



2025 Annual Business Update

February 2025



Elba LNG Storage Tanks

Forward-Looking Statements / Non-GAAP Financial Measures / Industry & Market Data

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GAAP – Unless otherwise stated, all historical and estimated future financial information included in this presentation has been prepared in accordance with generally accepted accounting principles in the United States (“GAAP”).

Non-GAAP – In addition to using financial measures prescribed by GAAP, we use non-generally accepted accounting principles (“non-GAAP”) financial measures in this presentation. Descriptions of our non-GAAP financial measures, and reconciliations to comparable GAAP measures, can be found in this presentation under “Non-GAAP Financial Measures and Reconciliations”. These non-GAAP financial measures do not have any standardized meaning under GAAP and may not be comparable to similarly titled measures presented by other issuers. As such, they should not be considered as alternatives to GAAP financial measures.

Industry & Market Data – Certain data included in this presentation has been derived from a variety of sources, including independent industry publications, government publications and other published independent sources. Although we believe that such third-party sources are reliable, we have not independently verified, and take no responsibility for, the accuracy or completeness of such data.

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A wide-angle photograph of an industrial compressor station at dusk. The scene features large white pipes, valves, and a tall light pole with three illuminated lamps. In the background, there are mountains under a cloudy sky with a hint of sunset colors. The foreground is a flat, dusty area.

INTRODUCTION

Delivering Energy, Improving Lives

EPNG Mojave Compressor Station

Delivering Energy. Improving Lives.



- ~66,000 miles of natural gas pipelines moving ~40% of U.S. natural gas production
- Interest in over 700 bcf of working storage capacity, ~15% of U.S. capacity

Largest U.S. Independent Refined Products
Transporter & Terminal Operator

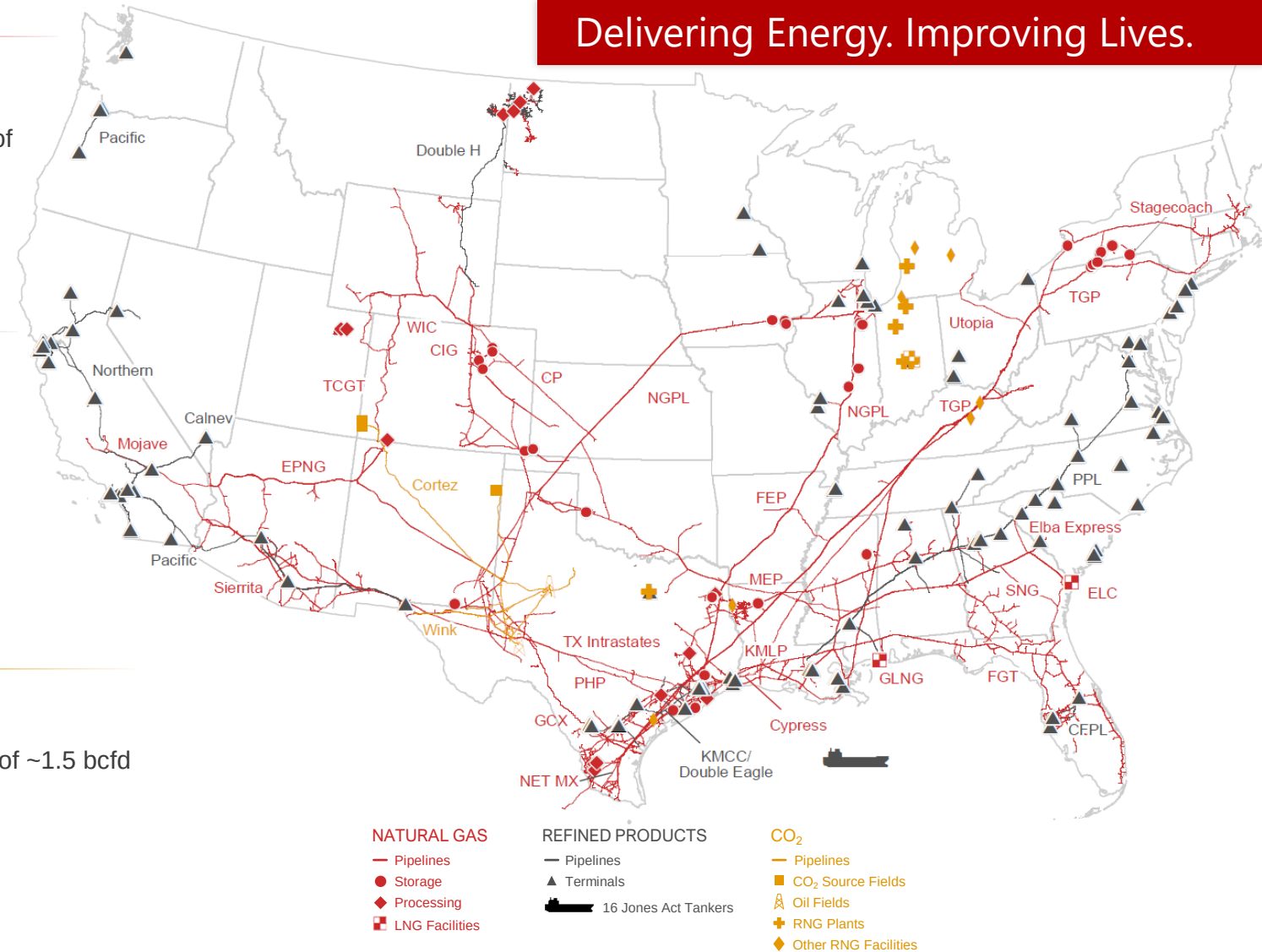
- Transport ~1.7 mmbbl of refined product volumes
- ~9,500 miles of refined products & crude pipelines
- 139 liquids & bulk terminals; 16 Jones Act vessels
- 135 mmbbl of total liquids storage capacity

One of the Largest CO₂ Transporters in the U.S.

- ~1,500 miles of CO₂ pipelines with transport capacity of ~1.5 bcfd
- Produce and transport CO₂ for enhanced oil recovery

Growing Energy Transition Portfolio

- RNG production capacity of 6.4 bcf^(b)



Note: Volumes per 2025 budget. Business mix based on 2025 budgeted Total Adjusted Segment EBDA, which is a non-GAAP financial measure. See Non-GAAP Financial Measures & Reconciliations.

a) Refined Products includes 13% from our Products Segment and 13% from our Terminals Segment.

b) Annual capacity at KMI share expected Q1 2025. Autumn Hills RNG facility in late stages of commissioning.

Driving Long-Term Shareholder Value



Natural Gas Focus

~**2/3** of cash flows come from midstream natural gas^(a)

Transport ~**40%** of U.S. natural gas production



Balance Sheet Strength

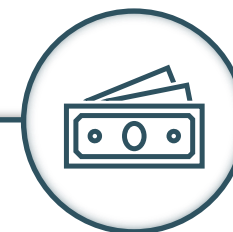
~**3.8x** YE 2025B Net Debt / Adjusted EBITDA

BBB investment grade balance sheet



High-Returning Growth Projects

~**\$8.1 billion** of committed projects at **<6x** EBITDA build multiple



Predictable & Growing Cash Flows

~**69%** of cash flows are take-or-pay or hedged^(a)

+10% Adj. EPS and **+4%** Adj. EBITDA growth budgeted in 2025



Returns to Shareholders

Increasing dividend for **8th** straight year

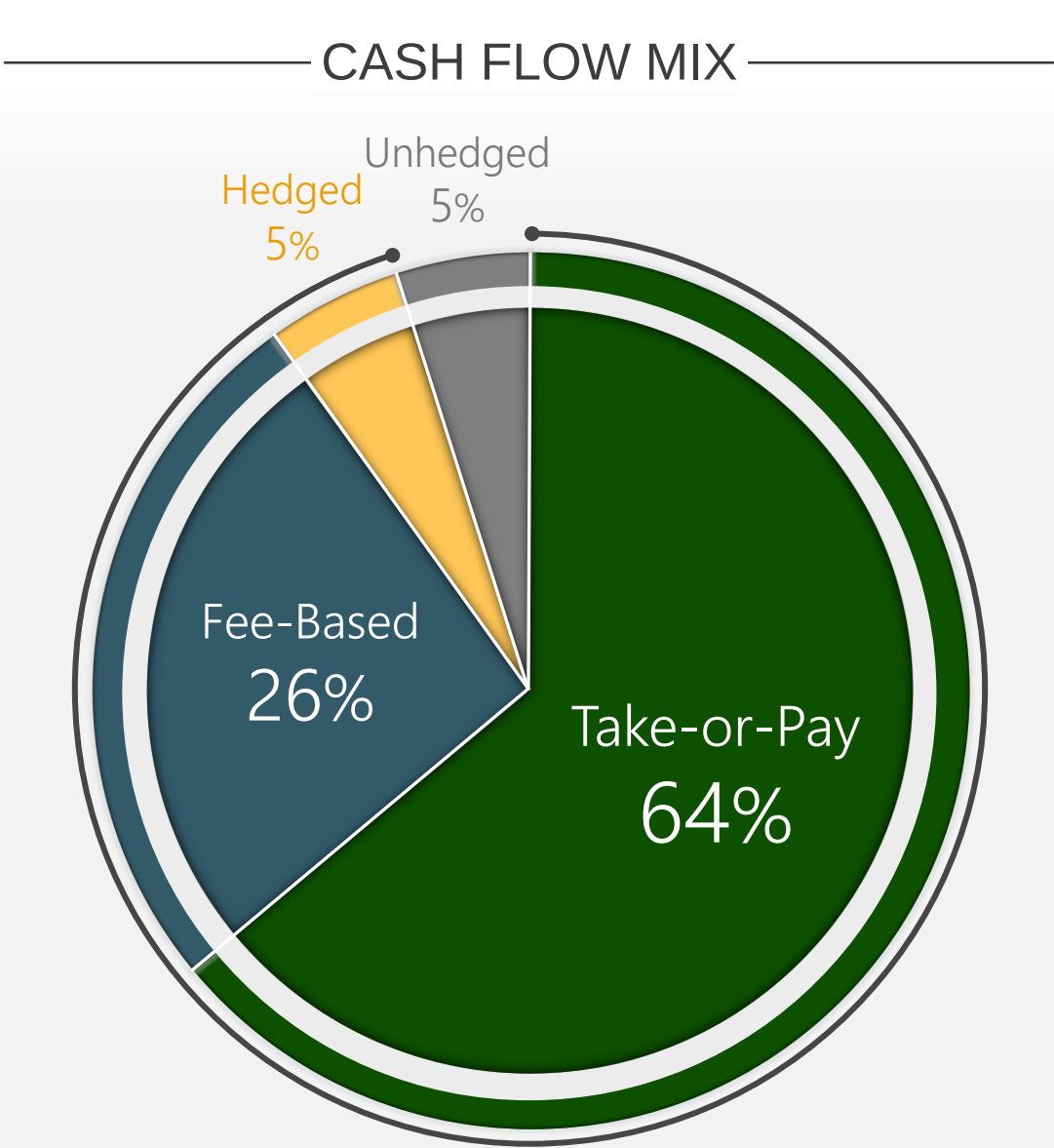
~**33%** of market cap value returned to shareholders since 2016^(b)

Note: Total Adjusted Segment EBITDA, Adjusted EPS, Adjusted EBITDA, Net Debt, and EBITDA build multiple (calculated based on Project EBITDA) are non-GAAP financial measures. See Non-GAAP Financial Measures & Reconciliations.

a) Based on 2025 budgeted Total Adjusted Segment EBITDA.

b) Market capitalization as of 12/31/2024. Returns via dividends paid and share repurchases.

Highly Contracted, Predictable Cash Flows

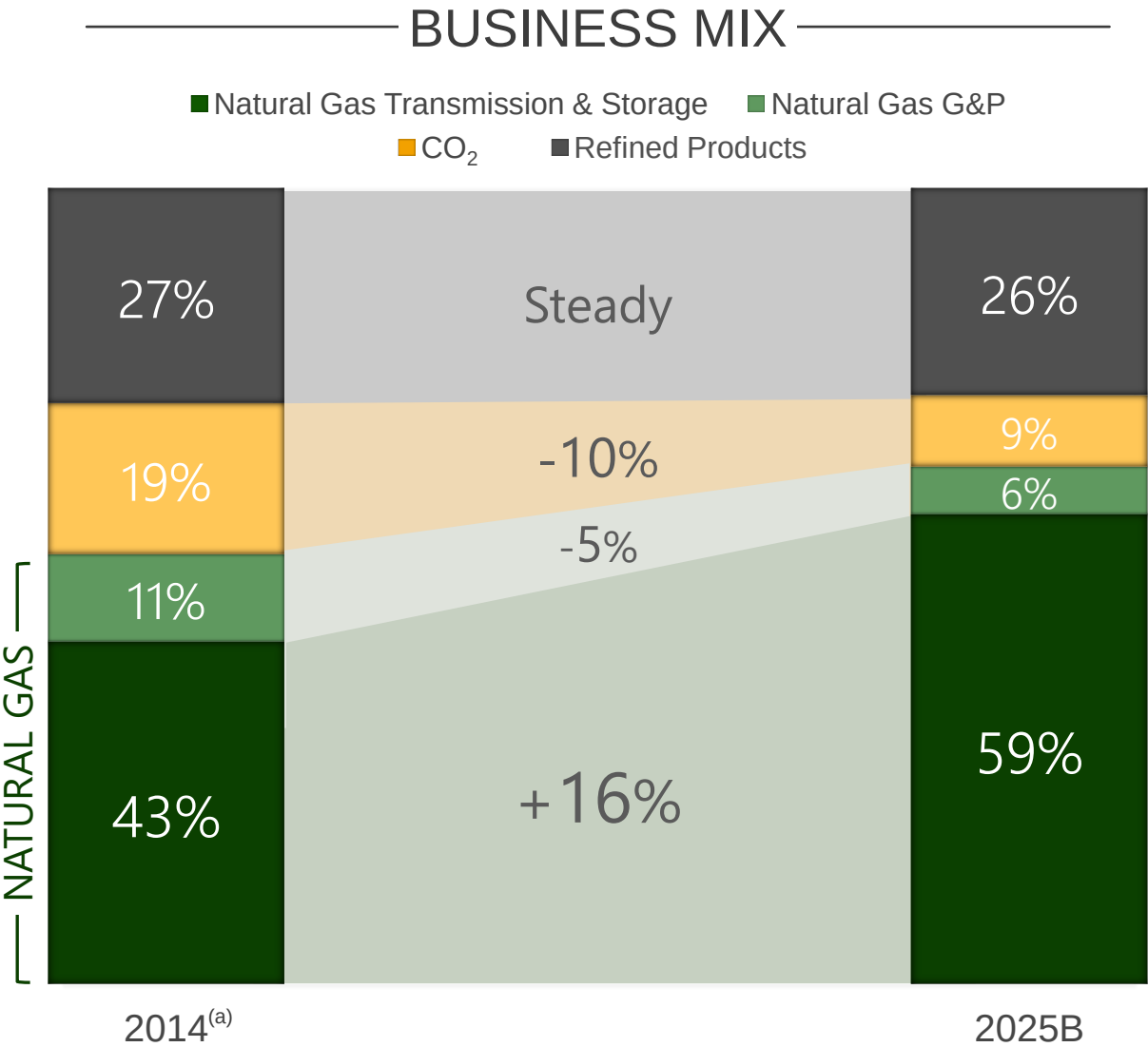


95% Take-or-Pay, Fee-Based, or Hedged Cash Flows

- 64% Take-or-Pay**
Entitled to payment regardless of throughput
Reservation fee for capacity
- 26% Fee-Based**
Fixed fee collected regardless of commodity price
Volumetric based revenues
Over 40% highly stable refined product cash flows
- 5% Hedged**
Disciplined approach to managing price volatility
Substantially hedged near-term price exposure
- 5% Unhedged**
Commodity price based

Note: Cash flow mix based on 2025 budgeted Total Adjusted Segment EBDA, which is a non-GAAP financial measure. See Non-GAAP Financial Measures & Reconciliations.

Strong Business Mix Continues to Improve



CHANGES SINCE 2014

Natural Gas Transmission & Storage increased +16%

Natural Gas G&P decreased -5%

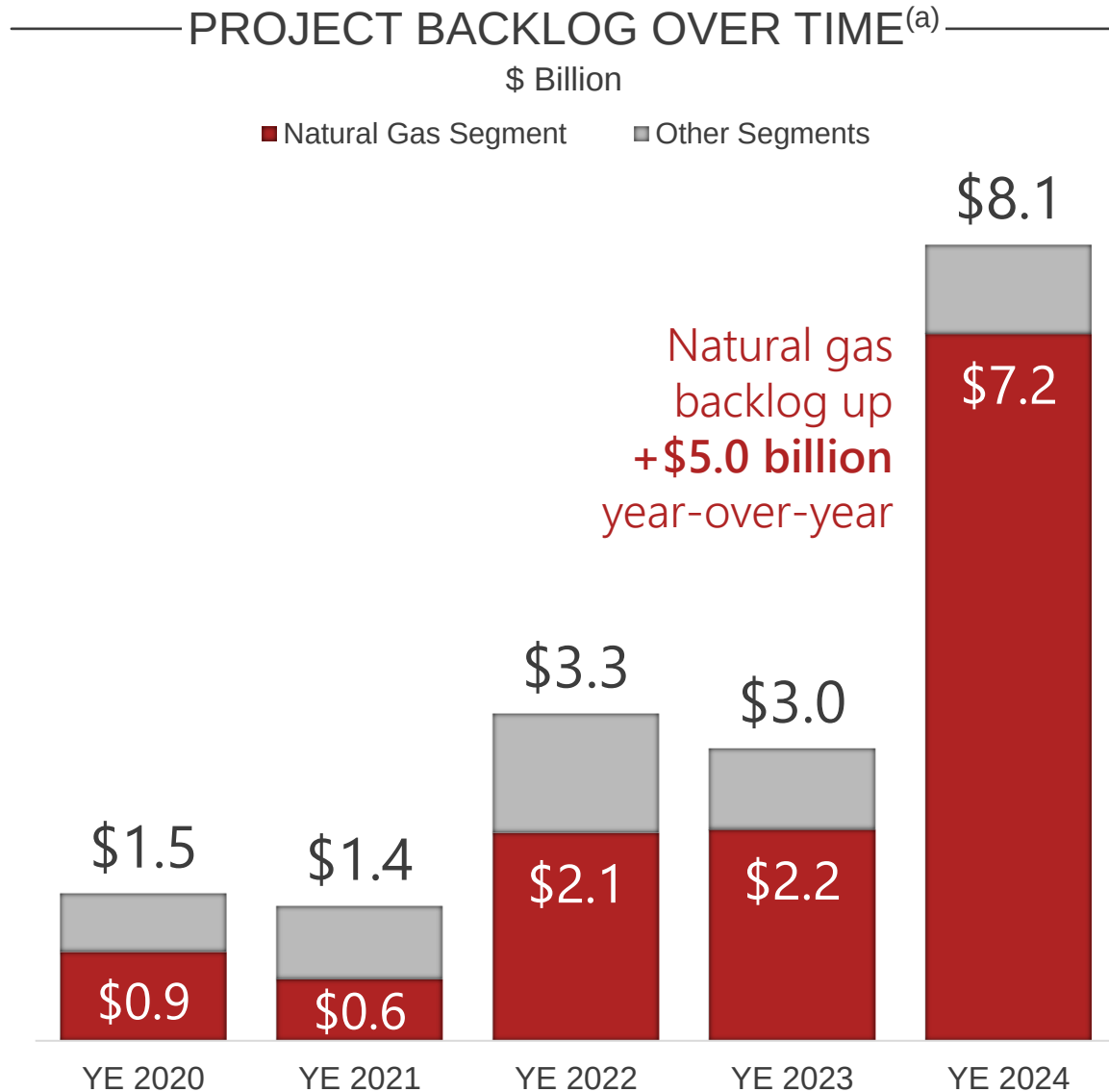
CO₂ reduced -10%

Steady Refined Products

Note: Business mix based on Total Adjusted Segment EBDA, which is a non-GAAP financial measure. See Non-GAAP Financial Measures & Reconciliations. Refined Products includes contributions from Products Pipelines and Terminals segments, as well as KM Canada in 2014. 2014 amounts are adjusted to reflect categorization of basis difference amortization (amortization of excess cost of equity investments) consistent with 2025 Segment EBDA accounting change.

a) First year of combined KMI.

Growing Our Project Backlog While Maintaining Discipline on Returns



Expansive footprint creates opportunities for differentiated returns

Every project must meet **disciplined return criteria** before being added to the backlog

Utilize a **consistent return framework**

Adjust return threshold based on each project's individual risk profile; in all cases, returns are **well in excess of our cost of capital**

Current **~\$8.1 billion** project backlog being constructed at **<6x EBITDA build multiple**

Note: EBITDA build multiple reflects KMI share of estimated capital divided by estimated Project EBITDA (a non-GAAP financial measure). See Non-GAAP Financial Measures & Reconciliations.

a) Project backlog figures are net of projects placed in service.

\$8.1bn Committed Growth Capital Project Backlog as of 12/31/2024

~25% of Backlog Capital in Service During 2025

\$ million	TOTAL	
Natural Gas (excluding G&P)	\$6,724	Mostly for LNG, Power, and LDC demand
Other	277	Primarily renewable feedstocks & RNG projects
Subtotal	\$7,001	Contracted, stable cash flows, minimal direct commodity exposure
EBITDA Build Multiple	~5.8x	
Gathering & Processing	511	Mostly natural gas, volume-based projects
EOR	597	Commodity price & volume-based cash flows
Total Backlog	\$8,109	

Expect annual growth capital spend of around \$2.5 billion

Natural gas investments ~90% of backlog

Note: The EBITDA build multiple reflects KMI share of estimated capital divided by estimated Project EBITDA (a non-GAAP financial measure). See Non-GAAP Financial Measures & Reconciliations. Figures may not sum due to rounding. Other includes projects in our Products and Terminals segments and ETV group.

Positioned for Sustained Growth

	2024 <i>Robust Growth and Shareholder Returns</i>	2025 <i>Strong Fundamentals Driving Continued Growth</i>
 Strong Earnings Growth	+7% Adj. EPS and +5% Adj. EBITDA Year-Over-Year Growth	+10% Adj. EPS and +4% Adj. EBITDA Budgeted Year-Over-Year Growth
 Significant Cash Flow Generation	Generated \$5.6 Billion CFFO and \$3.0 Billion Free Cash Flow	Forecasting \$5.9 Billion CFFO and \$2.8 Billion Free Cash Flow
 Project Development and Execution	Added \$6.3 Billion of Projects to Our Backlog & Placed \$1.2 Billion In Service	Investing \$2.3 Billion in Attractive Growth Projects; Expect to Place \$2.1 billion In Service
 Shareholder Returns	64% Total Shareholder Return; Returned \$2.6 Billion via Dividends	Increasing Dividend 8 th Consecutive Year

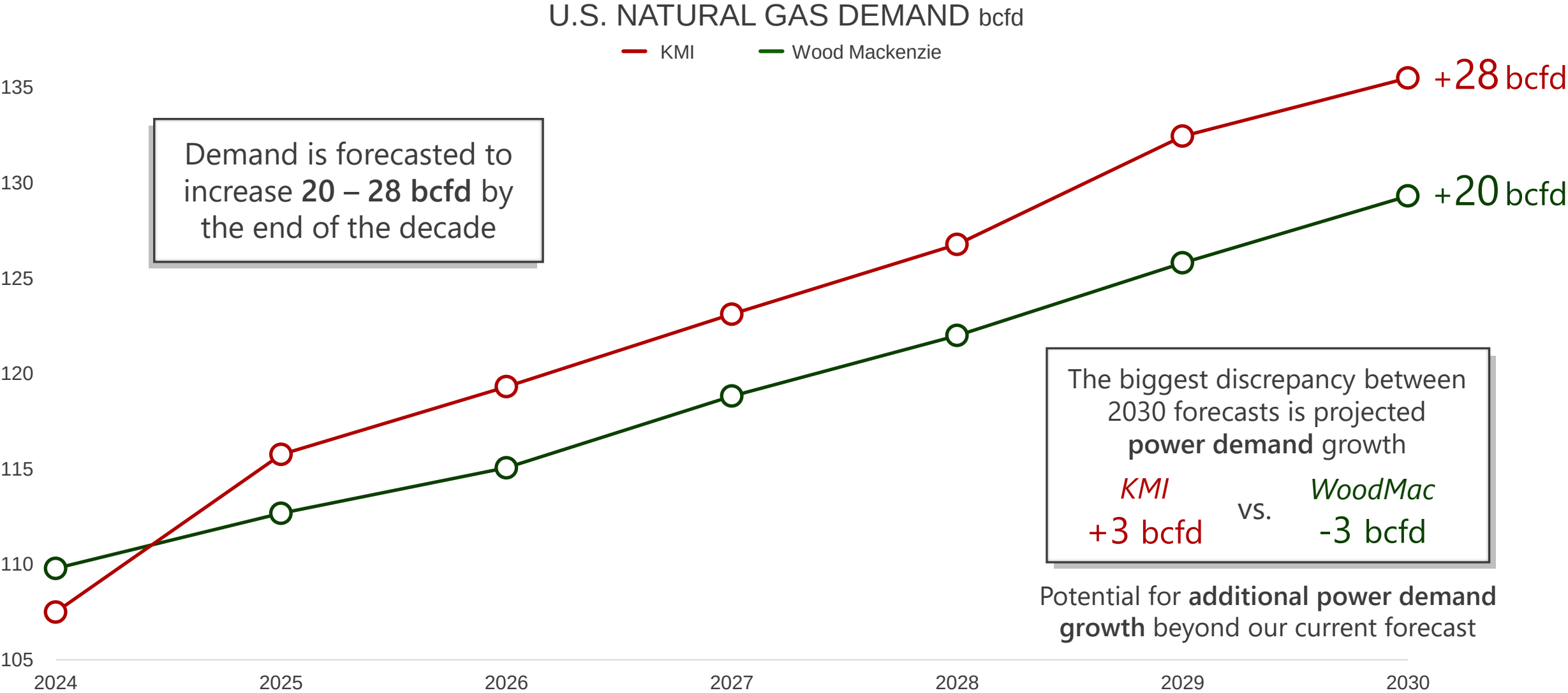


Macro Outlook

Strong Fundamentals Supporting Sustainable Growth

SNG Rose Hill Compressor Station

Demand for U.S. Natural Gas Projected to Grow



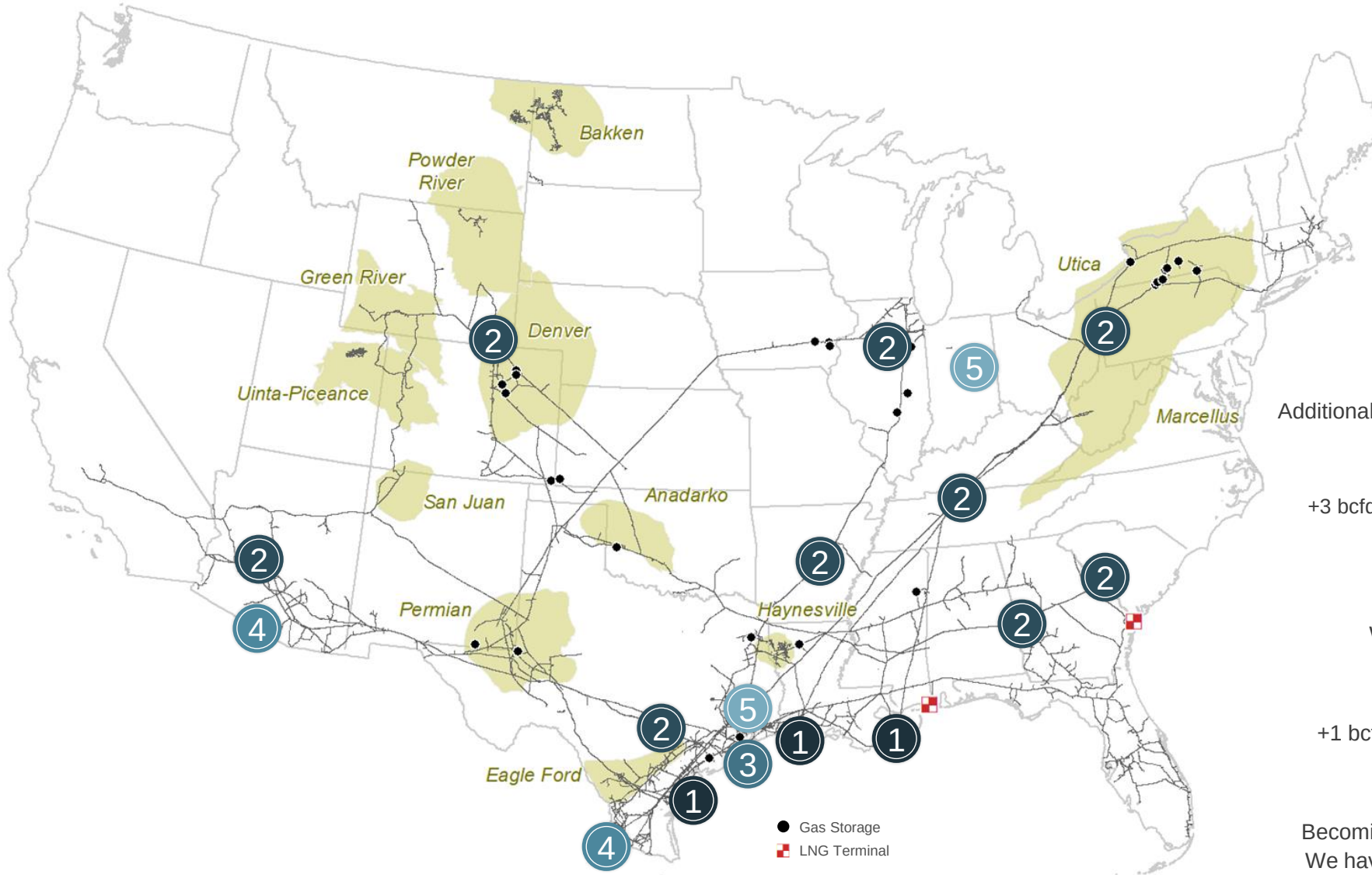
Existing Infrastructure is Highly Utilized; New Investment Will be Needed to Meet Projected Incremental Demand

WoodMac Natural Gas Demand Overview: 2024 – 2030

>95% of Demand Growth is Expected to Occur in Texas & Louisiana, Driven by Exports & Industrial



2024 U.S. Demand
110 bcf/d
Increase in demand by 2030
+20 bcf/d



LNG Feedgas ①

+14 bcf/d of Gulf Coast demand growth
Well positioned to grow our deliveries over time

Power Demand ②

Population and economic growth
Coal retirements/coal-to-gas conversions
Manufacturing re-shoring & data centers
Additional capacity needed to backstop intermittent renewables

Industrial Demand ③

+3 bcf/d of demand growth mainly along the TX & LA Gulf Coast

Mexico Exports ④

+1 bcf/d of export demand growth
We can deliver into Mexico at multiple strategic points

Residential & Commercial ⑤

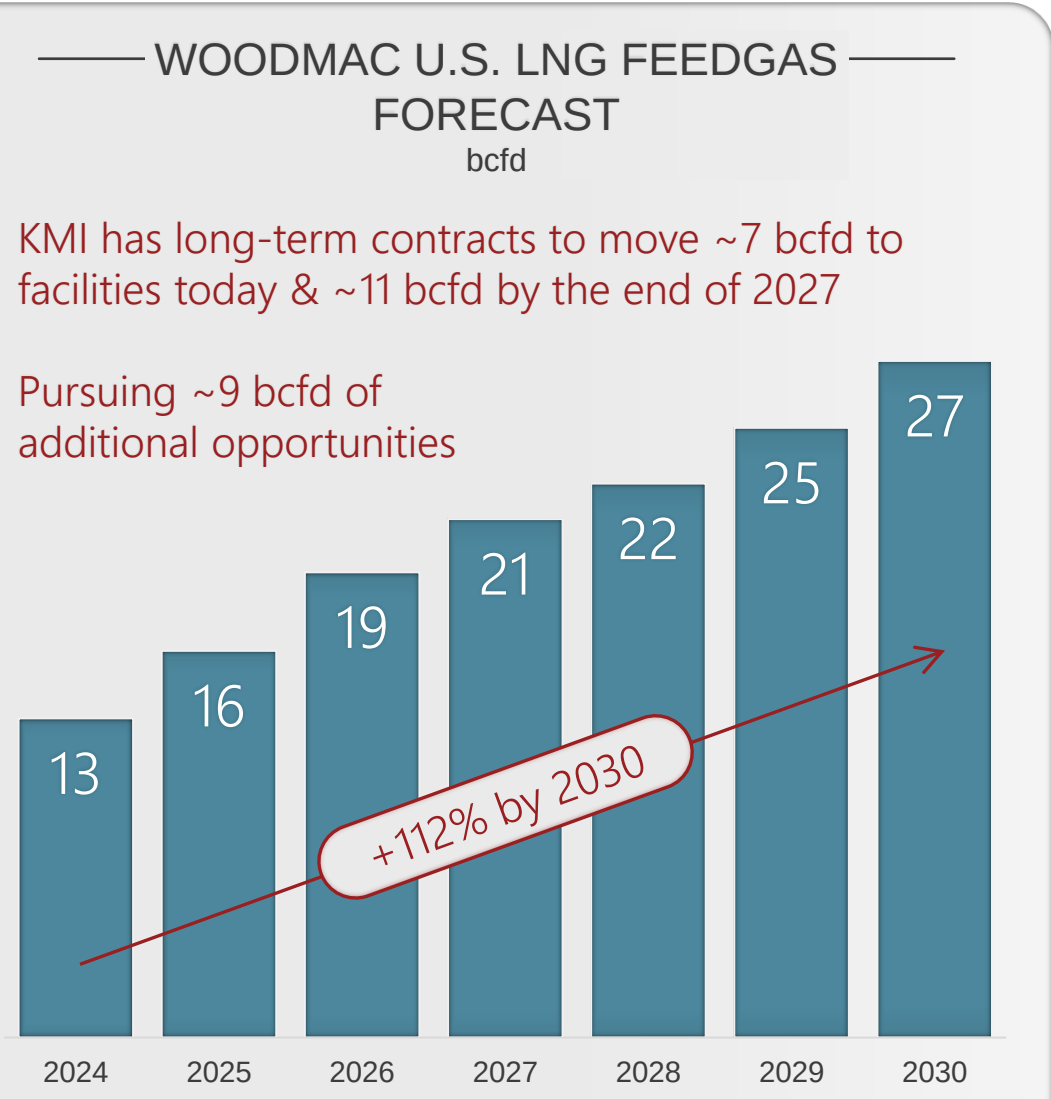
+1 bcf/d of growth, primarily in the Southern U.S. & Midwest

Storage

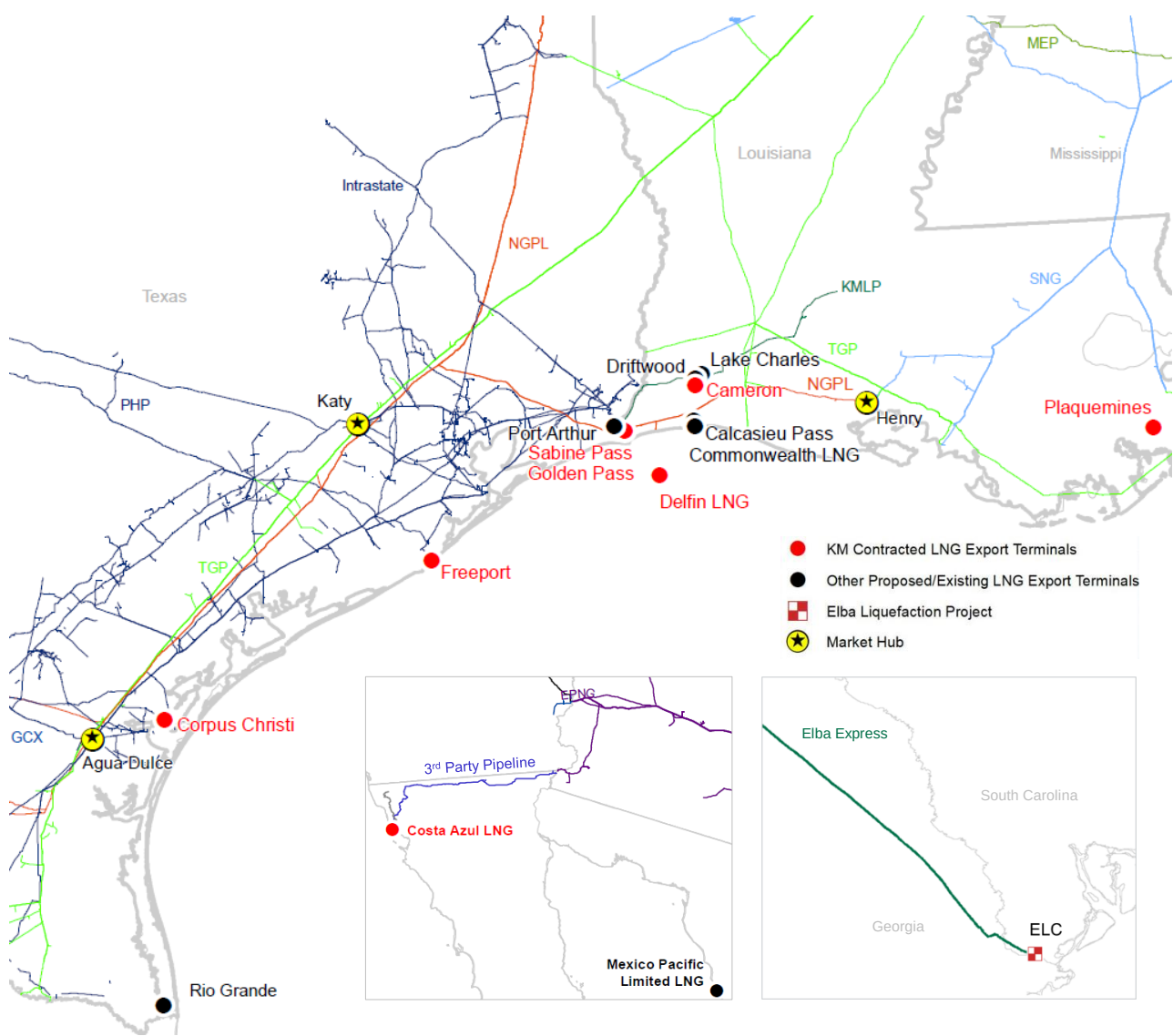
Becoming increasingly important to support variable demand
We have interest in over 700 bcf of working storage capacity

LNG Exports Driving Natural Gas Demand Growth

Growth Primarily Along the Texas & Louisiana Gulf Coast with Great Overlap with Our Assets

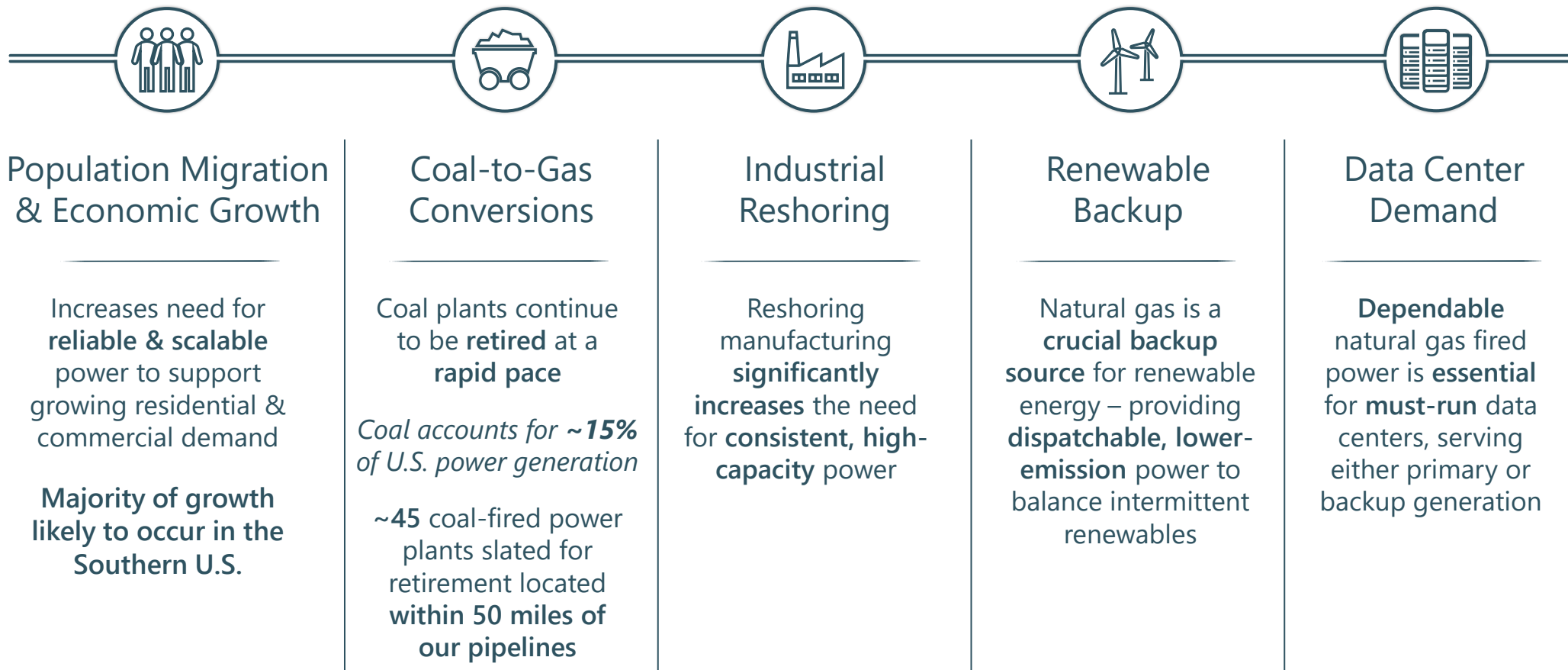


Note: Wood Mackenzie North America Gas 10-Year Investment Horizon Outlook, November 2024. LNG feedgas equals exports plus an assumed 9% increase for plant fuel.



Growing Power Needs Boosting Demand for Natural Gas

INCREASING NATURAL GAS FIRED POWER DEMAND DRIVEN BY



KMI forecasting **3 bcfd** increase in **natural gas fired power demand** by 2030

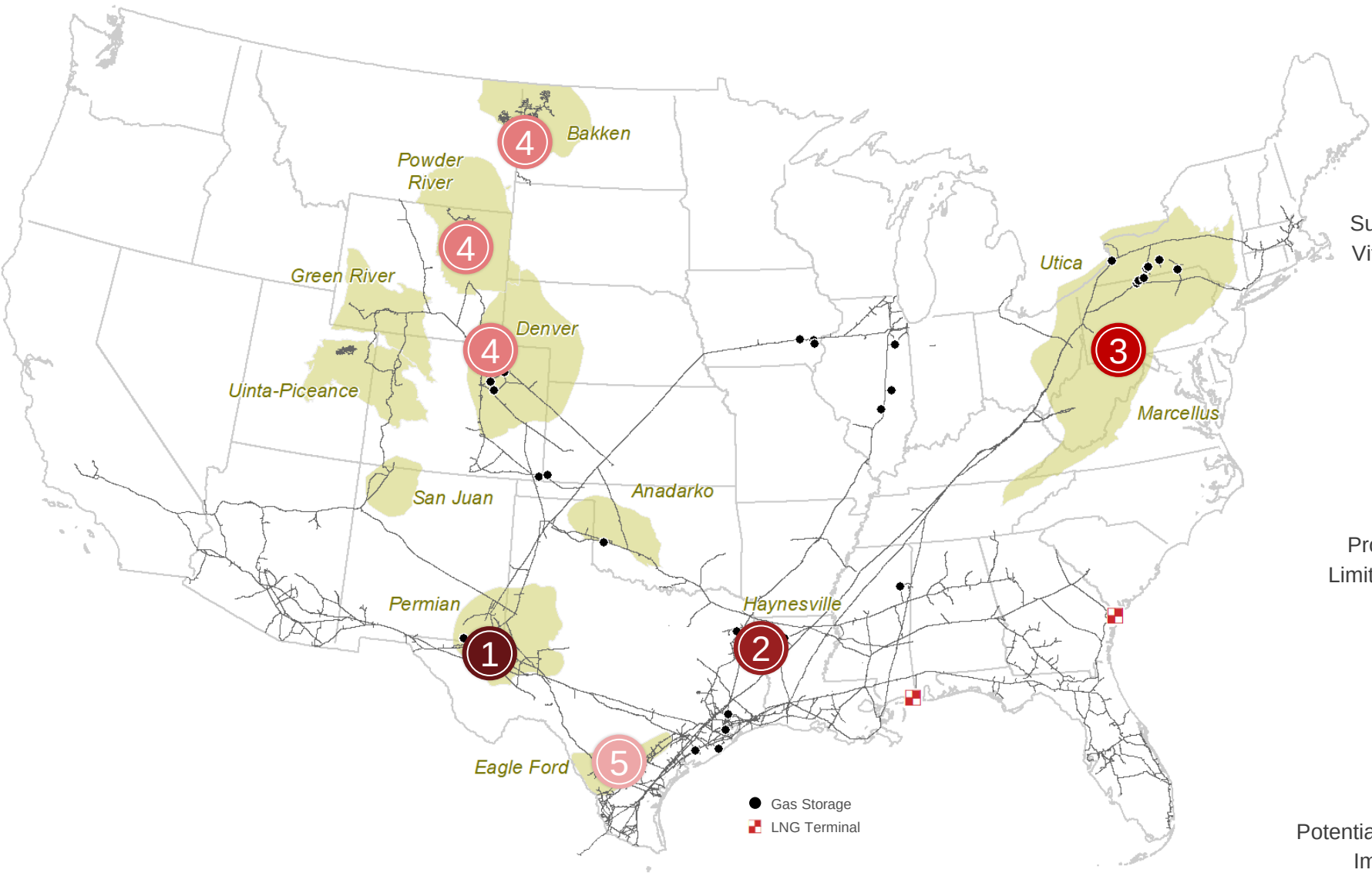
Actively pursuing **well in excess of 5 bcfd** of power opportunities

Rising Power Demand Not Yet Fully Captured in Many Natural Gas Projections

WoodMac Natural Gas Supply Overview: 2024 – 2030



2024 U.S. Production
103 bcf/d
Increase in supply by 2030
+20 bcf/d



Permian +8 bcf/d of associated gas growth **1**
Supply grows as oil production increases & GORs rise
Vital to supplying West Coast, Gulf Coast, and Mexico

Haynesville +6 bcf/d of growth **2**
Abundant, low-cost, low-nitrogen supply
Key to serving Gulf Coast demand markets

Northeast +6 bcf/d from the Marcellus/Utica **3**
Production constrained despite ample, low-cost supply
Limited infrastructure opportunity despite strong demand

Rockies +1 bcf/d Bakken/DJ/Powder River **4**
Serves Rockies and West Coast demand

Eagle Ford +0.3 bcf/d of growth **5**
Potential upside to forecast; critical supply link to Gulf Coast
Important source of low-nitrogen gas for LNG facilities

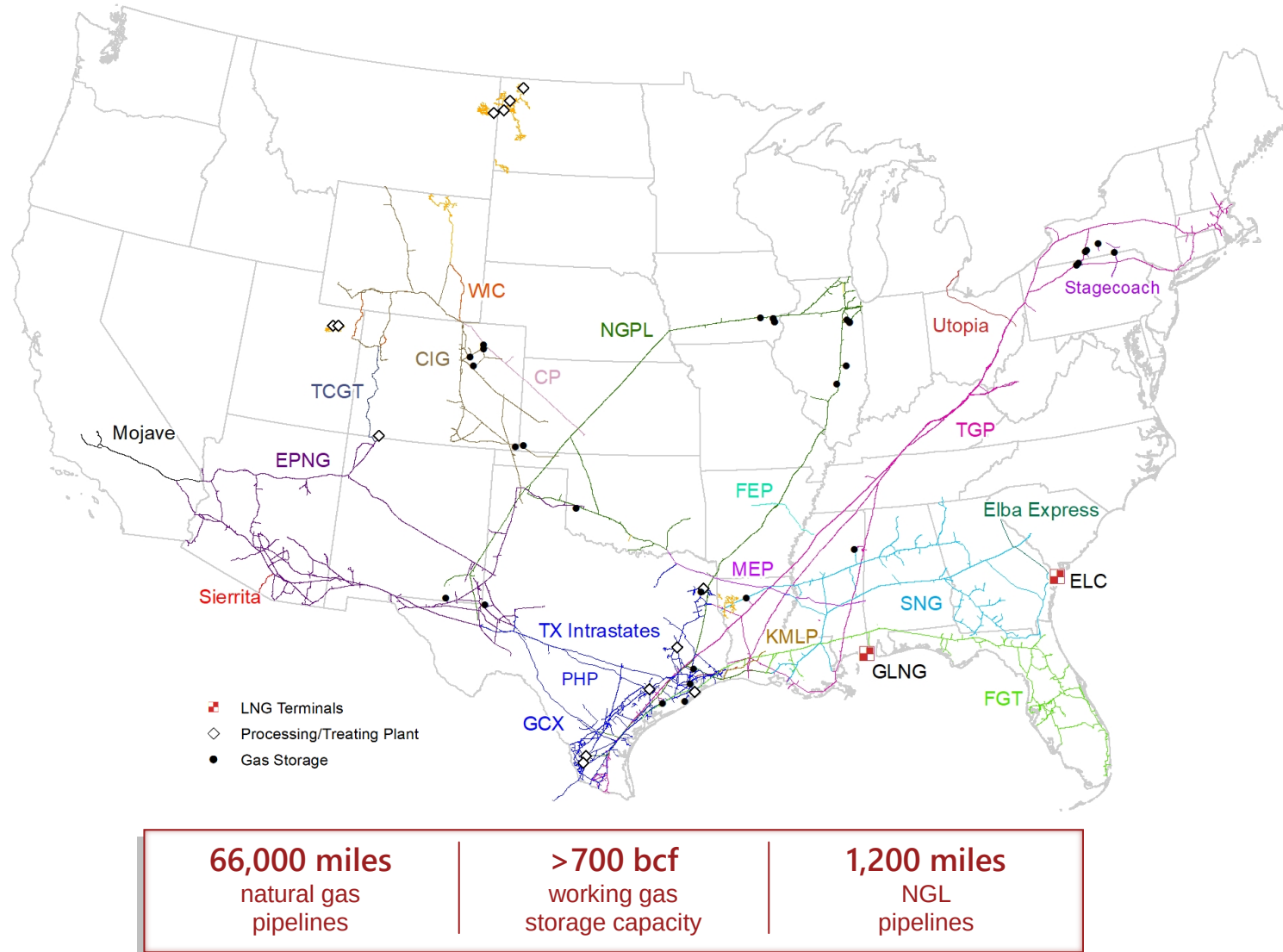


BUSINESS OUTLOOK

Operational Excellence & Execution

Natural Gas Segment Overview

Connecting Key Natural Gas Resources with Major Demand Centers



Largest Natural Gas Transmission Network in the U.S.

KMI Transports ~40% of U.S. Natural Gas Production

~45%
of all feedgas
deliveries to U.S.
LNG facilities

~50%
of all U.S. natural
gas exports to
Mexico

~45%
of all direct natural
gas deliveries to
Southern U.S.
power plants^(a)
*Areas with high
forecasted natural gas
fired power demand
growth*

Irreplaceable Assets

Long-Lived Infrastructure

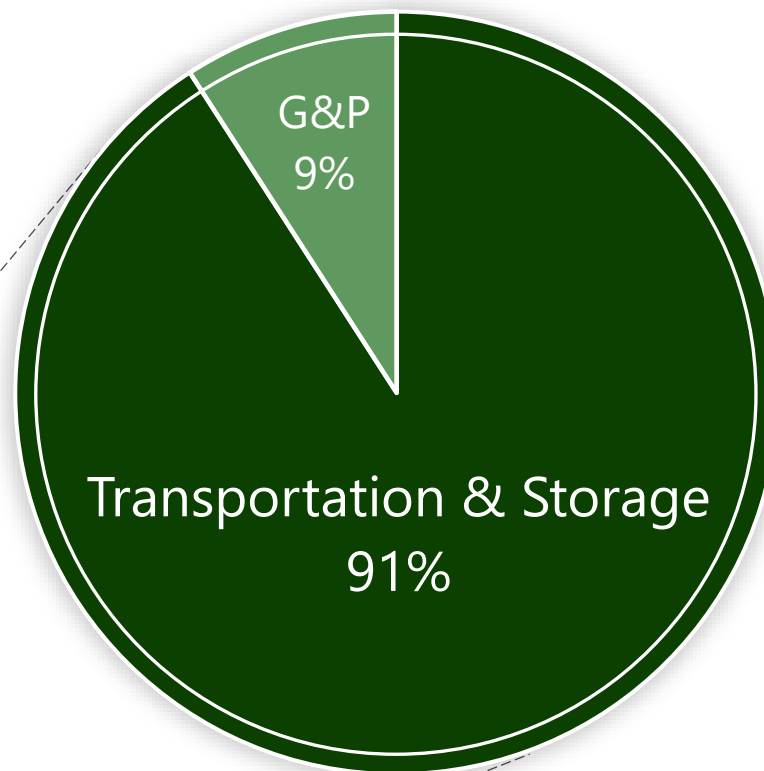
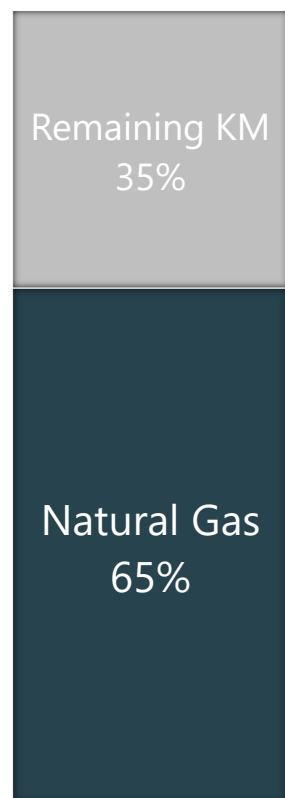
Principally Transmission & Storage Assets,
with Gathering & Processing Assets in
Key Basins

Robust Opportunity Set for Growth

a) Includes deliveries in Arizona, New Mexico, Texas, Arkansas, Louisiana, Tennessee, Mississippi, Alabama, Georgia, and Florida.

High-Quality, Natural Gas Focused Cash Flows

CASH FLOW MIX^(a)



Natural Gas Transportation & Storage

- Accounts for 59% of 2025B KMI Adjusted Segment EBDA
- 88% take-or-pay cash flows^(a)
- Average remaining contract life:
 - ~7 years for transportation
 - ~4 years for storage

KMI's percent cash flow contribution from long-haul natural gas pipelines is greater than any other large U.S. midstream company^(b)

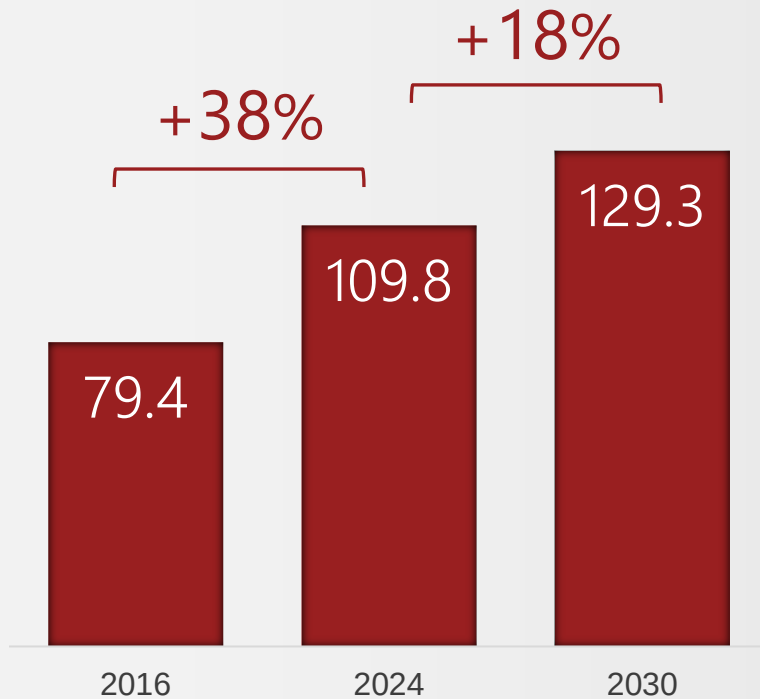
a) Based on 2025 budgeted Total Adjusted Segment EBDA, which is a non-GAAP financial measure. See Non-GAAP Financial Measures & Reconciliations.

b) Includes U.S. based midstream companies with market capitalizations greater than \$20 billion.

Rising Demand Benefitting Our Natural Gas Transportation Business

Increased Demand Leading To

WOODMAC
U.S. NATURAL GAS DEMAND
bcfd



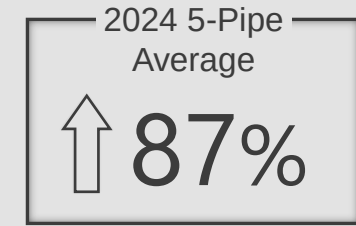
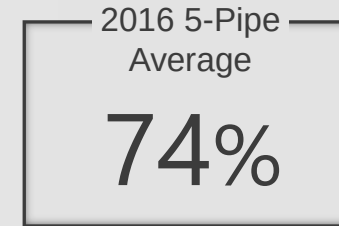
Source: Wood Mackenzie North America Gas 10-Year Investment Horizon Outlook, November 2024.

a) Represents the capacity weighted average usage factor of TGP, EPNG, NGPL, SNG, and the Texas Intrastates. Usage factor is calculated as billed throughput divided by average annual designed pipeline capacity.

b) TX Intrastates average remaining contract life includes term sale portfolio.

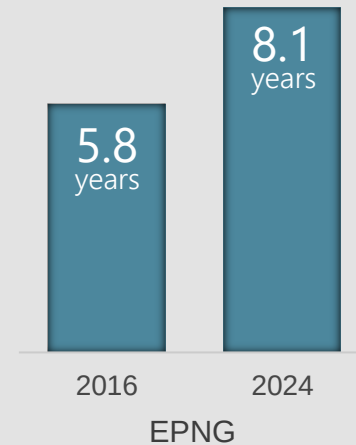
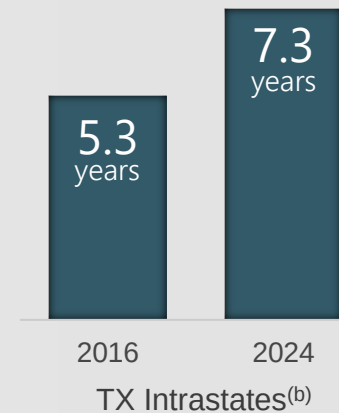
c) Total includes ~\$0.5bn of natural gas gathering & processing projects.

• INCREASED PIPELINE USAGE FACTOR^(a)



• INCREASED CONTRACT TERMS AND/OR RATES

EXAMPLES



• NEW PROJECTS

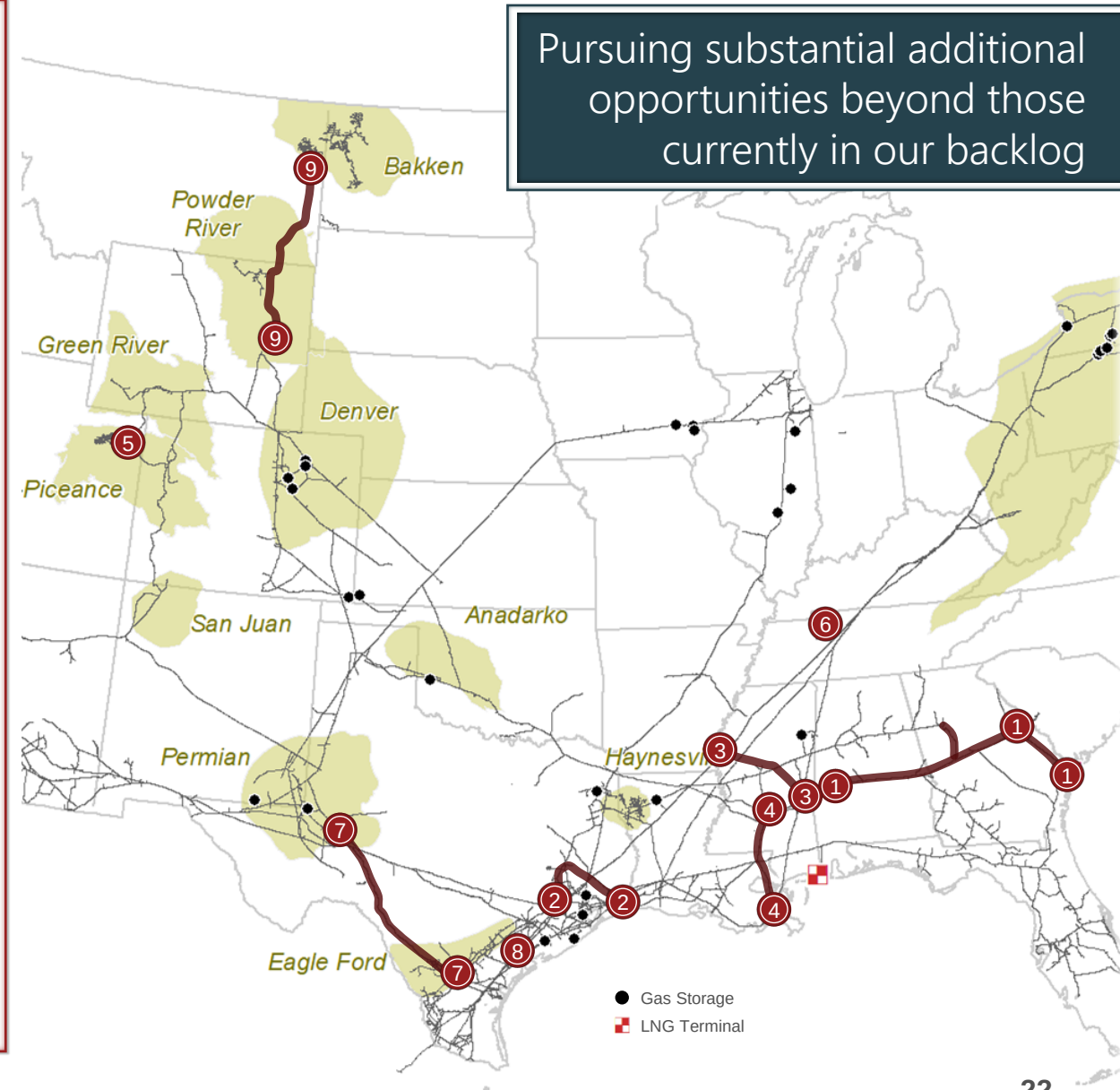
~\$7.2 billion of natural gas projects in our backlog; expect to continue adding projects over time^(c)

~\$7.2 Billion of Approved Natural Gas Projects

Major Projects	Capital ^(a) (\$mm)	Capacity (bcfd)	In-Service Date	Status
① South System Expansion 4 SNG & EEC	\$1,659	1.2	4Q28, 4Q29	Permitting
② Trident TX Intrastates	\$1,650	1.5	1Q27	Permitting
③ Mississippi Crossing TGP	\$1,637	2.1	4Q28	Permitting
④ Evangeline Pass (Phase II) TGP & SNG	\$389	1.1	3Q25	Construction
⑤ Green River Pipeline Altamont	\$263	0.1	3Q25	Permitting
⑥ Cumberland TGP	\$222	0.2	3Q25 ^(b)	Permitting
⑦ GCX Expansion TX Intrastates	\$161	0.6	2Q26	Construction
⑧ S. TX to Houston Market (I & II) TX Intrastates	\$154	0.8	1Q25, 3Q25	Construction
⑨ Hiland Express (NGL Conversion) Double H	\$149	--	1Q26	Permitting

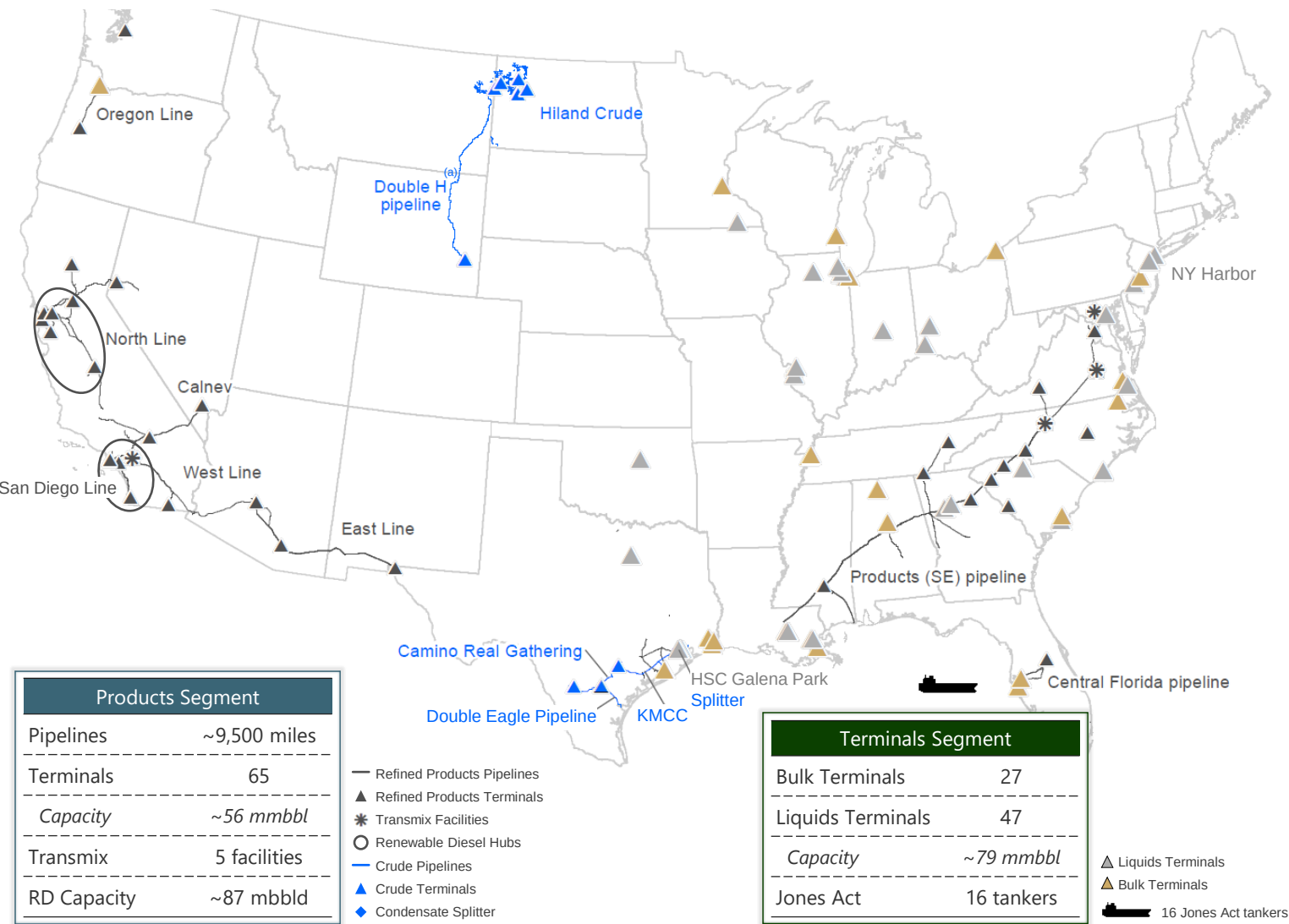
a) KMI share of estimated project capital.

b) Pending litigation may delay project.



Products Segment & Terminals Segment Overview

Both Segments Principally Refined Products Focused

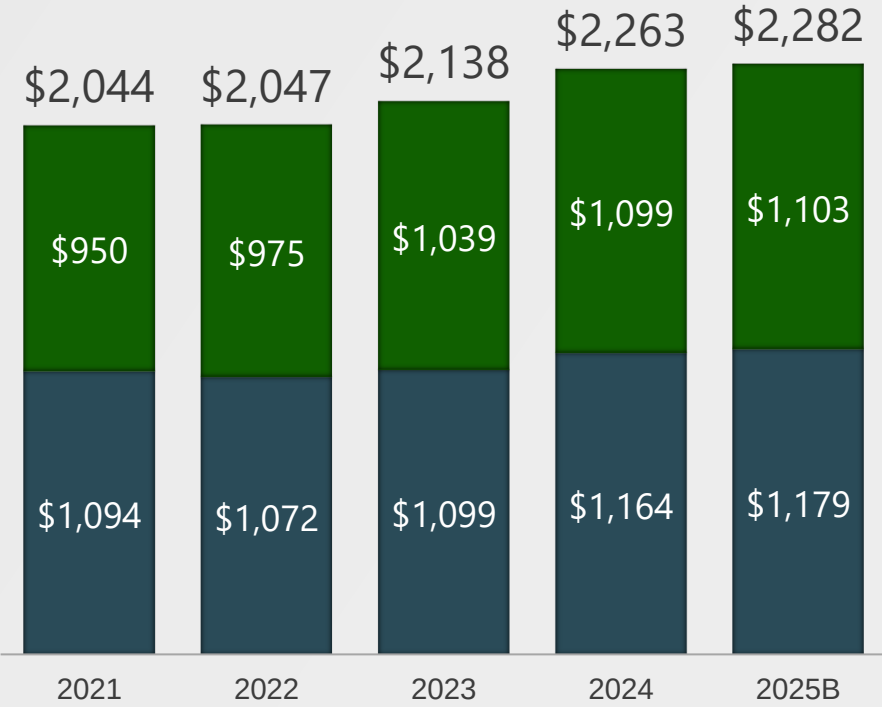


Note: Adjusted Segment EBDA and Terminals and Product Pipelines FCF are non-GAAP financial measures. See Non-GAAP Financial Measures & Reconciliations. 2021 – 2024 Adjusted Segment EBDA amounts are adjusted to reflect categorization of basis difference amortization (amortization of excess cost of equity investments) consistent with 2025 Segment EBDA accounting change.
a) Double H will continue in crude service through mid-2025, then convert to NGL service, expected to be in service Q1 2026.

Nearly \$11bn of Adjusted Segment EBDA & \$8bn of FCF Generated Over 5 Years

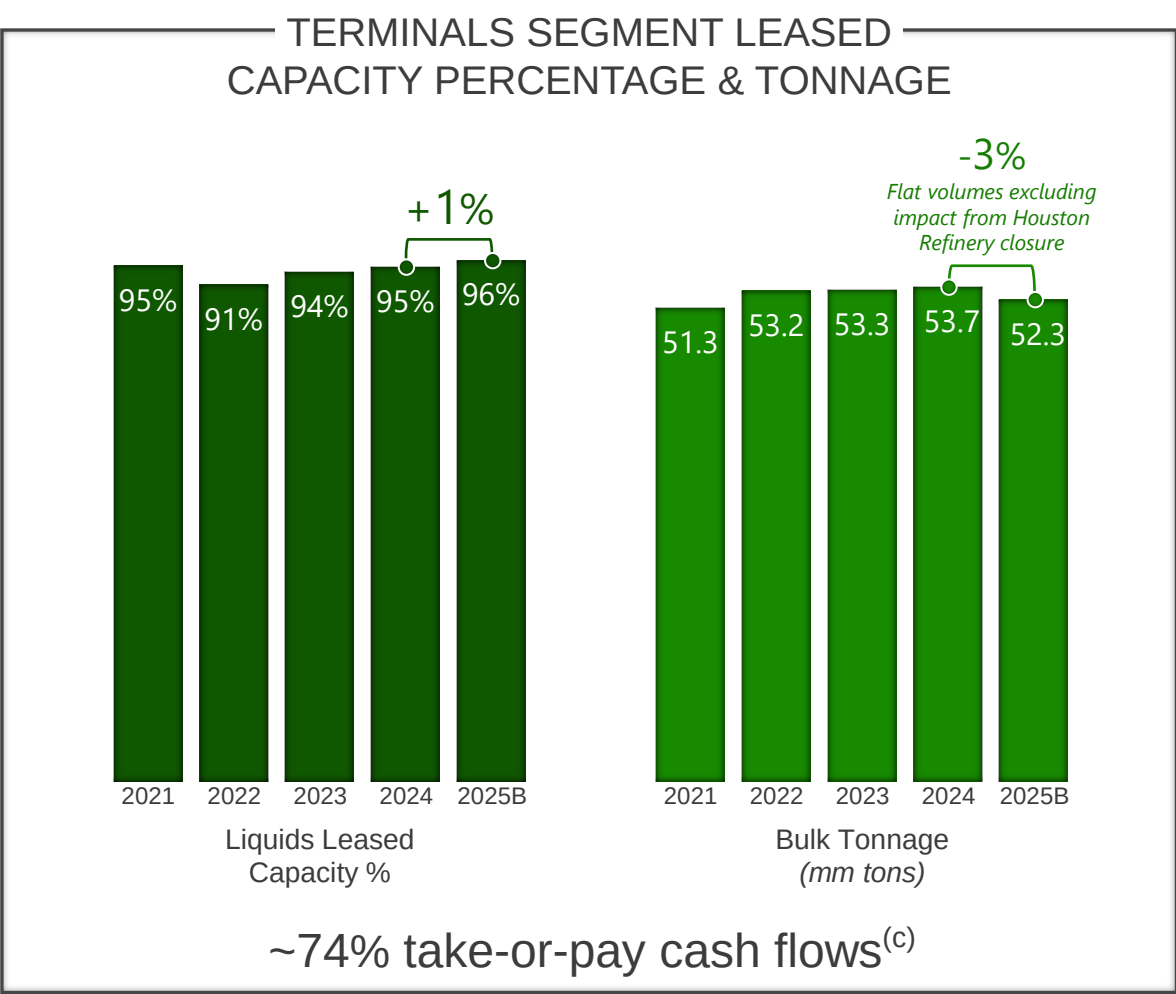
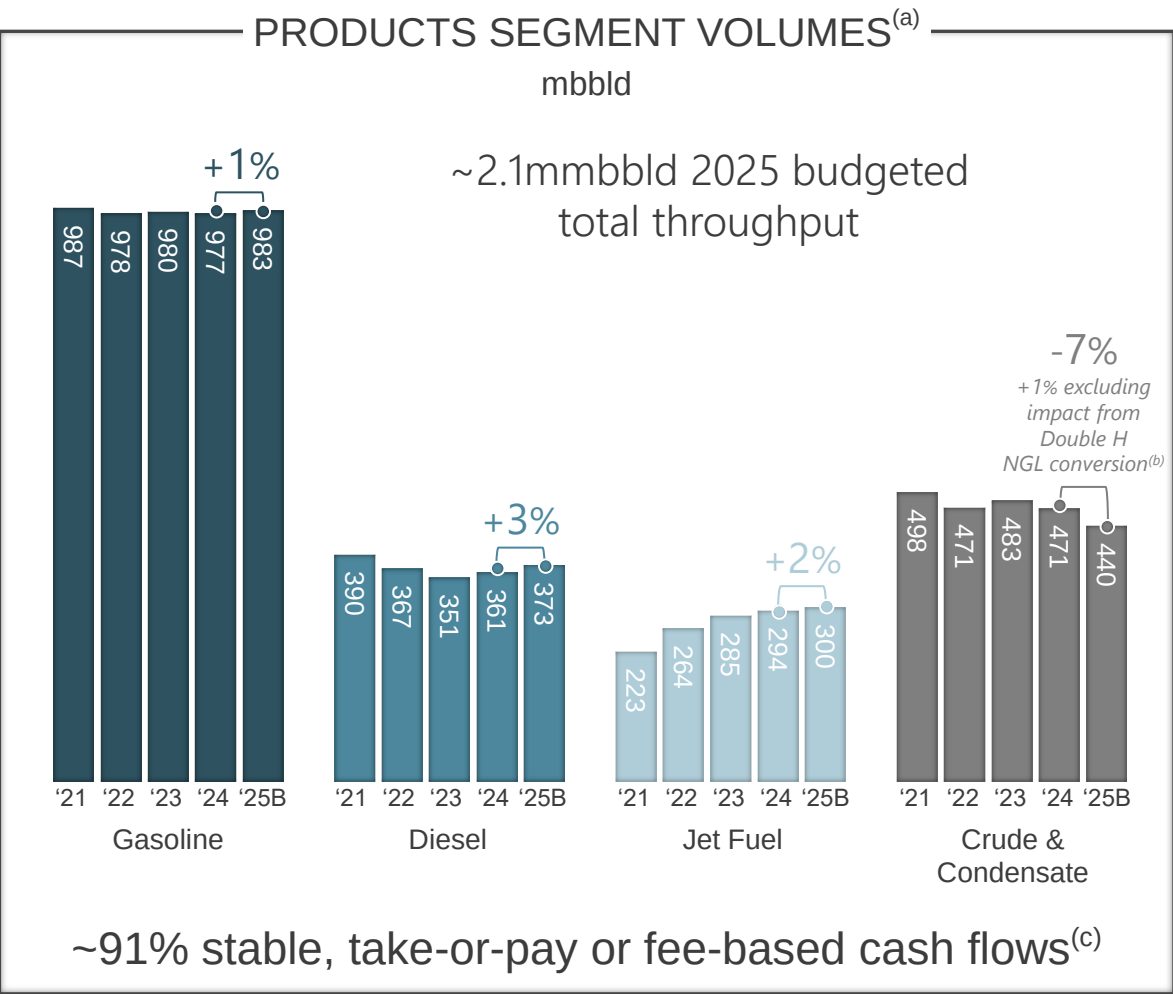
— TERMINALS & PRODUCTS PIPELINES —
ADJUSTED SEGMENT EBDA
\$ Millions

■ Products Segment ■ Terminals Segment



Highly Utilized Products & Terminals Assets

Steady Volumes with Annual Rate Escalators

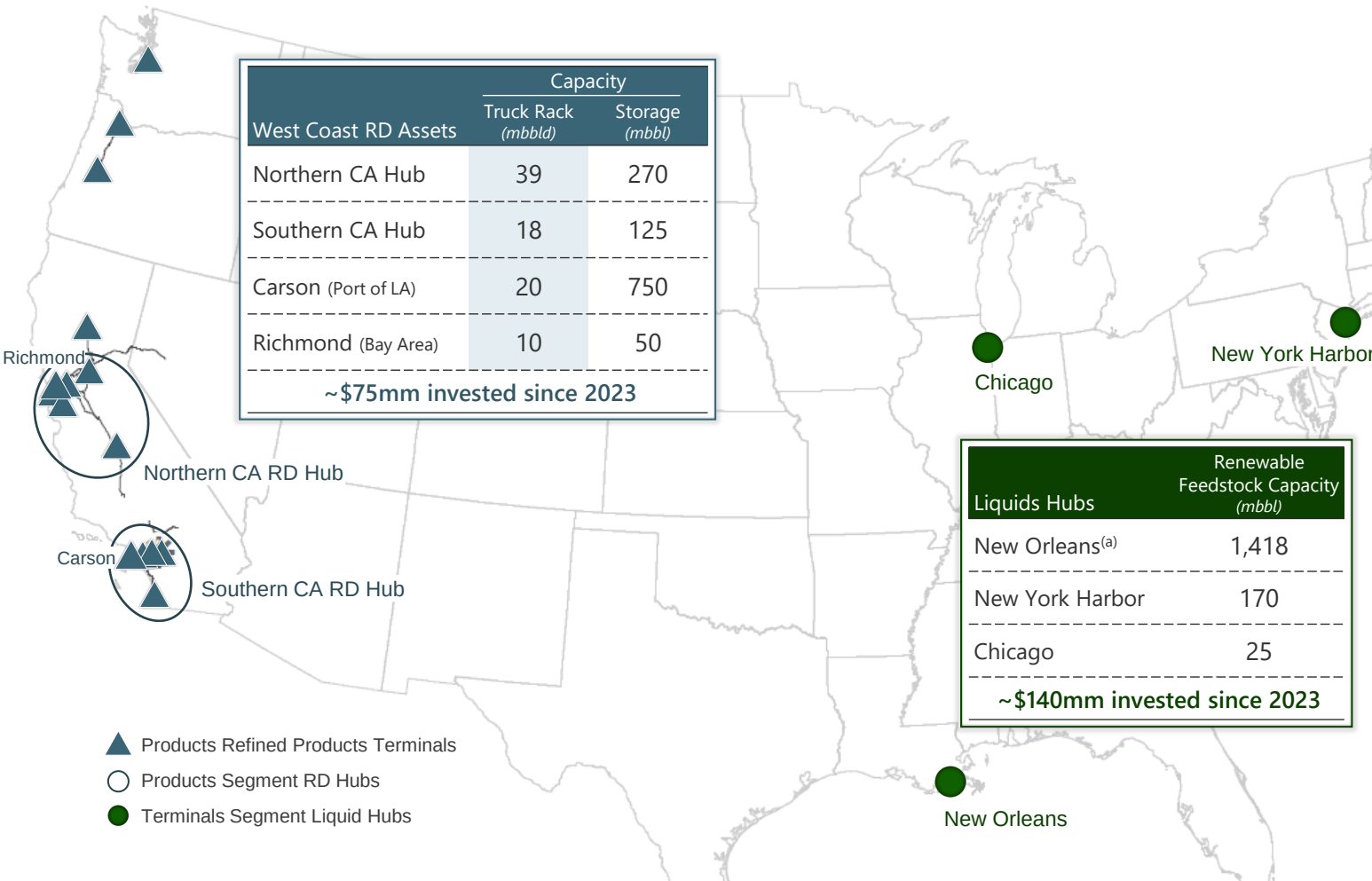


Annual inflation-linked escalator on 72% of cash flows^(c)

Annual inflation or fixed-rate escalators on 73% cash flows^(c)

a) Kinder Morgan volumes include SFPP, CALNEV, Central Florida, PPL (KMI share), KMCC, Camino Real, Double Eagle (KMI share), Double H & Hiland Crude Gathering; Gasoline volumes include ethanol; Diesel volumes include RD.
b) Double H conversion from crude oil service to NGL service expected Q1 2026; thereafter will report under our Natural Gas business unit.
c) Based on 2025 budgeted Adjusted Segment EBDA, which is a non-GAAP financial measure. See Non-GAAP Financial Measures & Reconciliations.

Leveraging Our Existing Assets to Meet Growing Demand for Renewable Fuels and Feedstocks



PRODUCTS

- Ability to throughput combined ~57mbbl/d of RD at Northern and Southern California hubs today
 - >90% subscribed with customer commitments
- Ability to deliver and store additional RD barrels at the Port of LA and in the Bay Area
- Scoping Phase 3 expansion of our CA hubs, which could add up to 20mbbl/d of additional RD capacity
- Evaluating additional RD conversion opportunities in Oregon and Washington

TERMINALS

- One of the largest handlers of renewable feedstocks in the U.S.
- >1.6mmbl^(a) of capacity leased for renewable feedstock storage across our network, with majority under term take-or-pay commitments
- Utilizing existing assets towards capital-efficient, attractive-returning projects supporting the growing renewable fuels market
- Advantaged network provides customers with flexible transportation options via rail, truck, vessel, and pipeline

Combined, Our Products & Terminals Segments Are the Largest Handler of Ethanol in the U.S., Handling ~1/3 of Total U.S. Ethanol Production

a) Includes tanks under construction.

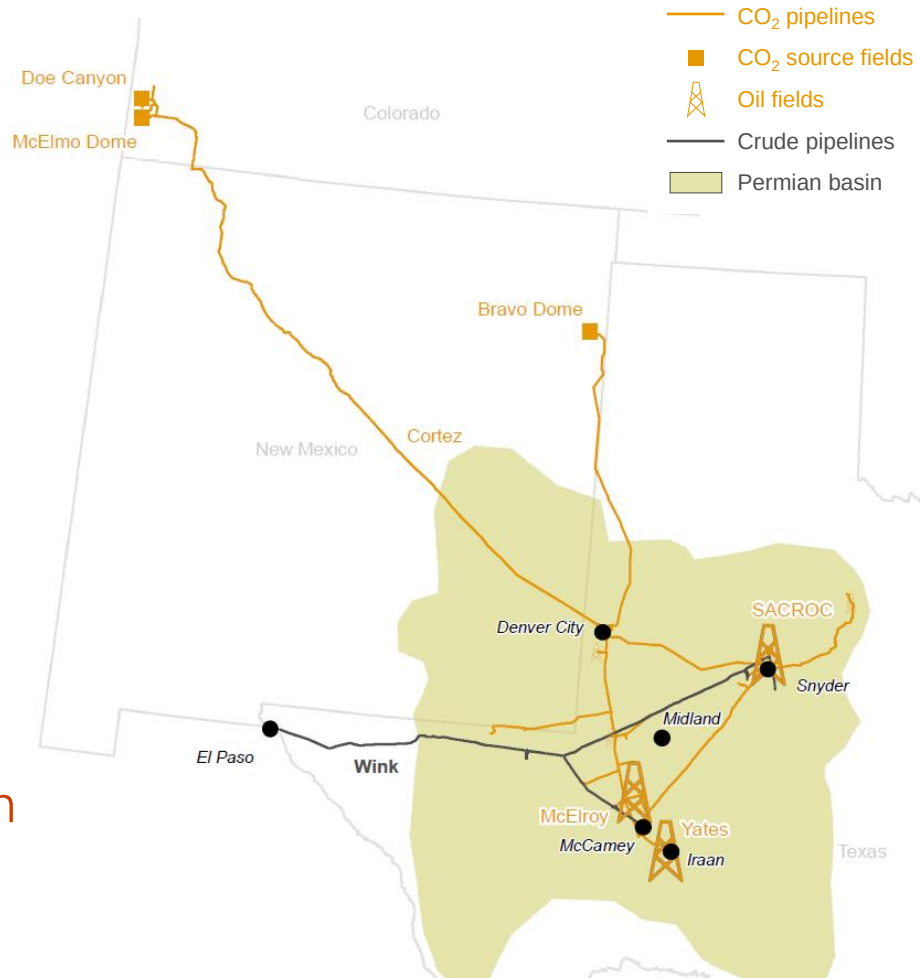
CO₂ Segment: EOR and CO₂ Transport Overview

World Class, Fully-Integrated Assets Consistently Generating Robust Free Cash Flow

Interest in 3 oil fields with 8.8 billion barrels of Original Oil In Place

Interest in 3 CO₂ fields with 37 tcf of Original Gas In Place

~1,500 miles of CO₂ pipelines with capacity to move up to 1.5 bcfd



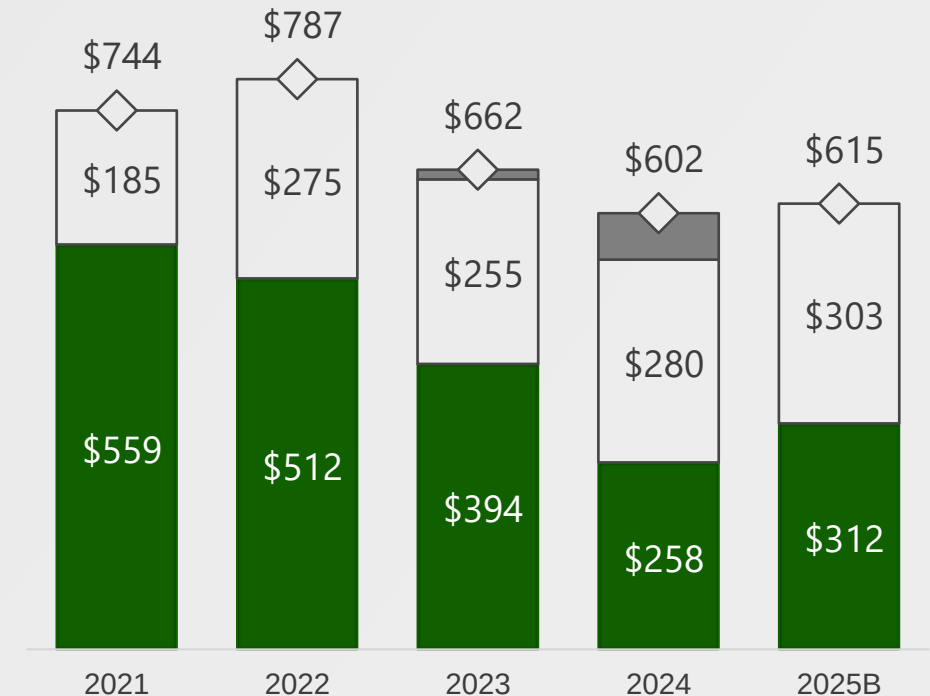
Note: CO₂ EOR & Transport FCF and Adjusted Segment EBDA are non-GAAP financial measures. See Non-GAAP Financial Measures & Reconciliations. 2021 – 2024 Adj. Segment EBDA amounts are adjusted to reflect categorization of basis difference amortization (amortization of excess cost of equity investments) consistent with 2025 Segment EBDA accounting change. SACROC includes Diamond M acreage.

a) Includes sustaining and expansion capital expenditures.

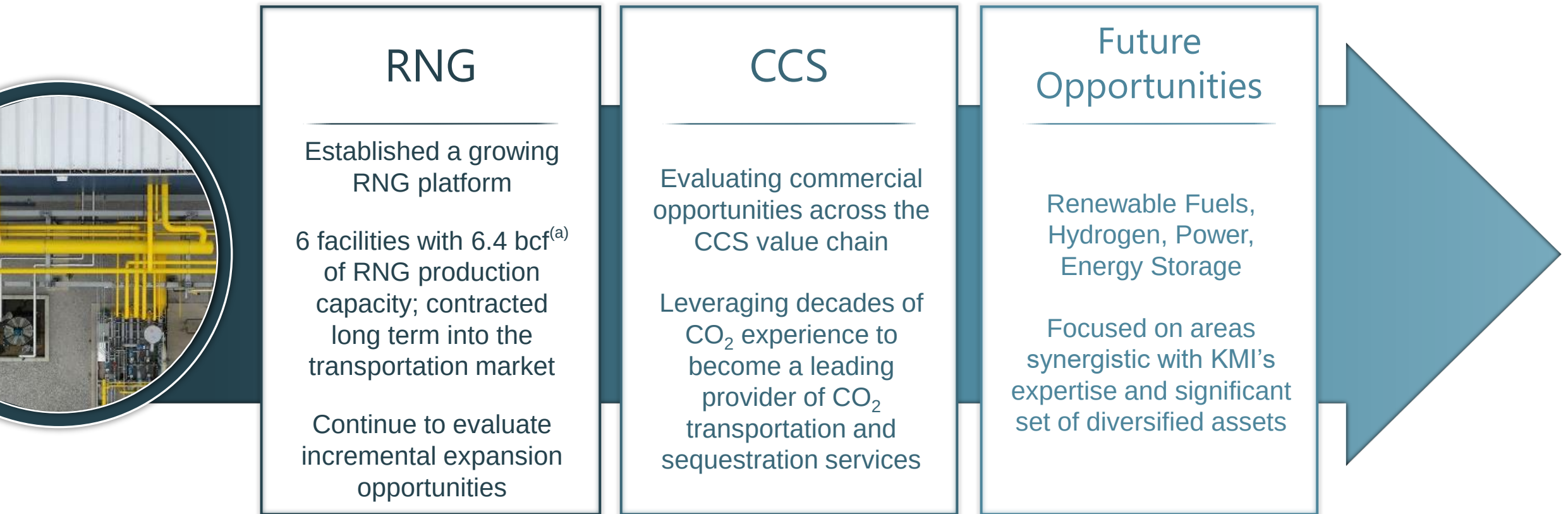
— CO₂ EOR & TRANSPORT FREE CASH FLOW — \$ Millions

■ FCF □ Capex^(a) ■ Acquisitions ◇ Adj. Segment EBDA

>\$2 billion FCF Generated Over 5 years



Pursuing Commercial Opportunities Emerging from the Lower Carbon Energy Evolution



Committed to Being a Good Steward



Reduce &
Avoid Methane
Emissions

~8%

Reduction in
absolute methane
emissions since 2021



Leak
Detection

100%

Of our natural gas
compressor stations
surveyed annually &
transitioning to quarterly



Safety
Culture

42%

Reduction in
Employee TRIR
2015 – 2023^(a)



Continuous
Improvement

BB → AAA

MSCI score
improvement
2018 – 2024



Diversity &
Inclusion

33%

Total gender
and minority
diversity of the
KMI Board



Investing in Lower
Carbon Fuels

\$7.3bn

Primarily natural gas;
remaining investment
in RNG, renewable
feedstocks, and CCS^(b)

Dedicated to Doing Business the Right Way, Every Day – Serving Our Investors,
Our Colleagues, Our Customers, and Our Neighbors to Improve Lives and Create A Better World

a) 2015 was first year company-wide TRIR was reported publicly in 2017 ESG Report.

b) Lower carbon projects included in our 12/31/2024 backlog.

Highly Rated by Sustainability Ratings Agencies

Upgrade by MSCI to AAA in 2024

MSCI **AAA**

Oil & Gas Refining,
Marketing, Transportation
& Storage Industry

Sustainalytics **Top 15%**

out of 106 Oil & Gas
Storage and Transportation Companies &
194 Refiners & Pipelines

SSGA **Top 10%**

R-Factor in
Oil & Gas – Midstream sector

FTSE **#2**

of Oil & Gas
Pipelines subsector

Refinitiv **#5**

of 234 Oil & Gas
Related Equipment
and Services Companies

S&P Global CSA

**Sustainability Yearbook
Member**

Included in Several ESG Indices FTSE4Good, S&P 500 ESG, JULCD, MSCI Climate & ESG Indices



2025 BUDGET

Another Year of Robust Financial Growth



High-Quality and Secure Cash Flows

Natural gas focused, long-term, take-or-pay cash flows



Balance Sheet Strength

Capacity provides value and flexibility



Disciplined Capital Allocation

Investing in projects well above our cost of capital



Significant Free Cash Flow Generation

Enables additional opportunities to increase shareholder value



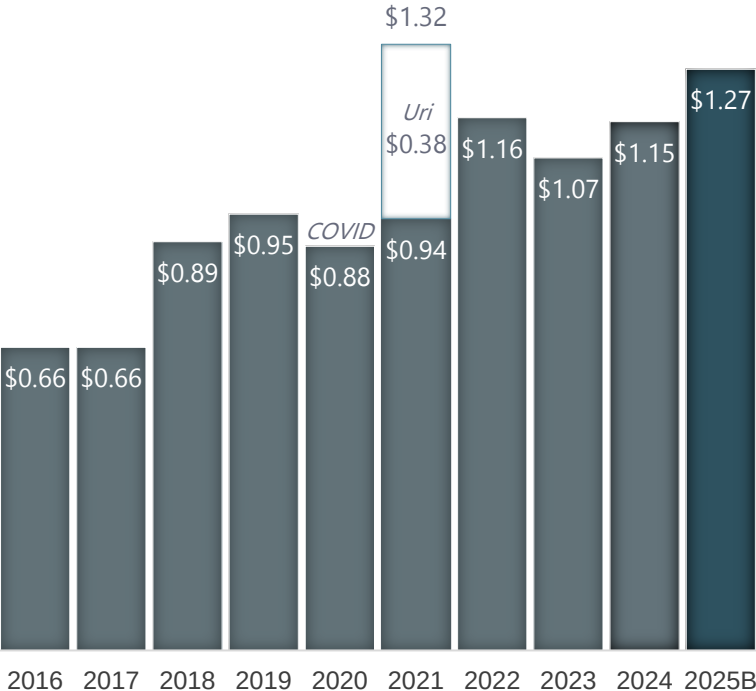
Committed to Shareholder Value

Well-covered dividends and opportunistic share buybacks

Growing Earnings While Reducing Leverage and Returning Meaningful Value to Shareholders

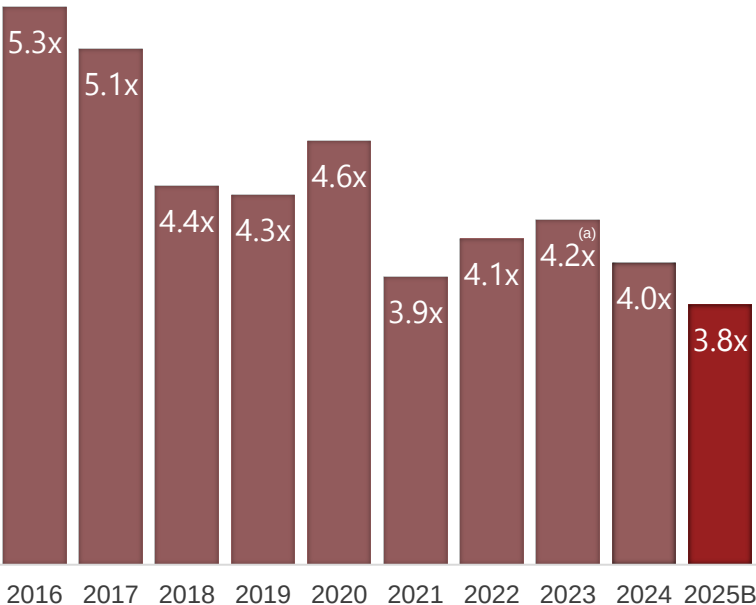
ADJUSTED
EPS

8% CAGR



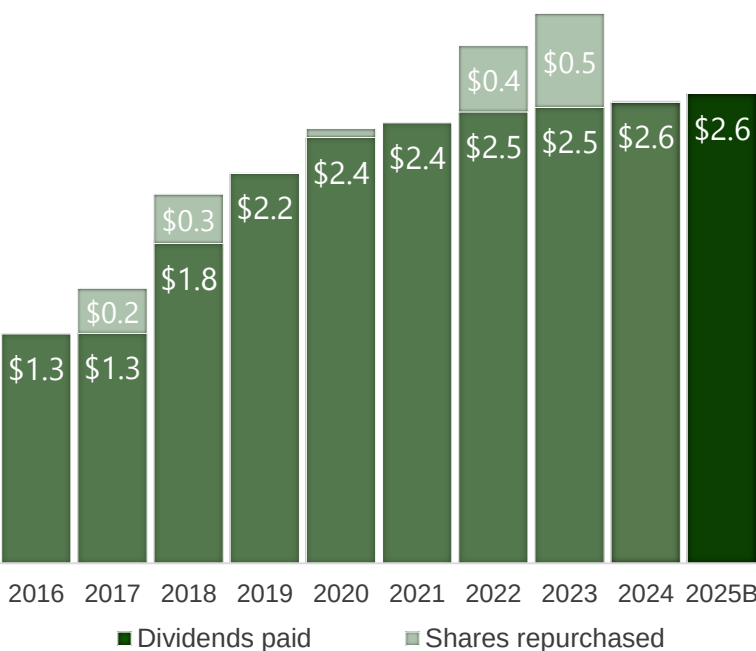
NET DEBT /
ADJUSTED EBITDA

28% decrease in
leverage



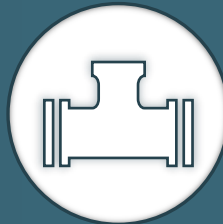
DIVIDENDS PAID &
SHARES REPURCHASED^(b)
\$ Billion

\$23 billion returned
to shareholders



Note: Adjusted EPS, Adjusted EBITDA and Net Debt are non-GAAP financial measures. See Non-GAAP Financial Measures & Reconciliations. Individual years may not sum to total due to rounding.
a) Includes debt associated with STX Midstream acquisition, which closed on 12/28/2023. Year-end 2023 leverage would have been 4.1x with a full-year EBITDA contribution from the acquired assets.
b) No share repurchases assumed in 2025 budget. 2016, 2017, and 2018 include dividends paid to preferred shareholders.

2025 Budget Highlights



Adjusted
EPS

\$1.27

~10% increase
vs. 2024

Adjusted
EBITDA

\$8.3bn

~4% increase
vs. 2024

Net Debt /
Adj. EBITDA

3.8x

-0.2x decrease
vs. year-end 2024

Discretionary
Capital^(a)

\$2.3bn

infrastructure projects
with attractive returns

Cash
Returns

\$2.6bn

dividends expected
in 2025

Note: 2025 budget does not include contributions from Outrigger Energy II acquisition and does not assume any share repurchases. Adjusted EPS, Adjusted EBITDA, and Net Debt are non-GAAP financial measures. See Non-GAAP Financial Measures & Reconciliations.

a) Includes growth capital & JV contributions for expansion capital & net of partner contributions for our consolidated JVs.

Steady Base Business & Growth From Investments



Note: Adjusted EBITDA is a non-GAAP financial measure. See Non-GAAP Financial Measures & Reconciliations. Figures do not sum due to rounding.
a) Includes contributions from our G&P business related to new well connects, offset by base volume declines.

2025B Adjusted Segment EBDA, Adjusted EBITDA, and Adjusted Net Income Attributable to KMI

\$ in Millions

	2025 Budget	2024 Actual	Change	
			\$	%
Natural Gas Pipelines Adjusted Segment EBDA ^(a)	\$ 5,636	\$ 5,439	\$ 197	4%
Products Pipelines Adjusted Segment EBDA ^(a)	1,179	1,164	15	1%
Terminals Adjusted Segment EBDA ^(a)	1,103	1,099	4	0%
CO ₂ Adjusted Segment EBDA ^(a)	755	647	108	17%
Total Adjusted Segment EBDA^(a)	8,673	8,349	324	4%
G&A and corporate charges ^(b)	(712)	(729)	17	2%
JV DD&A and income tax expense ^{(a)(b)(c)}	429	425	4	1%
Net income attributable to NCI	(106)	(107)	1	1%
Adjusted EBITDA	8,284	7,938	346	4%
DD&A	(2,411)	(2,354)	(57)	(2%)
Interest, net ^(b)	(1,796)	(1,849)	53	3%
Income tax expense ^(b)	(817)	(739)	(78)	(11%)
JV DD&A and income tax expense ^{(a)(b)(c)}	(429)	(425)	(4)	(1%)
Adjusted Net income attributable to KMI	\$ 2,831	\$ 2,571	\$ 260	10%

2025B KEY DRIVERS

Natural Gas	– Contributions from expansion projects – Stable base business
Products	– Favorable rate escalators (FERC Index & Other) – Unfavorable impact from Double H NGL conversion
Terminals	– Favorable contract escalations (CPI/PPI) & renewals (terminals & vessels) – Unfavorable impact from Houston Refinery closure
CO ₂	– Contributions from RNG facilities placed in service – Lower oil volumes partially offset by lower opex

Note: Adjusted Segment EBDA and Adjusted EBITDA are non-GAAP financial measures. See Non-GAAP Financial Measures and Reconciliations.

a) 2024 amounts are adjusted to reflect categorization of basis difference amortization (amortization of excess cost of equity investments) consistent with 2025 Segment EBDA accounting change.

b) Amounts are adjusted for Certain Items.

c) Includes or represents DD&A, amortization of basis differences, and/or income tax expense (as applicable for each item) related to our JVs.

2025B Adjusted EPS

\$ in Millions, Except Per Share

	2025 Budget	2024 Actual	Change	
			\$	%
Net income attributable to KMI	\$ 2,829	\$ 2,613	\$ 216	8%
Total Certain Items ^(a)	2	(42)	44	105%
Adjusted Net Income attributable to KMI	2,831	2,571	260	10%
Net income Allocated to participating securities and other ^(b)	(19)	(14)	(5)	(36%)
Adjusted Net income attributable to Common Stock	\$ 2,812	\$ 2,557	\$ 255	10%
Weighted average shares outstanding	2,222	2,220	2	0%
EPS	\$ 1.26	\$ 1.17	\$ 0.09	8%
Adjusted EPS	\$ 1.27	\$ 1.15	\$ 0.12	10%
Expected/Declared dividend per share	\$ 1.17	\$ 1.15	\$ 0.02	2%

+10% Adjusted EPS increase driven by expected growth in Natural Gas and RNG

Note: Adjusted Net Income attributable to Common Stock, in aggregate and per share, and Adjusted EPS are non-GAAP financial measures. See Non-GAAP Financial Measures and Reconciliations.

a) See table included in "Non-GAAP Financial Measures—Certain Items."

b) Net income allocated to participating securities (this only includes restricted stock for the periods shown) is based on the amount of dividends paid in the current period plus an allocation of the undistributed earnings or excess distributions over earnings to the extent that each security participates in earnings or excess distributions over earnings, as applicable. 2024 includes \$1 million of adjusted net income in excess of distributions for participating securities.

2025B Discretionary Capital Expenditures

\$ in Millions

	2025 Budget	2024 Actual
Discretionary Capital		
Natural Gas Pipelines ^(a)	\$ 1,854	\$ 1,348
Products Pipelines	72	79
Terminals	117	108
CO ₂ - Source & Transport/Oil & Gas ^(b)	276	323
CO ₂ - Energy Transition Ventures	21	63
Corporate/Other	0	1
Total discretionary capital	2,340	1,922
Sustaining capital expenditures incl. KM share of JV ^(c)	1,112	1,165
Acquisitions ^(b)	-	(60)
Contributions to unconsolidated JVs	(158)	(154)
JV Sustaining capital expenditures	(174)	(179)
Increase in capital accruals and other	21	(65)
Capital expenditures (GAAP)	\$ 3,141	\$ 2,629

a) Includes KM share of JV expansion spending of \$158 million and \$154 million in 2025 and 2024, respectively.

b) 2024 includes \$60 million for CO₂ acquisitions.

c) Includes sustaining capital expenditures from JVs of \$174 million and \$179 million in 2025 and 2024, respectively.

2025B KEY PROJECTS

Discretionary Capital

Natural Gas	– TX Intrastate Trident project
	– Hiland Express NGL conversion project
	– Altamont Green River Pipeline project
	– TGP & SNG Evangeline Pass projects
	– TX Intrastate S. TX to Houston Market projects
	– CIG Totem Storage Expansion project
	– TGP Station 40 project
Products	– Hiland crude well connects
	– West Coast refined products projects
Terminals	– Projects at existing liquids & bulk terminals, primarily in Northeast, Gulf, and Mid-Atlantic
CO ₂	– SACROC development projects

2025B Cash Flow from Operations (CFFO) & Free Cash Flow (FCF)

\$ in Millions

	2025 Budget	2024 Actual	Change	
			\$	%
Net income attributable to KMI	\$ 2,829	\$ 2,613	\$ 216	8%
Net income attributable to noncontrolling interests	106	107	(1)	(1%)
DD&A	2,411	2,354	57	2%
Deferred income taxes	739	647	92	14%
Earnings from equity investments ^(a)	(855)	(840)	(15)	(2%)
Distribution of equity investment earnings ^(b)	806	823	(17)	(2%)
Working Capital and other items	(137)	(69)	(68)	NM
CFFO (GAAP)	5,899	5,635	264	5%
Capital expenditures (GAAP)	(3,141)	(2,629)	(512)	(19%)
FCF	2,758	3,006	(248)	(8%)
Dividends paid (GAAP)	(2,606)	(2,557)	(49)	(2%)
FCF after dividends	\$ 152	\$ 449	\$ (297)	(66%)

Attractive investments and excess cash flow creating additional shareholder value

Note: See Non-GAAP Financial Measures and Reconciliations.

a) 2024 amounts are adjusted to reflect categorization of basis difference amortization (amortization of excess cost of equity investments) consistent with 2025 Segment EBDA accounting change.

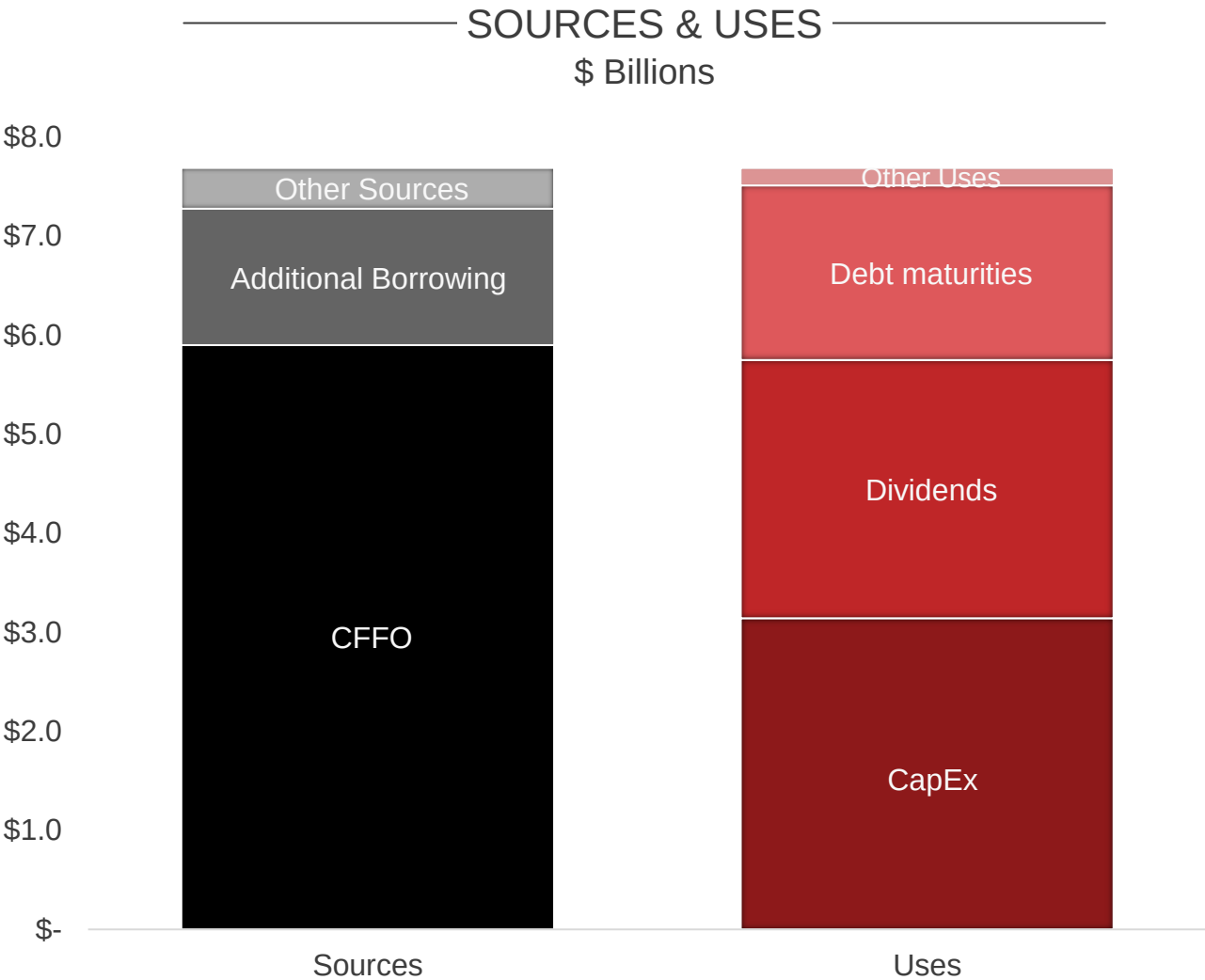
b) Excludes distributions from equity investment in excess of cumulative earnings, \$411 million and \$177 million in 2025 and 2024, respectively. These are included in Cash Flows Used In Investing Activities on our Consolidated Statements of Cash Flows.

2025B Sources & Uses^(a)

\$ in Millions

Sources	2025 Budget
CFFO (GAAP) Revolver Borrowing/Debt Issuances Distributions from equity investments in CFFI^(b) Total sources	\$ 5,899 1,377 411 \$ 7,687

Uses	2025 Budget
Capital expenditures (GAAP) Dividends paid (GAAP) Debt maturities^(c) Contributions to Equity Investments Other Uses^(d) Total uses	\$ 3,141 2,606 1,764 158 18 \$ 7,687



a) High level view of sources and uses, and will vary depending on discretionary use of free cash flow. Does not include recently announced Outrigger acquisition.
b) Reflects distributions from equity investments in excess of cumulative earnings.
c) Includes \$243 million of commercial paper borrowing at year-end 2024, net of cash.
d) Includes NCI share of CFFO net of 2024 cash timing.

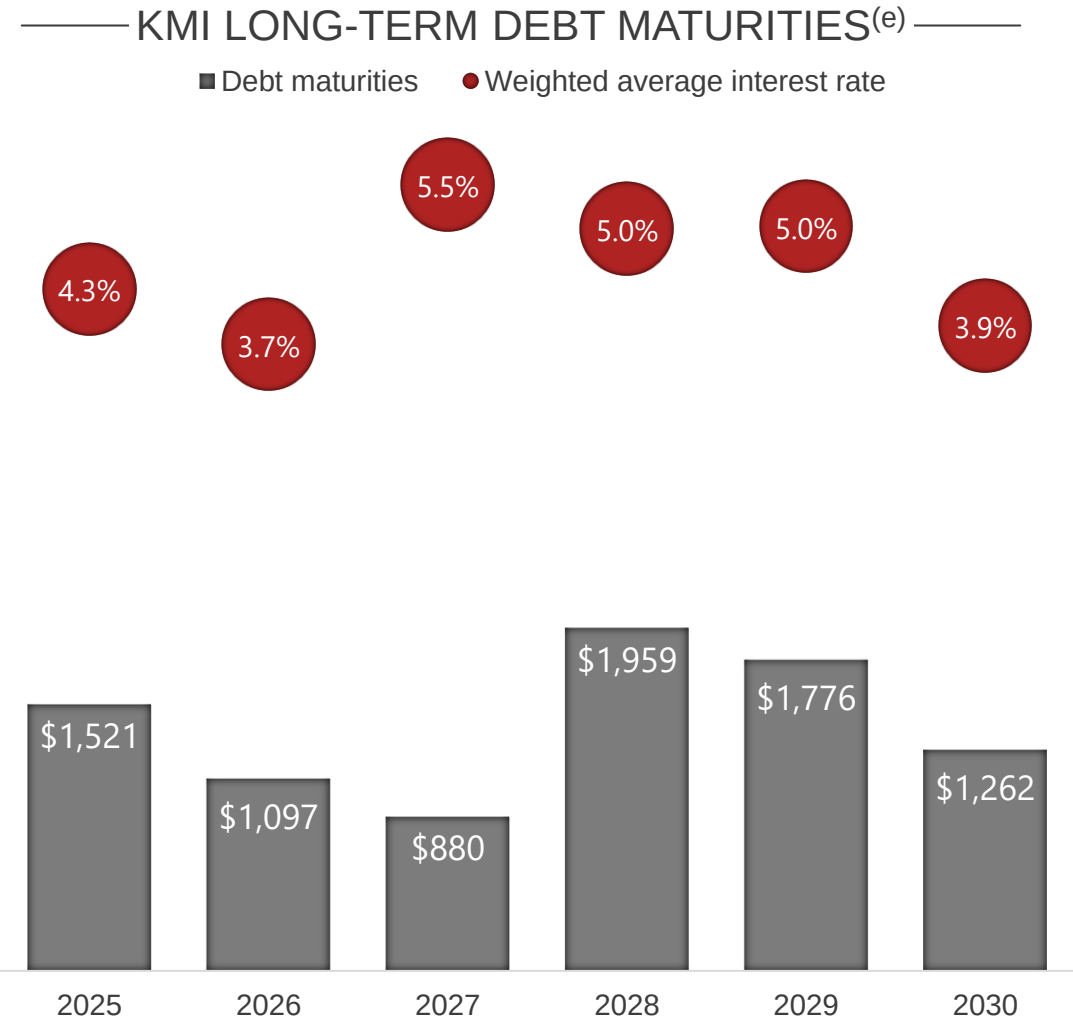
2025B Leverage & Liquidity^(a)

\$ in Millions

	2025 Budget
Net Debt (Year End)	\$ 31,408
Adjusted EBITDA	\$ 8,284
Net Debt^(b) to Adjusted EBITDA	3.8x^(c)

KMI revolver capacity	12/31/2024
Committed revolving credit facility ^(d)	\$ 3,500
CP / Revolver borrowing	(331)
Letters of credit	(57)
Available capacity	\$ 3,112

~12-year average maturity life &
~5.4% weighted average interest rate



Note: See Non-GAAP Financial Measures and Reconciliations.

a) Debt of KMI and its consolidated subsidiaries excluding fair value adjustments.

b) Debt as defined in footnote (a), net of cash and foreign exchange impact on Euro denominated debt.

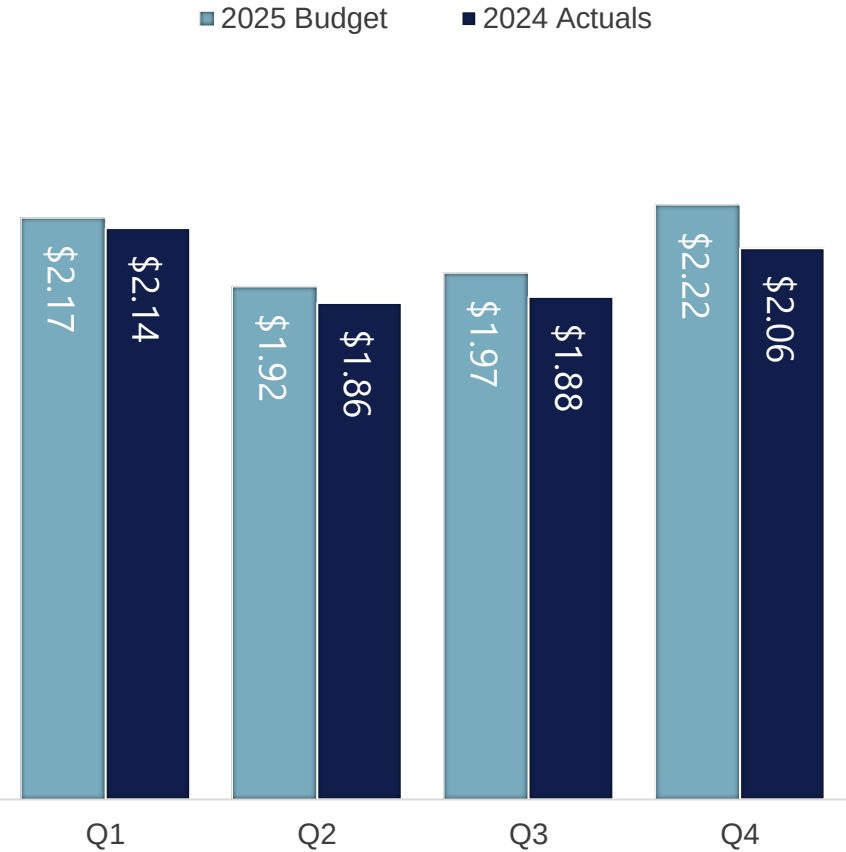
c) Long-term leverage target of around 3.5x - 4.5x.

d) KMI corporate revolver facility of \$3.5 billion (August 2027 maturity).

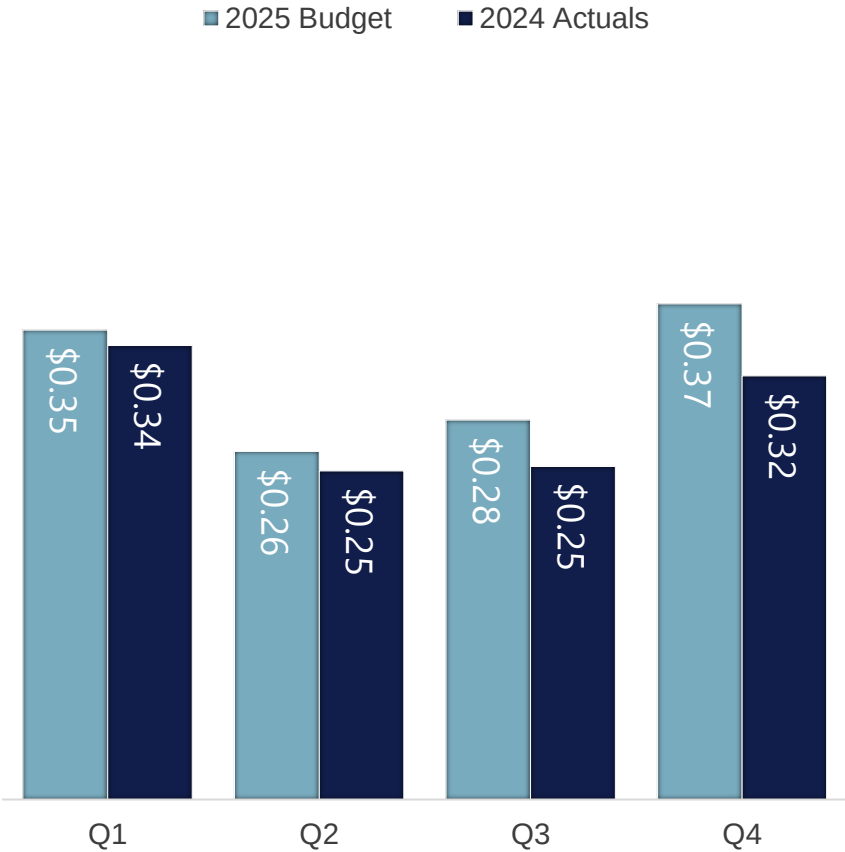
e) Maturity schedule includes KMI's consolidated long-term debt, excluding fair value adjustments, \$220 million preferred securities, (\$25) million non-cash foreign exchange impact on Euro denominated debt, and immaterial capital lease and other obligations.

2025B Quarterly Profile

ADJUSTED EBITDA
\$ Billions

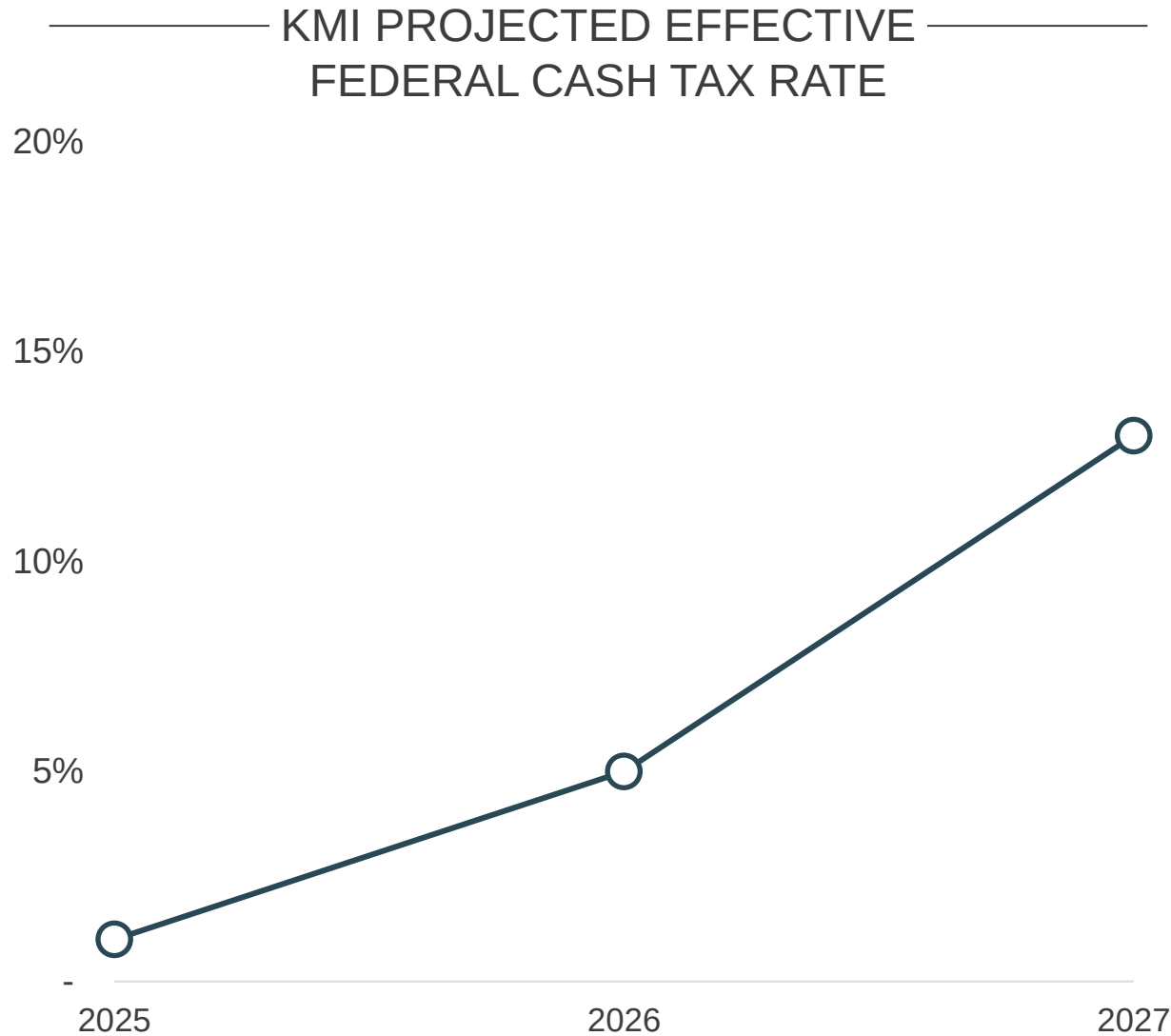


ADJUSTED EPS



Note: Adjusted EBITDA and Adjusted EPS are non-GAAP financial measures. See Non-GAAP Financial Measures and Reconciliations. Individual quarters may not sum to full-year totals due to rounding.

Cash Taxes: Do Not Expect to Be a Material Cash Taxpayer Until 2026



Do not expect KMI to be a material federal income taxpayer in 2025

\$312 million of General Business Credits^(a), limited to offsetting up to 75% of our annual tax liability

100% of CAMT payments can be credited against future regular federal income taxes

Cash tax position may be impacted by future policy changes

Note: Does not include cash taxes paid by our JVs.

a) Total as of 12/31/2024.

A photograph of an industrial facility, likely a refinery or chemical plant, at dusk. The scene is filled with complex piping, structural steel frameworks, and several tall vertical distillation columns. The facility is illuminated by bright artificial lights, creating a strong contrast with the dark, cloudy sky. In the foreground, there are concrete barriers and a paved walkway. The overall atmosphere is industrial and somewhat somber due to the twilight setting.

APPENDIX

Contract Strategy Insulates Cash Flows Through Commodity Cycles

Structure Long-Term Contracts That Minimize Price & Volume Volatility

		Take-or-Pay or Hedged Volumes & price are contractually fixed	Fee-Based Price is fixed, volumes are variable	Commodity- Price Based	Avg. remaining contract term as of 12/31/2024	Additional cash flow security
Natural Gas	Interstate / LNG	40%	3%		6.3 / 15.7 years	Tariffs are FERC-regulated
	TX Intrastate	12%	4%		7.3 years	
	G&P	1% ^(a)	4%	1%	3.9 years	Primarily acreage dedications for fee-based contracts
Products	Refined products	1%	9%	1%	generally not applicable	Pipeline tariffs are FERC-regulated
	Crude transport	1%			4.4 years ^(b)	~72% of 2025B Products Adj. Segment EBDA has an annual inflation-linked tariff escalator
	Crude G&P		1%			
Terminals	Liquids terminals	5%	2%		1.8 years	~73% of 2025B Terminals Adj. Segment EBDA has annual price escalators (inflation-linked or fixed-price escalators)
	Jones Act tankers	3%			4.0 years	
	Bulk terminals	1%	2%		3.0 years	Bulk terminals: primarily minimum volume guarantee or requirements
CO ₂	EOR Oil & Gas	4% ^(a)		1%		
	CO ₂ & Transport	1%	1%		5.8 years	Commodity-price based contracts are mostly minimum volume committed
	ETV			2%		
		69%	26%	5%		

Note: Total Adjusted Segment EBDA is a non-GAAP financial measure. See Non-GAAP Financial Measures & Reconciliations. TX Intrastate average remaining contract life includes term sale portfolio.

a) Hedged cash flows.

b) Includes condensate splitter. Excludes remaining contract life for Double H, which is to be converted from crude oil service to NGL service and will report under our Natural Gas business unit going forward.

2025 Budget Sensitivities

Limited Overall Commodity Exposure

2025B Assumptions	Change	Potential Impact to Adjusted EBITDA (Full Year)				
		Natural Gas	Products	Terminals	CO ₂	Total
Natural gas G&P volumes 4,125 bbtud	+/- 5%	\$32.8 million				\$32.8 million
Crude oil & NGL production volumes 34 mbbld net	+/- 5% in net volumes	\$35.5 million				\$35.5 million
\$68.00/bbl WTI crude oil price	+/- \$1/bbl WTI	\$0.8 million	\$1.1 million		\$3.9 million	\$5.8 million
\$3.00/Dth natural gas price	+/- \$0.10/Dth	\$5.0 million ^(a)			\$0.7 million	\$5.7 million ^(a)
NGL / crude oil price ratio 55% in Natural Gas segment & 49% in CO ₂ segment	+/- 1% price ratio	\$1.0 million			\$2.4 million	\$3.4 million
\$3.25/RIN D3 RIN price	+/- \$0.10/RIN				\$4.7 million	\$4.7 million
Potential Impact to Interest Expense (Full Year)						
SOFR rate: 4.31%	+/-10-bp change in SOFR					\$3.4 million ^(b)

Note: These sensitivities are general estimates of anticipated impacts on our business segments & overall business of changes relative to our assumptions; the impact of actual changes may vary significantly depending on the affected asset, product & contract. Adjusted EBITDA is a non-GAAP financial measure. See Non-GAAP Financial Measures & Reconciliations at the end of this presentation for additional information.

a) Assumes constant ethane frac spread vs. natural gas prices. Natural gas sensitivity predominantly applies only between \$2.25 – \$3.75/Dth.

b) As of 12/31/2024, we had \$4.75 billion of fixed-to-floating interest rate swaps on our long-term debt. Taking into account SOFR locks, we have fixed the SOFR component on \$1.5 billion of our floating rate swaps through the end of 2025.

2025B Sustaining Capital Expenditures

\$ in Millions

Sustaining Capital	2025 Budget	2024 Actual	Change
Natural Gas Pipelines ^(a)	\$ 623	\$ 703	\$ (80)
Products Pipelines	171	172	(1)
Terminals	242	232	10
CO ₂ ^(b)	42	27	15
Corporate/Other	34	31	3
Total sustaining capital expenditures incl. KM share of JV^(c)	\$ 1,112	\$ 1,165	(53)

2025B KEY DRIVERS

Sustaining Capital

- Fewer compressor repairs
- Natural Gas – Less regulatory compliance work
- Fewer class changes

a) Net of \$21 million and \$23 million insurance reimbursement in 2025 and 2024, respectively.

b) CO₂ sustaining capital includes \$14 million and \$8 million for ETV in 2025 and 2024, respectively.

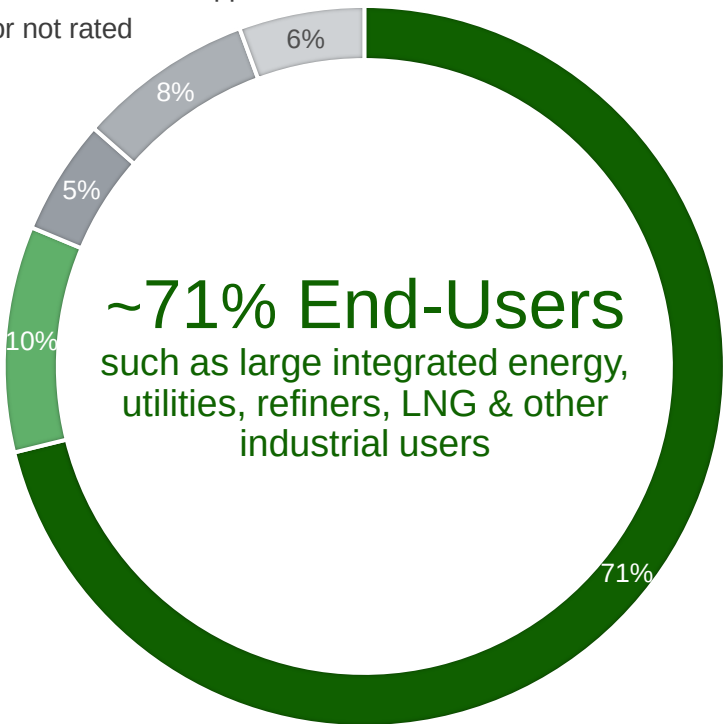
c) Includes sustaining capital expenditures from JVs of \$174 million and \$179 million in 2025 and 2024, respectively.

Customers Are Primarily End-Users of the Products We Handle

Net Revenues Underpinned by Investment Grade Counterparties & Credit Support | Ratings as of January 10, 2025

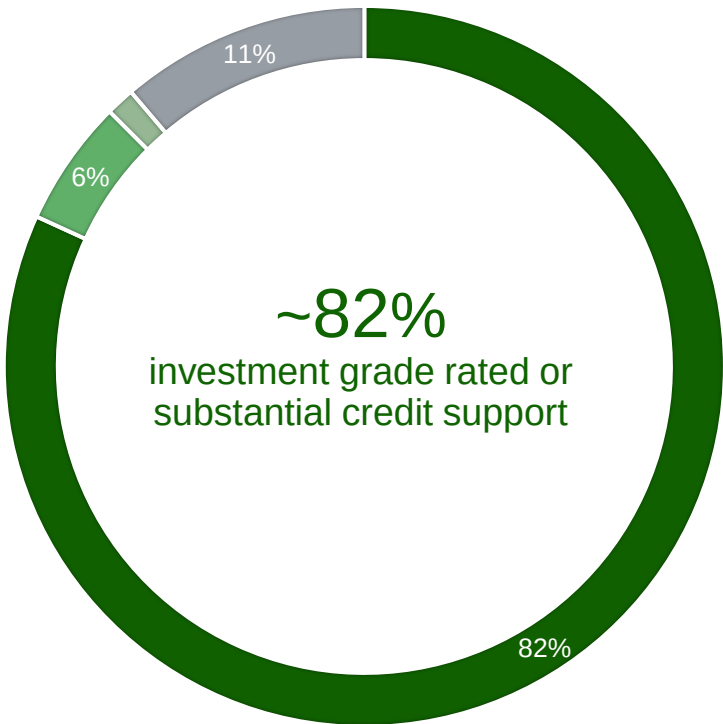
CUSTOMER TYPE

- End-user
- Producer - IG or substantial credit support
- Producer - non-IG or not rated
- Midstream
- Marketer



CREDIT RATING

- IG or substantial credit support
- BB+ to B
- B- or below
- Not rated



~1% of customers are B- or lower rated after collateral & remarketing efforts

Natural Gas Projects Placed Into Service During 2024

ASSET	PROJECT	IN-SERVICE DATE: 2024												CAPACITY (mDthd)	KM SHARE CAPITAL (\$mm)
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		
TGP	Evangeline Pass Phase I													900	\$283
	Port Sulphur Dispatch													235	70
	Sunnyside Lackawanna													40	18
	Heidelberg													50	8
Texas	Central Texas Pipeline													225	110
Intrastates	Markham Storage Expansion													7 Bcf	49
NGPL	Permian North I													80	27
EPNG	Line No. 1110 Expansion													20	10
	Copper Crossing													195	7
	Apache II													35	4
SNG	Eastern Flex													6	2
FGT	Lakeland													55	13
	Livingston Parish													5	1
Subtotal Pipelines & Storage															\$602
EBITDA build multiple															4.5x
Gathering & Processing	KMTP Eagleford Gathering													400	158
	Hiland Rough Creek CS													25	50
	KinderHawk Elm Grove Plant Expansion													210	45
	KinderHawk Coughatta Gathering North Loop													150	27
	Altamont Bluebell Plant Expansion													5	16
Subtotal Gathering & Processing															\$296
Total Natural Gas Segment															\$898

Note: EBITDA build multiple reflects KMI share of estimated capital divided by estimated Project EBITDA (a non-GAAP financial measure). See Non-GAAP Financial Measures & Reconciliations.

~\$7.2 Billion Natural Gas Project Backlog

ASSET	PROJECT	KM SHARE CAPITAL (\$mm)	CAPACITY (mdTHD)	IN-SERVICE DATE	PROJECT STATUS
TGP	Mississippi Crossing	\$1,637	2,100	4Q28	Permitting
	Evangeline Pass Project	293	1,100	3Q25	Under construction
	Cumberland Project	222	245	3Q25 ^(a)	Permitting
	Sta. 40	78	200	4Q25	Under construction
	Cheatham County Project	65	255	2Q28	Permitting
	Muskrat Expansion	63	225	3Q25	Under construction
TX Intrastates	Trident Pipeline	1,650	1,500	1Q27	Permitting
	GCX Horsepower Expansion	161	570	2Q26	Under construction
	Tejas South to Houston Mkt (Phase I & 2)	154	780	1Q25, 3Q25	Under construction
	Various TX Intrastate Projects	111	920	Various 2025	Various
SNG	South System 4 (including EEC portion of project)	1,659	1,200	4Q28, 4Q29	Permitting
	Evangeline Pass Project	96	1,100	3Q25	Under construction
	Various SNG Projects	13	35	Various 2025	Various
Double H	Hiland Express NGL Conversion	149	--	1Q26	Permitting
NGPL	Various NGPL Projects	96	350	Various 2025, 2026, 2027	Various
FGT	South Louisiana (I & II)	59	175	2Q25, 1Q27	Under construction (Ph. I), Permitting (Ph. II)
	Other FGT Projects	36	360	Various 2025	Various
WYCO & WIC	Various WYCO & WIC Projects	70	235	Various 2025, 2026	Various
EPNG	Various EPNG Projects	42	90	Various 2025, 2026	Various
Red Cedar	CCS Project	40	25	1Q25	Under construction
KMLP	Texas Header Project	31	5,000	4Q27	Permitting
Subtotal Pipelines & Storage, CCS EBITDA build multiple		\$6,724 6.0x	Contracted, stable cash flows, minimal direct commodity exposure		
Gathering & Processing	Altamont Projects	263	100	Various 2025	Various
	Haynesville Projects	58	340	Various 2025	Various
	Bakken Projects	51	45	Various 2025	Various
	Rockies Projects	23	300	Various 2026	Various
	Well Connects / Other	82	Various	Various 2025	Various
Subtotal Gathering & Processing		\$477	Primarily fixed-fee, volume-based cash flows		
Total Natural Gas segment		\$7,201			

Note: EBITDA build multiple reflects KMI share of estimated capital divided by estimated Project EBITDA (a non-GAAP financial measure). See Non-GAAP Financial Measures & Reconciliations.

a) Pending litigation may delay project.

Tankers Meeting Domestic Maritime Demand

Largest Jones Act Tanker Fleet and Most Efficient Vessels

American Petroleum Tankers

- 16 fuel-efficient Jones Act tankers
- Largest fleet with the most modern vessels; average age of 10.8 years

Jones Act fundamentals are strong

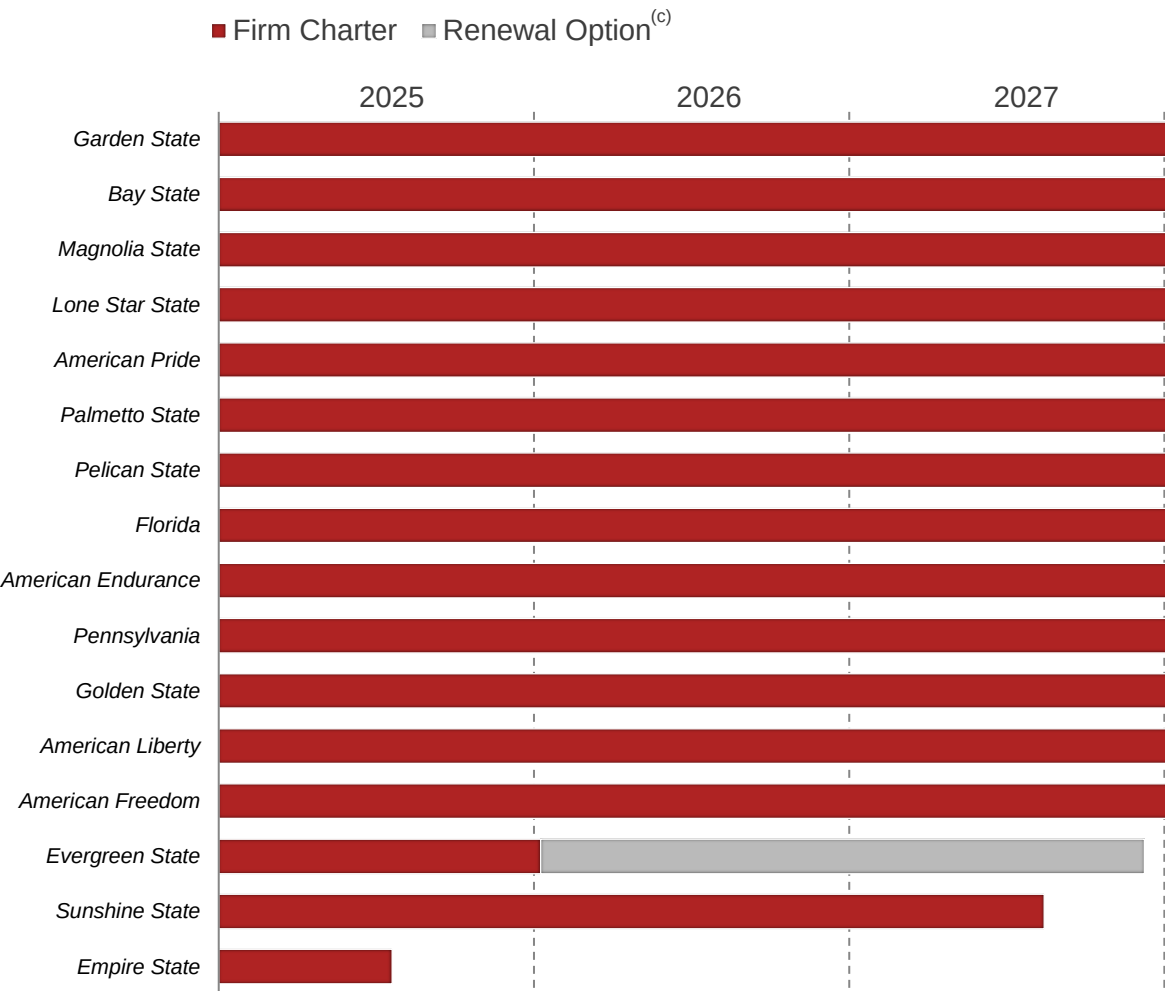
- Spot rates for Medium Range (MR) Jones Act tankers have increased nearly 50% over the past 3 years
- 100% of fleet is utilized under favorable market fundamentals
- Global maritime emission regulations favor KMI’s efficient vessels over older vessels

Multiple charters extended at higher rates with additional long-term upside upon renewal

- Spot time charter rates for MR Jones Act tankers are nearing \$90k per day^(a)
- New-build MR capital cost >\$200MM/vessel with earliest potential deliveries in 2028^(a); would require term charter rate of >\$115K/day^(a) to underwrite

APT charter profile has little near term risk and will benefit from an increasing rate environment

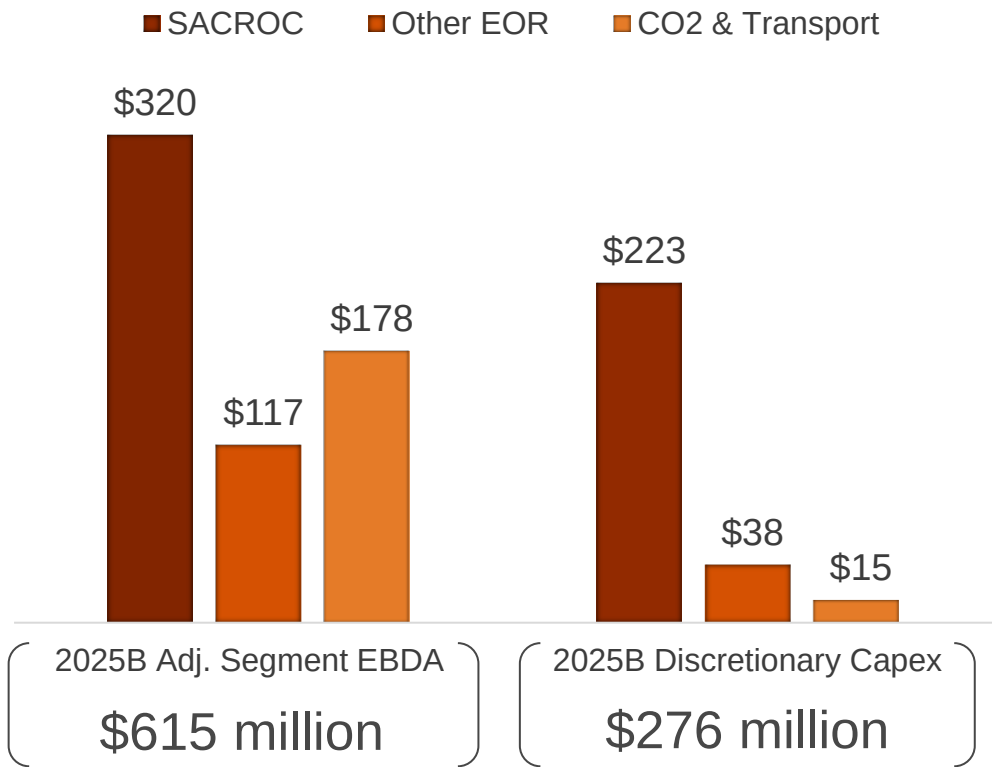
% of Vessel Days Under Charter ^(b)			
	2025	2026	2027
Firm	97%	88%	85%
With Likely Options	97%	94%	91%



Average firm charter term remaining is over 4 years

a) Source: Wilson Gillette Report, December 2024 by Navigistics Consulting.
b) Percentage of Vessel Days Under Charter calculated as 16 vessels x 365 days, adjusted for scheduled dry docks.
c) All option days are US Gov’t contracts which are restricted to one-year terms.

CO₂ EOR & Transport Budget and Sensitivities



Proven capital discipline

2025B CO₂ EOR & Transport Free Cash Flow of \$312 million^(a)

2025B Assumptions	Change	Potential Impact to Adj. EBITDA (full year)
Crude oil & NGL production 34 mbbld net	+/- 5% in net volumes	\$35.5 million
CO ₂ sales 329 mmcf/d net	+/- 5% mmcf/d in net volumes	\$5.7 million
\$68.00/bbl WTI crude oil price	+/- \$1/bbl WTI	\$3.9 million
49% NGL/crude oil price ratio ^(b)	+/- 1% NGL / crude oil price ratio	\$2.4 million

HEDGED VOLUMES as of 1/9/2025				
	2025	2026	2027	2028
Crude Oil – West Texas Intermediate				
\$/bbl	\$66.87	\$65.94	\$65.71	\$64.55
bbl/d	22,299	13,400	8,100	3,700
NGLs				
\$/bbl	\$49.13			
bbl/d	3,312			

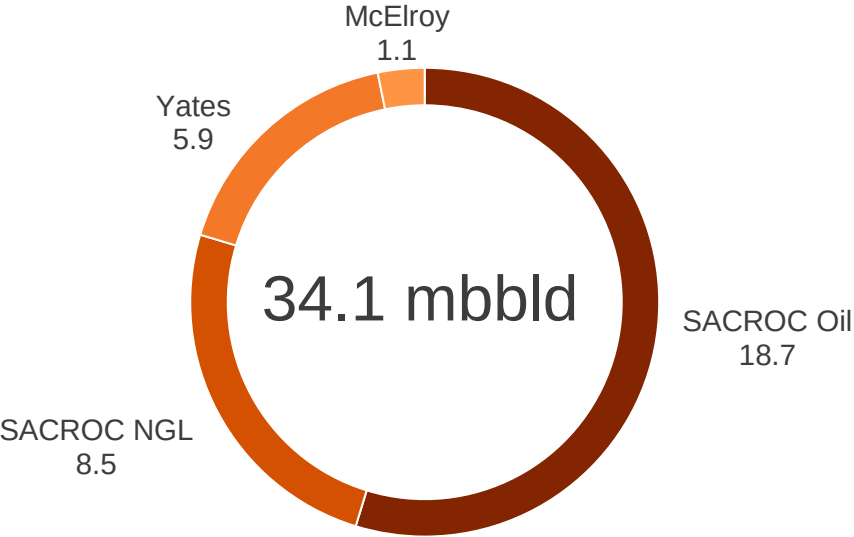
Note: Adjusted Segment EBDA, CO₂ EOR & Transport Free Cash Flow, and Adjusted EBITDA are non-GAAP financial measures. See Non-GAAP Financial Measures & Reconciliations. SACROC statistics include Diamond M.

a) 2025B capex includes \$276 million discretionary and \$27 million sustaining capital.

b) NGL to crude oil price ratio excludes transportation and fractionation fees. When accounting for these fees, the ratio would be 46%, with no impact on the full-year sensitivity of \$2.4 million.

CO₂ Segment Budgeted Volumes & Highlights

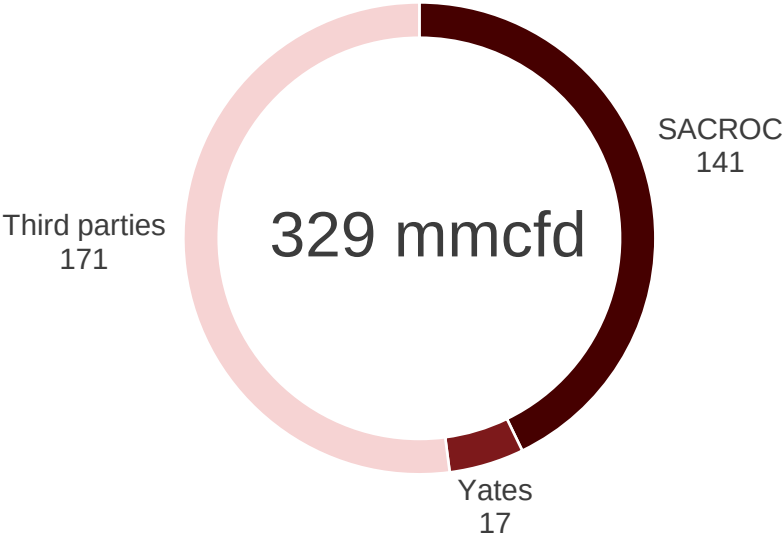
2025B NET OIL & NGL PRODUCTION
mbbld



Oil & Gas

- Majority of required takeaway capacity provided by KMI-owned Wink pipeline
- ~87% of 2025B oil production hedged to WTI price

2025B NET CO₂ SALES
mmcf



CO₂ & Transport

- Supplies >80% of CO₂ to Permian including 100% to KMI oil & gas business
- 100% of 2025B CO₂ production is contracted, including 83% subject to minimum volume commitments
- ~5.8 years weighted average remaining contract life with third parties

Note: SACROC statistics include Diamond M. Production figures do not sum to total due to rounding.

Joint Venture Treatment in Key Metrics

	KM does not control nor consolidate KM portion referred to as equity investments in financial statements	KM controls & fully consolidates Third party portion referred to as noncontrolling interests in financial statements	
Example JVs	SNG (50%), NGPL (37.5%), GCX (34%) Please see Note 7 in our 10K for list of material equity investments	Elba Liquefaction (25.5%), BOSTCO (55%)	
Financial Metrics	Earnings from Equity Investments <i>KM share of JV Net Income</i>	Consolidated throughout income statement <i>100% of JV</i>	Consolidated throughout income statement <i>100% of JV</i>
	Net Income & Segment EBDA	Net Income	Net Income
	+ Certain Items <i>KM Share</i>	+ DD&A + G&A and Corporate Charges + Interest Expense + Book Taxes <i>100% of JV</i>	- Net Income Attributable to Noncontrolling Interests Net Income Attributable to Kinder Morgan, Inc.
	Adjusted Segment EBDA	Segment EBDA	+ DD&A + Book Taxes + Interest Expense + Certain Items <i>KM share</i>
	+ DD&A ^(a) + Book Takes <i>KM Share</i>	+ Certain Items <i>100% of JV</i>	Adjusted EBITDA
	Adjusted EBITDA	Adjusted Segment EBDA	
Debt	No JV debt included JV's Adjusted EBITDA contribution is <u>after subtracting</u> interest expense	100% of JV debt included, if any fully consolidated on balance sheet	
Sustaining Capital	Includes KM owned % of JV sustaining capital		
Discretionary Capital	Includes KM contributions to JVs based on % owned, including for projects & debt repayment		

Note: Adjusted Segment EBDA and Adjusted EBITDA are non-GAAP financial measures. See Non-GAAP Financial Measures & Reconciliations.

a) Includes amortization of basis differences related to our JVs.



NON-GAAP FINANCIAL MEASURES & RECONCILIATIONS

Altamont Ravolla Compressor Station

Use of Non-GAAP Financial Measures

Our non-GAAP financial measures described below should not be considered alternatives to GAAP net income attributable to Kinder Morgan, Inc. or other GAAP measures and have important limitations as analytical tools. Our computations of these non-GAAP financial measures may differ from similarly titled measures used by others. You should not consider these non-GAAP financial measures in isolation or as substitutes for an analysis of our results as reported under GAAP. Management compensates for the limitations of our consolidated non-GAAP financial measures by reviewing our comparable GAAP measures identified in the descriptions of consolidated non-GAAP measures below, understanding the differences between the measures and taking this information into account in its analysis and its decision-making processes.

Adjusted Net Income Attributable to Kinder Morgan, Inc. (previously referred to as “Adjusted Earnings”) is calculated by adjusting net income attributable to Kinder Morgan, Inc. for Certain Items. Adjusted Net Income Attributable to Kinder Morgan, Inc. is used by us, investors and other external users of our financial statements as a supplemental measure that provides decision-useful information regarding our period-over-period performance and ability to generate earnings that are core to our ongoing operations. We believe the GAAP measure most directly comparable to Adjusted Net Income Attributable to Kinder Morgan, Inc. is net income attributable to Kinder Morgan, Inc.

Adjusted Net Income Attributable to Common Stock is calculated by adjusting net income attributable to Kinder Morgan, Inc., the most comparable GAAP measure, for Certain Items, and further for net income allocated to participating securities. For periods from 2016 to 2018, also reflects an adjustment for preferred stock dividends. We are adopting Adjusted Net Income Attributable to Common Stock because we believe it allows for calculation of Adjusted EPS on the most comparable basis with earnings per share, the comparable GAAP measure to Adjusted EPS. **Adjusted EPS** is calculated as Adjusted Net Income Attributable to Common Stock divided by our weighted average shares outstanding. Adjusted EPS applies the same two-class method used in arriving at basic earnings per share. Adjusted EPS is used by us, investors and other external users of our financial statements as a per-share supplemental measure that provides decision-useful information regarding our period-over-period performance and ability to generate earnings that are core to our ongoing operations.

Certain Items, as adjustments used to calculate our non-GAAP financial measures, are items that are required by GAAP to be reflected in net income attributable to Kinder Morgan, Inc., but typically either (i) do not have a cash impact (for example, unsettled commodity hedges and asset impairments), or (ii) by their nature are separately identifiable from our normal business operations and in most cases are likely to occur only sporadically (for example, certain legal settlements, enactment of new tax legislation and casualty losses). We also include adjustments related to joint ventures (see “Amounts from Joint Ventures” below).

Adjusted Segment EBDA is calculated, for an individual segment, by adjusting segment earnings before DD&A, amortization of excess cost of equity investments, general and administrative expenses and corporate charges, interest expense, and income taxes (Segment EBDA) for Certain Items attributable to the segment. Adjusted Segment EBDA is used by management in its analysis of segment performance and management of our business. We believe Adjusted Segment EBDA is a useful performance metric because it provides management, investors and other external users of our financial statements additional insight into performance trends across our business segments, our segments’ relative contributions to our consolidated performance and the ability of our segments to generate earnings on an ongoing basis. Adjusted Segment EBDA is also used as a factor in determining compensation under our annual incentive compensation program for our business segment presidents and other business segment employees. We believe it is useful to investors because it is a measure that management uses to allocate resources to our segments and assess each segment’s performance. We believe the GAAP measure most directly comparable to Adjusted Segment EBDA is Segment EBDA. **Total Adjusted Segment EBDA** is calculated as the sum of all our segments’ respective Adjusted Segment EBDA or, to the extent that a segment has no reportable Certain Items, Segment EBDA.

Adjusted EBITDA is calculated by adjusting net income attributable to Kinder Morgan, Inc. before interest expense, income taxes, DD&A, and amortization of excess cost of equity investments (EBITDA) for Certain Items. For periods from 2017 to 2019, Adjusted EBITDA also reflects an adjustment for Kinder Morgan Canada Limited noncontrolling interest. We also include amounts from joint ventures for income taxes and DD&A (see “Amounts from Joint Ventures” below). Adjusted EBITDA (on a rolling 12-months basis) is used by management, investors and other external users, in conjunction with our Net Debt (as described further below), to evaluate our leverage. Management and external users also use Adjusted EBITDA as an important metric to compare the valuations of companies across our industry. Our ratio of Net Debt-to-Adjusted EBITDA is used as a supplemental performance target for purposes of our annual incentive compensation program. We believe the GAAP measure most directly comparable to Adjusted EBITDA is net income attributable to Kinder Morgan, Inc.

Use of Non-GAAP Financial Measures (Continued)

Amounts from Joint Ventures - Certain Items, DCF and Adjusted EBITDA reflect amounts from unconsolidated joint ventures (JVs) and consolidated JVs utilizing the same recognition and measurement methods used to record “Earnings from equity investments” and “Noncontrolling interests (NCI),” respectively. The calculations of DCF and Adjusted EBITDA related to our unconsolidated and consolidated JVs include the same items (DD&A and income tax expense, and for DCF only, also cash taxes and sustaining capital expenditures) with respect to the JVs as those included in the calculations of DCF and Adjusted EBITDA for our wholly-owned consolidated subsidiaries; further, we remove the portion of these adjustments attributable to non-controlling interests. Although these amounts related to our unconsolidated JVs are included in the calculations of DCF and Adjusted EBITDA, such inclusion should not be understood to imply that we have control over the operations and resulting revenues, expenses or cash flows of such unconsolidated JVs.

Net Debt is calculated by subtracting from debt (1) cash and cash equivalents, (2) debt fair value adjustments, and (3) the foreign exchange impact on Euro-denominated bonds for which we have entered into currency swaps. Net Debt, on its own and in conjunction with our Adjusted EBITDA (on a rolling 12-months basis) as part of a ratio of Net Debt-to-Adjusted EBITDA, is a non-GAAP financial measure that is used by management, investors, and other external users of our financial information to evaluate our leverage. For periods from 2016 to 2018, Net Debt also reflects subtraction of the preferred interest in the general partner of Kinder Morgan Energy Partners L.P. Our ratio of Net Debt-to-Adjusted EBITDA is also used as a supplemental performance target for purposes of our annual incentive compensation program. We believe the GAAP measure most comparable measure to Net Debt is total debt.

DCF, or Distributable Cash Flow, is calculated by adjusting net income attributable to Kinder Morgan, Inc. for Certain Items, and further for DD&A and amortization of excess cost of equity investments, income tax expense, cash taxes, sustaining capital expenditures and other items. We also adjust amounts from joint ventures for income taxes, DD&A, cash taxes and sustaining capital expenditures (see “Amounts from Joint Ventures” above). DCF is used by us to evaluate our performance and to measure and estimate the ability of our assets to generate economic earnings after paying interest expense, paying cash taxes and expending sustaining capital. DCF provides additional insight into the specific costs associated with our assets in the current period and facilitates period-to-period comparisons of our performance from ongoing business activities. DCF per share serves as the primary financial performance target for purposes of annual bonuses under our annual incentive compensation program and for performance-based vesting of equity compensation grants under our long-term incentive compensation program. DCF should not be used as an alternative to net cash provided by operating activities computed under GAAP. We believe the GAAP measure most directly comparable to DCF is net income attributable to Kinder Morgan, Inc. **DCF per share** is DCF divided by average outstanding shares, including restricted stock awards that participate in dividends.

Project EBITDA, which we use to calculate EBITDA build multiples, is calculated for an individual capital project as earnings before interest expense, taxes, DD&A and general and administrative expenses attributable to such project, or for JV projects, consistent with the methods described above under “Amounts from Joint Ventures,” and in conjunction with capital expenditures for the project. Management, investors and others use Project EBITDA to evaluate our return on investment for capital projects before expenses that are generally not controllable by operating managers in our business segments. We believe the GAAP measure most directly comparable to Project EBITDA is the portion of net income attributable to a capital project. We do not provide the portion of budgeted net income attributable to individual capital projects (the GAAP financial measure most directly comparable to Project EBITDA) due to the impracticality of predicting, on a project-by-project basis through the second full year of operations, certain amounts required by GAAP, such as projected commodity prices, unrealized gains and losses on derivatives marked to market, and potential estimates for certain contingent liabilities associated with the project completion.

Acquisition EBITDA Multiples - With respect to projected EBITDA multiples associated with acquired assets or businesses, we do not provide the portion of budgeted net income attributable to individual acquisitions (the GAAP financial measure most directly comparable to projected EBITDA for acquired assets or businesses) due to the impracticality of predicting, certain amounts required by GAAP, such as projected commodity prices, unrealized gains and losses on derivatives marked to market, and potential estimates for certain contingent liabilities associated with the acquisition.

FCF, or Free Cash Flow, is calculated by reducing cash flow from operations for capital expenditures (sustaining and expansion), and FCF after dividends is calculated by further reducing FCF for dividends paid during the period. FCF is used by management, investors and other external users as an additional leverage metric, and FCF after dividends provides additional insight into cash flow generation. We believe the GAAP measure most directly comparable to FCF is cash flow from operations.

CO₂ EOR & Transport, Terminals and Product Pipelines Free Cash Flow is calculated by reducing Segment EBDA from our CO₂ EOR & Transport assets, Terminals, and Products Pipeline segment by Certain Items, capital expenditures (sustaining and expansion) and acquisitions attributable to the EOR & Transport assets, Terminals, and Products Pipeline segment. Management uses CO₂ EOR & Transport, Terminals, and Product Pipelines Free Cash Flow as an additional performance measure for our CO₂ EOR & Transport assets, Terminals, and Products Pipelines segment. We do not provide budgeted CO₂ EOR & Transport, Terminals, and Products Pipeline Segment EBDA (the GAAP financial measure most directly comparable to 2025 budgeted CO₂ EOR & Transport, Terminals, and Product Pipelines FCF) due to the inherent difficulty and impracticability of predicting certain amounts required by GAAP, such as potential changes in estimates for certain contingent liabilities and unrealized gains and losses.

Net Income, Adjusted Net Income Attributable to KMI, and DCF

\$ in millions

	2025 Budget	2024 Actual	Change	
			\$	%
Net income attributable to KMI	\$ 2,829	\$ 2,613	\$ 216	8%
Certain Items				
Change in fair value of derivative contracts	-	72	(72)	(100%)
Loss on impairment	-	(69)	69	100%
Income tax Certain Items	-	(52)	52	100%
Other	2	7	(5)	(71%)
Total Certain Items	2	(42)	44	105%
Adjusted Net income attributable to KMI	\$ 2,831	\$ 2,571	\$ 260	10%
Net income attributable to KMI	\$ 2,829	\$ 2,613	\$ 216	8%
Total Certain Items	2	(42)	44	105%
DD&A	2,411	2,354	57	2%
Income tax expense ^(a)	817	739	78	11%
Cash taxes	(77)	(33)	(44)	(133%)
Sustaining capital expenditures	(938)	(986)	48	5%
Amounts associated with joint ventures				
Unconsolidated JV DD&A ^(b)	408	409	(1)	(0%)
Remove consolidated JV partners' DD&A	(64)	(62)	(2)	(3%)
Unconsolidated JV income tax expense ^{(c)(d)}	85	78	7	9%
Unconsolidated JV cash taxes ^(c)	(82)	(48)	(34)	(71%)
Unconsolidated JV sustaining capital expenditures	(184)	(189)	5	3%
Remove consolidated JV partners' sustaining capital expenditures	10	10	-	-
Other items ^(e)	24	38	(14)	(37%)
DCF	\$ 5,241	\$ 4,881	\$ 360	7%
Weighted average shares outstanding for dividends ^(f)	2,237	2,233	4	0%
DCF per share ^(g)	\$ 2.34	\$ 2.19	\$ 0.15	7%

Note: Adjusted Earnings and Distributable Cash Flow (DCF), in aggregate and per share, are non-GAAP financial measures. See Non-GAAP Financial Measures and Reconciliations.

- a) To avoid duplication, amounts are adjusted to exclude amounts which are already included within "Certain Items" above.
- b) Includes amortization of basis differences related to our JVs.
- c) Associated with our Citrus, NGPL and Products (SE) Pipe Line equity investments.
- d) Includes the tax provision on Certain Items recognized by the investees that are taxable entities. The impact of KMI's income tax provision on Certain Items affecting earnings from equity investments is included within "Certain Items" above. See table included in "Non-GAAP Financial Measures—Certain Item."
- e) Includes pension contributions, non-cash pension expense and non-cash compensation associated with our restricted stock program.
- f) Includes 15 million and 15 million average unvested restricted shares that participate in dividends in 2025 and 2024, respectively.
- g) 2025 Budget DCF per share of \$2.34 consists of the following quarterly amounts: Q1 \$0.66, Q2 \$0.49, Q3 \$0.54, Q4 \$0.65.

2014 and 2025B Reconciliation of Segment EBDA to Adjusted Segment EBDA

\$ in millions

Segment EBDA ^(a)	2025 Budget	2014 Actual
Natural Gas Pipelines Segment EBDA	\$ 5,636	\$ 4,288
Certain Items ^(b)		
Contract early termination revenue	-	(198)
Change in fair value of derivative contracts	-	2
Loss on impairments, divestitures and other write-downs, net	-	(1)
Other	-	4
Certain Items	-	(193)
Natural Gas Pipelines Adjusted Segment EBDA	5,636	4,095
Products Pipelines Segment EBDA	1,179	787
Certain Items ^(b)		
Loss on impairments, divestitures and other write-downs, net	-	3
Other	-	4
Certain Items	-	7
Products Pipelines Adjusted Segment EBDA	1,179	794
Terminals Segment EBDA	1,103	973
Certain Items ^(b)		
Loss on impairments, divestitures and other write-downs, net	-	29
Other	-	6
Certain Items	-	35
Terminals Adjusted Segment EBDA	1,103	1,008

Segment EBDA ^(a)	2025 Budget	2014 Actual
CO ₂ Segment EBDA	755	1,248
Certain Items ^(b)		
Change in fair value of derivative contracts	-	(25)
Loss on impairments, divestitures and other write-downs, net	-	243
Certain Items	-	218
CO ₂ Adjusted Segment EBDA ^(c)	755	1,466
Canada Adjusted Segment EBDA	-	200
Total Adjusted Segment EBDA ^(d)	\$ 8,673	\$ 7,563

a) Includes revenues, earnings from equity investments, operating expenses, other (income) expense, net, and other, net. Operating expenses include costs of sales, operations and maintenance expenses, and taxes, other than income taxes. The composition of Segment EBDA is not addressed nor prescribed by generally accepted accounting principles. 2014 amounts are adjusted to reflect categorization of basis difference amortization (amortization of excess cost of equity investments) consistent with 2025 Segment EBDA accounting change.

b) See "Non-GAAP Financial Measures—Certain Items."

c) 2025 includes \$140 million of EBDA associated with our ETV business. 2014 actuals consist of only our CO₂ EOR and Transport business.

d) Calculated as the sum of all our segments' respective Adjusted Segment EBDA or, to the extent that a segment has no reportable Certain Items, Segment EBDA.

2024 Reconciliation of Recasted Adjusted Segment EBDA

\$ in millions

Segment EBDA ^(a)	2024 Actual	Adjustment ^(b)	2024 Recasted
Natural Gas Pipelines Segment EBDA	\$ 5,427	\$ (34)	\$ 5,393
Certain Items ^(c)			-
Change in fair value of derivative contracts	75	-	75
Loss on impairments, divestitures and other write-downs, net	(29)	-	(29)
Certain Items	46	-	46
Natural Gas Pipelines Adjusted Segment EBDA	5,473	(34)	5,439
Products Pipelines Segment EBDA	1,173	(9)	1,164
Certain Items	-	-	-
Products Pipelines Adjusted Segment EBDA	1,173	(9)	1,164
Terminals Segment EBDA	1,099	(0)	1,099
Certain Items	-	-	-
Terminals Adjusted Segment EBDA	1,099	(0)	1,099
CO ₂ Segment EBDA	692	(7)	685
Certain Items ^(c)			-
Change in fair value of derivative contracts	2	-	2
Loss on impairments, divestitures and other write-downs, net	(40)	-	(40)
Certain Items	(38)	-	(38)
CO ₂ Adjusted Segment EBDA ^(d)	654	(7)	647
Total Adjusted Segment EBDA ^(e)	\$ 8,399	\$ (50)	\$ 8,349

a) Includes revenues, earnings from equity investments, operating expenses, other (income) expense, net, and other, net. Operating expenses include costs of sales, operations and maintenance expenses, and taxes, other than income taxes. The composition of Segment EBDA is not addressed nor prescribed by generally accepted accounting principles.

b) Represents categorization of basis difference amortization (amortization of excess cost of equity investments) consistent with 2025 Segment EBDA accounting change.

c) See "Non-GAAP Financial Measures—Certain Items."

d) Includes \$45 million of EBDA associated with our ETV business.

e) Calculated as the sum of all our segments' respective Adjusted Segment EBDA or, to the extent that a segment has no reportable Certain Items, Segment EBDA.

Reconciliation of Adjusted Net Income Attributable to Common Stock and Adjusted EPS

\$ in millions

	2016	2017	2018	2019	2020	2021	2022	2023	2024
Net income attributable to KMI	\$ 708	\$ 183	\$ 1,609	\$ 2,190	\$ 119	\$ 1,784	\$ 2,548	\$ 2,391	\$ 2,613
NCI associated with Certain Items	(8)	-	-	-	-	-	-	-	-
Certain Items									
Fair value amortization	(143)	(53)	(34)	(29)	(21)	(19)	(15)	-	-
Legal, environmental and other reserves	(16)	(37)	12	46	26	160	51	-	-
Change in fair value of derivative contracts	75	40	80	(24)	(5)	19	57	(126)	72
Loss on impairment	848	170	317	(280)	1,927	1,535	-	67	(69)
Project write-offs	171	-	-	-	-	-	-	-	-
Impact of 2017 Tax Cuts and Jobs Act	-	219	(36)	-	-	-	-	-	-
Income tax Certain Items	18	1,085	(58)	299	(107)	(491)	(37)	33	(52)
Noncontrolling interests	-	-	240	(4)	-	-	-	-	-
Other	(20)	21	(20)	(37)	72	16	32	45	7
Total Certain Items	933	1,445	501	(29)	1,892	1,220	88	19	(42)
Preferred stock dividends	(156)	(156)	(128)	-	-	-	-	-	-
Net income allocated to participating securities ^(a)	(4)	(5)	(8)	(12)	(13)	(14)	(13)	(14)	(15)
Other ^(b)	(1)	(1)	(2)	-	-	(3)	(1)	-	1
Adjusted Net income attributable to Common Stock	\$ 1,472	\$ 1,466	\$ 1,972	\$ 2,149	\$ 1,998	\$ 2,987	\$ 2,622	\$ 2,396	\$ 2,557
Weighted average shares outstanding	2,230	2,230	2,216	2,264	2,263	2,266	2,258	2,234	2,220
Adjusted EPS	\$ 0.66	\$ 0.66	\$ 0.89	\$ 0.95	\$ 0.88	\$ 1.32	\$ 1.16	\$ 1.07	\$ 1.15

a) Net income allocated to participating securities is based on the amount of dividends paid in the current period plus an allocation of the undistributed earnings or excess distributions over earnings, as applicable.

b) Adjusted net income in excess of distributions for participating securities.

Reconciliations of KMI FCF and CO₂ EOR & Transport FCF

\$ in millions

Reconciliation of KMI FCF	2020	2021	2022	2023	2024	2025B
CFFO (GAAP)	\$ 4,550	\$ 5,708	\$ 4,967	\$ 6,491	\$ 5,635	\$ 5,899
Capital expenditures (GAAP) ^(a)	(1,707)	(1,281)	(1,621)	(2,317)	(2,629)	(3,141)
FCF	2,843	4,427	3,346	4,174	3,006	2,758
Dividends paid (GAAP)	(2,362)	(2,443)	(2,504)	(2,529)	(2,557)	(2,606)
FCF after dividends	\$ 481	\$ 1,984	\$ 842	\$ 1,645	\$ 449	\$ 152

Reconciliation of CO₂ EOR & Transport FCF

EBDA for CO ₂ EOR & Transport ^(b)	\$ (294)	\$ 750	\$ 798	\$ 658	\$ 640	\$ 615
Certain items:						
Change in fair value of derivative contracts	(6)	4	(11)	4	2	-
Loss (gain) on impairments, divestitures and other write-downs, net	950	(10)	-	-	(40)	-
Segment Certain Items	944	(6)	(11)	4	(38)	-
Adjusted EBDA for CO₂ EOR & Transport	650	744	787	662	602	615
Capital expenditures (GAAP) ^(a)	(186)	(185)	(275)	(255)	(280)	(303)
Acquisitions	-	-	-	(13)	(64)	-
CO₂ EOR & Transport FCF	\$ 464	\$ 559	\$ 512	\$ 394	\$ 258	\$ 312

a) Includes sustaining and expansion capital expenditures.

b) Includes revenues, earnings from equity investments, operating expenses, other (income) expense, net, and other, net. Operating expenses include costs of sales, operations and maintenance expenses, and taxes, other than income taxes. The composition of Segment EBDA is not addressed nor prescribed by generally accepted accounting principles.

Reconciliations of Terminals FCF and Products Pipelines FCF

\$ in millions

Reconciliation of Terminals FCF	2020	2021	2022	2023	2024	2025B
EBDA for Terminals ^(b)	\$ 1,045	\$ 908	\$ 975	\$ 1,039	\$ 1,099	\$ 1,103
Certain items:						
Loss (gain) on impairments, divestitures and other write-downs, net	(55)	34	-	-	-	-
Other	-	8	-	-	-	-
Segment Certain Items	(55)	42	-	-	-	-
Adjusted EBDA for Terminals	990	950	975	1,039	1,099	1,103
Capital expenditures (GAAP) ^(a)	(433)	(332)	(552)	(406)	(385)	(367)
Acquisitions	(8)	-	-	-	-	-
Terminals FCF	\$ 549	\$ 618	\$ 423	\$ 633	\$ 714	\$ 736

Reconciliation of Products Pipelines FCF	2020	2021	2022	2023	2024	2025B
EBDA for Products Pipelines ^(b)	\$ 967	\$ 1,041	\$ 1,072	\$ 1,033	\$ 1,164	\$ 1,179
Certain items:						
Legal, environmental and other reserves	46	53	-	-	-	-
Change in fair value of derivative contracts	-	-	-	(1)	-	-
Loss on impairments and divestitures, net	21	-	-	67	-	-
Other	(17)	-	-	-	-	-
Segment Certain Items	50	53	-	66	-	-
Adjusted EBDA for Products Pipelines	1,017	1,094	1,072	1,099	1,164	1,179
Capital expenditures (GAAP) ^(a)	(122)	(122)	-	(221)	(210)	(222)
Acquisitions	(8)	-	-	-	-	-
Products Pipelines FCF	\$ 887	\$ 972	\$ 1,072	\$ 878	\$ 954	\$ 957

a) Includes sustaining and expansion capital expenditures.

b) Includes revenues, earnings from equity investments, operating expenses, other (income) expense, net, and other, net. Operating expenses include costs of sales, operations and maintenance expenses, and taxes, other than income taxes. The composition of Segment EBDA is not addressed nor prescribed by generally accepted accounting principles.

Reconciliation of Adjusted EBITDA, Normalized for Divestitures

\$ in millions

Reconciliation of Adjusted EBITDA, Normalized for Divestitures	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025B
Net income attributable to KMI	\$ 708	\$ 183	\$ 1,609	\$ 2,190	\$ 119	\$ 1,784	\$ 2,548	\$ 2,391	\$ 2,613	\$ 2,829
NCI associated with Certain Items	(8)	-	-	-	-	-	-	-	-	-
KML noncontrolling interests ^(a)	-	28	58	33	-	-	-	-	-	-
Certain Items										
Fair value amortization	(143)	(53)	(34)	(29)	(21)	(19)	(15)	-	-	-
Legal, environmental and other reserves	(16)	(37)	12	46	26	160	51	-	-	-
Change in fair value of derivative contracts	75	40	80	(24)	(5)	19	57	(126)	72	-
Loss on impairment	848	170	317	(280)	1,927	1,535	-	67	(69)	-
Project write-offs	171	-	-	-	-	-	-	-	-	-
Impact of 2017 Tax Cuts and Jobs Act	-	219	(36)	-	-	-	-	-	-	-
Income tax Certain Items	18	1,085	(58)	299	(107)	(491)	(37)	33	(52)	-
Noncontrolling interests	-	-	240	(4)	-	-	-	-	-	-
Other	(20)	21	(20)	(37)	72	16	32	45	7	2
Total Certain Items	933	1,445	501	(29)	1,892	1,220	88	19	(42)	2
DD&A	2,209	2,261	2,297	2,411	2,164	2,135	2,186	2,250	2,354	2,411
Income tax expense ^(a)	899	853	645	627	588	860	747	682	739	817
Interest, net ^(a)	1,999	1,871	1,891	1,816	1,610	1,518	1,524	1,804	1,849	1,796
Amounts associated with joint ventures										
Unconsolidated JV DD&A ^(b)	421	459	507	494	547	390	398	389	409	408
Remove consolidated JV partners' DD&A	(13)	(16)	(22)	(19)	(40)	(44)	(50)	(63)	(62)	(64)
Unconsolidated JV income tax expense ^(a)	94	114	82	95	82	83	75	89	78	85
Adjusted EBITDA	\$ 7,242	\$ 7,198	\$ 7,568	\$ 7,618	\$ 6,962	\$ 7,946	\$ 7,516	\$ 7,561	\$ 7,938	\$ 8,284
Divested adjusted EBITDA ^(a)	(789)	(672)	(660)	(503)	(142)	(118)	(139)	(54)	(17)	-
As normalized for divestitures	\$ 6,453	\$ 6,526	\$ 6,908	\$ 7,115	\$ 6,820	\$ 7,828	\$ 7,377	\$ 7,507	\$ 7,921	\$ 8,284

a) To avoid duplication, amounts are adjusted to exclude amounts which are already included within "Certain Items" above.

b) Includes amortization of basis differences related to our JVs.

Reconciliation of Net Debt

\$ in millions

Reconciliation of Net Debt	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025B
Current portion of debt	\$ 2,696	\$ 2,828	\$ 3,388	\$ 2,377	\$ 2,558	\$ 2,646	\$ 3,385	\$ 4,049	\$ 2,009	\$ 1,209
Total long-term debt	37,354	35,015	33,936	31,915	32,131	30,674	28,403	28,067	29,881	30,207
Debt fair value adjustments	(1,149)	(927)	(731)	(1,032)	(1,293)	(902)	(115)	(187)	(102)	
Preferred interest in general partner of KMP	(100)	(100)	(100)	-	-	-	-	-	-	-
Foreign exchange impact on hedges for Euro Debt outstanding	43	(143)	(76)	(44)	(170)	(64)	8	(9)	25	
Less: cash & cash equivalents	(684)	(264)	(3,280)	(185)	(1,184)	(1,140)	(745)	(83)	(88)	(8)
Net Debt	\$ 38,160	\$ 36,409	\$ 33,137	\$ 33,031	\$ 32,042	\$ 31,214	\$ 30,936	\$ 31,837	\$ 31,725	\$ 31,408
Adjusted EBITDA	\$ 7,242	\$ 7,198	\$ 7,568	\$ 7,618	\$ 6,962	\$ 7,946	\$ 7,516	\$ 7,561	\$ 7,938	\$ 8,284
Net Debt to Adjusted EBITDA	5.3X	5.1X	4.4X	4.3X	4.6X	3.9X	4.1X	4.2X	4.0X	3.8X

Reconciliation of Adjusted Net Income Attributable to KMI Excluding Uri

\$ in millions

	2021 Actual	2021 Actual Excluding Uri
Reconciliation of Adjusted Net income attributable to KM		
Net income attributable to KMI	\$ 1,784	\$ 932
Certain Items		
Fair value amortization	(19)	(19)
Legal, environmental and other reserves	160	160
Change in fair value of derivative contracts	19	19
Loss on impairment	1,535	1,535
Income tax Certain Items	(491)	(491)
Other	16	16
Total Certain Items	1,220	1,220
Adjusted Net Income attributable to KMI	\$ 3,004	\$ 2,152