KINDER MORGAN

4Q 2026 Investor Presentation

November 2026


Elba LNG

Disclosure

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.

Irreplaceable Infrastructure Portfolio

Delivering Energy. Improving Lives.

NATURAL GAS

67%

Largest U.S. Natural Gas Transmission Network[a]

- ~58,600 miles of transmission, ~6,800 miles of gathering, & 1,300 miles of NGL pipelines
- Transport ~40% of U.S. natural gas production
- >700 bcf of working storage capacity, ~15% of U.S. capacity

REFINED PRODUCTS

26%[b]

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

- Transport ~1.7 mmbbld of refined product volumes
- ~9,000 miles of refined products & crude pipelines
- 136 liquids & bulk terminals; 16 Jones Act tankers
- 135 mmbbl of total liquids storage capacity

CO_2

7%

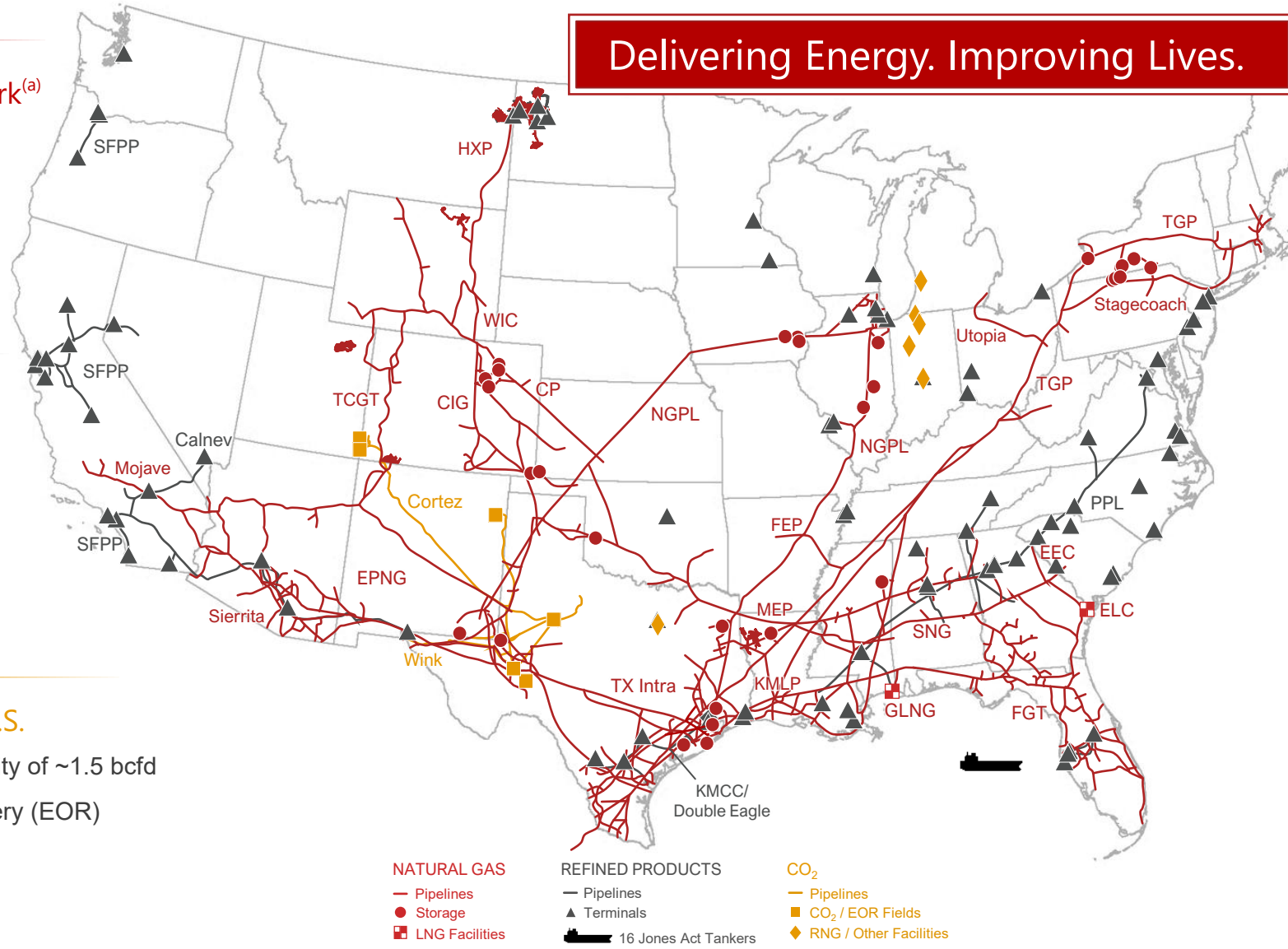
BUSINESS MIX

One of the Largest CO_2 Transporters in the U.S.

- ~1,500 miles of CO_2 pipelines with transport capacity of ~1.5 bcfd
- Produce and transport CO_2 for enhanced oil recovery (EOR)

Strategic Renewable Natural Gas Portfolio

- RNG production capacity of 6.4 bcf[c]



Note: Volumes per 2026 budget. Business mix based on 2026 budgeted Total Adjusted Segment EBDA, which is a non-GAAP financial measure. See Non-GAAP Financial Measures & Reconciliations.

a) Does not include mileage associated with natural gas gathering assets.
b) Refined Products includes 13% from our Products Pipelines Segment and 13% from our Terminals Segment.
c) Annual capacity at KMI share.

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

Currently expect **~3.6x** YE 2026 Net Debt / Adjusted EBITDA, ~0.2x favorable to budget[b]

BBB+ investment grade balance sheet

Attractive Growth Projects

~$14.4 billion of committed projects at **<6x** EBITDA build multiple

Added **~$16.0 billion** of projects to the backlog since the beginning of 2024[c]

Predictable & Growing Cash Flows

~70% of cash flows are take-or-pay or hedged[a]

Currently expect **>13%** Adj. EPS and **>6%** Adj. EBITDA growth vs 2026 budget[b]

Shareholder Returns

Increased dividend for **9th** straight year

Returned nearly **$23 billion** to shareholders over the past 10 years[d]

Note: Total Adjusted Segment EBDA, 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.

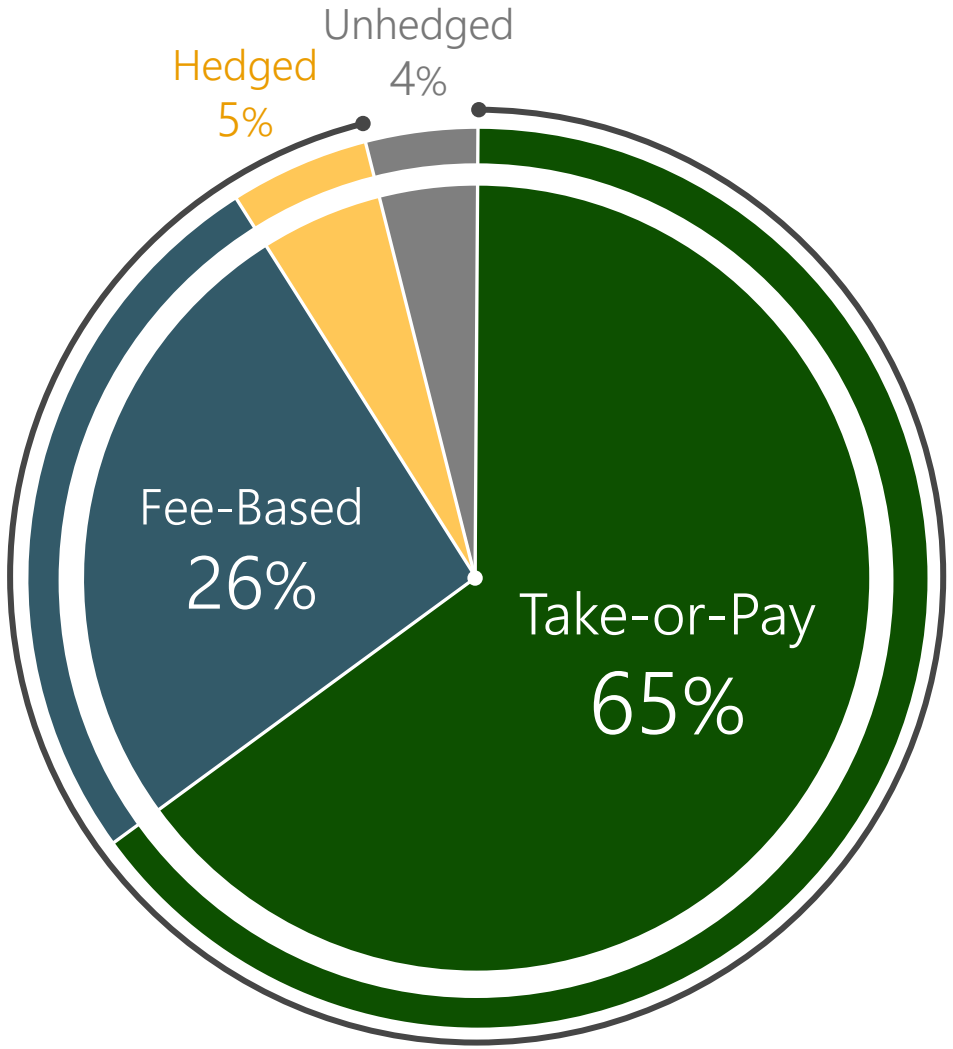
a) Based on 2026 budgeted Total Adjusted Segment EBDA.
b) Forecast as of 3Q'26 earnings.
c) We also placed nearly $4.6 billion of projects in service since 2024.
d) 2016 – 2025 dividends and share repurchases.

Highly Contracted, Predictable Cash Flows

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96% Take-or-Pay, Fee-Based, or Hedged Cash Flows

CASH FLOW MIX



65% **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
- ~40% highly stable, refined product cash flows

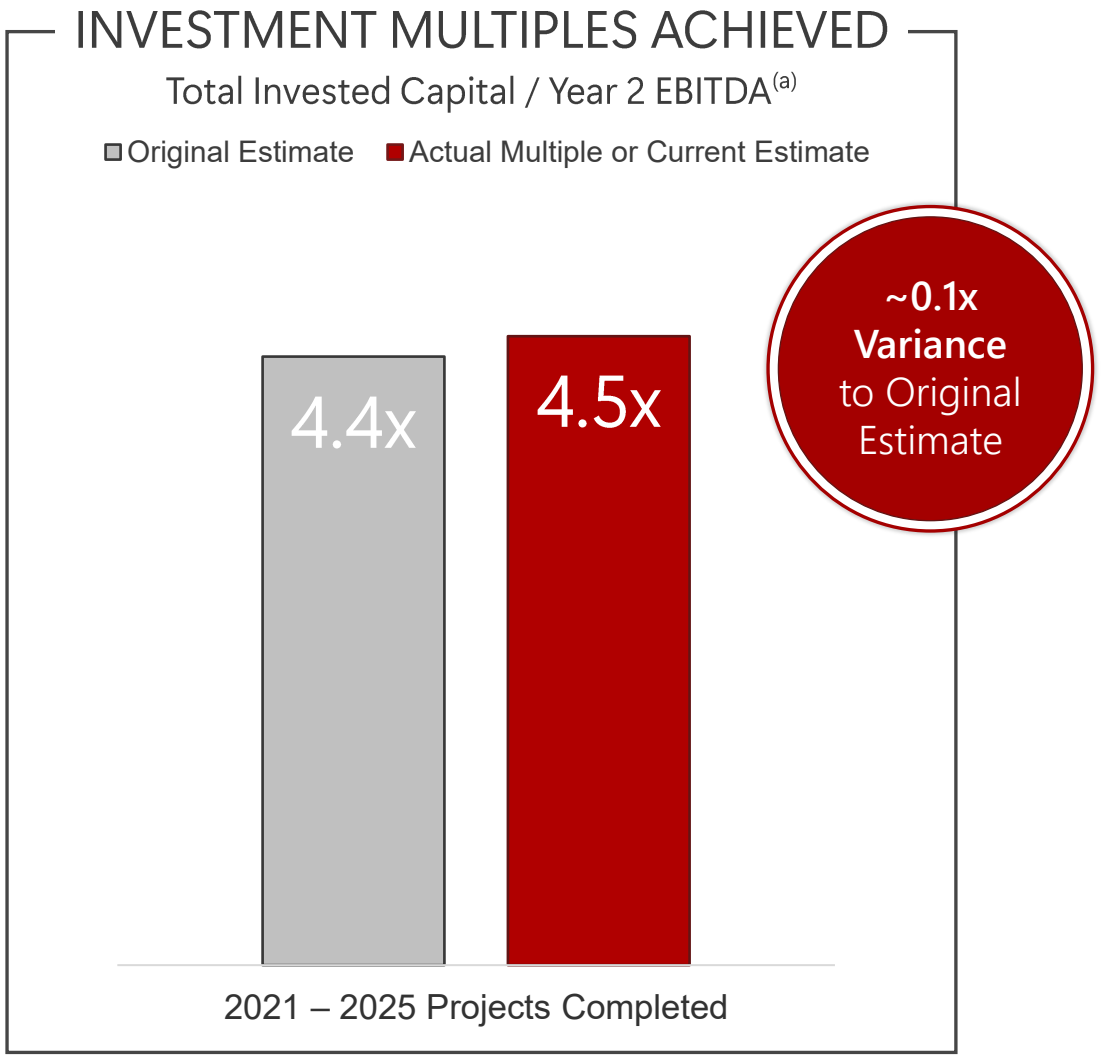
5% **Hedged**
- Disciplined approach to managing price volatility
- Substantially hedged near-term price exposure

4% **Unhedged**
- Commodity price based

Note: Cash flow mix based on 2026 budgeted Total Adjusted Segment EBDA, which is a non-GAAP financial measure. See Non-GAAP Financial Measures & Reconciliations. Includes hedging as of 1/16/2026.

Successfully Achieving Attractive Returns

Demonstrated Project Execution Provides Foundation for Delivering Future Returns



273 projects placed in service 2021-2025, representing nearly **$5.4 billion** of capital

Total capex **within 0.5%** of original estimate, despite a backdrop of **26% cumulative inflation**(b)

Vast majority of projects completed **on time** and **on budget** or **better**

Currently expect project returns(c) to be **within 100bps** from original expectations and well above our cost of capital

Proven project execution underpins confidence in our ability to deliver our **$14.4 billion backlog** at a **<6x EBITDA build multiple**

a) Multiple reflects KMI share of invested capital divided by Project EBITDA, a non-GAAP measure (see Non-GAAP Financial Measures & Reconciliations), generated in its second full year of operation. G&P projects are excluded from the investment multiple but included in all other statistics. CO_2 EOR projects are excluded from all statistics.
b) Based on cumulative U.S. PPI Final Demand inflation between November 2020 – November 2025.
c) Project returns reflect the capital-weighted average IRR for projects placed in service between 2021 – 2025.

$14.4bn Committed Growth Capital Project Backlog as of 3Q 2026 Earnings

~20% of Backlog Capital Going into Service Between 4Q 2026 and end of 2027

$ Billion	Total	
Natural Gas (excluding G&P)	$13.1	Nearly all serving end-use power, LDC, and LNG demand
Other	0.6	Primarily refined product projects
Subtotal	**$13.7**	**Contracted, stable cash flows, minimal direct commodity exposure**
EBITDA Build Multiple	**~5.7x**	
Gathering & Processing	0.2	Mostly natural gas, volume-based projects
EOR	0.5	Commodity price & volume-based cash flows
Total Backlog	**$14.4**	

$13.2 billion
Record natural gas backlog

1H 2029
Capital-weighted average expected in-service date

~$4 billion
Expected annual growth capex over next few years

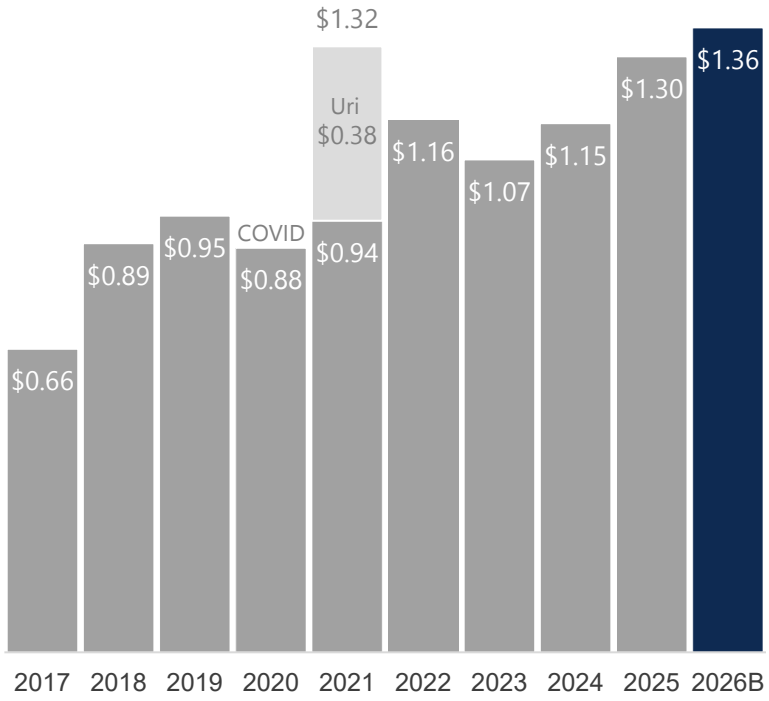
Note: Figures may not sum due to rounding. Other includes projects in our Products Pipelines and Terminals Segments. EBITDA build multiple reflects KMI share of estimated capital divided by estimated Project EBITDA (a non-GAAP financial measure). See Non-GAAP Financial Measures & Reconciliations.

Growing Earnings While Reducing Leverage

Trend Over the Past Decade

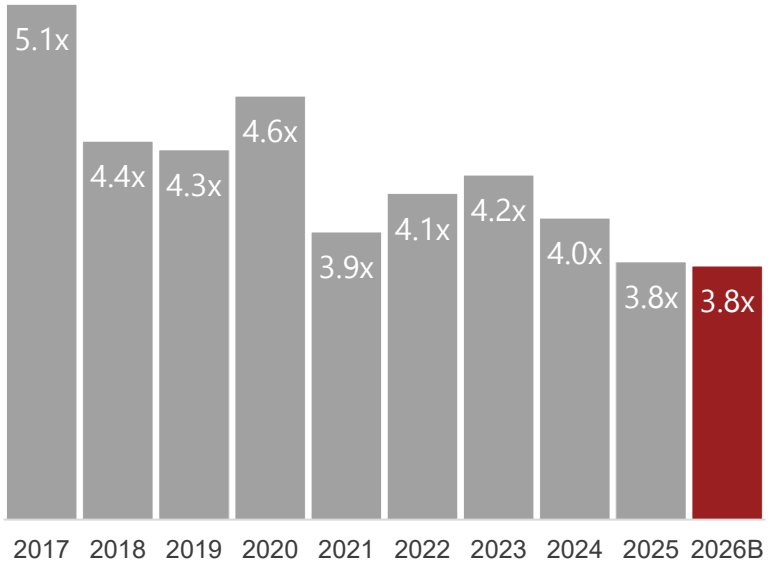
ADJUSTED EPS

8% CAGR



NET DEBT / ADJUSTED EBITDA

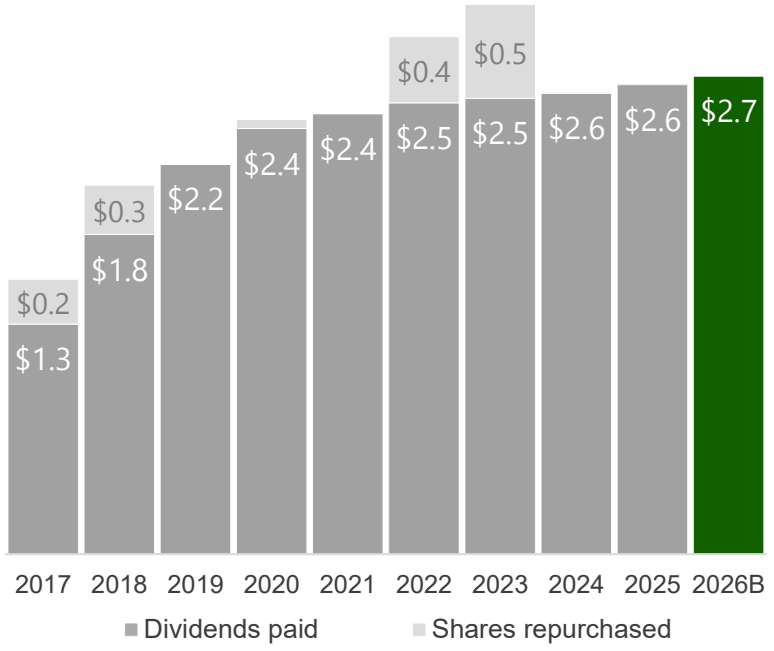
26% decrease in leverage



DIVIDENDS PAID & SHARES REPURCHASED[a]

$ Billion

$24 billion returned to shareholders

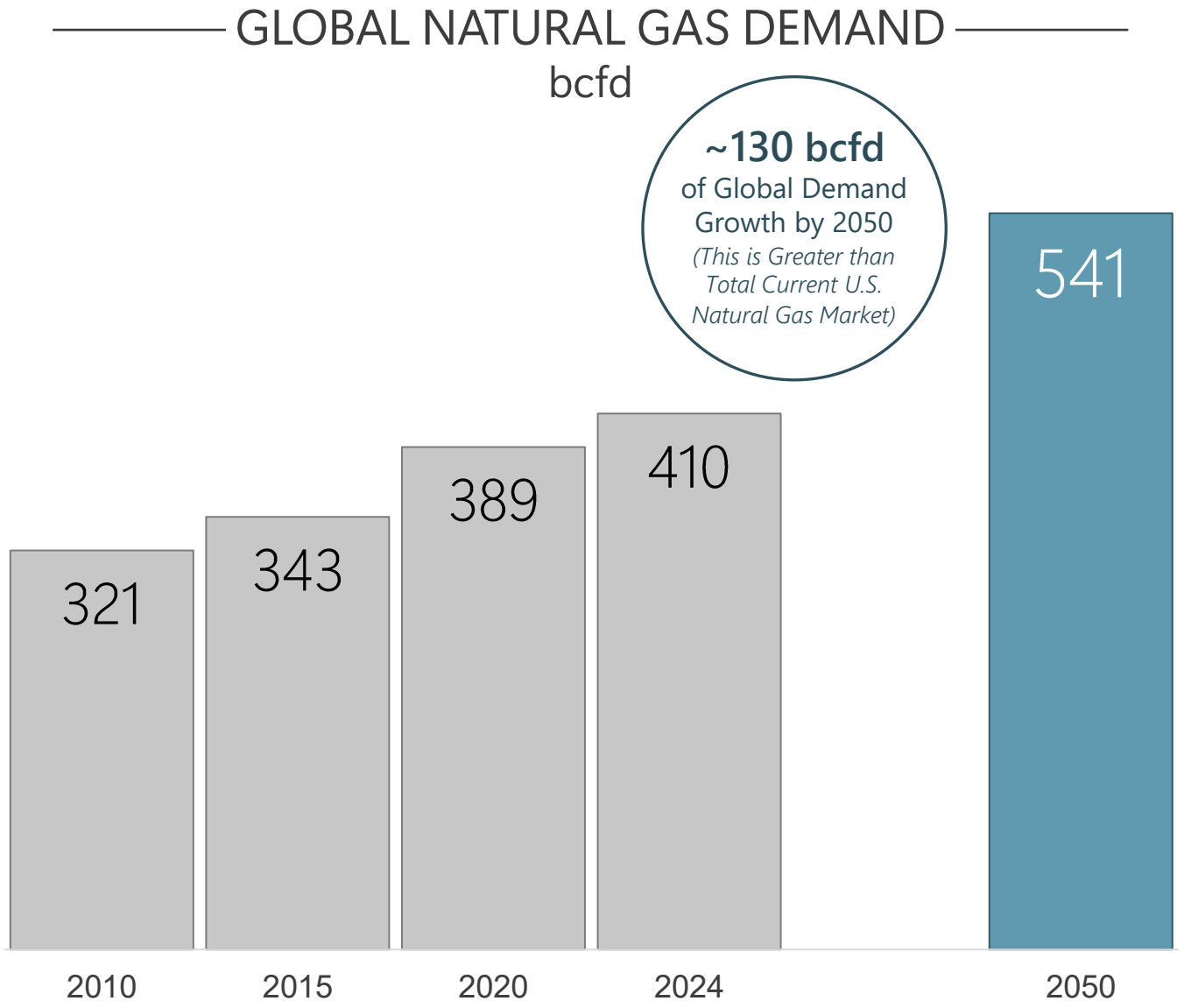


Note: Adjusted EPS, Adjusted EBITDA and Net Debt are non-GAAP financial measures. See Non-GAAP Financial Measures & Reconciliations. Individual years may not sum to total due to rounding.

a) No share repurchases assumed in 2026 budget. 2017 and 2018 include dividends paid to preferred shareholders.

Global Natural Gas Demand Poised for Long-Term Growth

U.S. LNG Well Positioned to Meet Global Demand



Source: IEA (2025) World Energy Outlook Current Policies Scenario, World Energy Outlook 2025 – Analysis – IEA. All rights reserved.

Demand growth largely expected from countries with limited domestic natural resources

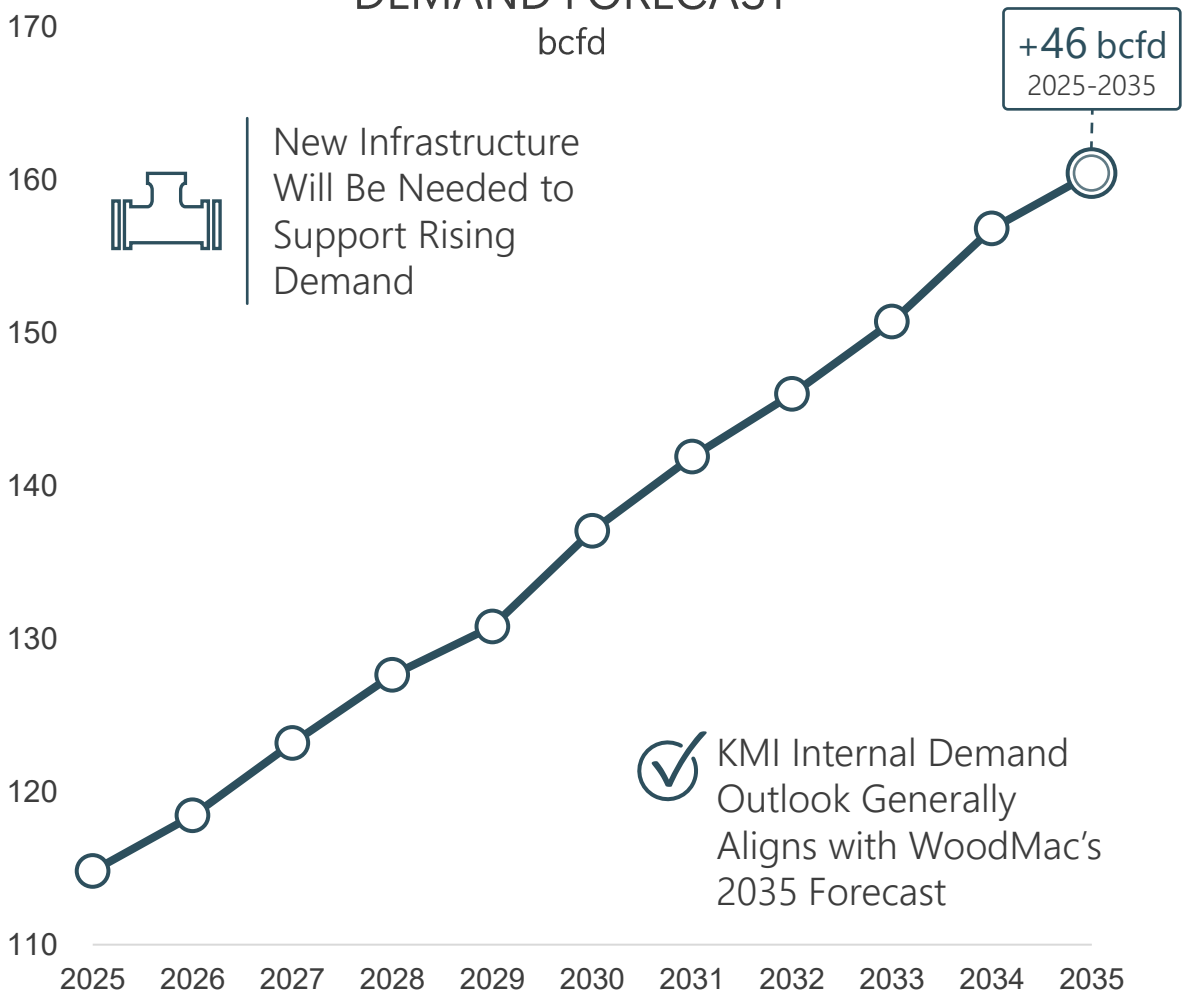
Additional U.S. LNG will be needed to meet growing global demand

KEY U.S. ADVANTAGES

- Abundant supply at a competitive cost
- Low geopolitical risk
- Established transport & storage infrastructure

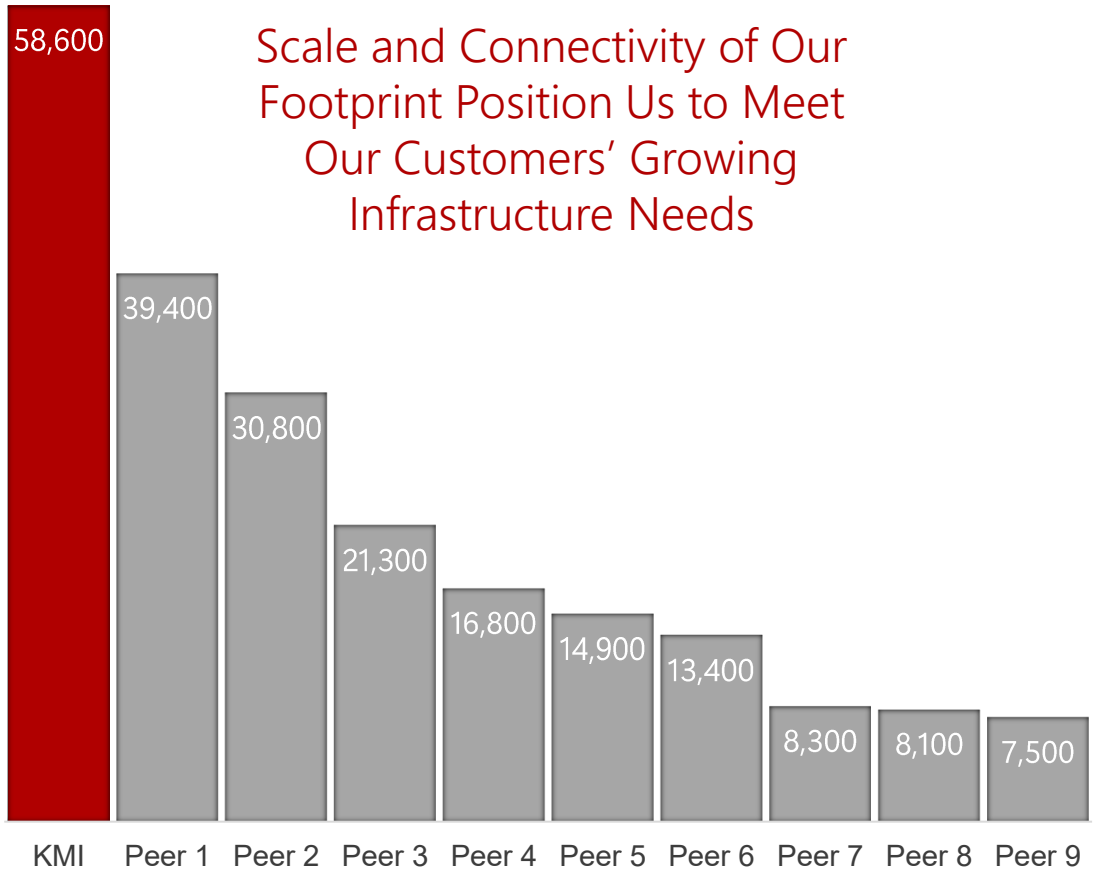
Extensive Network Well Positioned to Serve Growing U.S. Natural Gas Demand

WOODMAC U.S. NATURAL GAS DEMAND FORECAST



U.S. NATURAL GAS TRANSMISSION PIPELINE MILEAGE BY OPERATOR[a]

Scale and Connectivity of Our Footprint Position Us to Meet Our Customers' Growing Infrastructure Needs



Source: Wood Mackenzie North America Gas Strategic Planning Outlook, April 2026.

a) Data per recent peer company reports and presentations. Does not include mileage associated with gathering assets. Peers include Berkshire, Boardwalk, ENB CN, EPD, ET, OKE, Tallgrass, TRP CN, and WMB.

WoodMac U.S. Natural Gas Supply & Demand Outlook

2025 vs 2035

bcfd	2025	2035	Δ	Δ%
DEMAND				
LNG Feedgas	15.8	38.7	+22.9	+145%
Power	35.7	52.7	+16.9	+47%
Industrial	32.8	37.0	+4.3	+13%
Net Exports to Mexico	6.6	6.1	(0.5)	(8%)
Residential & Commercial	23.3	22.2	(1.1)	(5%)
Other Demand	0.6	3.7	+3.1	+543%
TOTAL DEMAND	**114.8**	**160.4**	**+45.6**	**+40%**
SUPPLY				
Haynesville	14.5	28.0	+13.5	+93%
Marcellus / Utica	36.3	49.0	+12.7	+35%
Permian	23.1	33.6	+10.5	+46%
Eagle Ford	6.3	11.1	+4.8	+76%
Rockies (Bakken / DJ / Powder River)	10.1	11.9	+1.9	+19%
Other Production	18.4	20.3	+2.0	+11%
Canadian & LNG Imports / Storge Withdraws	6.2	6.5	+0.3	+4%
TOTAL SUPPLY	**114.8**	**160.4**	**+45.6**	**+40%**

KEY TAKEAWAYS

Total Natural Gas Demand
+46 bcfd (+40%)
Broad-based growth across LNG feedgas, power, and industrial demand

LNG Feedgas Demand
+23 bcfd (+145%)
Driven by rising global demand for abundant and affordable U.S. natural gas

Power Demand
+17 bcfd (+47%)
Economic development, coal retirements, & data centers driving incremental demand growth

Natural Gas Production
+45 bcfd (+42%)
Haynesville, Marcellus / Utica, and Permian projected to lead growth

Source: Wood Mackenzie North America Gas Strategic Planning Outlook, April 2026. Industrial sector includes Wood Mackenzie's "Other" category, comprised of lease and plant fuel. LNG feedgas equals exports plus an assumed 9% increase for plant fuel. This volume would otherwise be included in the Industrial category. Other Demand includes Transportation and Blue Hydrogen. Eagle Ford outlook includes production from the Austin Chalk. Numbers may not sum due to rounding.

Premier Natural Gas Network Positioned to Capture Future Growth

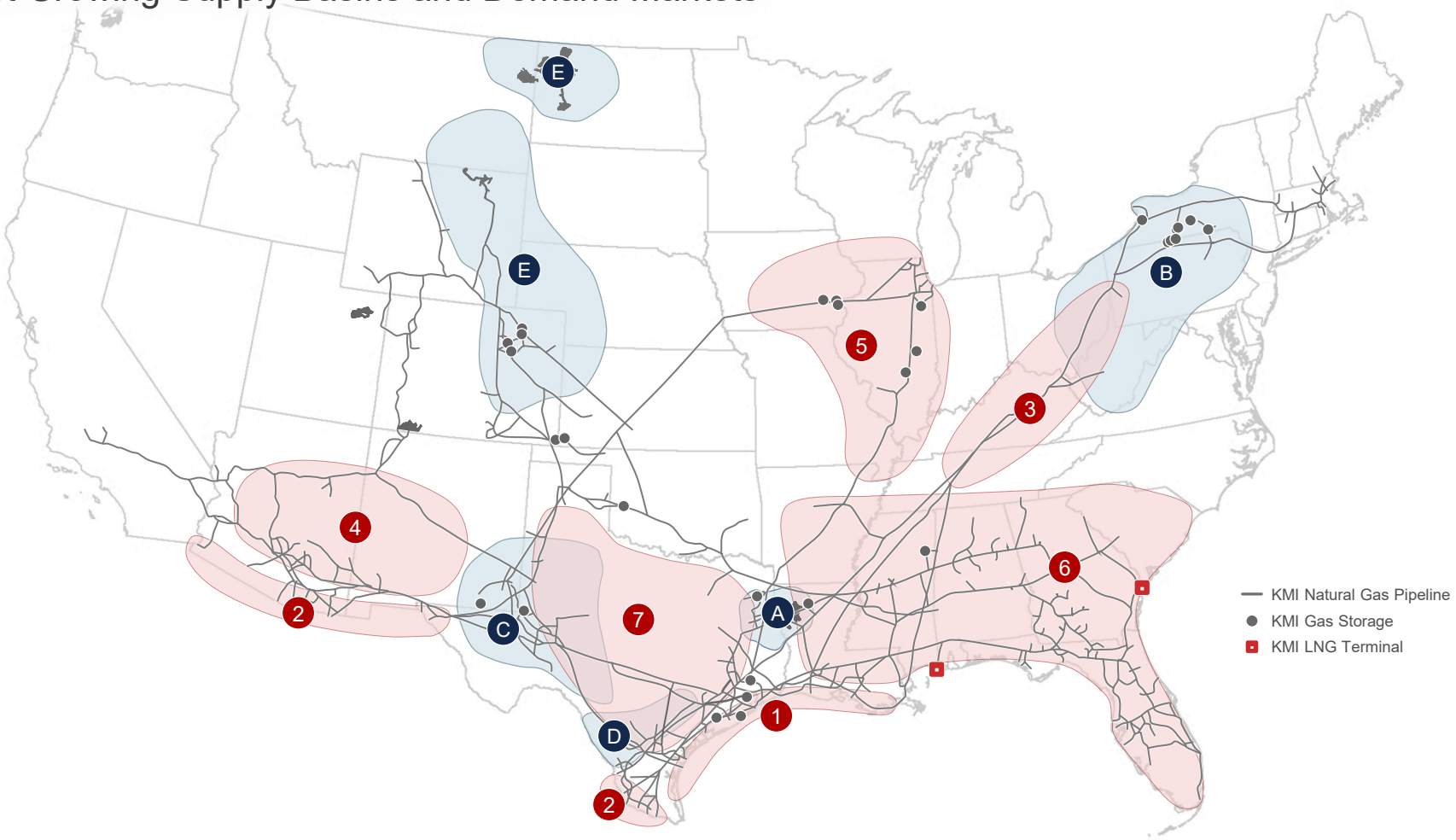
Connecting America's Fastest Growing Supply Basins and Demand Markets

PRIMARY DEMAND GROWTH REGIONS

EXPORTS
1. LNG
2. Mexico

POWER & INDUSTRIAL
3. Appalachia
4. Desert Southwest
5. Midwest
6. Southeast
7. Texas

PRIMARY SUPPLY GROWTH BASINS
- A Haynesville
- B Marcellus / Utica
- C Permian
- D Eagle Ford
- E Bakken / DJ / PRB



OUR COMPETITIVE ADVANTAGES

Extensive LNG Market Connectivity
Vast Gulf Coast footprint supports current and future LNG demand

Broad Power Market Reach
Serving high-growth power markets across the Southern U.S., Midwest, and Appalachia

Diverse Supply Basin Access
Connectivity to all major U.S. natural gas supply basins

Integrated Pipeline & Storage Network
Scale and flexibility of our system enable future expansion opportunities

LNG Exports Driving Natural Gas Demand Growth

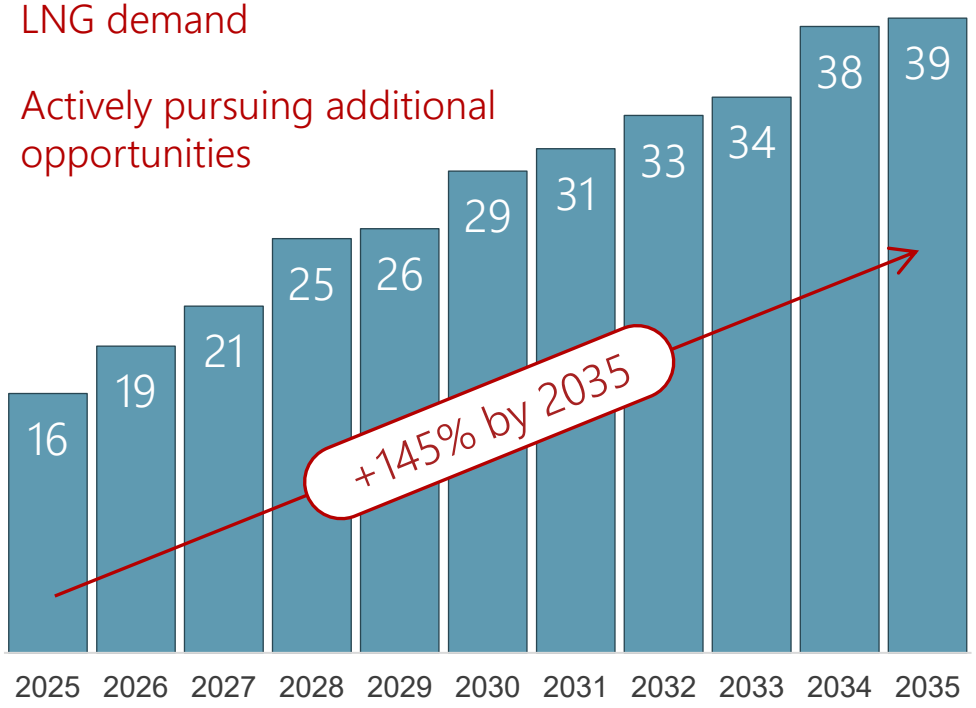
Our Assets Are Well Positioned to Supply Robust LNG Export Growth Along the Texas and Louisiana Gulf Coast

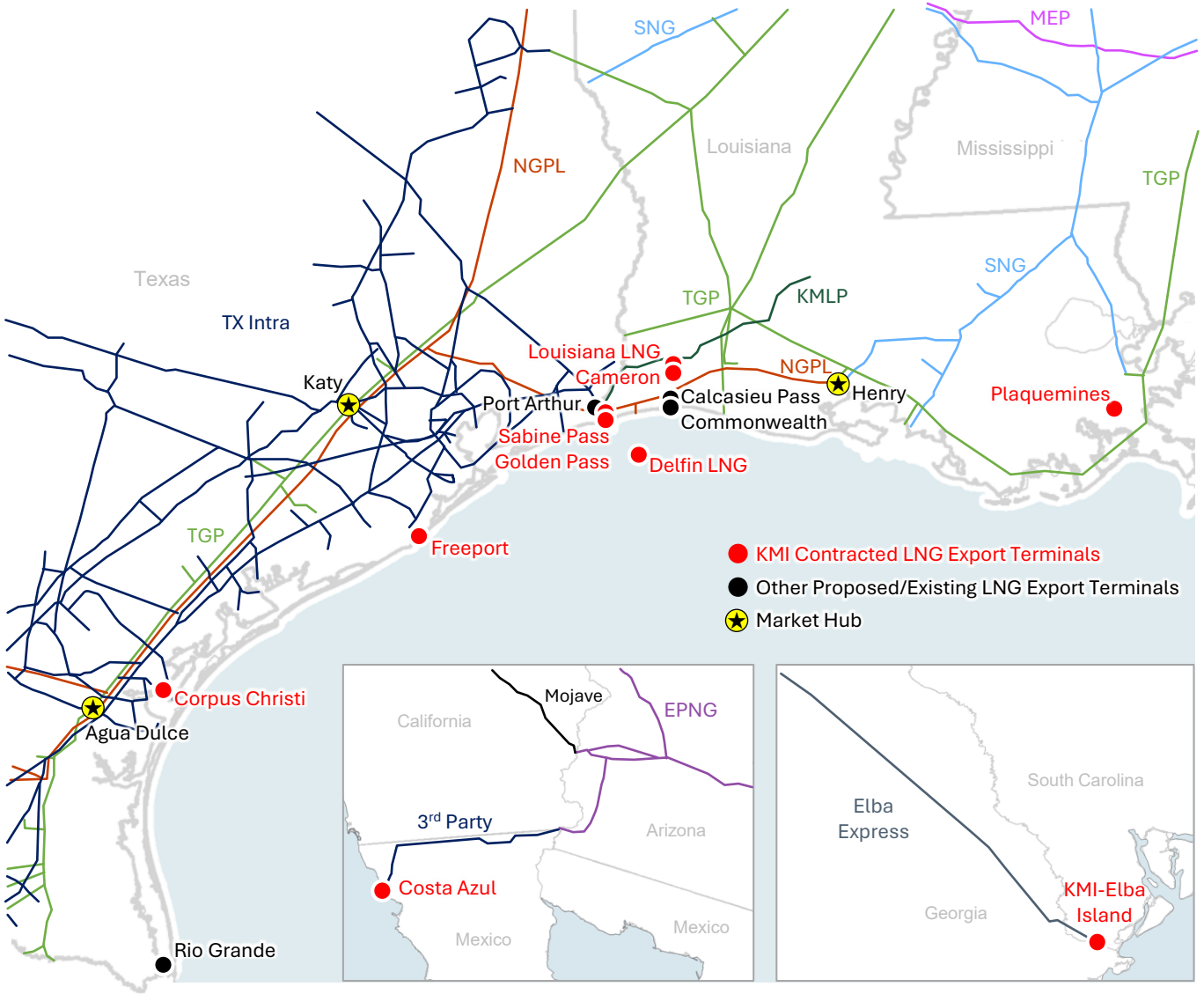
WOODMAC U.S. LNG FEEDGAS FORECAST
bcfd

KMI has long-term contracts to move 8 bcfd to LNG facilities today & nearly 13 bcfd by the end of 2030

~15% of contracted $14.4bn project backlog directed toward serving LNG demand

Actively pursuing additional opportunities





Note: Wood Mackenzie North America Gas Strategic Planning Outlook, April 2026. 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

Population Migration & Economic Growth

Majority of growth likely to occur in the **Southern U.S.**

Population growth in the **Southern U.S. 2x** the rest of the country

Growth largely occurring **within our geographic footprint**

Coal-to-Gas Conversions

Coal accounts for **~17%** of U.S. power generation

~45 coal-fired power plants slated for retirement located **within 50 miles of our pipelines**

Industrial Re-shoring

Re-shoring manufacturing **increases** the need for **consistent, high-capacity** power

Renewable Backup

Natural gas is a **crucial backup source** for renewable energy – providing **dispatchable, lower-emission** power to balance intermittent renewables

Data Center Demand

Dependable natural gas fired power is **essential** for **must-run** data centers

Global **AI driven capex** to average **>$1tn** annually through **2030**

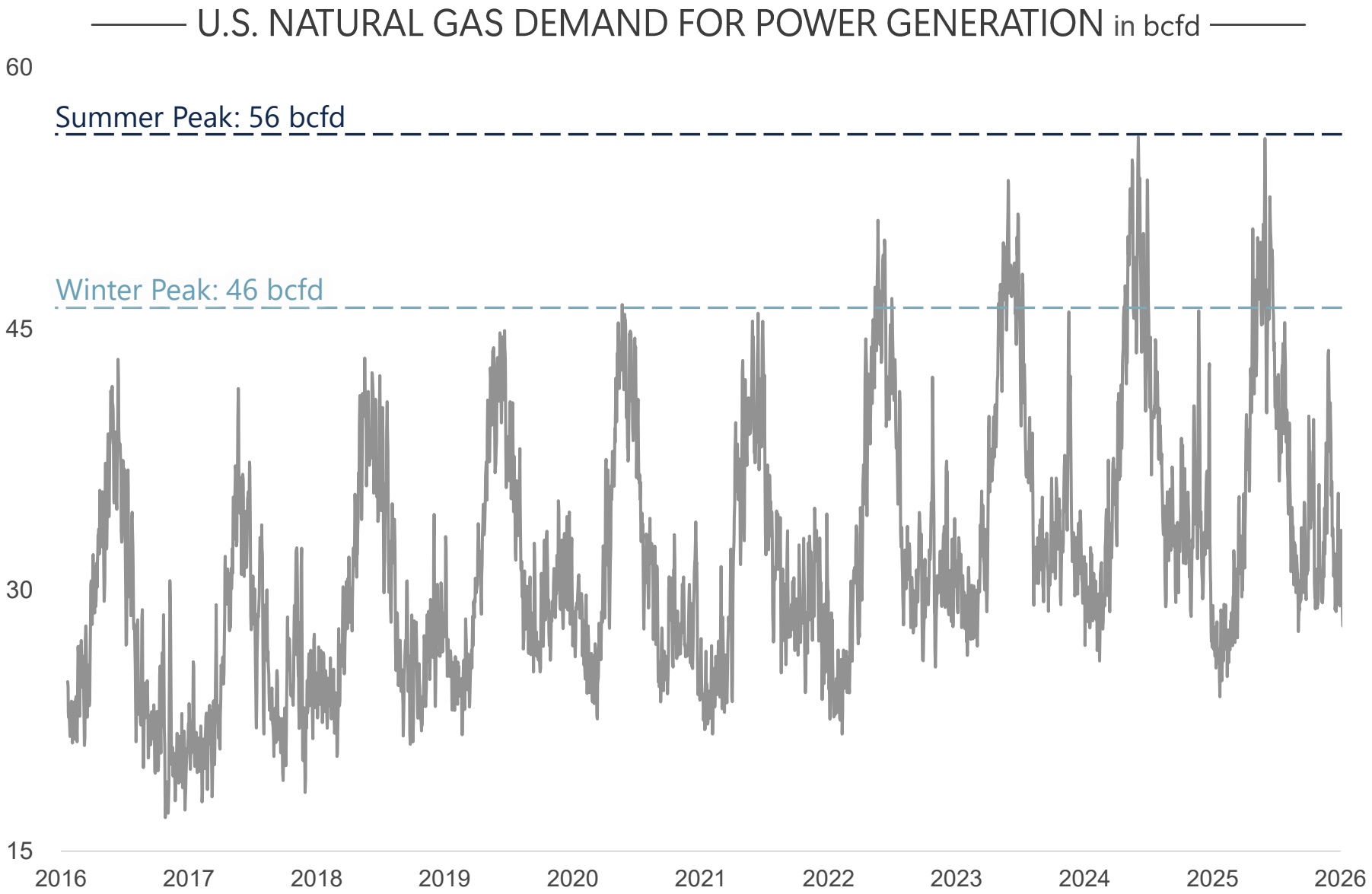
>75% of contracted **$14.4bn** project backlog directed to **power generation & utility demand**

Working with customers to develop **additional opportunities**

Actively Pursuing Significant Additional Power Opportunities

Source: Population growth per the U.S. Census Bureau; State Population Totals and Components of Change: 2020-2024. Southern U.S. includes Arizona, New Mexico, Texas, Arkansas, Louisiana, Tennessee, Mississippi, Alabama, South Carolina, Georgia, and Florida. Coal-fired power plant and 2025 generation data per the EIA as of January 2026. AI driven capex figure per McKinsey as of August 2025.

Rising Need for Natural Gas to Support Power Generation



Natural gas demand for power generation **continues to rise**

Increased demand has **magnified at the extremes**, driven by baseload coal retirements & growing intermittent renewable generation

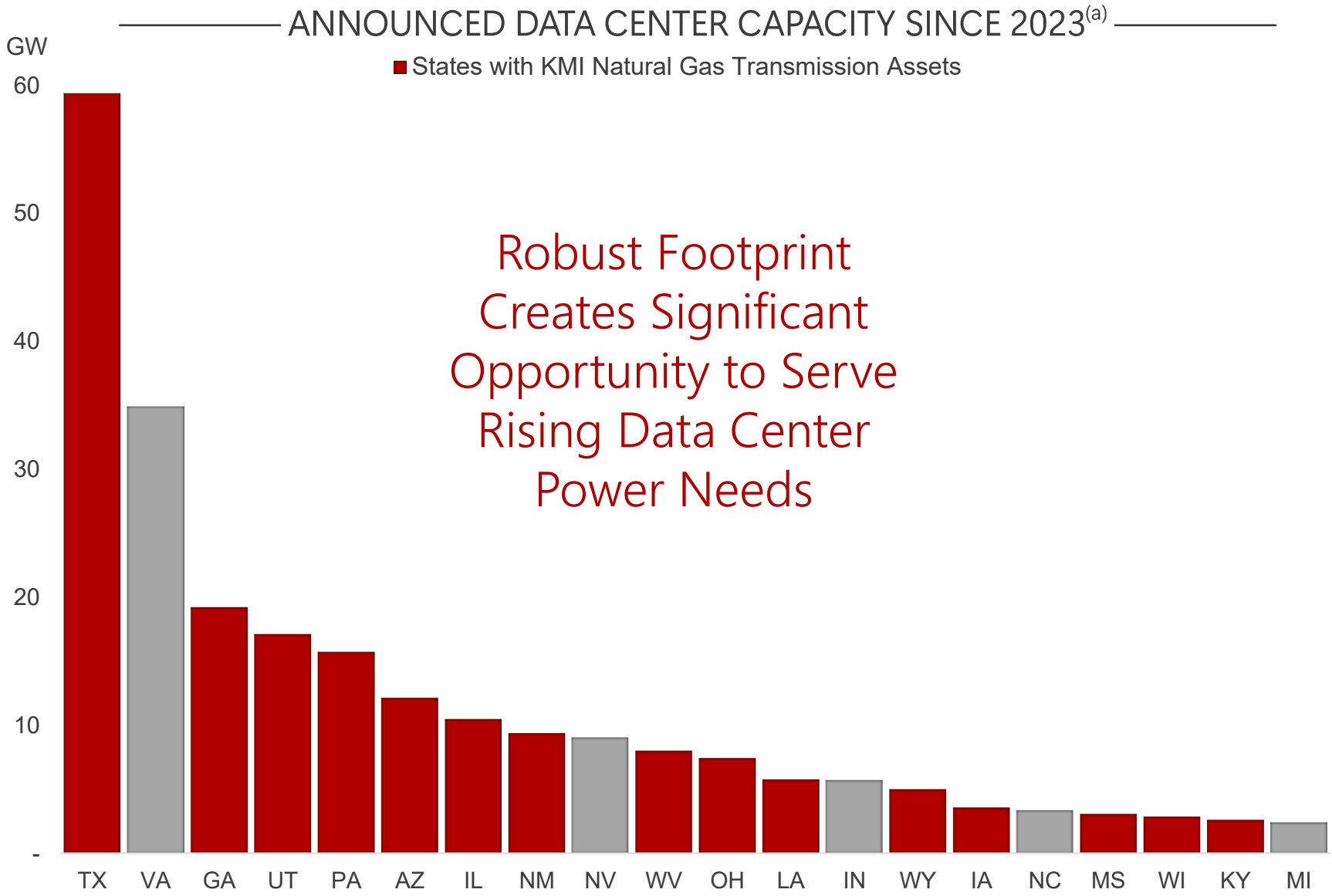
Data centers and other large loads are emerging as **key incremental drivers** of **demand**

Increased pipeline & **storage capacity needed** to serve growing **peak demand**

All top 10 natural gas power demand days have occurred **since 2023**

Source: Point Logic as of December 2025.

Positioned to Meet Surging Data Center Power Demand



Robust Footprint Creates Significant Opportunity to Serve Rising Data Center Power Needs

U.S. Data Center Demand Outlook

~277 GW
Power demand for U.S. data centers currently under development

~42 bcfd[(b)]
Potential natural gas capacity needed to meet associated peak power demand

~205 GW
Data center capacity under development in states with KMI gas transmission assets

Capital Investments

>$750bn
Projected 2026 hyperscaler capex

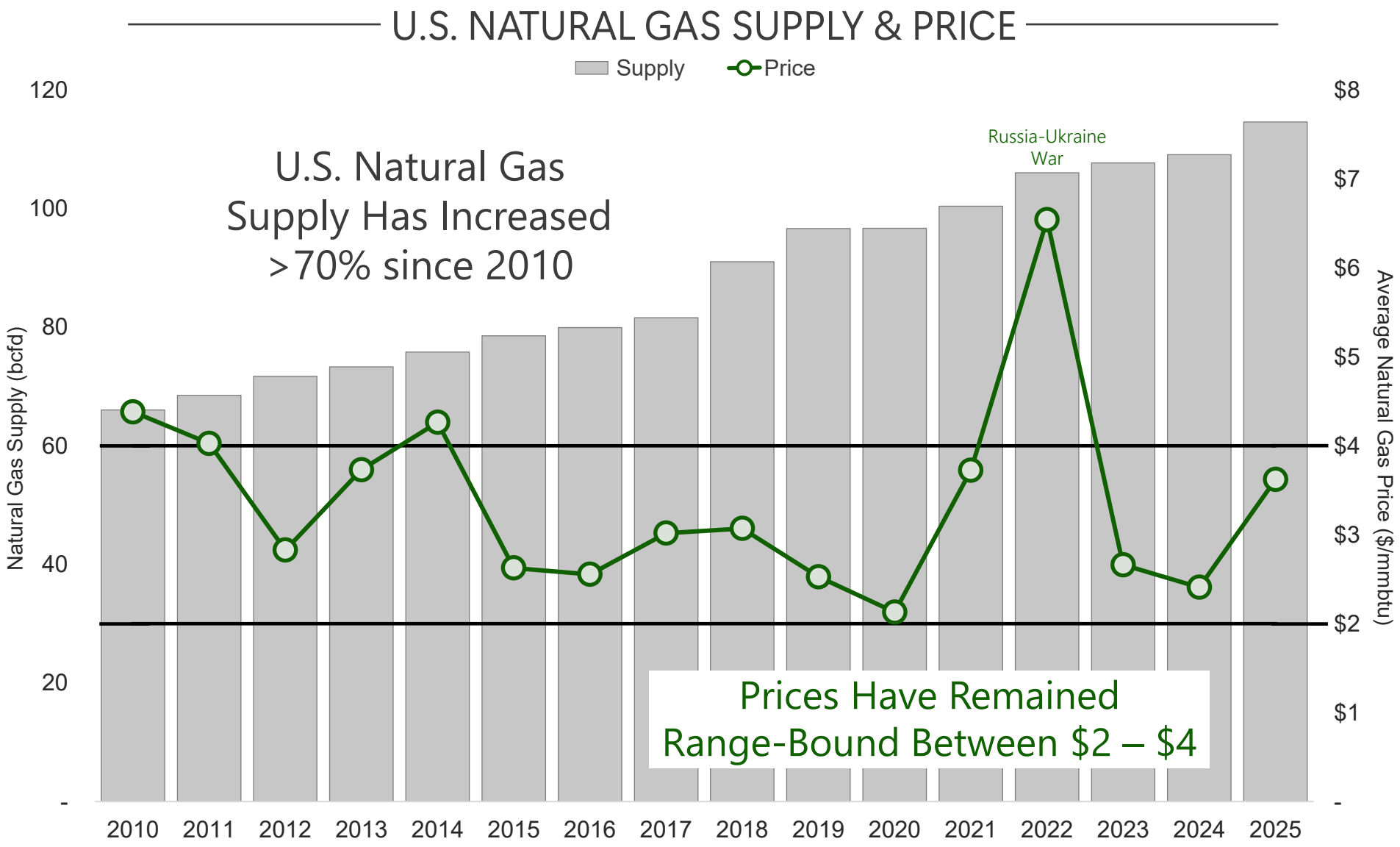
>$200bn
Expected 2026 U.S. electric utility capex

Source: Aterio, EEI, Goldman Sachs. Hyperscalers include AMZN, GOOG, META, MSFT, and ORCL.

a) Capacity data as of March 2026. Includes both announced capacity and capacity under construction. 2023 reflects the beginning of the recent generative-AI-driven data center buildout.

b) Assumes 1 GW = 0.15 bcfd of natural gas. ~42 bcfd represents the upper-range natural gas capacity needed to support the full set of data center projects currently under development across the U.S., regardless of overall usage.

Vast, Low-Cost U.S. Supply Meeting Growing Demand While Maintaining Reasonable Prices



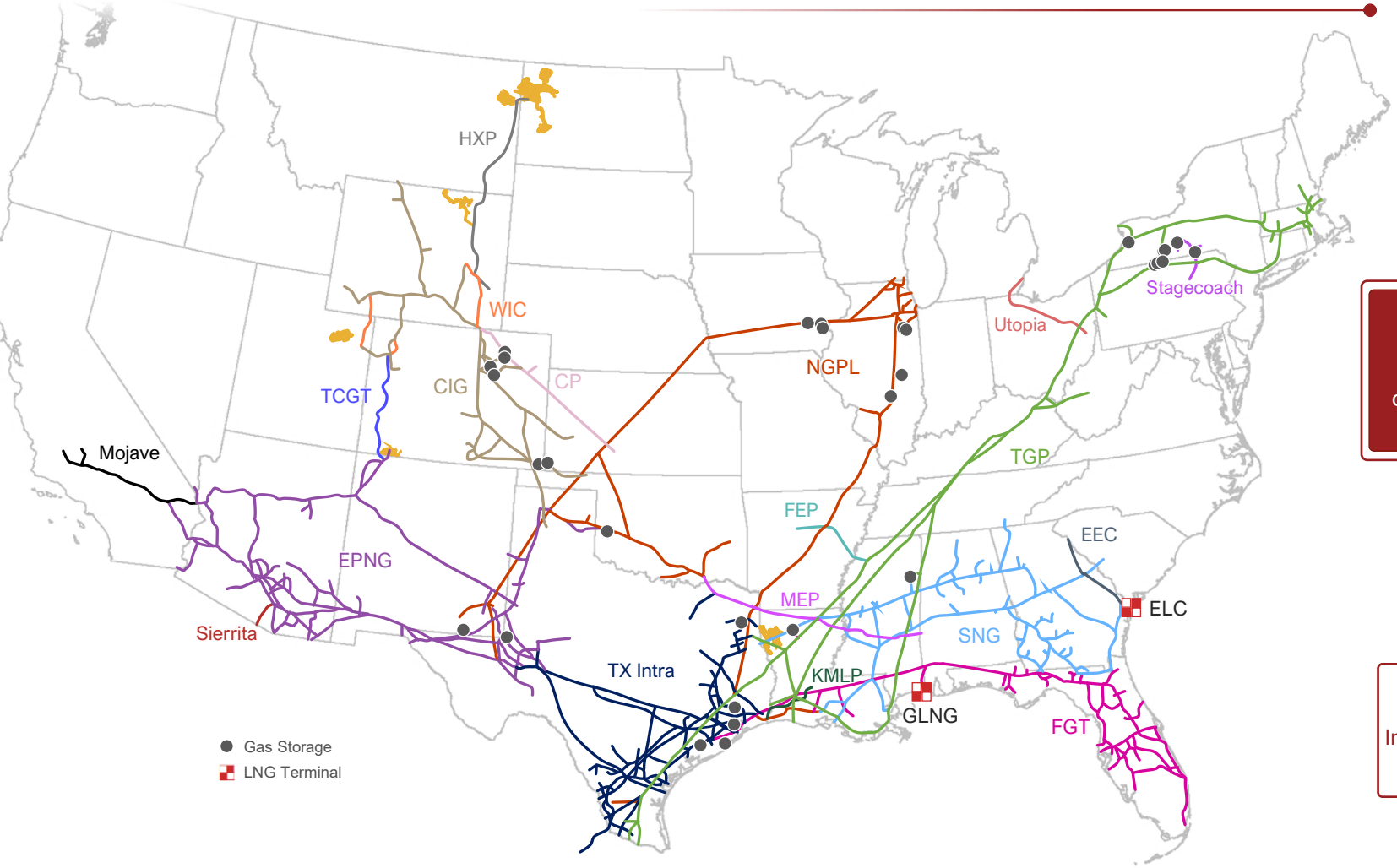
U.S. reserves are vast and low cost, given continued upstream efficiency gains

New supply can be accessed with minimal upward pressure on market price

Source: Supply data per Wood Mackenzie's North America Gas Strategic Planning Outlook, April 2026. Pricing per Bloomberg.

Natural Gas Segment Overview

Connecting Key Natural Gas Resources with Major Demand Centers



Largest Natural Gas Transmission Network in the U.S.[a]

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

~40% of all feedgas deliveries to U.S. LNG facilities

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

~45% of all direct-connect natural gas deliveries to Southern U.S. power plants[b]

Areas with high forecasted natural gas fired power demand growth

51,000 miles Interstate Transmission Pipelines

7,600 miles Intrastate Transmission Pipelines

6,800 miles Gathering Pipelines

1,300 miles NGL Pipelines

>700 bcf Working Gas Storage Capacity

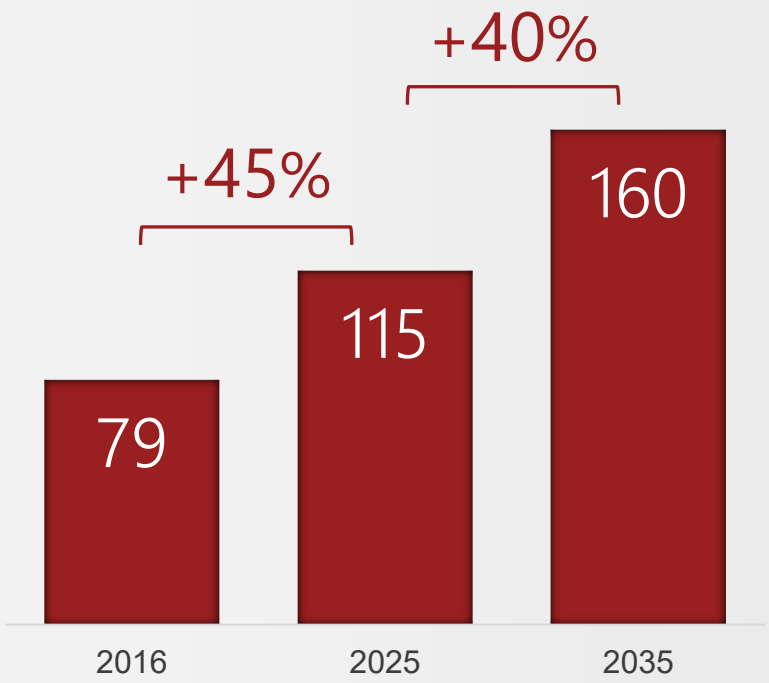
- Irreplaceable, Long-Lived Infrastructure • Primarily Transmission & Storage Assets
- Gathering & Processing Assets in Key Basins • Robust Opportunity Set for Growth

a) Does not include mileage associated with natural gas gathering assets.
b) Includes deliveries in Arizona, New Mexico, Texas, Arkansas, Louisiana, Tennessee, Mississippi, Alabama, South Carolina, Georgia, and Florida.

Rising Demand Benefitting Our Natural Gas Transmission Business

INCREASED DEMAND LEADING TO

WOODMAC
U.S. NATURAL GAS DEMAND
bcfd

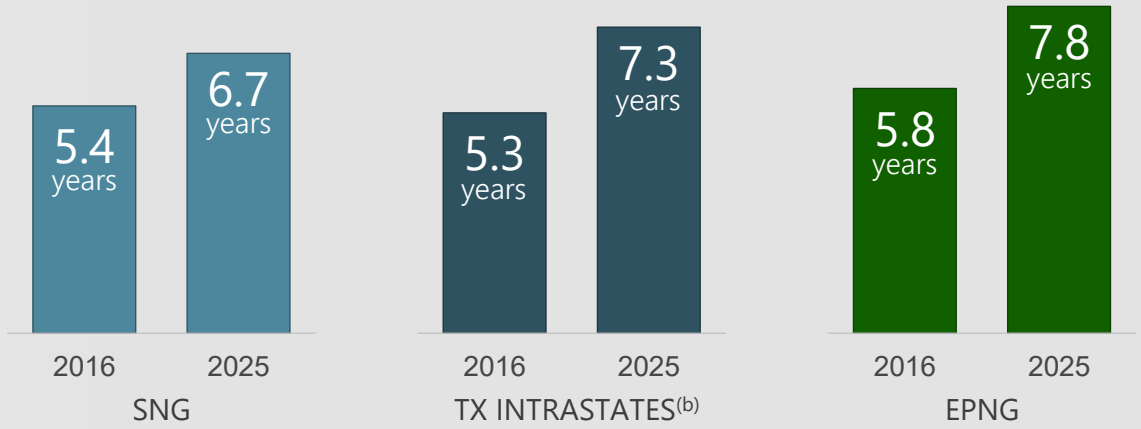


- INCREASED PIPELINE USAGE FACTOR[(a)]

2016 5-Pipe Average	2025 5-Pipe Average
74%	⇧90%

- INCREASED TENOR AND/OR RATES

EXAMPLES



- NEW PROJECTS

~$13.2 billion of natural gas projects in our backlog; expect to continue adding projects over time

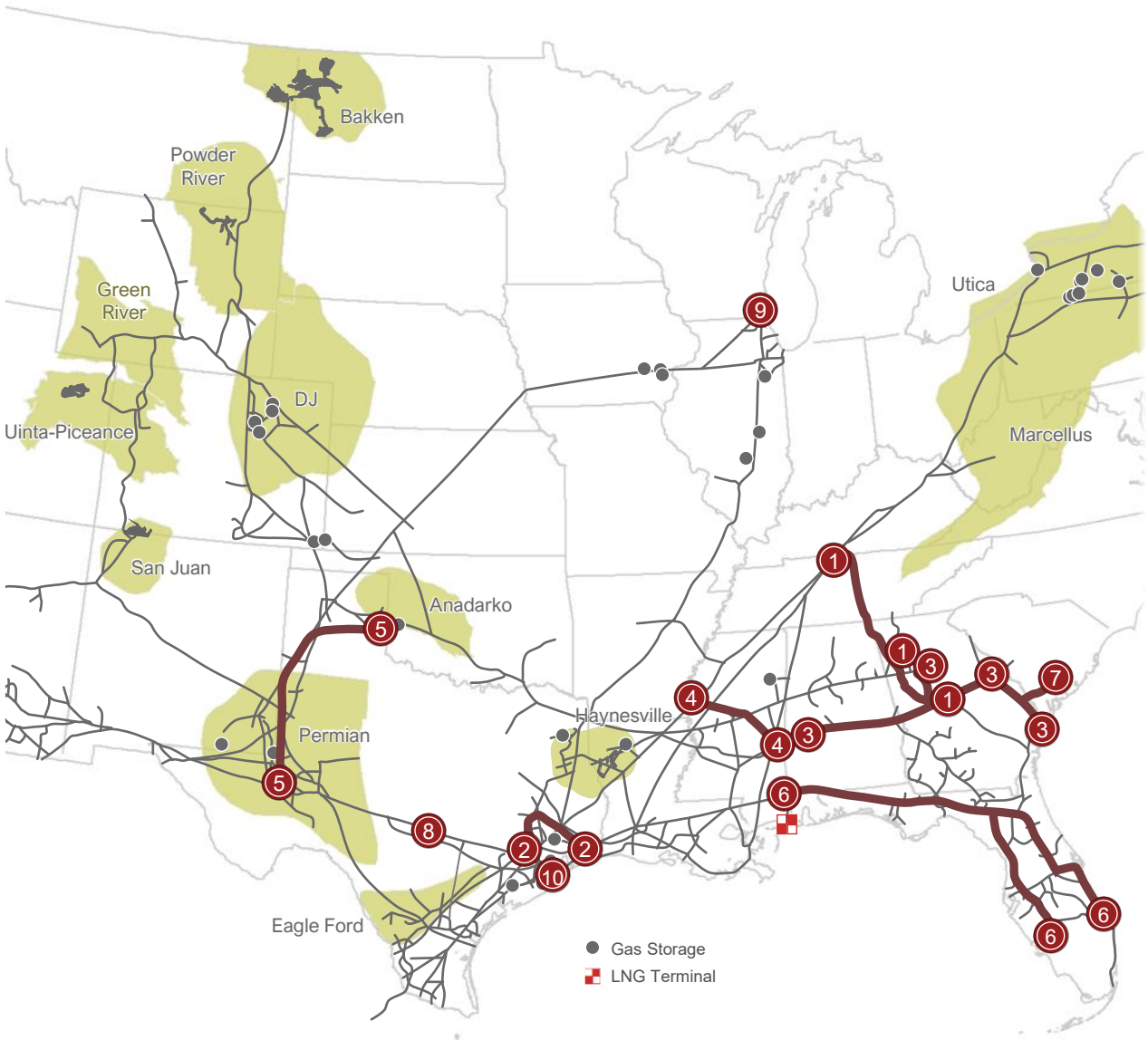
Source: Wood Mackenzie North America Gas Strategic Planning Outlook, April 2026.

a) Represents the capacity weighted average usage factor of TGP, EPNG, NGPL, SNG, and the Texas Intrastates collectively. 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.

~$13.2 Billion of Approved Natural Gas Projects

Projects >$150mm	Capital[a] ($bn)	Capacity (bcfd)	In-Service Date	Primary Driver
1 Southeast Connector *SNG*	$3.1	2.6	4Q30, 4Q31, 4Q32	Power
2 Trident (Phase I & II)[b] *TX Intrastates*	$1.8	2.0	1Q27, 4Q28	LNG
3 South System Expansion 4 *SNG & EEC*	$1.8	1.3	4Q28, 4Q29	Power
4 Mississippi Crossing *TGP*	$1.7	2.1	2Q28	Power
5 Permian Link *NGPL*	$1.6	2.8	3Q30	Power
6 Phase IX *FGT*	$0.6	0.5	4Q28	Power
7 Bridge *EEC*	$0.4	0.3	2Q30	Power
8 Creekside Lateral (Phase I, II & III) *TX Intrastates*	$0.2	1.3	4Q26, 4Q27	Power / Industrial
9 North Extension *NGPL*	$0.2	0.2	4Q28	Power
10 Houston Power Generation *TX Intrastates*	$0.2	0.5	2Q27, 2Q28	Power

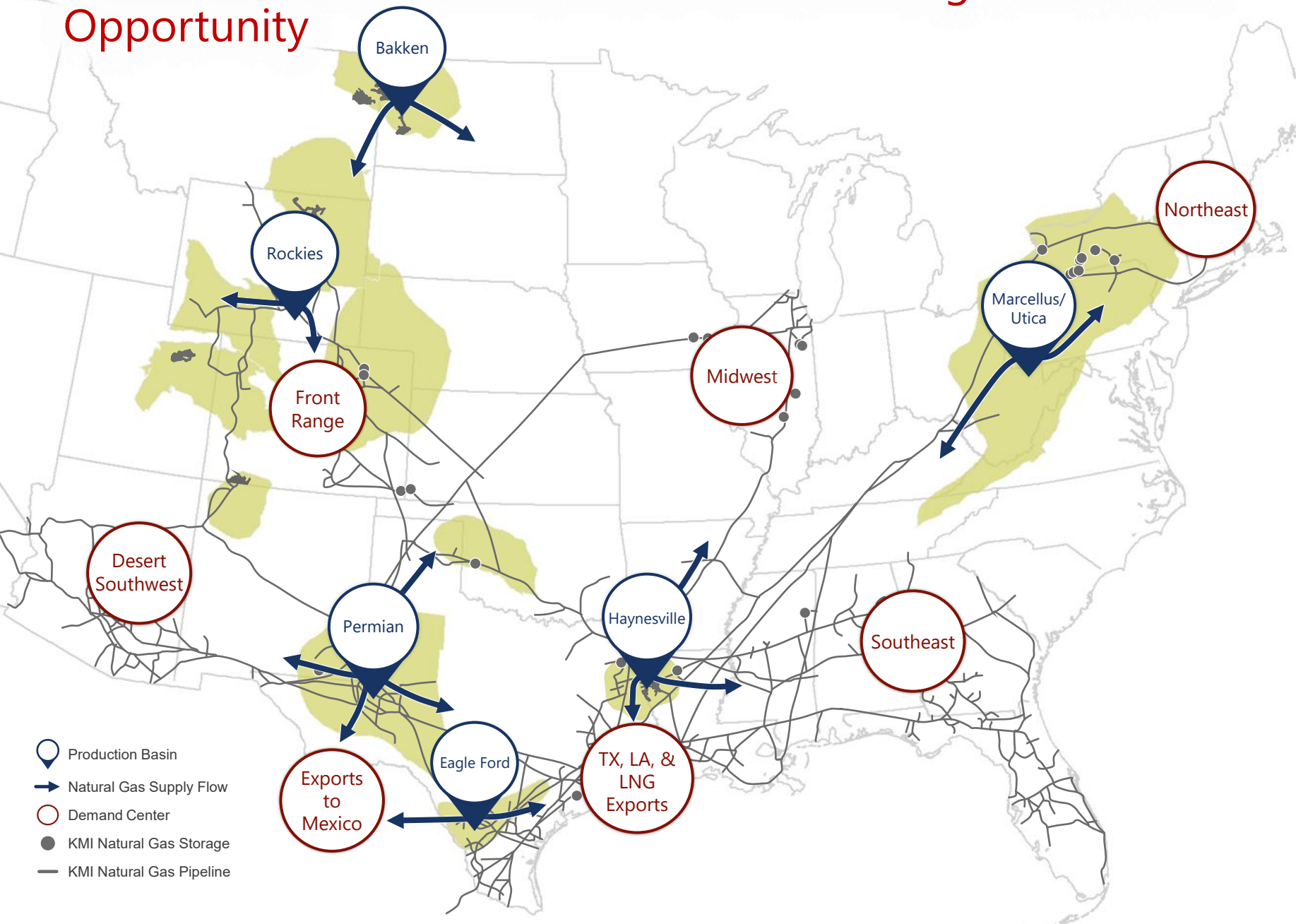


Note: Project EBITDA is a non-GAAP financial measure. See Non-GAAP Financial Measures & Reconciliations.

a) KMI share of estimated project capital for our 10 largest Natural Gas Pipelines Segment projects. Includes Allowance for Funds Used During Construction (AFUDC).

b) Expect Trident to generate ~30% of its full run-rate contracted Project EBITDA in 2027 and ~80% in 2028 due to staggered contract start dates.

Premier Network Positioned to Meet Growing Natural Gas Opportunity

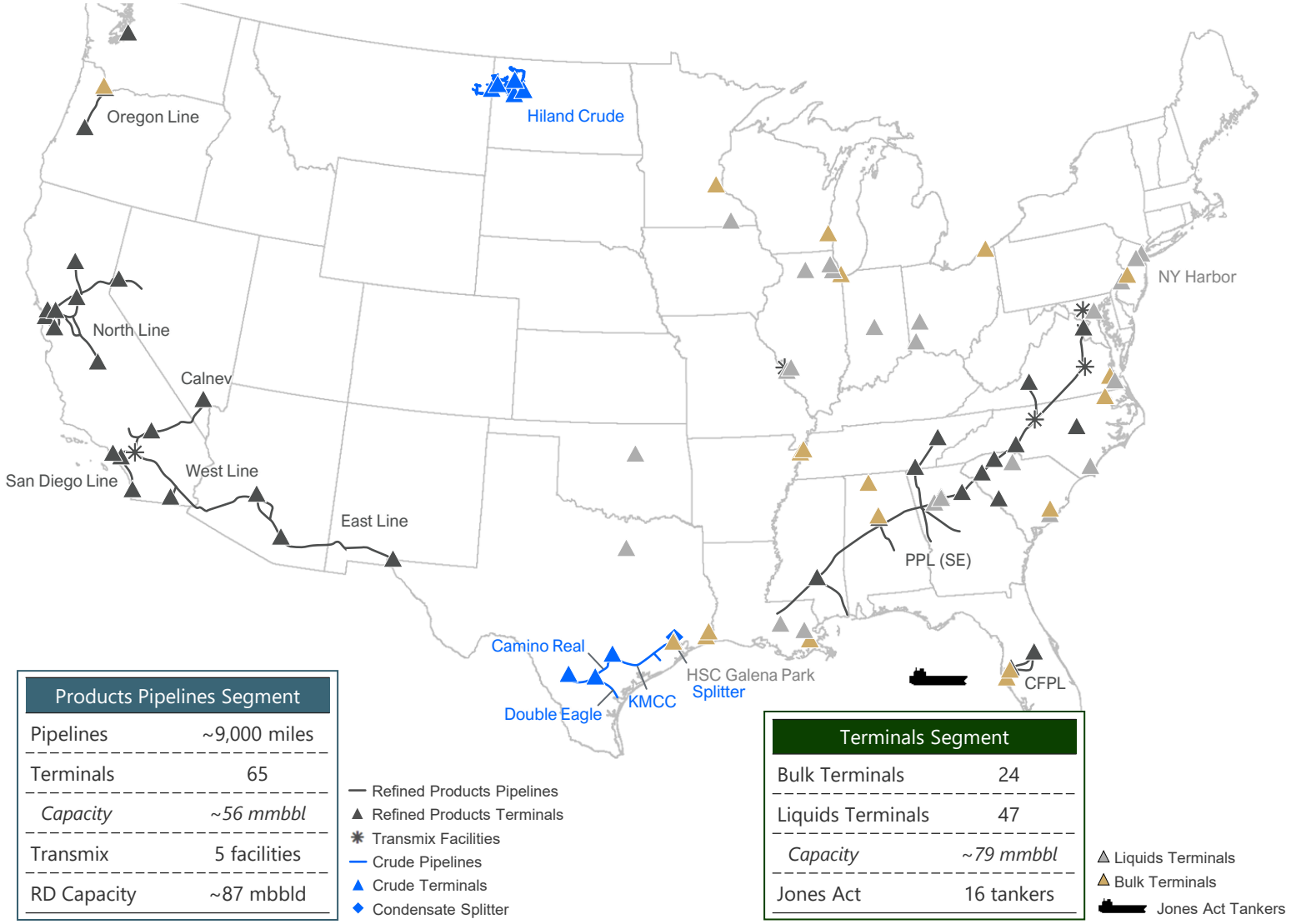


Pursuing Significant Opportunities Beyond Our Current Backlog

- TX & LA power & industrial
- Southeast power
- Desert Southwest power
- Midwest power
- Gulf Coast LNG exports
- Marcellus / Utica egress
- Haynesville egress
- Natural gas storage
- Exports to Mexico

Products Pipelines Segment & Terminals Segment Overview

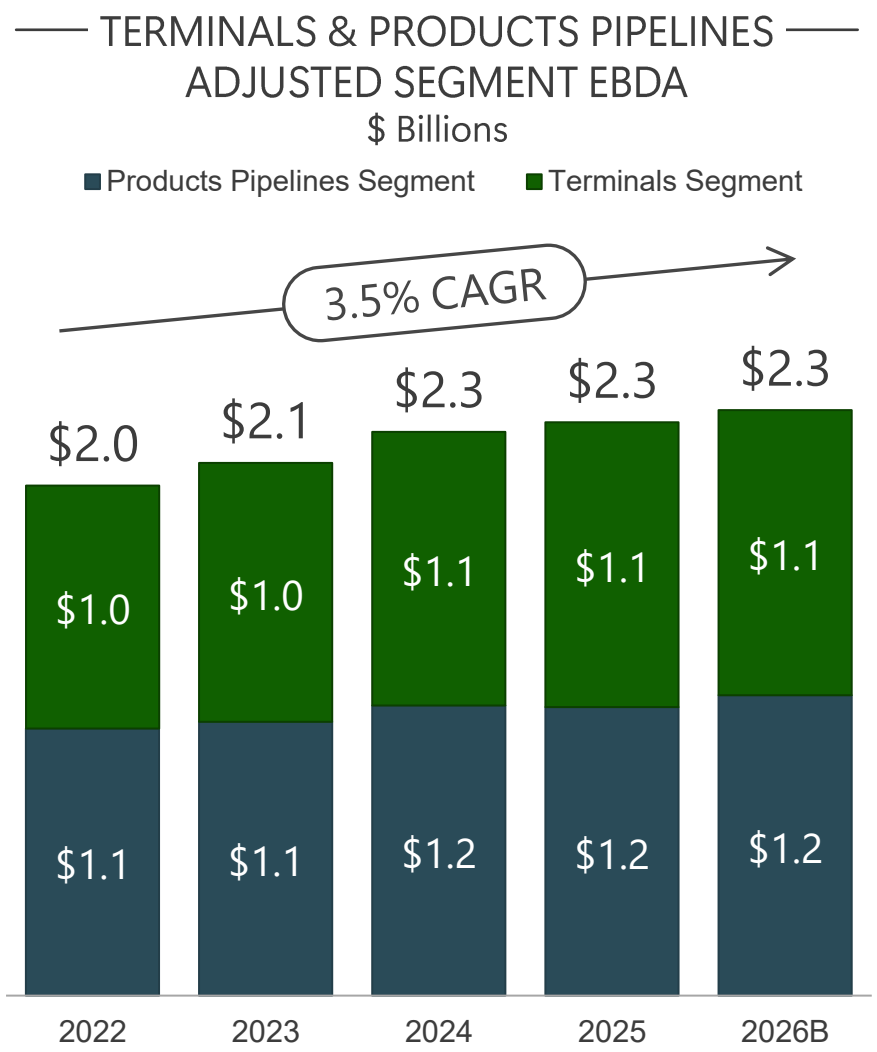
Both Segments Principally Refined Products Focused



Products Pipelines Segment	
Pipelines	~9,000 miles
Terminals	65
Capacity	*~56 mmbbl*
Transmix	5 facilities
RD Capacity	~87 mbbld

Terminals Segment	
Bulk Terminals	24
Liquids Terminals	47
Capacity	*~79 mmbbl*
Jones Act	16 tankers

>$11bn of Adjusted Segment EBDA &
>$8bn of FCF Expected Over 5 Years



Note: Adjusted Segment EBDA and Terminals and Product Pipelines FCF are non-GAAP financial measures. See Non-GAAP Financial Measures & Reconciliations. Figures may not sum due to rounding. 2022 – 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.

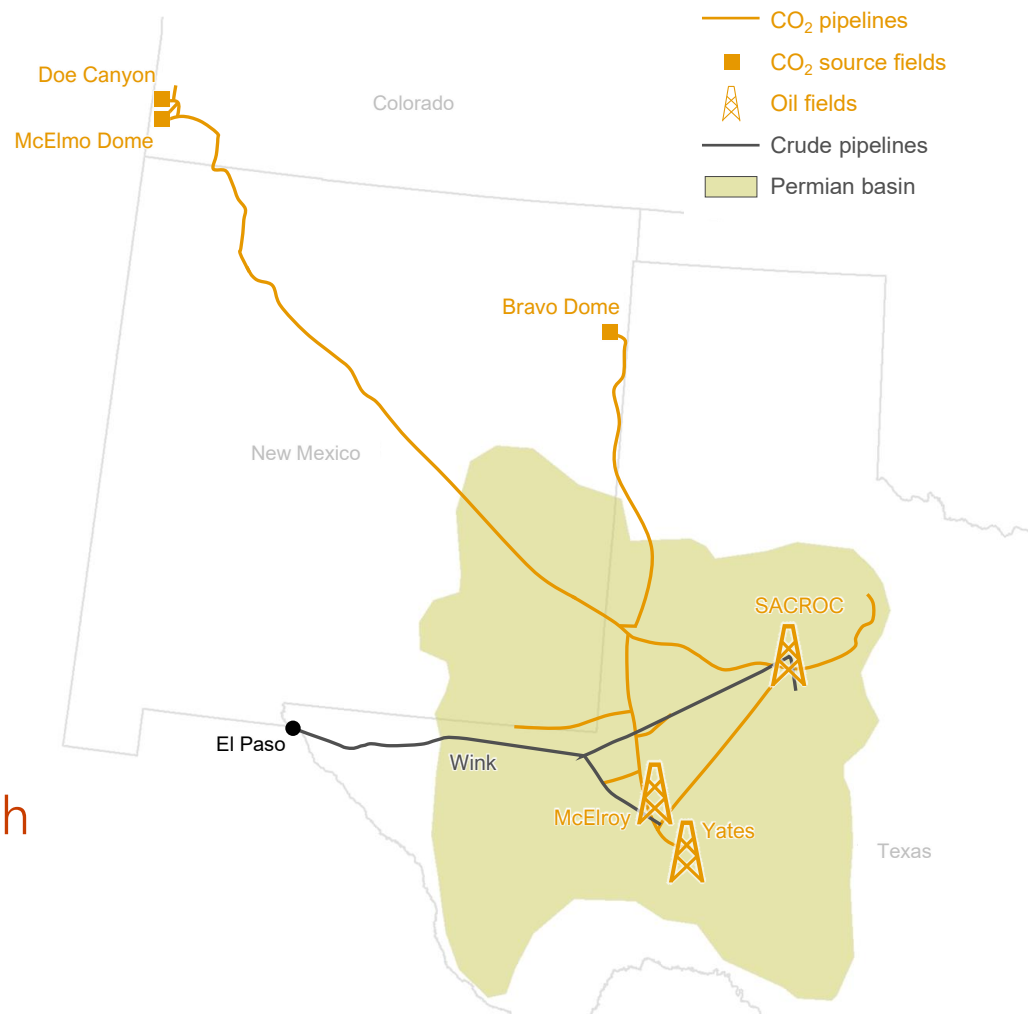
CO_2 Segment: EOR and Transport Overview

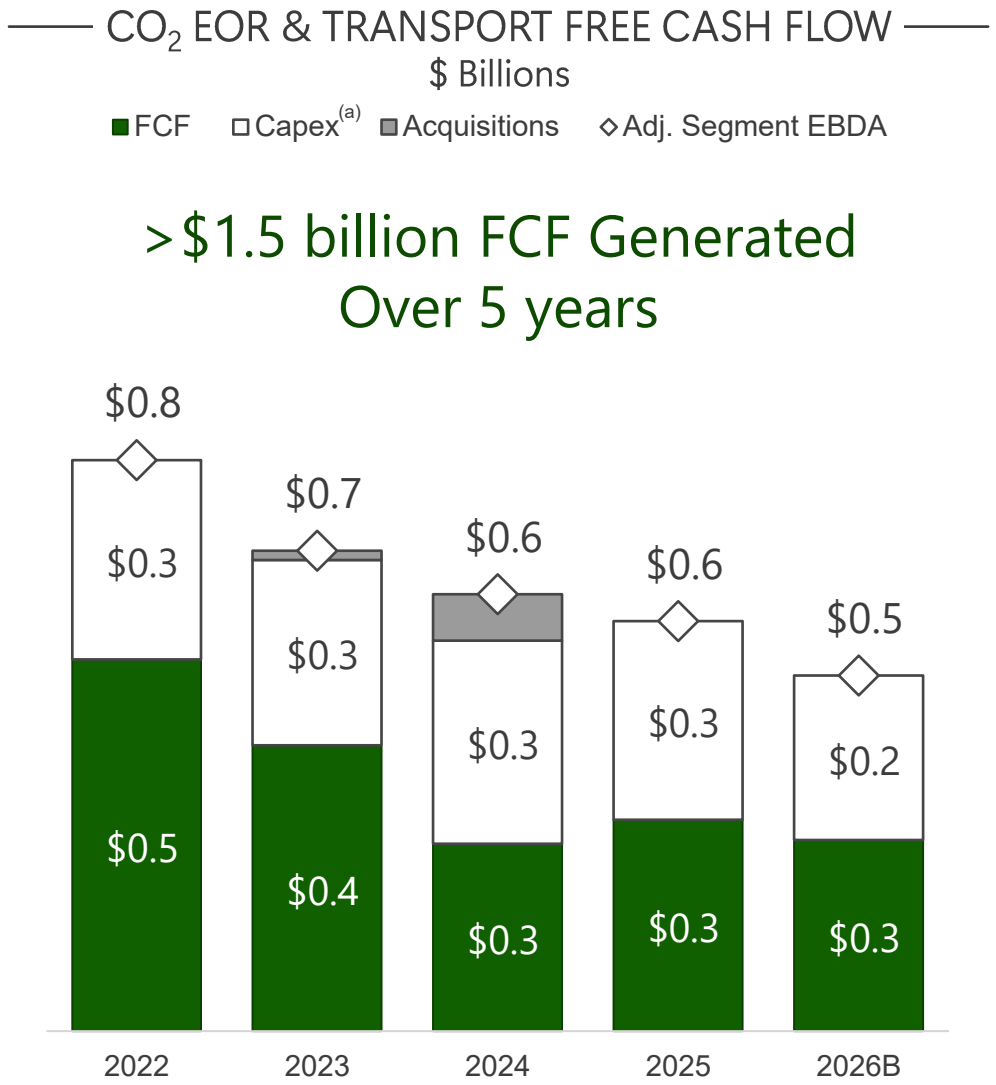
World Class, Fully-Integrated Assets Consistently Generating Robust Free Cash Flow

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

Interest in 3 CO_2 fields with 37 tcf of Original Gas In Place

~1,500 miles of CO_2 pipelines with capacity to move up to 1.5 bcfd





Note: CO_2 EOR & Transport FCF and Adjusted Segment EBDA are non-GAAP financial measures. See Non-GAAP Financial Measures & Reconciliations. 2022 – 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.

CO_2 Segment: Energy Transition Ventures (ETV) Group Overview

RNG

- Established a strategic RNG platform
- 6 facilities with 6.4 bcf[(a)] of RNG production capacity; contracted long term into the transportation market
- Focused on optimizing operations; potential for longer-term expansion opportunities

CCS

- Evaluating commercial opportunities across the CCS value chain
- Leveraging decades of CO_2 experience to become a leading provider of CO_2 transportation and sequestration services

Future Opportunities

- Focused on areas synergistic with KMI's expertise and significant set of diversified assets



Pursuing Economic Lower Carbon Energy Opportunities



a) Annual capacity at KMI share.

Committed to Being a Good Steward



Reduce & Avoid Methane Emissions

~17%

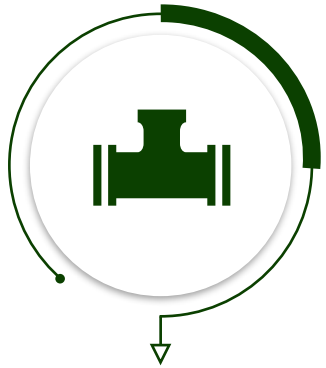
Reduction in methane emission intensity since 2023



Leak Detection

100%

Of our natural gas compressor stations surveyed annually



Pipeline Incidents

~16%

Reduction in reportable pipeline incidents since 2023



Employee Development

311

Participants in our leadership training



Investing in Lower Carbon Fuels

$13.2bn

Natural gas focused[(a)]

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

Note: Values shown are for 2025 unless otherwise indicated.

a) Natural Gas Pipelines Segment projects included in our backlog as of our 3Q 2026 earnings.

Sustainability Ratings Recognition

Highly Rated By Multiple Agencies

MSCI **AAA**

Oil & Gas Refining, Marketing, Transportation & Storage Industry

Sustainalytics **Top 15%**

out of 73 Oil & Gas Storage & Transportation Companies & 148 Refiners & Pipelines

LSEG Refinitiv **Top 20%**

of 166 Oil & Gas Related Equipment & Services Companies

FTSE **#2**

of Oil & Gas Pipelines subsector



Included in Several Sustainability Indices

FTSE4Good, S&P 500 Scored and Screened, JULCD, MSCI Sustainability and Climate indexes

Note: As of October 2026.

APPENDIX



KinderHawk Elm Grove Facility

Contract Strategy Insulates Cash Flows Through Commodity Cycles

Long-Term, Secure Cash Flows Minimize Price & Volume Volatility

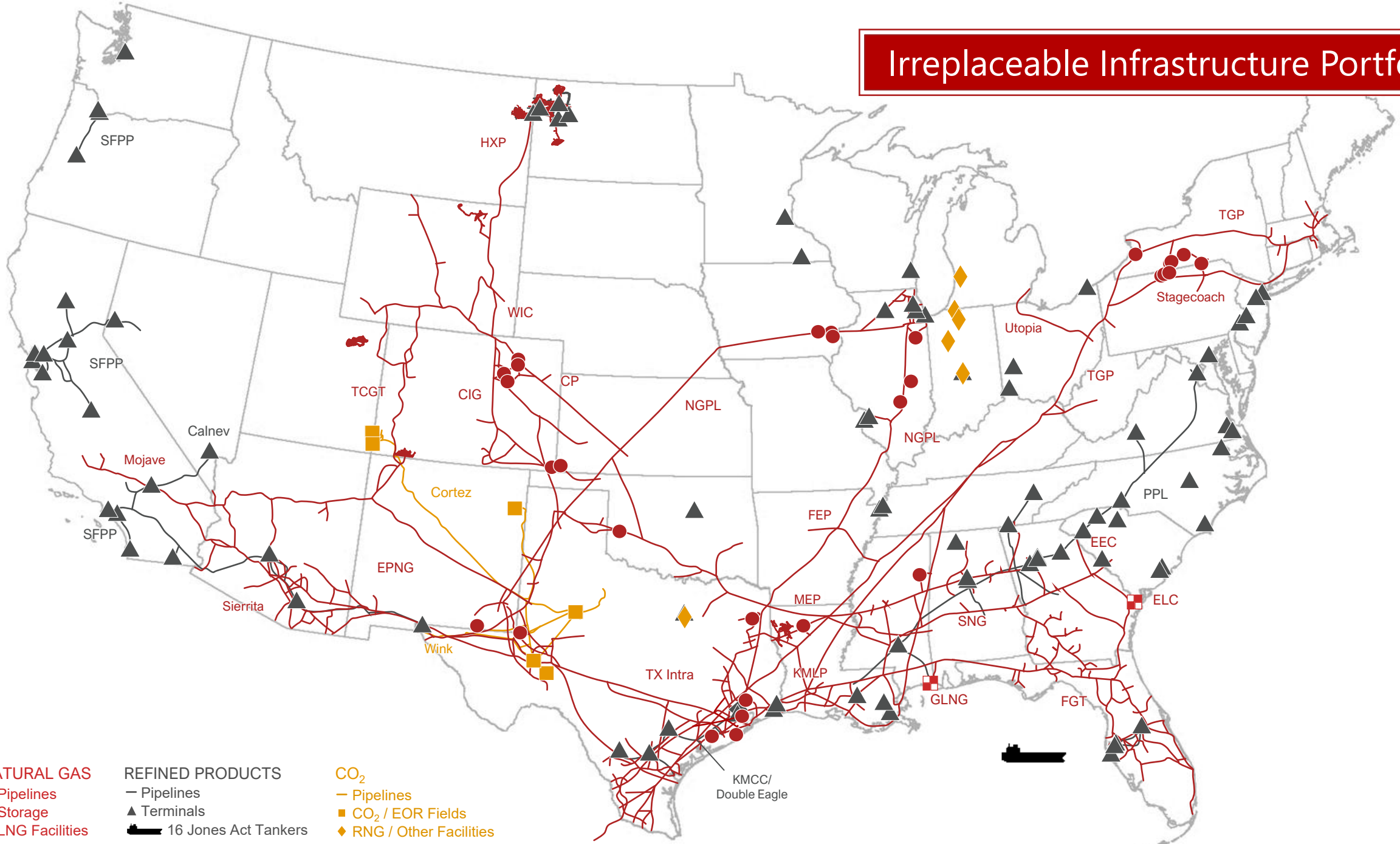
		Take-or-Pay or Hedged Volumes & price are contractually fixed	Fee-Based Price is fixed, volumes are variable	Commodity-Price Based	Avg. remaining contract term as of 12/31/2025	Additional cash flow security
Natural Gas	Interstate / LNG	40%	3%		6.6 / 14.7 years	Tariffs are FERC-regulated
	TX Intrastate	13%	3%		7.3 years	
	G&P	1%[a]	6%	1%	5.0 years	Primarily acreage dedications for fee-based contracts
Products	Refined products	1%	8%	1%	generally not applicable	Pipeline tariffs are FERC-regulated
	Crude transport	1%	1%		3.8 years[b]	~73% of 2026B Products Adj. Segment EBDA has an annual inflation-linked tariff escalator
	Crude G&P		1%			
Terminals	Liquids terminals	5%	2%		1.7 years	~76% of 2026B Terminals Adj. Segment EBDA has annual price escalators (inflation-linked or fixed-price escalators)
	Jones Act tankers	3%			3.3 years	
	Bulk terminals	2%	1%		4.6 years	Bulk terminals: primarily minimum volume guarantee or requirements
CO_2	EOR Oil & Gas	3%[a]		1%	5.5 years with third parties	Commodity-price based contracts are mostly minimum volume committed
	CO_2 & Transport		1%	1%		
	ETV	1%[a]				
		70%	26%	4%		

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.

Irreplaceable Infrastructure Portfolio



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.

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 (i) do not have a cash impact (for example, unsettled commodity hedges and asset impairments), (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), or (iii) align the timing of cash impacts from natural gas inventory hedges with the future associated physical withdrawals from inventory. We also include adjustments related to joint ventures (see “Amounts associated with Joint Ventures” below).

Adjusted Net Income Attributable to Kinder Morgan, Inc. 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 and adjusted net income in excess of distributions for participating securities. For periods from 2017 to 2018, also reflects an adjustment for preferred stock dividends. We believe Adjusted Net Income Attributable to Common Stock allows for calculation of Adjusted EPS on the most comparable basis with earnings per share, the most 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.

Adjusted Segment EBDA is calculated, for an individual segment, by adjusting segment earnings before DD&A, general and administrative expenses and corporate charges, interest expense, and income taxes (Segment EBDA), which is disclosed in our GAAP financial statements under the note captioned “Reportable Segments” pursuant to FASB ASC 280, for Certain Items attributable to the segment. The composition of Segment EBDA is not addressed nor prescribed by generally accepted accounting principles. 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. **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. for Certain Items and further for DD&A, including the amortization of basis differences related to our joint ventures, income tax expense, and interest. 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 associated with 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 associated with 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 adjustments (DD&A, including the amortization of basis differences related to joint ventures only, 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 to convert that debt to U.S. dollars. 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, that is used by management, investors, and other external users of our financial information to evaluate our leverage. For periods from 2017 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 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, including the amortization of basis differences related to joint ventures only, 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 associated with 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 unvested 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 associated with 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.

CO_2 EOR & Transport, Terminals and Product Pipelines Free Cash Flow is calculated by reducing Segment EBDA from our CO_2 EOR & Transport assets, and our Terminals and Products Pipelines segments by Certain Items, capital expenditures (sustaining and expansion) and acquisitions attributable to the EOR & Transport assets, Terminals, and Products Pipelines segment. Management uses CO_2 EOR & Transport, Terminals, and Product Pipelines Free Cash Flow as an additional performance measure for our CO_2 EOR & Transport assets, Terminals, and Products Pipelines segment. We do not provide budgeted CO_2 EOR & Transport, Terminals, and Products Pipelines Segment EBDA (the GAAP financial measure most directly comparable to 2025 budgeted CO_2 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

	2026 Budget	2025 Actual	Change $	Change %	Q3 2026 Actual
Net income attributable to KMI	**$ 3,066**	**$ 3,056**	**$ 10**	**0%**	**$ 764**
Certain Items[a]					
Legal, environmental and other reserves	-	-	-	n/a	138
Risk management activities	-	(29)	29	100%	3
Gain on divestitures	-	(123)	123	100%	(71)
Estimated gain on miscellaneous land sale	(29)	-	(29)	n/a	-
Income tax Certain Items	6	(2)	8	400%	(42)
Other	-	(3)	3	100%	-
Total Certain Items	(23)	(157)	134	85%	28
Adjusted Net income attributable to KMI	**$ 3,043**	**$ 2,899**	**$ 144**	**5%**	**$ 792**

Net income attributable to KMI	**$ 3,066**	**$ 3,056**	**$ 10**	**0%**	**$ 764**
Total Certain Items[a]	(23)	(157)	134	85%	28
DD&A	2,536	2,453	83	3%	628
Income tax expense[b]	895	834	61	7%	232
Cash taxes	(33)	(45)	12	27%	-
Sustaining capital expenditures	(944)	(937)	(7)	(1%)	(276)
Amounts associated with joint ventures					
Unconsolidated JV DD&A[c]	370	391	(21)	(5%)	92
Remove consolidated JV partners' DD&A	(63)	(63)	-	-	(16)
Unconsolidated JV income tax expense[d][e]	83	89	(6)	(7%)	22
Unconsolidated JV cash taxes[d]	(86)	(78)	(8)	(10%)	(7)
Unconsolidated JV sustaining capital expenditures	(178)	(175)	(3)	(2%)	(36)
Remove consolidated JV partners' sustaining capital expenditures	9	9	-	-	2
Other items[f]	13	29	(16)	(55%)	(1)
DCF	**$ 5,645**	**$ 5,406**	**$ 239**	**4%**	**$ 1,432**
Weighted average shares outstanding for dividends[g]	2,237	2,236	1	0%	2,238
DCF per share[h]	$ 2.52	$ 2.42	$ 0.10	4%	$ 0.64

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) See "Non-GAAP Financial Measures—Certain Items."
b) To avoid duplication, amounts are adjusted to exclude amounts which are already included within "Certain Items" above.
c) Includes amortization of basis differences related to our JVs.
d) Associated with our Citrus, NGPL and Products (SE) Pipe Line equity investments.
e) 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 Items."
f) Includes non-cash compensation associated with our unvested stock awards, pension contributions, and non-cash pension credits.
g) Includes average unvested stock awards that participate in dividends.
h) 2026 Budget DCF per share of $2.52 consists of the following quarterly amounts: Q1 $0.73, Q2 $0.55, Q3 $0.58, Q4 $0.67.

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

$ in Millions

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026B
Net income attributable to KMI	**$ 183**	**$ 1,609**	**$ 2,190**	**$ 119**	**$ 1,784**	**$ 2,548**	**$ 2,391**	**$ 2,613**	**$ 3,056**	**$ 3,066**
NCI associated with Certain Items	-	-	-	-	-	-	-	-	-	-
Certain Items[(a)]										
Fair value amortization	(53)	(34)	(29)	(21)	(19)	(15)	-	-	-	-
Legal, environmental and other reserves	(37)	12	46	26	160	51	-	-	-	-
Risk management activities	40	80	(24)	(5)	19	57	(126)	72	(29)	-
Loss on impairment/Gain on divestitures	170	317	(280)	1,927	1,535	-	67	(69)	(123)	(29)
Impact of 2017 Tax Cuts and Jobs Act	219	(36)	-	-	-	-	-	-	-	-
Income tax Certain Items	1,085	(58)	299	(107)	(491)	(37)	33	(52)	(2)	6
Noncontrolling interests	-	240	(4)	-	-	-	-	-	-	-
Other	21	(20)	(37)	72	16	32	45	7	(3)	-
Total Certain Items	1,445	501	(29)	1,892	1,220	88	19	(42)	(157)	(23)
Preferred stock dividends	(156)	(128)	-	-	-	-	-	-	-	-
Net income allocated to participating securities[(b)]	(5)	(8)	(12)	(13)	(14)	(13)	(14)	(15)	(16)	(15)
Other[(c)]	(1)	(2)	-	-	(3)	(1)	-	1	1	-
Adjusted Net Income Attributable to Common Stock	**$ 1,466**	**$ 1,972**	**$ 2,149**	**$ 1,998**	**$ 2,987**	**$ 2,622**	**$ 2,396**	**$ 2,557**	**$ 2,884**	**$ 3,028**
									-	-
Weighted average shares outstanding	2,230	2,216	2,264	2,263	2,266	2,258	2,234	2,220	2,223	2,226
Adjusted EPS	**$ 0.66**	**$ 0.89**	**$ 0.95**	**$ 0.88**	**$ 1.32**	**$ 1.16**	**$ 1.07**	**$ 1.15**	**$ 1.30**	**$ 1.36**

a) See "Non-GAAP Financial Measures—Certain Items."
b) 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.
c) Adjusted net income in excess of distributions for participating securities.

Reconciliations of Terminals FCF and Products Pipelines FCF

$ in Millions

Reconciliation of Terminals FCF	2022	2023	2024	2025	2026B
EBDA for Terminals[a]	$ 975	$ 1,039	$ 1,099	$ 1,143	$ 1,172
Certain items[b]					
Loss (gain) on impairments, divestitures and other write-downs, net	-	-	-	-	(29)
Other	-	-	-	-	-
Segment Certain Items	-	-	-	-	(29)
Adjusted EBDA for Terminals	**975**	**1,039**	**1,099**	**1,143**	**1,143**
Capital expenditures (GAAP)[c]	(552)	(406)	(385)	(326)	(400)
Acquisitions	-	-	-	-	-
Terminals FCF	**$ 423**	**$ 633**	**$ 714**	**$ 817**	**$ 743**

Reconciliation of Products Pipelines FCF					
EBDA for Products Pipelines[a]	$ 1,072	$ 1,033	$ 1,164	$ 1,157	$ 1,206
Certain items[b]					
Legal, environmental and other reserves	-	-	-	-	-
Risk management activities	-	(1)	-	1	-
Loss on impairments and divestitures, net	-	67	-	-	-
Other	-	-	-	-	-
Segment Certain Items	-	66	-	1	-
Adjusted EBDA for Products Pipelines	**1,072**	**1,099**	**1,164**	**1,158**	**1,206**
Capital expenditures (GAAP)[c]	-	(221)	(210)	(242)	(160)
Acquisitions	-	-	-	-	-
Products Pipelines FCF	**$ 1,072**	**$ 878**	**$ 954**	**$ 916**	**$ 1,046**

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. 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) Includes sustaining and expansion capital expenditures.

Reconciliations of CO_2 EOR & Transport FCF

$ in Millions

Reconciliation of CO_2 EOR & Transport FCF	2022	2023	2024	2025	2026B
EBDA for CO_2 EOR & Transport[(a)]	$ 798	$ 658	$ 640	$ 569	$ 490
Certain items[(b)]					
Risk management activities	(11)	4	2	(4)	-
Loss (gain) on impairments, divestitures and other write-downs, net	-	-	(40)	-	-
Segment Certain Items	(11)	4	(38)	(4)	-
Adjusted EBDA for CO_2 EOR & Transport	**787**	**662**	**602**	**565**	**490**
Capital expenditures (GAAP)[(c)]	(275)	(255)	(280)	(274)	(227)
Acquisitions	-	(13)	(64)	-	-
CO_2 EOR & Transport FCF	**$ 512**	**$ 394**	**$ 258**	**$ 291**	**$ 263**

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. 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) Includes sustaining and expansion capital expenditures.

Reconciliation of Adjusted EBITDA, Normalized for Divestitures

$ in Millions

Reconciliation of Adjusted EBITDA, Normalized for Divestitures	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026B
Net income attributable to KMI	**$ 183**	**$ 1,609**	**$ 2,190**	**$ 119**	**$ 1,784**	**$ 2,548**	**$ 2,391**	**$ 2,613**	**$ 3,056**	**$ 3,066**
NCI associated with Certain Items[a]	-	-	-	-	-	-	-	-	-	-
KML noncontrolling interests[b]	28	58	33	-	-	-	-	-	-	-
Certain Items[a]										
Fair value amortization	(53)	(34)	(29)	(21)	(19)	(15)	-	-	-	-
Legal, environmental and other reserves	(37)	12	46	26	160	51	-	-	-	-
Risk management activities	40	80	(24)	(5)	19	57	(126)	72	(29)	-
Loss on impairment/Gain on divestitures	170	317	(280)	1,927	1,535	-	67	(69)	(123)	-
Estimated gain on miscellaneous land sale	-	-	-	-	-	-	-	-	-	(29)
Impact of 2017 Tax Cuts and Jobs Act	219	(36)	-	-	-	-	-	-	-	-
Income tax Certain Items	1,085	(58)	299	(107)	(491)	(37)	33	(52)	(2)	6
Noncontrolling interests	-	240	(4)	-	-	-	-	-	-	-
Other	21	(20)	(37)	72	16	32	45	7	(3)	-
Total Certain Items	1,445	501	(29)	1,892	1,220	88	19	(42)	(157)	(23)
DD&A	2,261	2,297	2,411	2,164	2,135	2,186	2,250	2,354	2,453	2,536
Income tax expense[b]	853	645	627	588	860	747	682	739	834	895
Interest, net[b]	1,871	1,891	1,816	1,610	1,518	1,524	1,804	1,849	1,788	1,734
Amounts associated with joint ventures										
Unconsolidated JV DD&A[c]	459	507	494	547	390	398	389	409	391	370
Remove consolidated JV partners' DD&A	(16)	(22)	(19)	(40)	(44)	(50)	(63)	(62)	(63)	(63)
Unconsolidated JV income tax expense[b]	114	82	95	82	83	75	89	78	89	83
Adjusted EBITDA	**$ 7,198**	**$ 7,568**	**$ 7,618**	**$ 6,962**	**$ 7,946**	**$ 7,516**	**$ 7,561**	**$ 7,938**	**$ 8,391**	**$ 8,598**
Divested adjusted EBITDA[b]	(683)	(667)	(520)	(159)	(126)	(153)	(73)	(43)	(33)	-
As normalized for divestitures	**$ 6,515**	**$ 6,901**	**$ 7,098**	**$ 6,803**	**$ 7,820**	**$ 7,363**	**$ 7,488**	**$ 7,895**	**$ 8,358**	**$ 8,598**

a) See “Non-GAAP Financial Measures—Certain Items.”
b) To avoid duplication, amounts are adjusted to exclude amounts which are already included within “Certain Items” above.
c) Includes amortization of basis differences related to our JVs.

Reconciliation of Net Debt

$ in Millions

Reconciliation of Net Debt	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026B
Current portion of debt	$ 2,828	$ 3,388	$ 2,377	$ 2,558	$ 2,646	$ 3,385	$ 4,049	$ 2,009	$ 1,226	$ 1,337
Total long-term debt	35,015	33,936	31,915	32,131	30,674	28,403	28,067	29,881	30,777	30,984
Debt fair value adjustments	(927)	(731)	(1,032)	(1,293)	(902)	(115)	(187)	(102)	(180)	
Preferred interest in general partner of KMP	(100)	(100)	-	-	-	-	-	-	-	-
Foreign exchange impact on hedges for Euro Debt outstanding	(143)	(76)	(44)	(170)	(64)	8	(9)	25	(44)	
Less: cash & cash equivalents	(264)	(3,280)	(185)	(1,184)	(1,140)	(745)	(83)	(88)	(63)	-
Net Debt	**$ 36,409**	**$ 33,137**	**$ 33,031**	**$ 32,042**	**$ 31,214**	**$ 30,936**	**$ 31,837**	**$ 31,725**	**$ 31,716**	**$ 32,322**
Adjusted EBITDA	$ 7,198	$ 7,568	$ 7,618	$ 6,962	$ 7,946	$ 7,516	$ 7,561	$ 7,938	$ 8,391	$ 8,598
Net Debt to Adjusted EBITDA	**5.1x**	**4.4x**	**4.3x**	**4.6x**	**3.9x**	**4.1x**	**4.2x**	**4.0x**	**3.8x**	**3.8x**