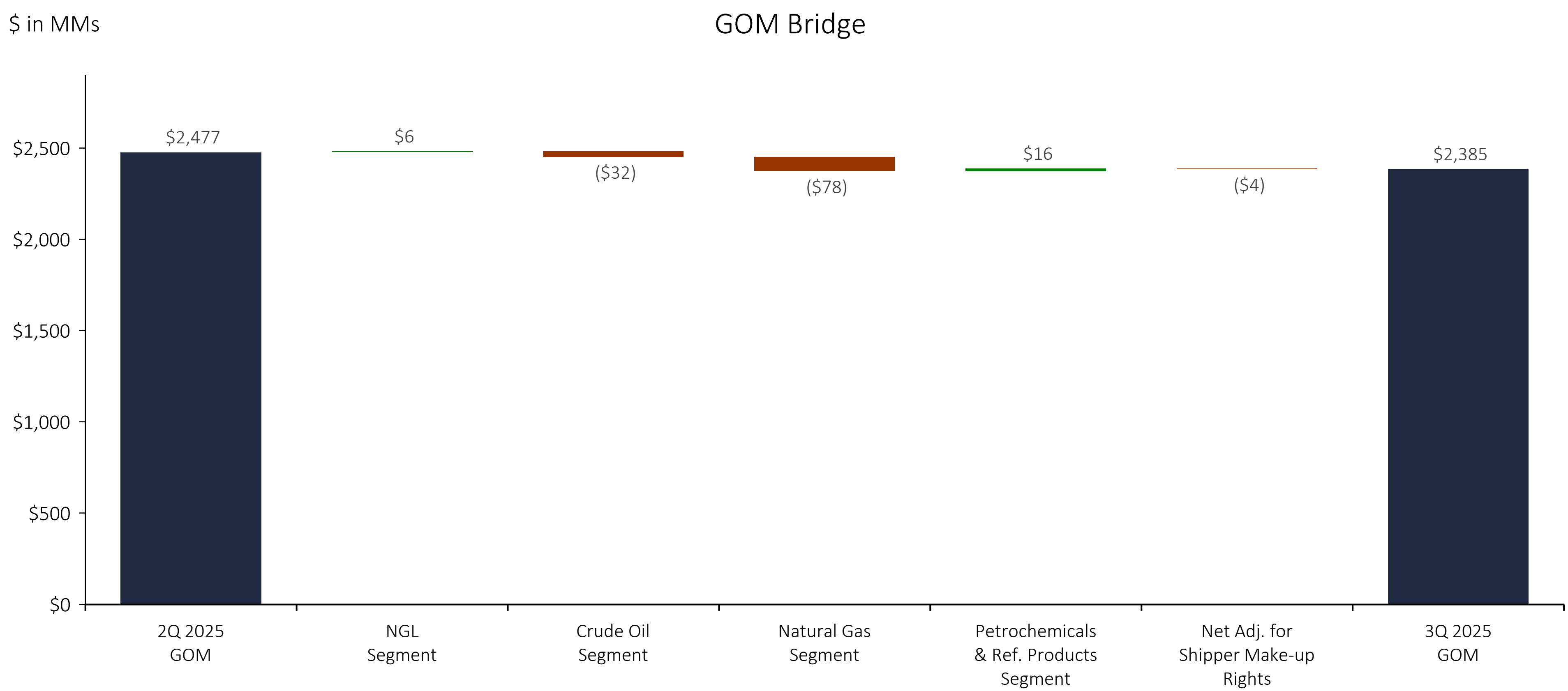
- MTM activity resulted in a loss of $4MM in 3Q 2025 compared to an immaterial loss in 3Q 2024
- Refined products pipelines and related activities (excluding MTM) GOM increased primarily due to the full start-up of the TW Products System and a combined 76 MBPD increase in refined product pipeline transportation volumes
- Ethylene exports and related activities GOM increased primarily due to a 28 MBPD increase in ethylene export volumes
- Propylene production and related activities (excluding MTM) GOM decreased primarily due to higher operating costs
- Octane enhancement and related plant operations (excluding MTM) GOM decreased primarily due to lower average sales margins

Segment Gross Operating Margin Variance
3Q 2025 vs. 2Q 2025

Enterprise Products Partners L.P.

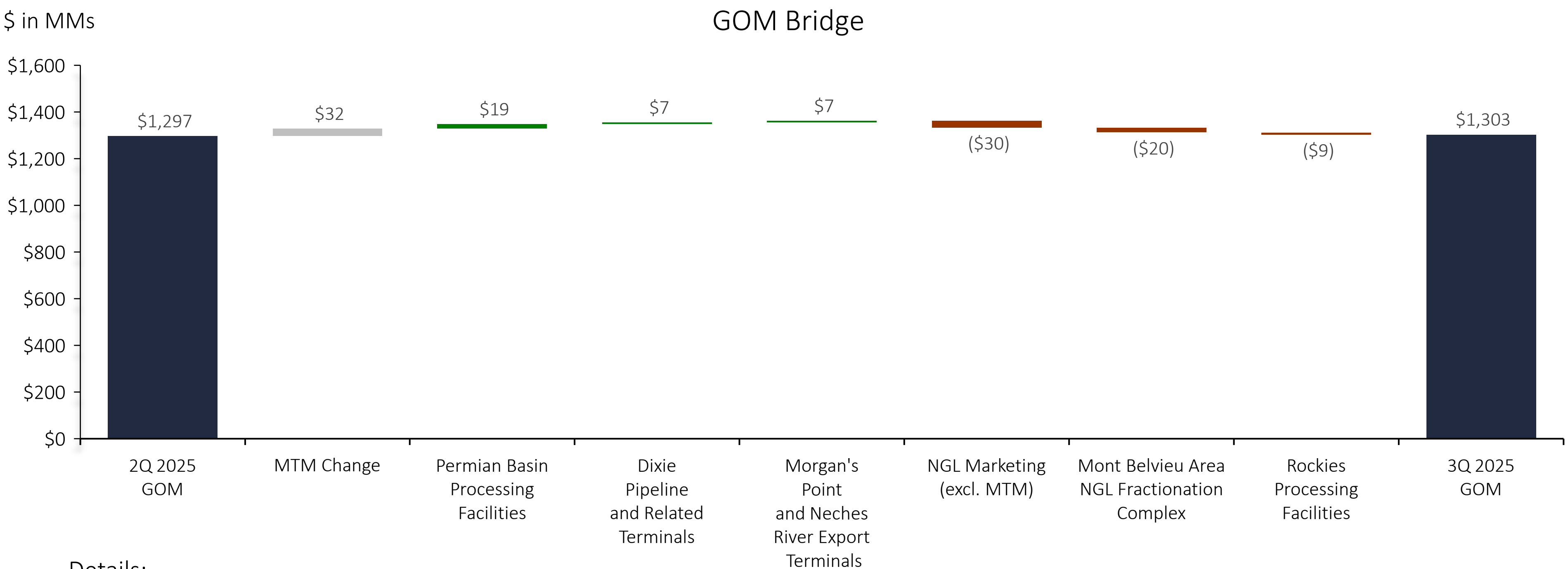
Total GOM Bridge by Segment

3Q 2025 vs. 2Q 2025



The following slides summarize the primary drivers for changes in gross operating margin for each segment between 3Q 2025 and 2Q 2025. Total gross operating margin is a Non-GAAP measure. For a reconciliation of these amounts to their nearest GAAP counterparts, see "Non-GAAP Financial Measures" on our website

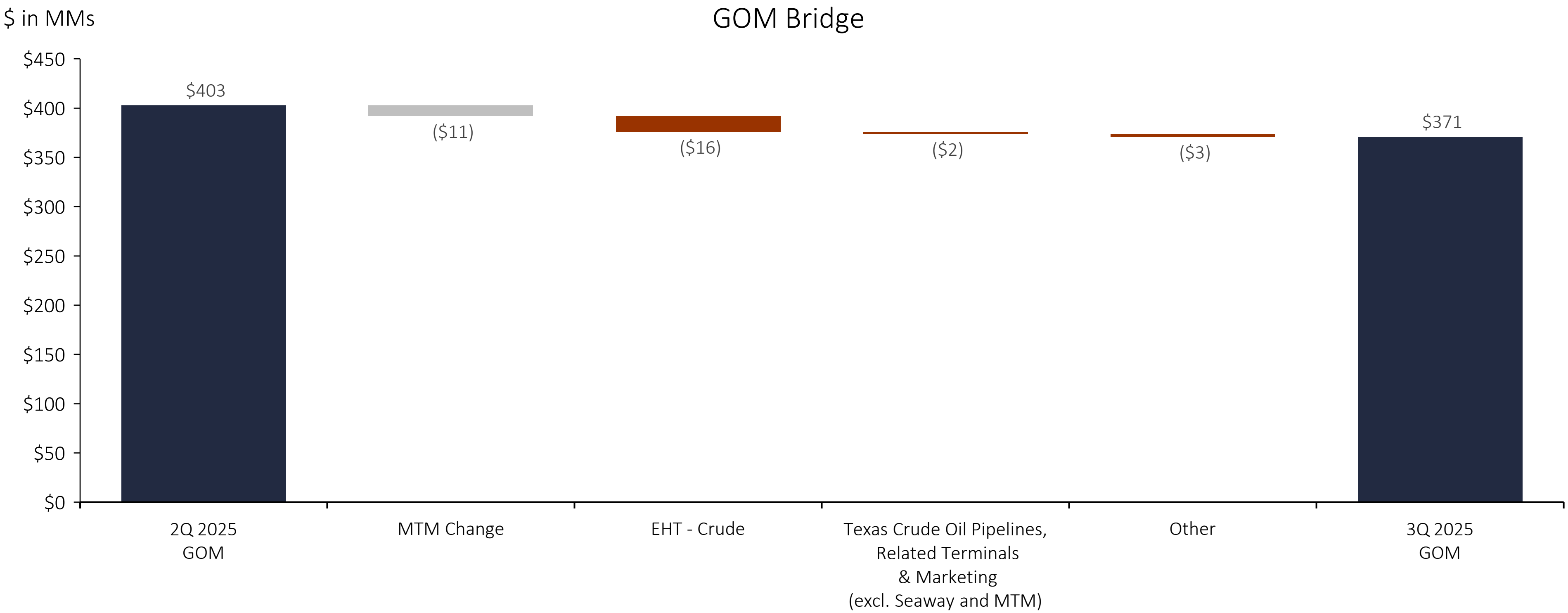
NGL Segment
3Q 2025 vs. 2Q 2025



Details:

- MTM activity resulted in a gain of $16MM in 3Q 2025 compared to a loss of $16MM in 2Q 2025
- Permian Basin processing facilities (Delaware Basin and Midland Basin) GOM increased primarily due to higher average processing margins, including the impact of hedging, and a combined 219 MMcf/d increase processing volumes. In July 2025, we began service at the Orion plant in the Midland Basin and the Mentone West 1 plant in the Delaware Basin
- Dixie Pipeline and related terminals GOM increased primarily due to a 21 MBPD increase in transportation volumes and higher other fee revenues
- Morgan's Point and Neches River Terminals GOM increased primarily due to a combined 36 MBPD increase in ethane export volumes, partially offset by higher operating costs. In July 2025, we began initial service at the Neches River export facility
- NGL marketing activities (excluding MTM) GOM decreased primarily due to lower average sales margins
- Mont Belvieu area NGL Fractionation Complex GOM decreased primarily due to higher operating costs, a 40 MBPD decrease in fractionation volumes, and lower ancillary services revenues stemming from plant maintenance and fractionator turnarounds
- Rockies processing facilities (Pioneer, Meeker and Chaco) GOM decreased primarily due to lower average processing margins, including the impact of hedging

Crude Oil Segment
3Q 2025 vs. 2Q 2025

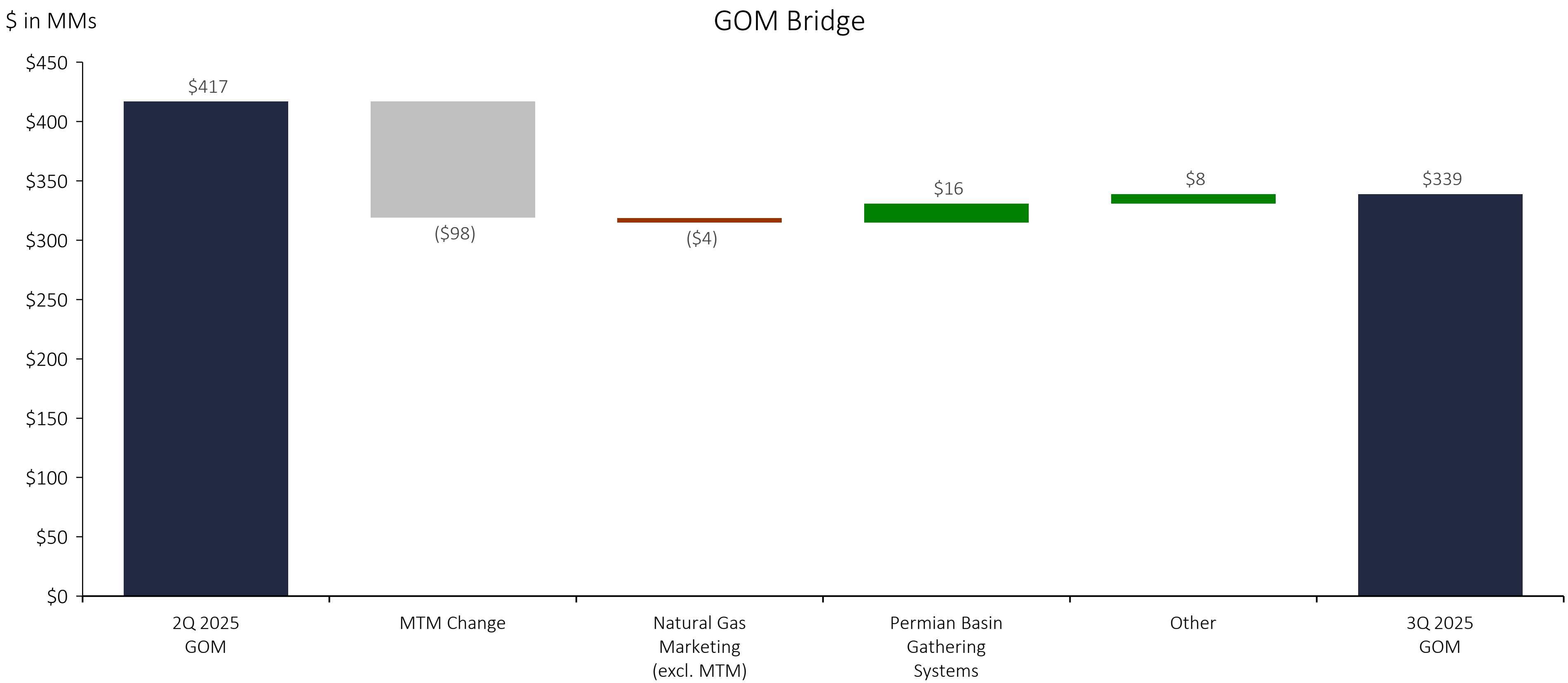


Details:

- MTM activity resulted in a loss of $6MM in 3Q 2025 compared to a gain of $5MM in 2Q 2025
- EHT GOM decreased primarily due to higher operating costs
- Texas crude oil pipelines, related terminals and marketing activities (excluding Seaway and MTM) GOM decreased primarily due to lower crude oil transportation revenues and higher operating costs, partially offset by higher other revenues

Natural Gas Segment

3Q 2025 vs. 2Q 2025



Details:

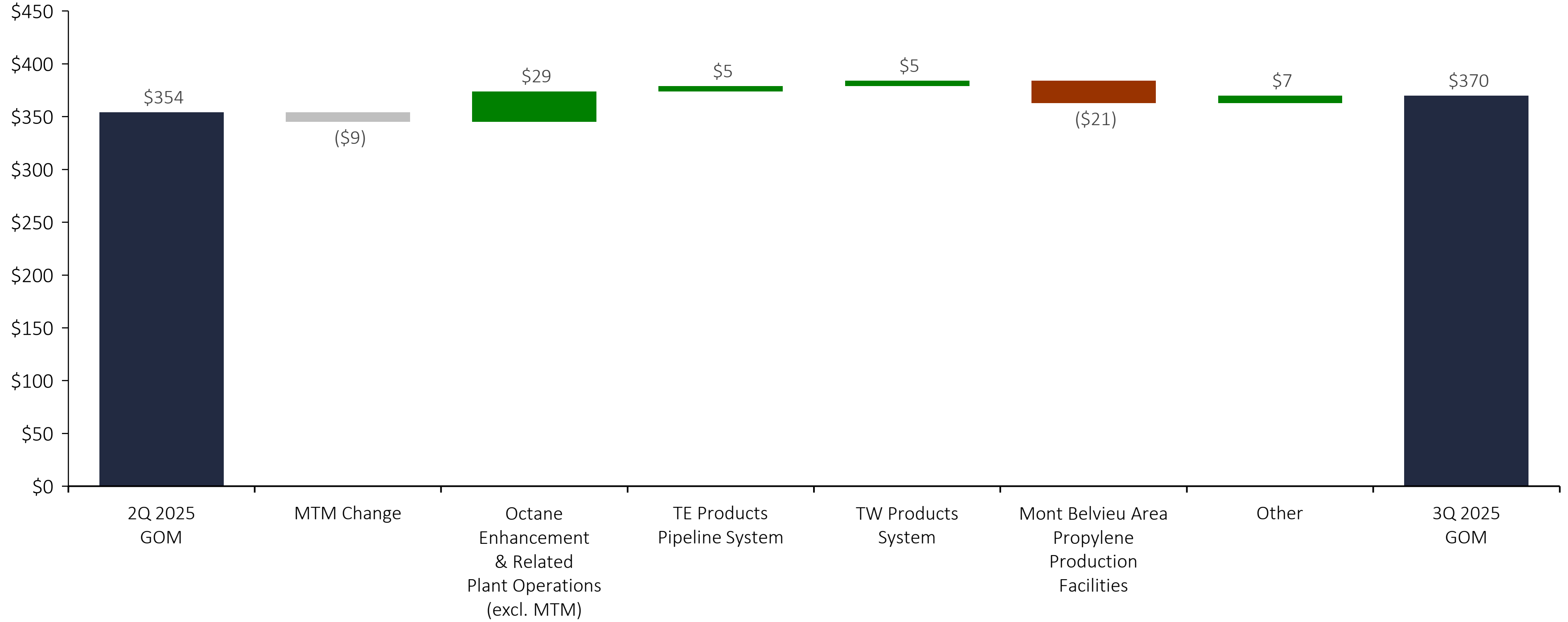
- MTM activity resulted in a loss of $40MM in 3Q 2025 compared to a gain of $58MM in 2Q 2025
- Natural gas marketing activities (excluding MTM) GOM decreased primarily due to lower average sales margins, partially offset by higher sales volumes
- Permian Basin Gathering Systems (Delaware Basin and Midland Basin) GOM increased primarily due to a combined 293 BBtus/d increase in gathering volumes and higher other fee revenues

Petrochemical & Ref. Products Segment

3Q 2025 vs. 2Q 2025

$ in MMs

GOM Bridge



Details:

- MTM activity resulted in a loss of $4MM in 3Q 2025 compared to a gain of $5MM in 2Q 2025
- Octane enhancement and related plant operations (excluding MTM) GOM increased primarily due to higher average sales margins
- TE Products Pipeline System GOM increased primarily due to a 65 MBPD increase in refined products transportation volumes, partially offset by higher operating costs
- TW Products System GOM increased primarily due higher sales volumes and higher average sales margins
- Mont Belvieu area propylene production facilities GOM decreased primarily due to lower results from our PDH 2 facility, which experienced planned downtime during the third quarter of 2025.

Indicative Attribution of GOM

- Slides 10 and 11 attribute gross operating margin (GOM) among various applicable business activities. Most activities fit easily into one category; however, the classification of certain activities involves an element of subjectivity. GOM classifications represent what we currently believe is the most logical fit of our business activities into each category, based on the underlying fee or pricing characteristics applicable thereto.
- These classifications may be subject to change in the event that management's estimates or assumptions underlying such classifications are revised or updated. In addition, our attribution of GOM into the categories may not be comparable to similar classifications by other companies because such companies may use different estimates and assumptions than we do in assigning such categories or otherwise calculating such attributions.
- Categories of GOM:
  - Fee-based: Pipeline transportation fees and tariffs, NGL and propylene fractionation fees, storage capacity reservation and throughput fees, export terminal fees, marine and trucking fees, fee-based natural gas processing arrangements, isomerization and dehydrogenation fees, demand and deficiency fees, and similar activities that are predominantly fee-oriented.
  - Commodity-based: percentage-of-liquids and percentage-of-proceeds natural gas processing arrangements, certain condensate sales, gathering revenues on our San Juan natural gas pipeline system, and similar activities that have commodity price exposure
  - Differential-based: certain business activities where earnings are generated based on price differentials or spreads between locations, time periods and products in excess of any related fees, tariffs and other expenses.

Definitions

Net Cash Flow Provided by Operating Activities (“**CFFO**”) represents the GAAP financial measure “Net cash flow provided by operating activities”.

Operational DCF is Distributable Cash Flow (“DCF”) excluding the impact of proceeds from asset sales and other matters and monetization of interest rate derivative instruments.

Operational DCF per Unit represents DCF excluding proceeds from asset sales and other matters and monetization of interest rate derivative instruments for a period divided by the average number of fully diluted common units outstanding for that period.

Adjusted CFFO is CFFO before the net effect of changes in operating accounts (working capital).

Adjusted CFFO per Unit is Adjusted CFFO divided by the average number of fully diluted common units outstanding for that period.

Adjusted CFFO Payout Ratio is calculated as trailing 12 months distributions + distribution equivalent rights + buybacks divided by the trailing 12 months Adjusted CFFO.

Adjusted EBITDA is earnings before interest, taxes, depreciation and amortization (“**EBITDA**”) adjusted for cash distributions received from unconsolidated affiliates, equity in income of unconsolidated affiliates, non-cash impairment charges, changes in the fair market value of commodity derivative instruments and net gains/losses attributable to asset sales and related matters. Additionally, amortization of major maintenance costs for reaction-based plants is excluded as this is a component of Adjusted EBITDA.

Leverage Ratio is defined as net debt adjusted for equity credit in junior subordinated notes (hybrids) divided by Adjusted EBITDA.