



# 2Q 2025

# Investor Presentation



*EPNG Mojave Compressor Station*

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

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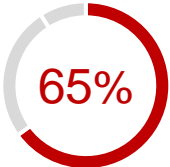
**GAAP** – Unless otherwise stated, all historical and estimated future financial information included in this presentation has been prepared in accordance with generally accepted accounting principles in the United States (“GAAP”).

**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

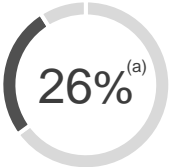
## NATURAL GAS



One of the Largest U.S. Natural Gas Transmission Networks

- ~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

## REFINED PRODUCTS



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

## CO<sub>2</sub>



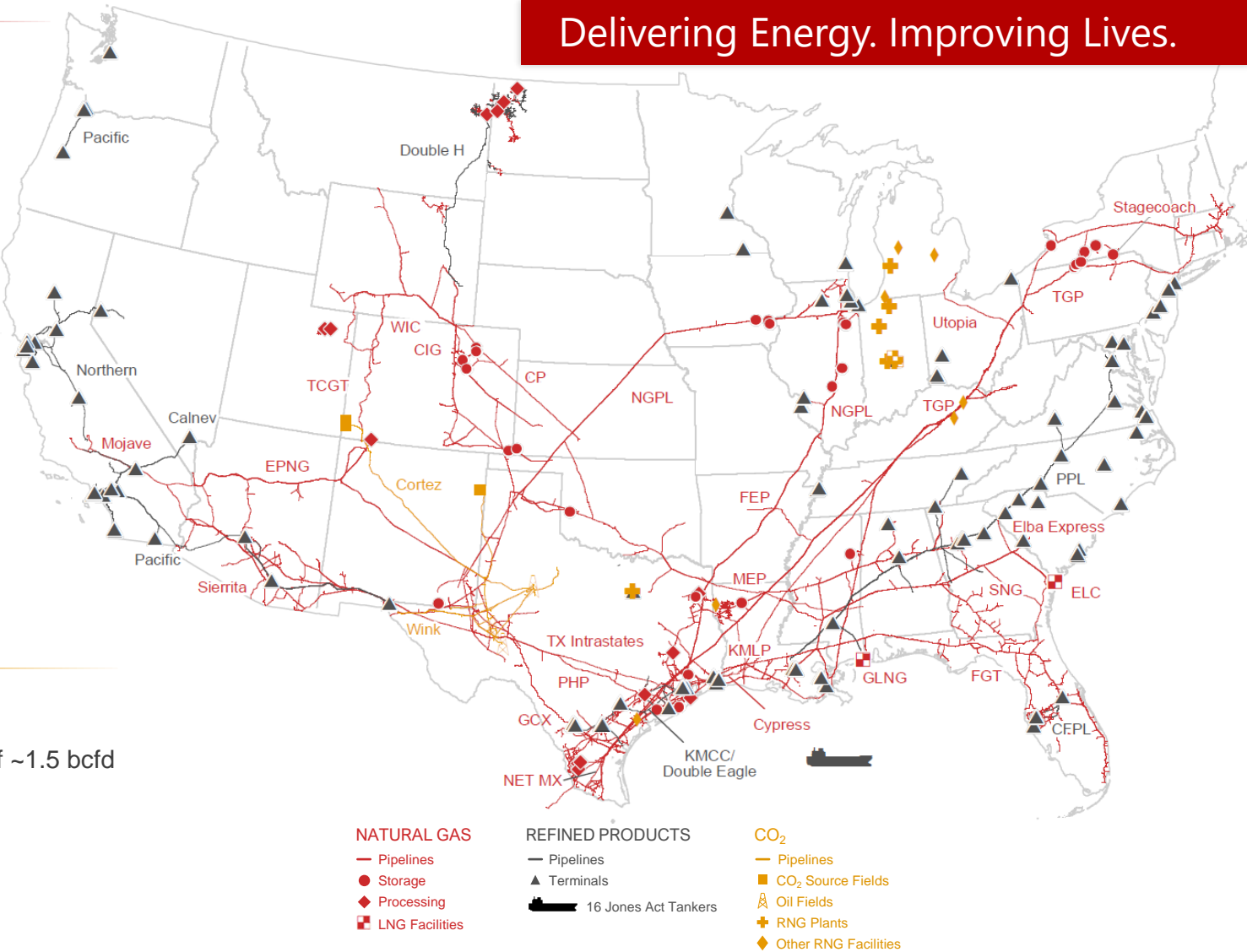
One of the Largest CO<sub>2</sub> Transporters in the U.S.

- ~1,500 miles of CO<sub>2</sub> pipelines with transport capacity of ~1.5 bcf/d
- Produce and transport CO<sub>2</sub> for enhanced oil recovery

Growing Energy Transition Portfolio

- RNG production capacity of 6.4 bcf<sup>(b)</sup>

## BUSINESS MIX



Delivering Energy. Improving Lives.

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.

# Driving Long-Term Shareholder Value



## Natural Gas Focus

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

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



## Balance Sheet Strength

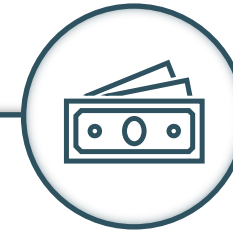
~**3.8x** YE 2025B Net Debt / Adjusted EBITDA

**BBB** investment grade balance sheet



## High-Returning Growth Projects

~**\$8.8 billion** of committed projects at **<6x** EBITDA build multiple



## Predictable & Growing Cash Flows

~**69%** of cash flows are take-or-pay or hedged<sup>(a)</sup>

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



## Returns to Shareholders

Increasing dividend for **8<sup>th</sup>** straight year

~**35%** of market cap value returned to shareholders since 2016<sup>(b)</sup>

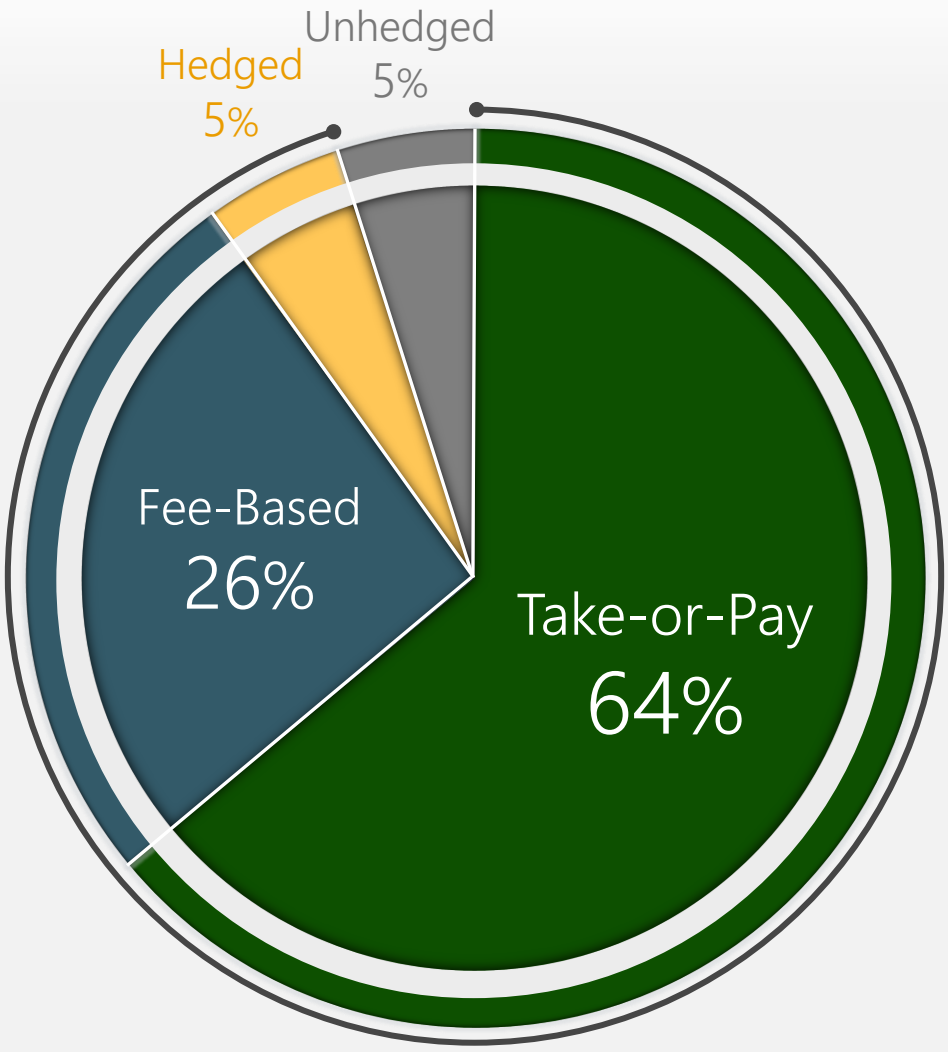
Note: Total Adjusted Segment EBITDA, Adjusted EPS, Adjusted EBITDA, Net Debt, and EBITDA build multiple (calculated based on Project EBITDA) are non-GAAP financial measures. See Non-GAAP Financial Measures & Reconciliations.

a) Based on 2025 budgeted Total Adjusted Segment EBITDA.

b) Market capitalization as of 4/11/2025. Returns via dividends paid and share repurchases.

# Highly Contracted, Predictable Cash Flows

## CASH FLOW MIX



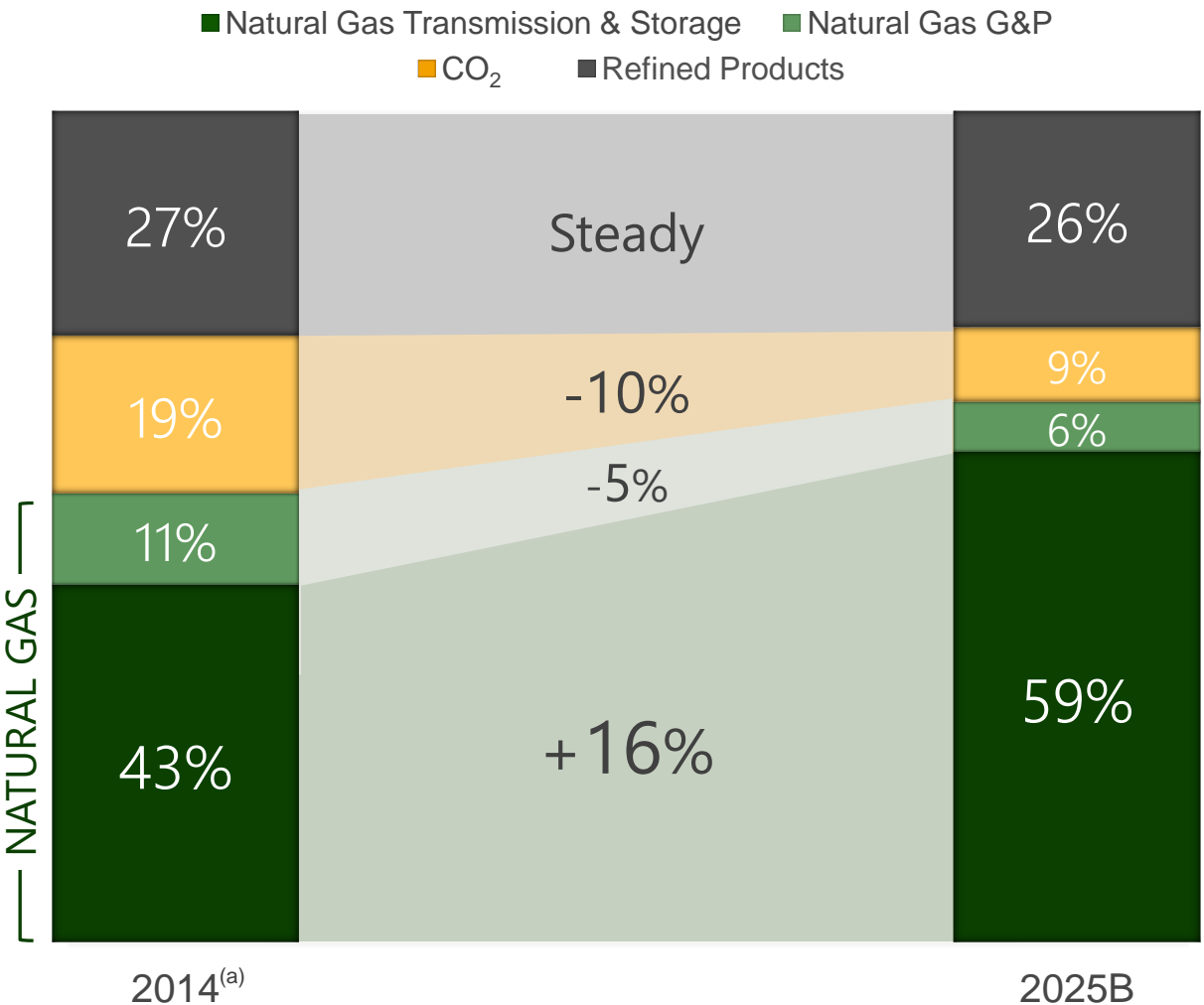
**95%** Take-or-Pay, Fee-Based, or Hedged Cash Flows

- 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

## BUSINESS MIX



## CHANGES SINCE 2014

**Natural Gas Transmission & Storage increased +16%**

**Natural Gas G&P decreased -5%**

**CO<sub>2</sub> 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.

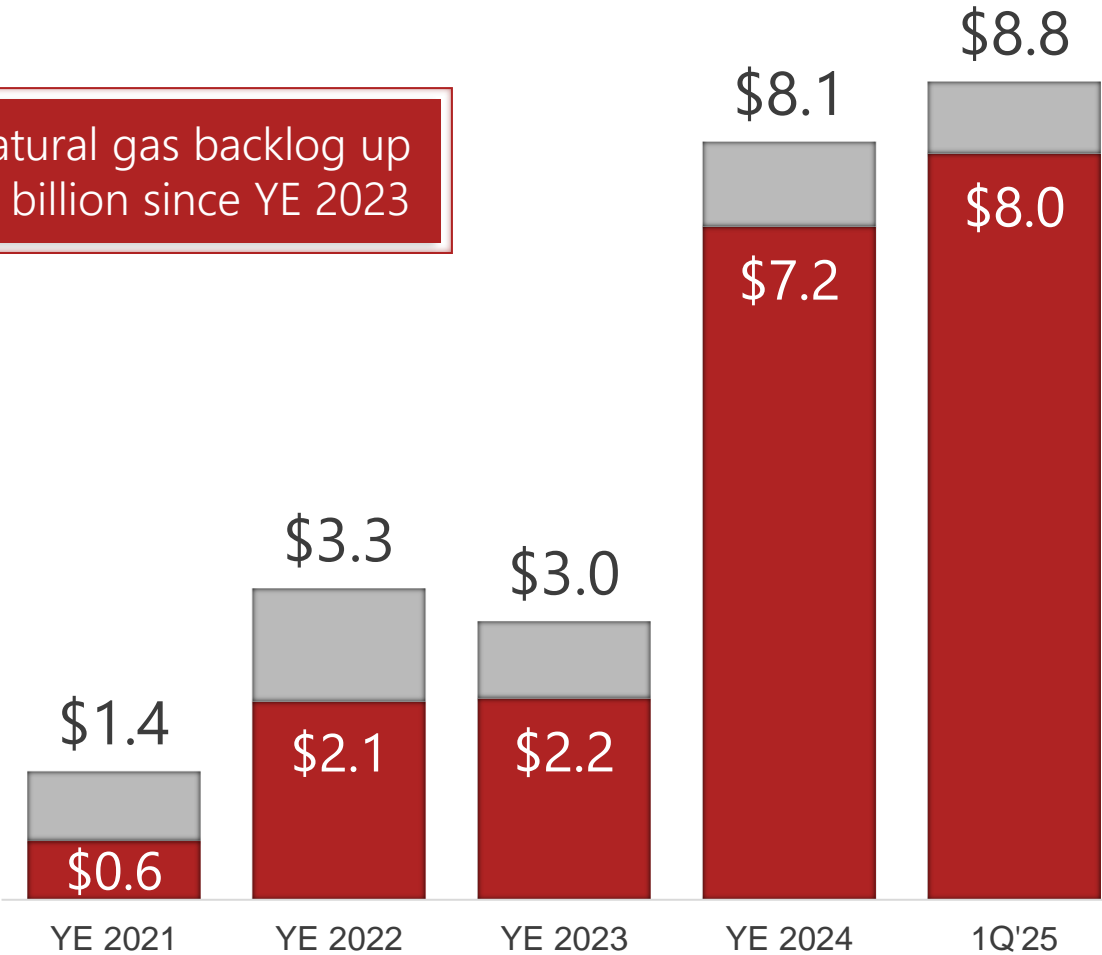
a) First year of combined KMI.

# Growing Our Project Backlog While Maintaining Discipline on Returns

PROJECT BACKLOG OVER TIME<sup>(a)</sup>

\$ Billion

■ Natural Gas Segment ■ Other Segments



Natural gas backlog up +\$5.8 billion since YE 2023

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 ~\$8.8 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.

# \$8.8bn Committed Growth Capital Project Backlog as of 3/31/2025

~20% of Backlog Capital in Service During Remainder of 2025

\$ million	TOTAL	
Natural Gas (excluding G&P)	\$7,394	Nearly all serving LNG, Power, and LDC demand
Other	137	Primarily refined product projects
<hr style="border-top: 1px dashed #ccc;"/>		
<b>Subtotal</b>	<b>\$7,531</b>	<b>Contracted, stable cash flows, minimal direct commodity exposure</b>
<b>EBITDA Build Multiple</b>	<b>~5.9x</b>	
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Gathering & Processing	623	Mostly natural gas, volume-based projects
EOR	600	Commodity price & volume-based cash flows
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<b>Total Backlog</b>	<b>\$8,754</b>	

Expect annual growth capital spend of around \$2.5 billion	Natural gas investments >90% of backlog
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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.

# 2025 Budget Highlights

Currently Expect to Exceed Budget by at Least the Contributions from the Outrigger Acquisition



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<sup>(a)</sup>

**\$2.3bn**

infrastructure projects  
with attractive returns

Cash  
Returns

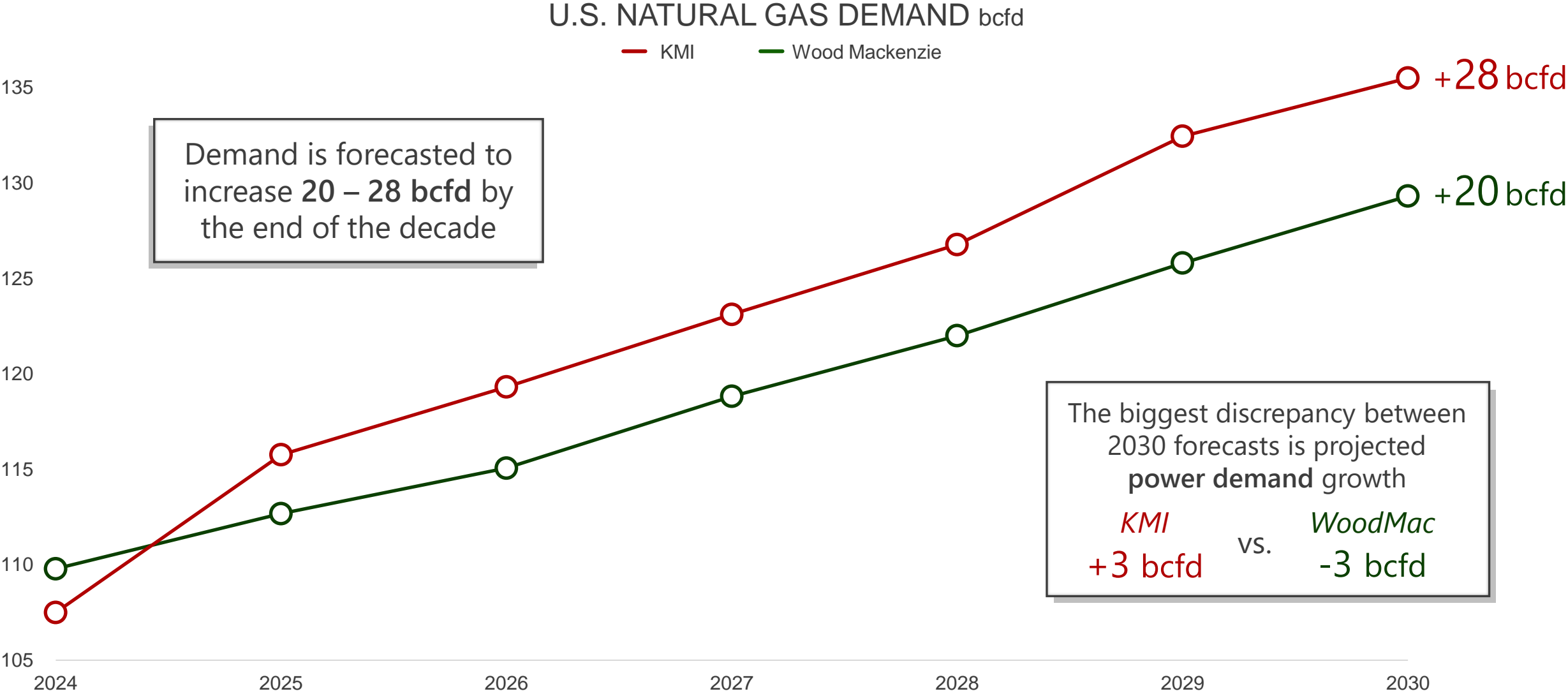
**\$2.6bn**

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.

# Demand for U.S. Natural Gas Projected to Grow



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

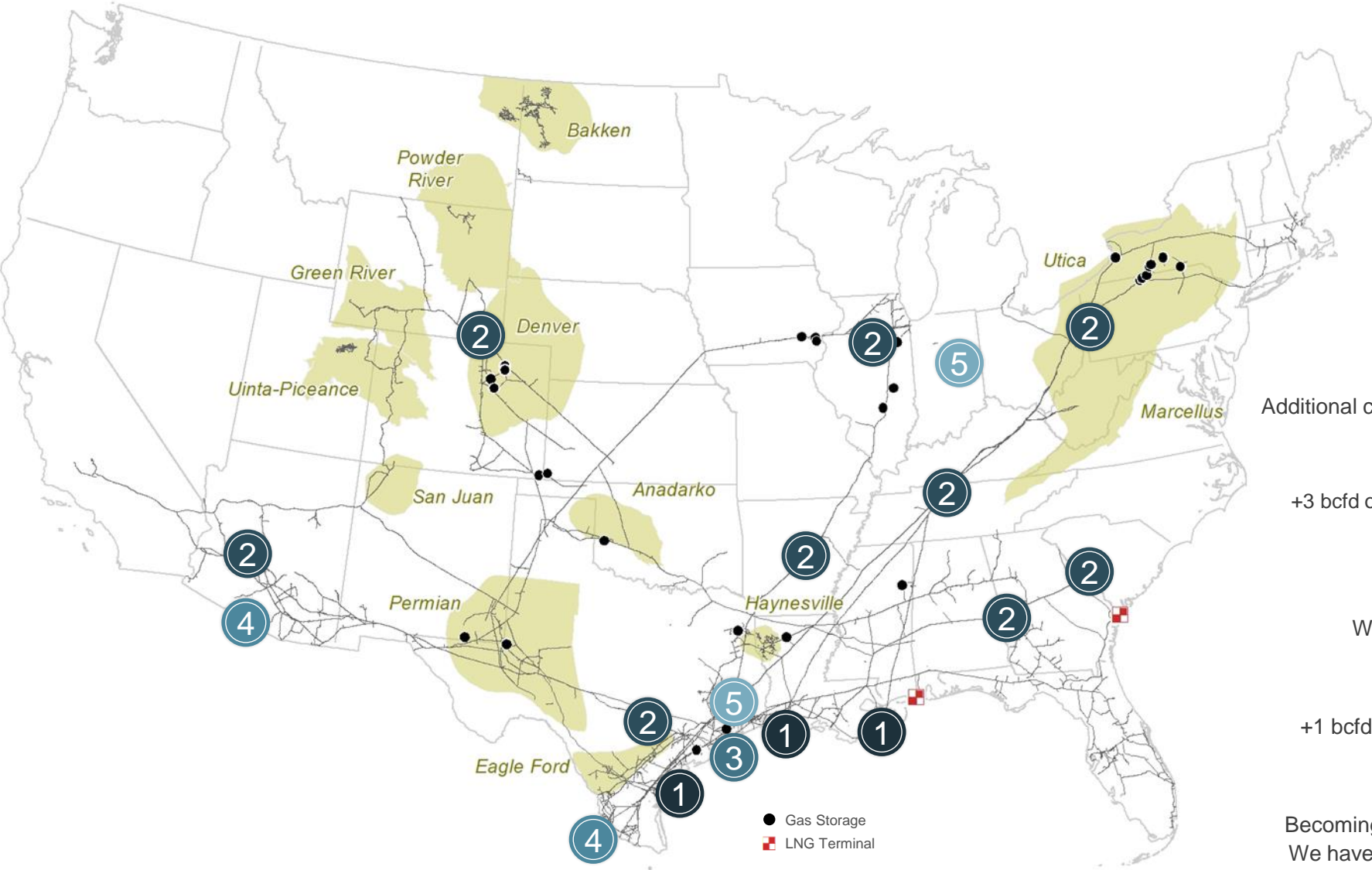
Source: KMI internal natural gas forecast. Wood Mackenzie North America Gas 10-Year Investment Horizon Outlook, November 2024.

# 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

Source: Wood Mackenzie North America Gas 10-Year Investment Horizon Outlook, November 2024. Industrial sector includes WoodMackenzie'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.

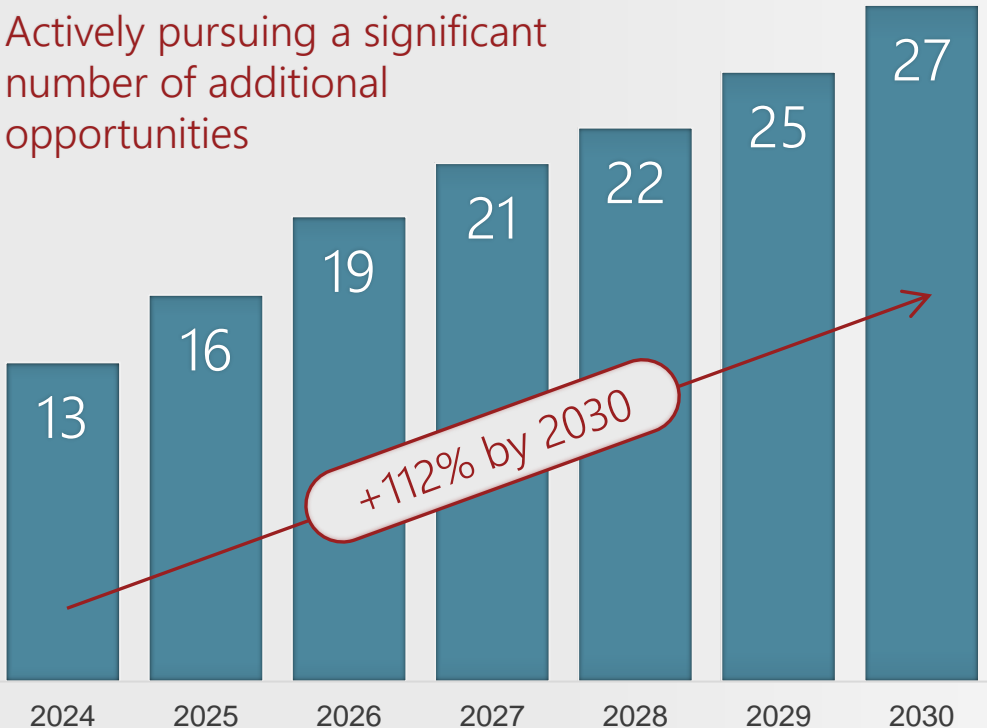
# LNG Exports Driving Natural Gas Demand Growth

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

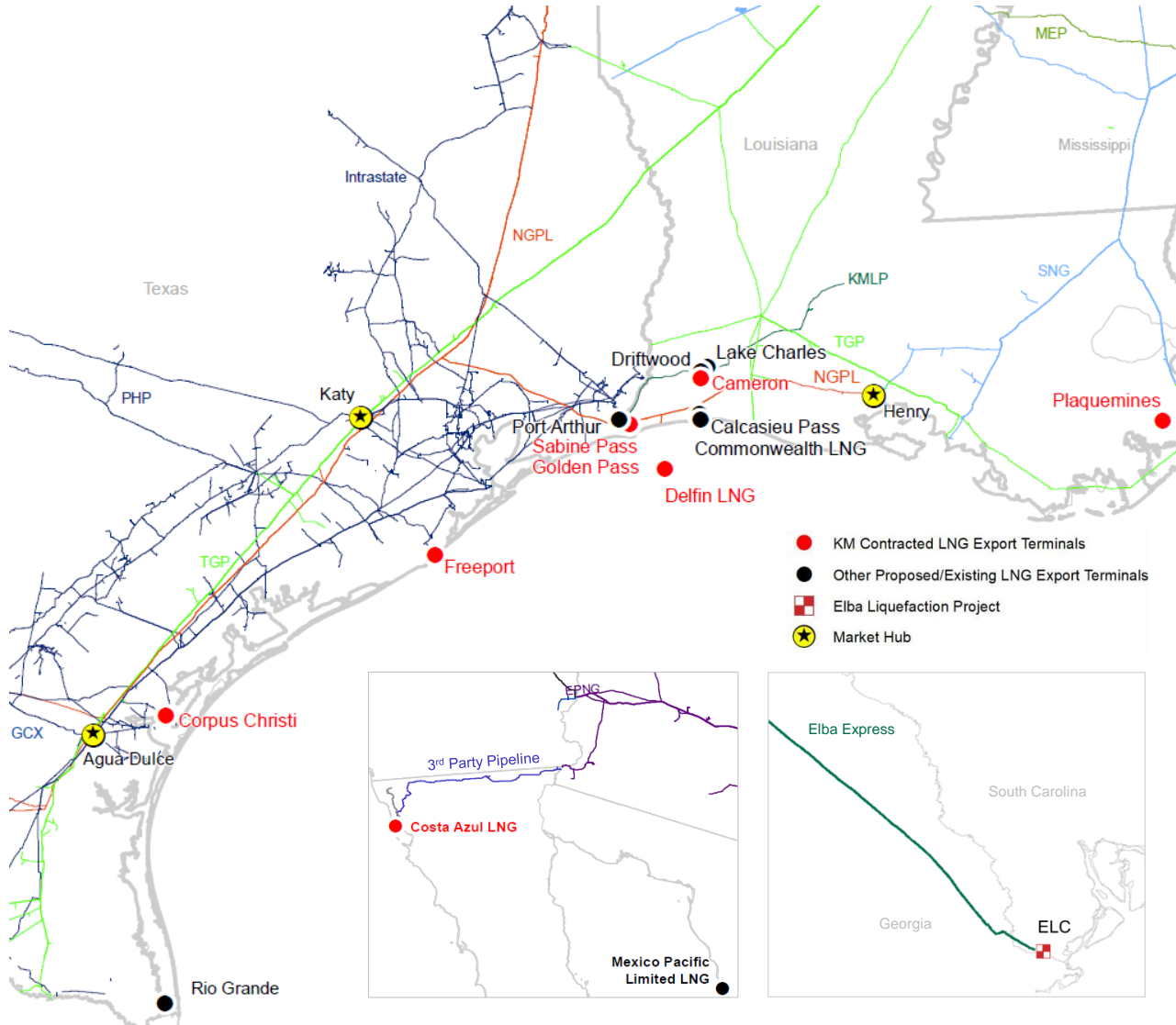
WOODMAC U.S. LNG FEEDGAS FORECAST  
bcfd

KMI has long-term contracts to move ~7 bcfd to facilities today & ~11 bcfd by the end of 2027

Actively pursuing a significant number of additional opportunities

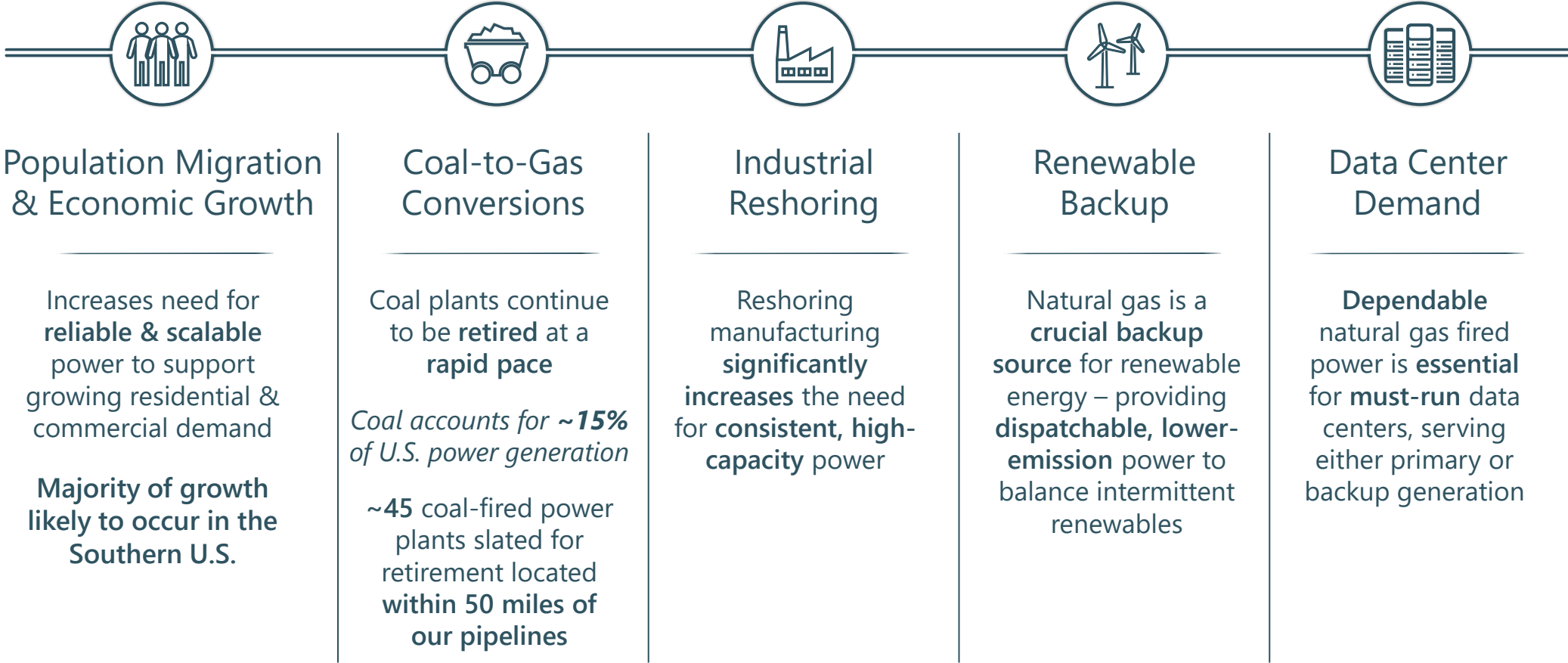


Note: Wood Mackenzie North America Gas 10-Year Investment Horizon Outlook, November 2024. LNG feedgas equals exports plus an assumed 9% increase for plant fuel.



# Growing Power Needs Boosting Demand for Natural Gas

## INCREASING NATURAL GAS FIRED POWER DEMAND DRIVEN BY



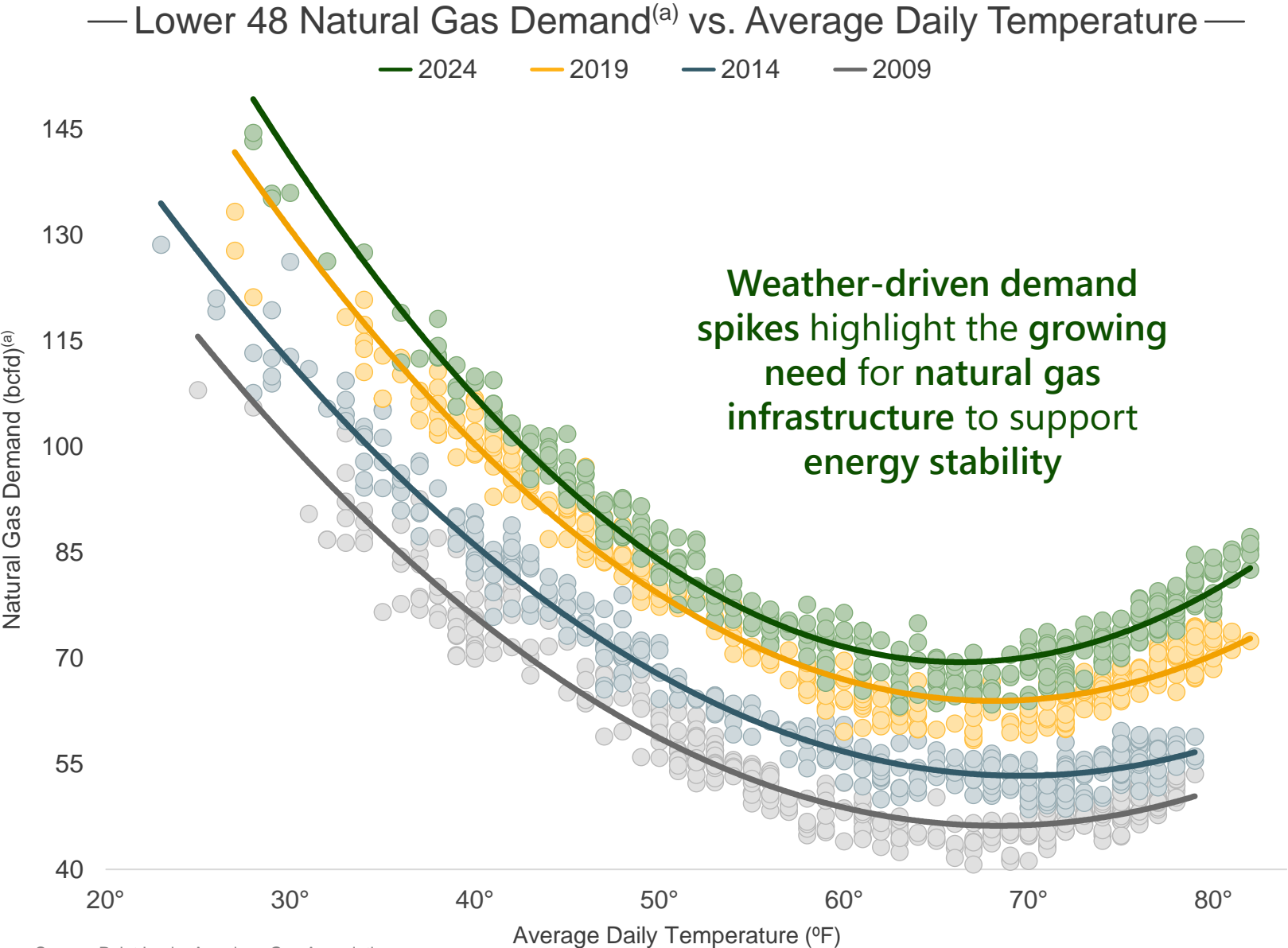
KMI forecasting **3 bcfd** increase in **natural gas fired power demand** by 2030

Actively pursuing **well over 5 bcfd** of power opportunities

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

Source: Coal-fired power plant and 2024 generation data per the EIA. KMI internal natural gas forecast.

# Rising Need for Natural Gas Amid Growing Market Volatility



Natural gas demand for a given degree day continues to increase

Increasingly variable demand leads to greater spikes in demand

The top 2 all-time record days for natural gas demand occurred in January 2025

Volatility at both ends of the demand curve is expected to rise

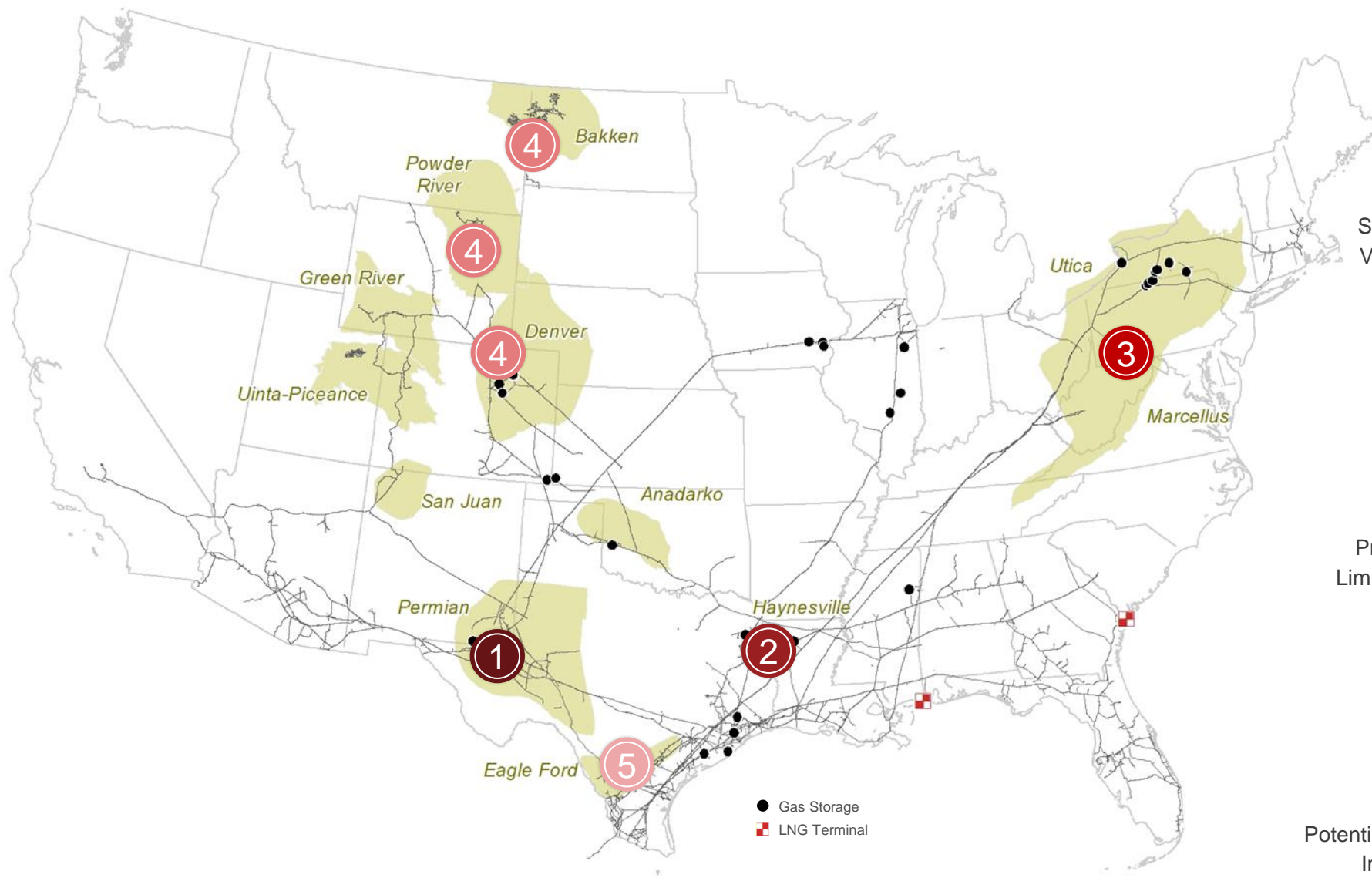
Additional investment in natural gas pipelines and storage will be needed to help meet rising demand and ensure reliability

Source: Point Logic, American Gas Association.  
a) Includes residential, commercial, industrial, and power demand.

# 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

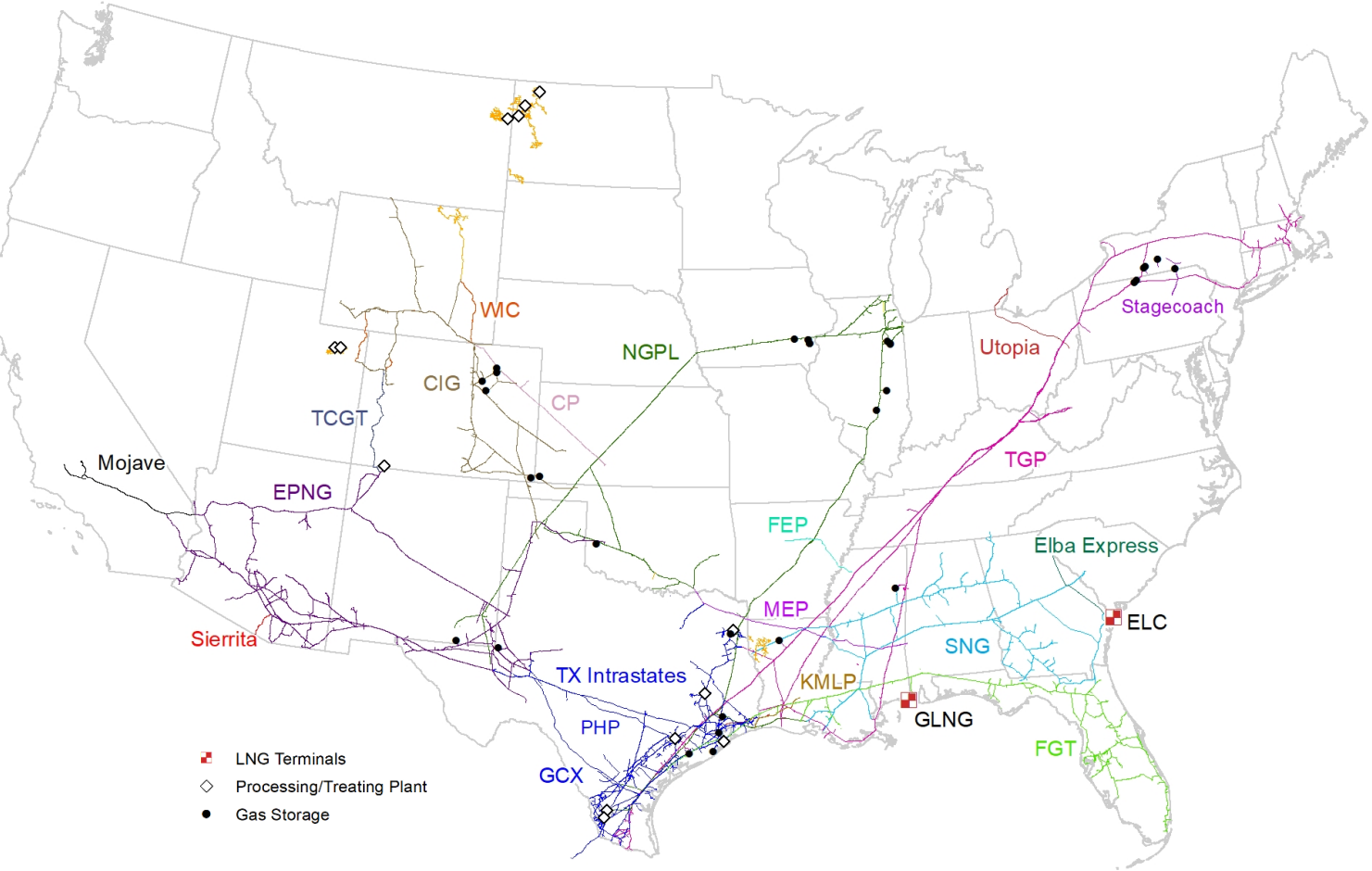
**Northeast** +6 bcf/d from the Marcellus/Utica **3**  
 Production constrained despite ample, low-cost supply  
 Limited infrastructure opportunity despite strong demand

**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

# Natural Gas Segment Overview

Connecting Key Natural Gas Resources with Major Demand Centers



<b>66,000 miles</b> natural gas pipelines	<b>&gt;700 bcf</b> working gas storage capacity	<b>1,200 miles</b> NGL pipelines
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One of the Largest Natural Gas Transmission Networks 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<sup>(a)</sup>  
*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

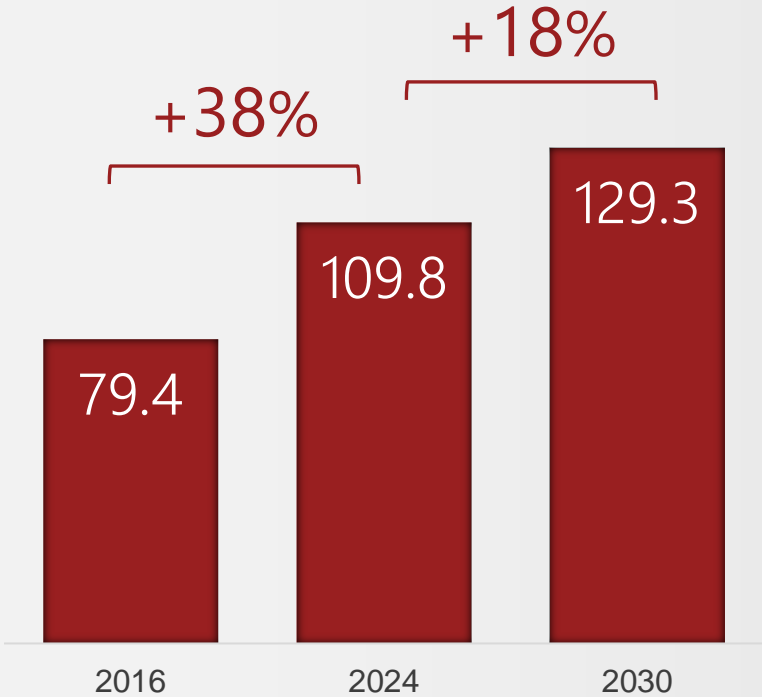
Robust Opportunity Set for Growth

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

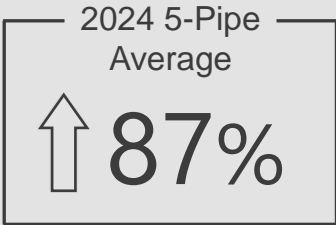
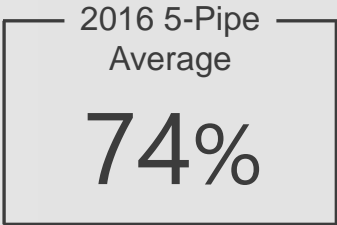
# Rising Demand Benefitting Our Natural Gas Transportation Business

Increased Demand Leading To

WOODMAC  
U.S. NATURAL GAS DEMAND  
bcfd

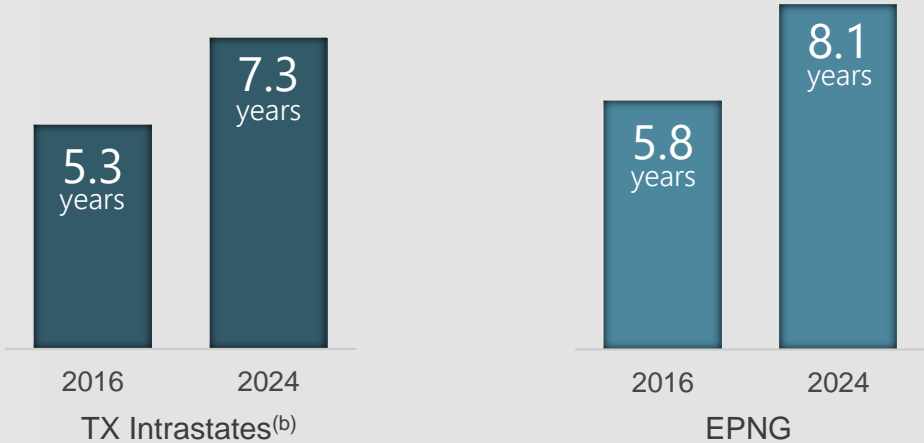


• INCREASED PIPELINE USAGE FACTOR<sup>(a)</sup>



• INCREASED CONTRACT TERMS AND/OR RATES

EXAMPLES



• NEW PROJECTS

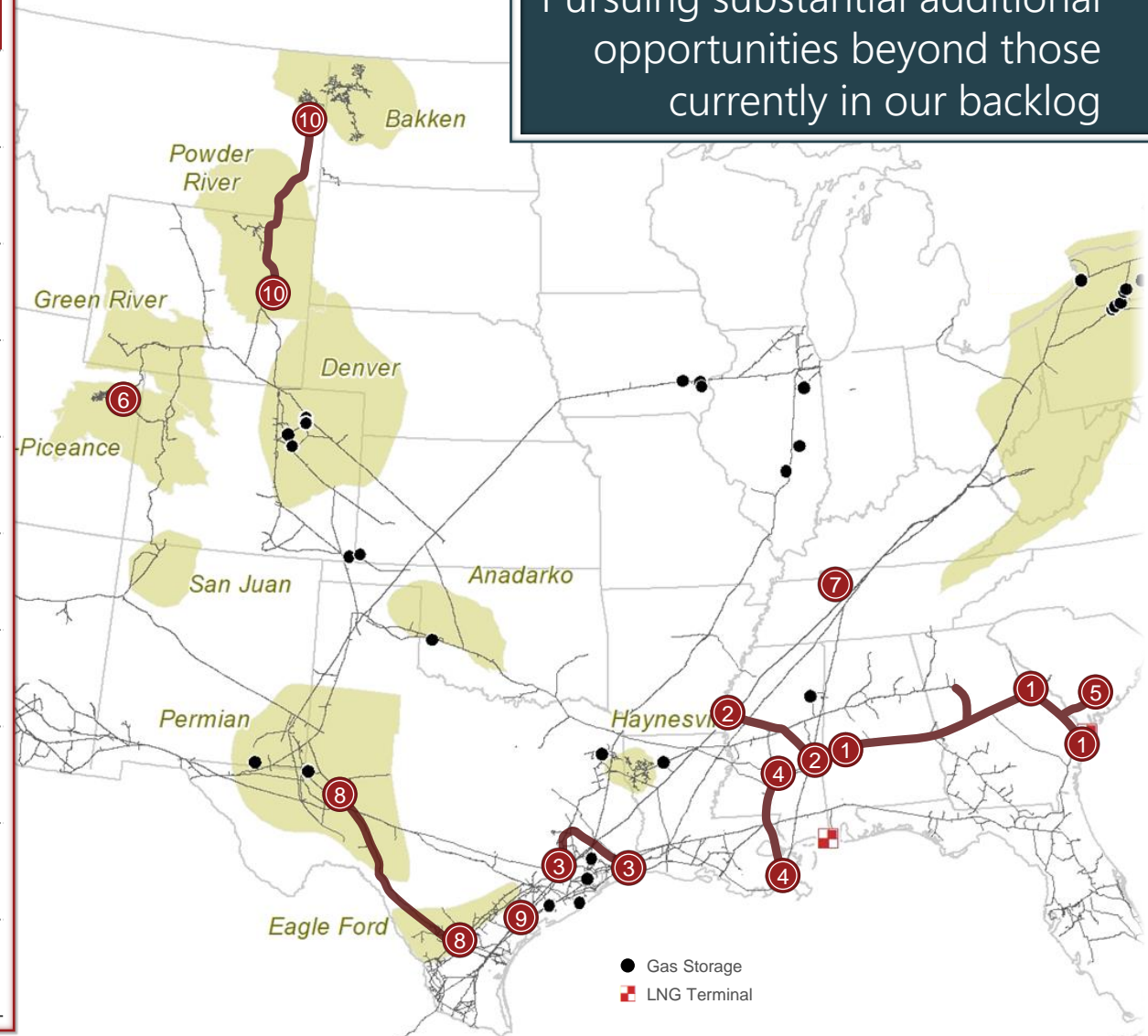
~\$8.0 billion of natural gas projects in our backlog; expect to continue adding projects over time<sup>(c)</sup>

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 ~\$0.6bn of natural gas gathering & processing projects.

# ~\$8.0 Billion of Approved Natural Gas Projects

Major Projects	Capital <sup>(a)</sup> (\$bn)	Capacity (bcfd)	In-Service Date	Status
① South System Expansion 4 <i>SNG &amp; EEC</i>	\$1.8	1.3	4Q28, 4Q29	Permitting
② Mississippi Crossing <i>TGP</i>	\$1.7	2.1	4Q28	Permitting
③ Trident <i>TX Intrastates</i>	\$1.6	1.5	1Q27	Permitting
④ Evangeline Pass (Phase II) <i>TGP &amp; SNG</i>	\$0.4	1.1	3Q25	Construction
⑤ Bridge <i>EEC</i>	\$0.4	0.3	2Q30	Permitting
⑥ Green River Pipeline <i>Altamont</i>	\$0.3	0.1	3Q25	Construction
⑦ Cumberland <i>TGP</i>	\$0.2	0.2	1Q26	Pre-Construction
⑧ GCX Expansion <i>TX Intrastates</i>	\$0.2	0.6	2Q26	Construction
⑨ S. TX to Houston Market (I & II) <i>TX Intrastates</i>	\$0.2	0.8	2Q25	Construction
⑩ Hiland Express (NGL Conversion) <i>Double H</i>	\$0.1	--	1Q26	Pre-Construction

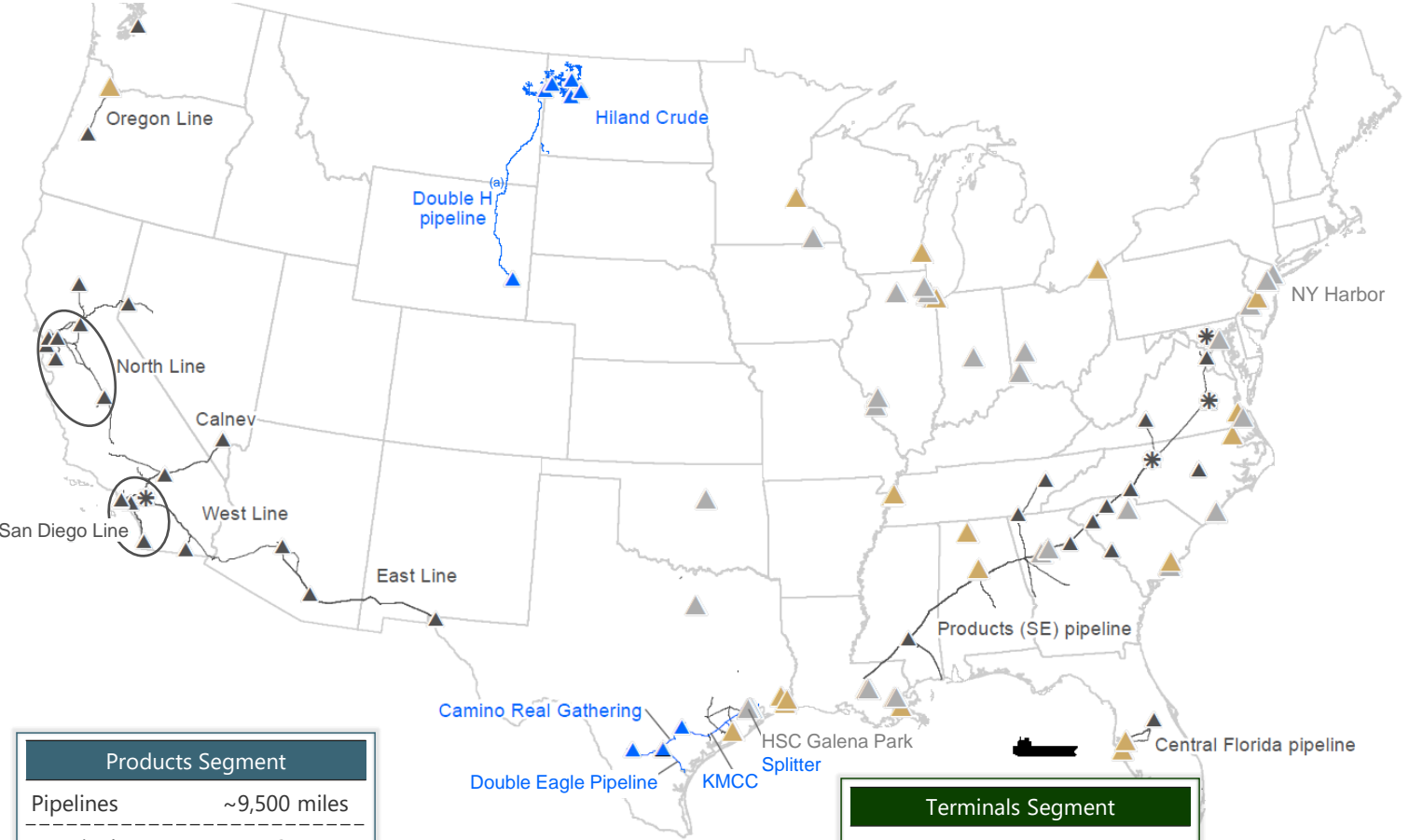
Pursuing substantial additional opportunities beyond those currently in our backlog



a) KMI share of estimated project capital.

# Products Segment & Terminals Segment Overview

Both Segments Principally Refined Products Focused



Products Segment	
Pipelines	~9,500 miles
Terminals	65
Capacity	~56 mmbbl
Transmix	5 facilities
RD Capacity	~87 mbbl/d

- Refined Products Pipelines
- ▲ Refined Products Terminals
- \* Transmix Facilities
- Renewable Diesel Hubs
- Crude Pipelines
- ▲ Crude Terminals
- ◆ Condensate Splitter

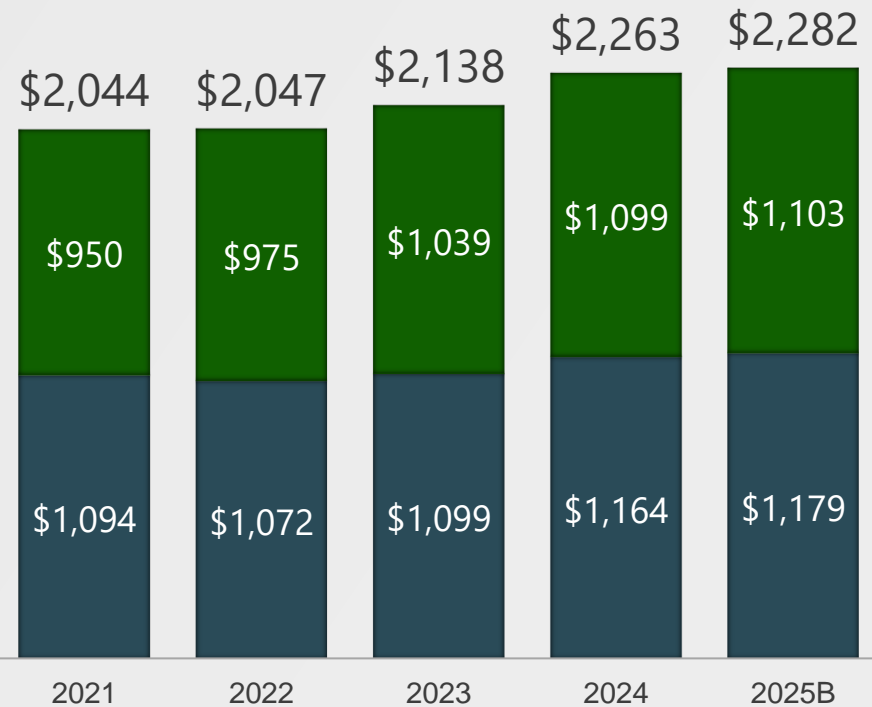
Terminals Segment	
Bulk Terminals	27
Liquids Terminals	47
Capacity	~79 mmbbl
Jones Act	16 tankers

- ▲ Liquids Terminals
- ▲ Bulk Terminals
- 16 Jones Act tankers

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

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

■ Products Segment ■ Terminals Segment



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.

# CO<sub>2</sub> Segment: EOR and CO<sub>2</sub> 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<sub>2</sub> fields with 37 tcf of Original Gas In Place

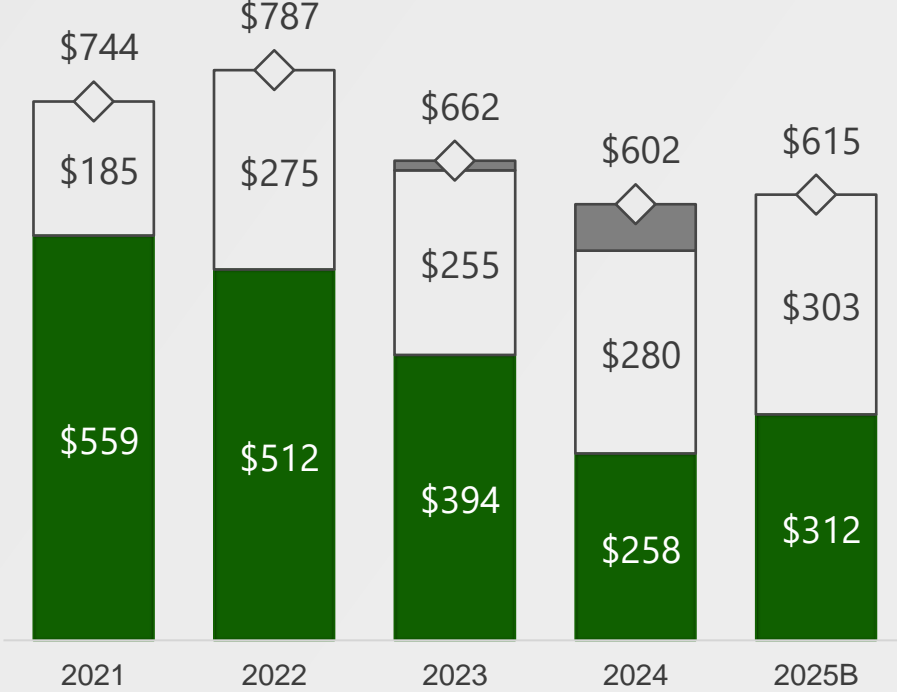
~1,500 miles of CO<sub>2</sub> pipelines with capacity to move up to 1.5 bcfd



— CO<sub>2</sub> EOR & TRANSPORT FREE CASH FLOW —  
\$ Millions

■ FCF □ Capex<sup>(a)</sup> ■ Acquisitions ◇ Adj. Segment EBDA

>\$2 billion FCF Generated Over 5 years



Note: CO<sub>2</sub> 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.

## Pursuing Commercial Opportunities Emerging from the Lower Carbon Energy Evolution



### RNG

Established a growing RNG platform

6 facilities with 6.4 bcf<sup>(a)</sup> of RNG production capacity; contracted long term into the transportation market

Continue to evaluate incremental expansion opportunities

### CCS

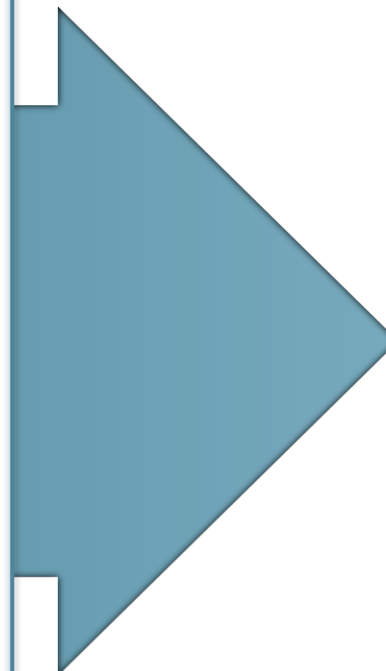
Evaluating commercial opportunities across the CCS value chain

Leveraging decades of CO<sub>2</sub> experience to become a leading provider of CO<sub>2</sub> transportation and sequestration services

### Future Opportunities

Renewable Fuels, Hydrogen, Power, Energy Storage

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



a) Annual capacity at KMI share.

# 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<sup>(a)</sup>



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

**\$8.0bn**

Primarily natural gas; remaining investment in RNG and CCS<sup>(b)</sup>

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 3/31/2025 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 105 Oil & Gas  
Storage and Transportation Companies &  
191 Refiners & Pipelines

**SSGA Top 10%**  
R-Factor in  
Oil & Gas – Midstream sector

**FTSE #2**  
of Oil & Gas  
Pipelines subsector

**Refinitiv #5**  
of 232 Oil & Gas  
Related Equipment  
and Services Companies

**S&P Global CSA**  
**Sustainability Yearbook  
Member**

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

Note: Sustainalytics ESG risk ranking, MSCI ESG rating, FTSE ESG rating rank, Refinitiv ESG score rank, S&P Global CSA score, and SSGA R-Factor as of April 2025.



# APPENDIX

# Contract Strategy Insulates Cash Flows Through Commodity Cycles

Structure Long-Term Contracts That Minimize Price & Volume Volatility

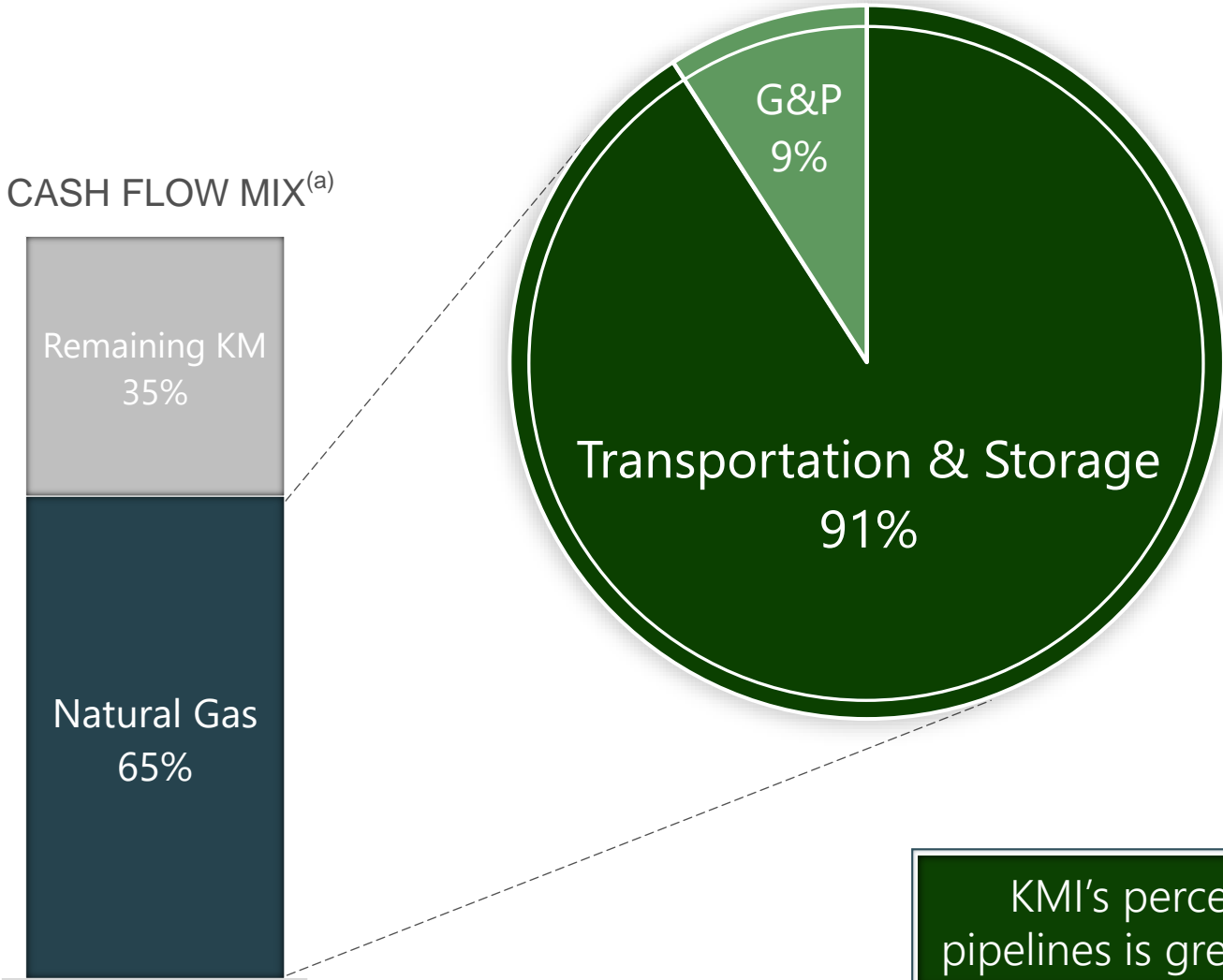
		Take-or-Pay or Hedged Volumes & price are contractually fixed	Fee-Based Price is fixed, volumes are variable	Commodity- Price Based	Avg. remaining contract term as of 12/31/2024	Additional cash flow security
Natural Gas	Interstate / LNG	40%	3%		6.3 / 15.7 years	Tariffs are FERC-regulated
	TX Intrastate	12%	4%		7.3 years	
	G&P	1% <sup>(a)</sup>	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 <sup>(b)</sup>	~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 <sub>2</sub>	EOR Oil & Gas	4% <sup>(a)</sup>		1%		
	CO <sub>2</sub> & 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.

# High-Quality, Natural Gas Focused Cash Flows



**Natural Gas Transportation & Storage**

- Accounts for 59% of 2025B KMI Adjusted Segment EBDA
- 88% take-or-pay cash flows<sup>(a)</sup>
- 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<sup>(b)</sup>

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.

# 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.** 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 2016 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 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 associated with Joint Ventures” below).

**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) 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 basis differences related to our joint ventures (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 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 items (DD&A amortization of basis differences 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 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<sub>2</sub> EOR & Transport, Terminals and Product Pipelines Free Cash Flow** is calculated by reducing Segment EBDA from our CO<sub>2</sub> 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 CO<sub>2</sub> EOR & Transport, Terminals, and Product Pipelines Free Cash Flow as an additional performance measure for our CO<sub>2</sub> EOR & Transport assets, Terminals, and Products Pipelines segment. We do not provide budgeted CO<sub>2</sub> EOR & Transport, Terminals, and Products Pipeline Segment EBDA (the GAAP financial measure most directly comparable to 2025 budgeted CO<sub>2</sub> 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		Q1 2025 Actual
			\$	%	
<b>Net income attributable to KMI</b>	<b>\$ 2,829</b>	<b>\$ 2,613</b>	<b>\$ 216</b>	<b>8%</b>	<b>\$ 717</b>
Certain Items					
Change in fair value of derivative contracts	-	72	(72)	(100%)	84
Loss on impairment	-	(69)	69	100%	-
Income tax Certain Items	-	(52)	52	100%	(35)
Other	2	7	(5)	(71%)	-
Total Certain Items	2	(42)	44	105%	49
<b>Adjusted Net income attributable to KMI</b>	<b>\$ 2,831</b>	<b>\$ 2,571</b>	<b>\$ 260</b>	<b>10%</b>	<b>\$ 766</b>
<b>Net income attributable to KMI</b>	<b>\$ 2,829</b>	<b>\$ 2,613</b>	<b>\$ 216</b>	<b>8%</b>	<b>\$ 717</b>
Total Certain Items	2	(42)	44	105%	49
DD&A	2,411	2,354	57	2%	610
Income tax expense <sup>(a)</sup>	817	739	78	11%	221
Cash taxes	(77)	(33)	(44)	(133%)	(3)
Sustaining capital expenditures	(938)	(986)	48	5%	(194)
Amounts associated with joint ventures					
Unconsolidated JV DD&A <sup>(b)</sup>	408	409	(1)	(0%)	100
Remove consolidated JV partners' DD&A	(64)	(62)	(2)	(3%)	(15)
Unconsolidated JV income tax expense <sup>(c)(d)</sup>	85	78	7	9%	26
Unconsolidated JV cash taxes <sup>(c)</sup>	(82)	(48)	(34)	(71%)	(3)
Unconsolidated JV sustaining capital expenditures	(184)	(189)	5	3%	(32)
Remove consolidated JV partners' sustaining capital expenditures	10	10	-	-	2
Other items <sup>(e)</sup>	24	38	(14)	(37%)	7
<b>DCF</b>	<b>\$ 5,241</b>	<b>\$ 4,881</b>	<b>\$ 360</b>	<b>7%</b>	<b>\$ 1,485</b>
Weighted average shares outstanding for dividends <sup>(f)</sup>	2,237	2,233	4	0%	2,235
DCF per share <sup>(g)</sup>	\$ 2.34	\$ 2.19	\$ 0.15	7%	\$ 0.66

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 Items."
- e) Includes pension contributions, non-cash pension expense and non-cash compensation associated with our restricted stock program.
- f) Includes 15 million, 15 million, and 13 million average unvested restricted shares that participate in dividends in 2025 Budget, 2024, and Q1 2025 actuals, 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 <sup>(a)</sup>	2025 Budget	2014 Actual
Natural Gas Pipelines Segment EBDA	\$ 5,636	\$ 4,288
Certain Items <sup>(b)</sup>		
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 <sup>(b)</sup>		
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 <sup>(b)</sup>		
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 <sup>(a)</sup>	2025 Budget	2014 Actual
CO <sub>2</sub> Segment EBDA	755	1,248
Certain Items <sup>(b)</sup>		
Change in fair value of derivative contracts	-	(25)
Loss on impairments, divestitures and other write-downs, net	-	243
Certain Items	-	218
CO <sub>2</sub> Adjusted Segment EBDA <sup>(c)</sup>	755	1,466
Canada Adjusted Segment EBDA	-	200
Total Adjusted Segment EBDA <sup>(d)</sup>	\$ 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 CO<sub>2</sub> 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 <sup>(a)</sup>	2024 Actual	Adjustment <sup>(b)</sup>	2024 Recasted
Natural Gas Pipelines Segment EBDA	\$ 5,427	\$ (34)	\$ 5,393
Certain Items <sup>(c)</sup>			-
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 <sub>2</sub> Segment EBDA	692	(7)	685
Certain Items <sup>(c)</sup>			-
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 <sub>2</sub> Adjusted Segment EBDA <sup>(d)</sup>	654	(7)	647
Total Adjusted Segment EBDA <sup>(e)</sup>	\$ 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	2025B
<b>Net income attributable to KMI</b>	<b>\$ 708</b>	<b>\$ 183</b>	<b>\$ 1,609</b>	<b>\$ 2,190</b>	<b>\$ 119</b>	<b>\$ 1,784</b>	<b>\$ 2,548</b>	<b>\$ 2,391</b>	<b>\$ 2,613</b>	<b>\$ 2,829</b>
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	2
<b>Total Certain Items</b>	<b>933</b>	<b>1,445</b>	<b>501</b>	<b>(29)</b>	<b>1,892</b>	<b>1,220</b>	<b>88</b>	<b>19</b>	<b>(42)</b>	<b>2</b>
Preferred stock dividends	(156)	(156)	(128)	-	-	-	-	-	-	-
Net income allocated to participating securities <sup>(a)</sup>	(4)	(5)	(8)	(12)	(13)	(14)	(13)	(14)	(15)	(19)
Other <sup>(b)</sup>	(1)	(1)	(2)	-	-	(3)	(1)	-	1	-
<b>Adjusted Net income attributable to Common Stock</b>	<b>\$ 1,472</b>	<b>\$ 1,466</b>	<b>\$ 1,972</b>	<b>\$ 2,149</b>	<b>\$ 1,998</b>	<b>\$ 2,987</b>	<b>\$ 2,622</b>	<b>\$ 2,396</b>	<b>\$ 2,557</b>	<b>\$ 2,812</b>
Weighted average shares outstanding	2,230	2,230	2,216	2,264	2,263	2,266	2,258	2,234	2,220	2,222
<b>Adjusted EPS</b>	<b>\$ 0.66</b>	<b>\$ 0.66</b>	<b>\$ 0.89</b>	<b>\$ 0.95</b>	<b>\$ 0.88</b>	<b>\$ 1.32</b>	<b>\$ 1.16</b>	<b>\$ 1.07</b>	<b>\$ 1.15</b>	<b>\$ 1.27</b>

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 CO<sub>2</sub> EOR & Transport FCF

\$ in Millions

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

## Reconciliation of CO<sub>2</sub> EOR & Transport FCF

EBDA for CO <sub>2</sub> EOR & Transport <sup>(b)</sup>	\$ (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)	-
<b>Adjusted EBDA for CO<sub>2</sub> EOR &amp; Transport</b>	<b>650</b>	<b>744</b>	<b>787</b>	<b>662</b>	<b>602</b>	<b>615</b>
Capital expenditures (GAAP) <sup>(a)</sup>	(186)	(185)	(275)	(255)	(280)	(303)
Acquisitions	-	-	-	(13)	(64)	-
<b>CO<sub>2</sub> EOR &amp; Transport FCF</b>	<b>\$ 464</b>	<b>\$ 559</b>	<b>\$ 512</b>	<b>\$ 394</b>	<b>\$ 258</b>	<b>\$ 312</b>

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

<b>Reconciliation of Terminals FCF</b>	2020	2021	2022	2023	2024	2025B
EBDA for Terminals <sup>(b)</sup>	\$ 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	-	-	-	-
<b>Adjusted EBDA for Terminals</b>	<b>990</b>	<b>950</b>	<b>975</b>	<b>1,039</b>	<b>1,099</b>	<b>1,103</b>
Capital expenditures (GAAP) <sup>(a)</sup>	(433)	(332)	(552)	(406)	(385)	(367)
Acquisitions	(8)	-	-	-	-	-
<b>Terminals FCF</b>	<b>\$ 549</b>	<b>\$ 618</b>	<b>\$ 423</b>	<b>\$ 633</b>	<b>\$ 714</b>	<b>\$ 736</b>

<b>Reconciliation of Products Pipelines FCF</b>	2020	2021	2022	2023	2024	2025B
EBDA for Products Pipelines <sup>(b)</sup>	\$ 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	-	-
<b>Adjusted EBDA for Products Pipelines</b>	<b>1,017</b>	<b>1,094</b>	<b>1,072</b>	<b>1,099</b>	<b>1,164</b>	<b>1,179</b>
Capital expenditures (GAAP) <sup>(a)</sup>	(122)	(122)	-	(221)	(210)	(222)
Acquisitions	(8)	-	-	-	-	-
<b>Products Pipelines FCF</b>	<b>\$ 887</b>	<b>\$ 972</b>	<b>\$ 1,072</b>	<b>\$ 878</b>	<b>\$ 954</b>	<b>\$ 957</b>

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
<b>Net income attributable to KMI</b>	<b>\$ 708</b>	<b>\$ 183</b>	<b>\$ 1,609</b>	<b>\$ 2,190</b>	<b>\$ 119</b>	<b>\$ 1,784</b>	<b>\$ 2,548</b>	<b>\$ 2,391</b>	<b>\$ 2,613</b>	<b>\$ 2,829</b>
NCI associated with Certain Items	(8)	-	-	-	-	-	-	-	-	-
KML noncontrolling interests <sup>(a)</sup>	-	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 <sup>(a)</sup>	899	853	645	627	588	860	747	682	739	817
Interest, net <sup>(a)</sup>	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 <sup>(b)</sup>	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 <sup>(a)</sup>	94	114	82	95	82	83	75	89	78	85
<b>Adjusted EBITDA</b>	<b>\$ 7,242</b>	<b>\$ 7,198</b>	<b>\$ 7,568</b>	<b>\$ 7,618</b>	<b>\$ 6,962</b>	<b>\$ 7,946</b>	<b>\$ 7,516</b>	<b>\$ 7,561</b>	<b>\$ 7,938</b>	<b>\$ 8,284</b>
Divested adjusted EBITDA <sup>(a)</sup>	(789)	(672)	(660)	(503)	(142)	(118)	(139)	(54)	(17)	-
<b>As normalized for divestitures</b>	<b>\$ 6,453</b>	<b>\$ 6,526</b>	<b>\$ 6,908</b>	<b>\$ 7,115</b>	<b>\$ 6,820</b>	<b>\$ 7,828</b>	<b>\$ 7,377</b>	<b>\$ 7,507</b>	<b>\$ 7,921</b>	<b>\$ 8,284</b>

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

<b>Reconciliation of Net Debt</b>	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)
<b>Net Debt</b>	<b>\$ 38,160</b>	<b>\$ 36,409</b>	<b>\$ 33,137</b>	<b>\$ 33,031</b>	<b>\$ 32,042</b>	<b>\$ 31,214</b>	<b>\$ 30,936</b>	<b>\$ 31,837</b>	<b>\$ 31,725</b>	<b>\$ 31,408</b>
Adjusted EBITDA	\$ 7,242	\$ 7,198	\$ 7,568	\$ 7,618	\$ 6,962	\$ 7,946	\$ 7,516	\$ 7,561	\$ 7,938	\$ 8,284
<b>Net Debt to Adjusted EBITDA</b>	<b>5.3X</b>	<b>5.1X</b>	<b>4.4X</b>	<b>4.3X</b>	<b>4.6X</b>	<b>3.9X</b>	<b>4.1X</b>	<b>4.2X</b>	<b>4.0X</b>	<b>3.8X</b>