1Q 2025

Investor Presentation

EPNG Mojave Compressor Station

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

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Delivering Energy. Improving Lives.

NATURAL GAS

65%

Largest U.S. Natural Gas Transmission Network

- ~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

26%[a]

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

- Transport ~1.7 mmbbld 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_2

9%

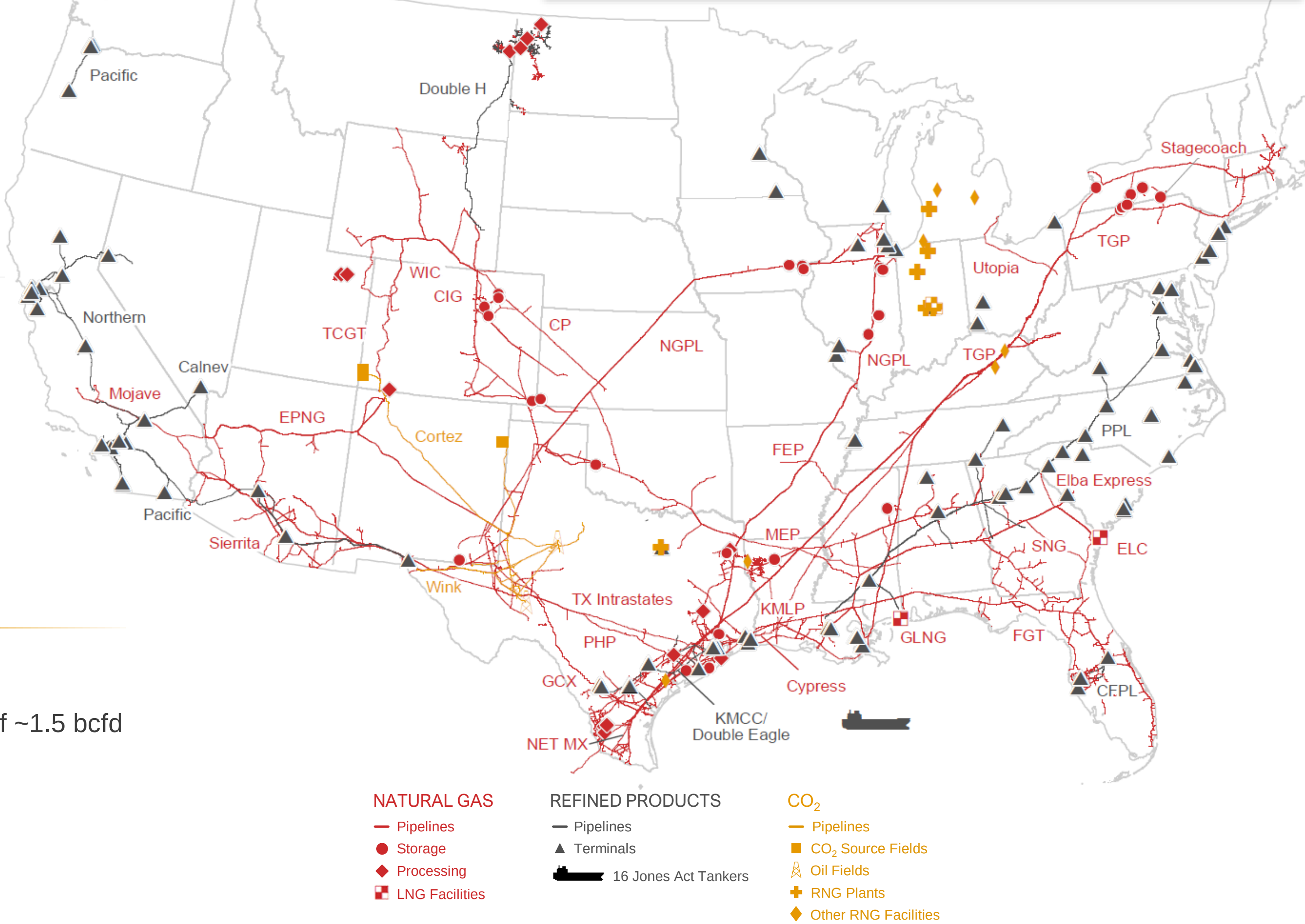
One of the Largest CO_2 Transporters in the U.S.

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

Growing Energy Transition Portfolio

- RNG production capacity of 6.4 bcf[b]

BUSINESS MIX



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

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

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

Driving Long-Term Shareholder Value

Natural Gas Focus

~2/3 of cash flows come from midstream natural gas[(a)]

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

Balance Sheet Strength

~3.8x YE 2025B Net Debt / Adjusted EBITDA

BBB investment grade balance sheet

High-Returning Growth Projects

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

Predictable & Growing Cash Flows

~69% of cash flows are take-or-pay or hedged[(a)]

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

Returns to Shareholders

Increasing dividend for **8th** straight year

~33% of market cap value returned to shareholders since 2016[(b)]

Note: Total Adjusted Segment 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 2025 budgeted Total Adjusted Segment EBDA.

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

Highly Contracted, Predictable Cash Flows

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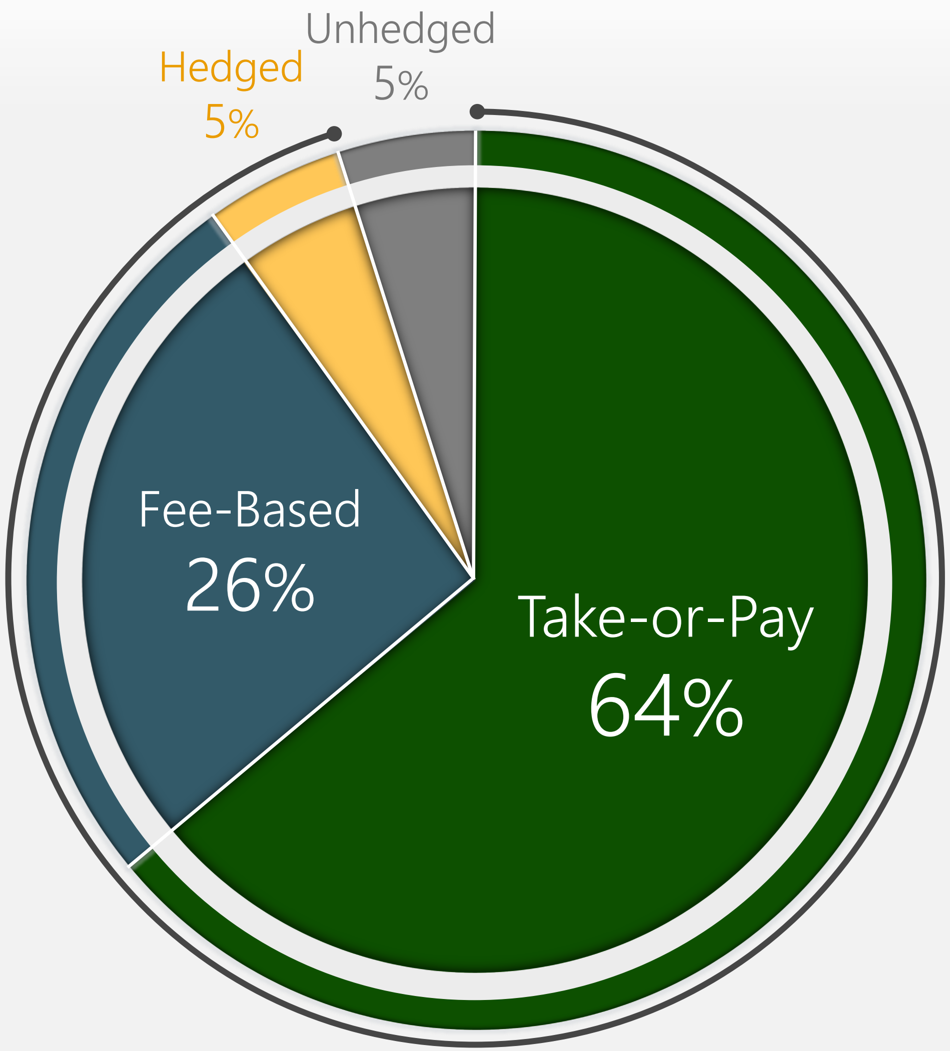
CASH FLOW MIX



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

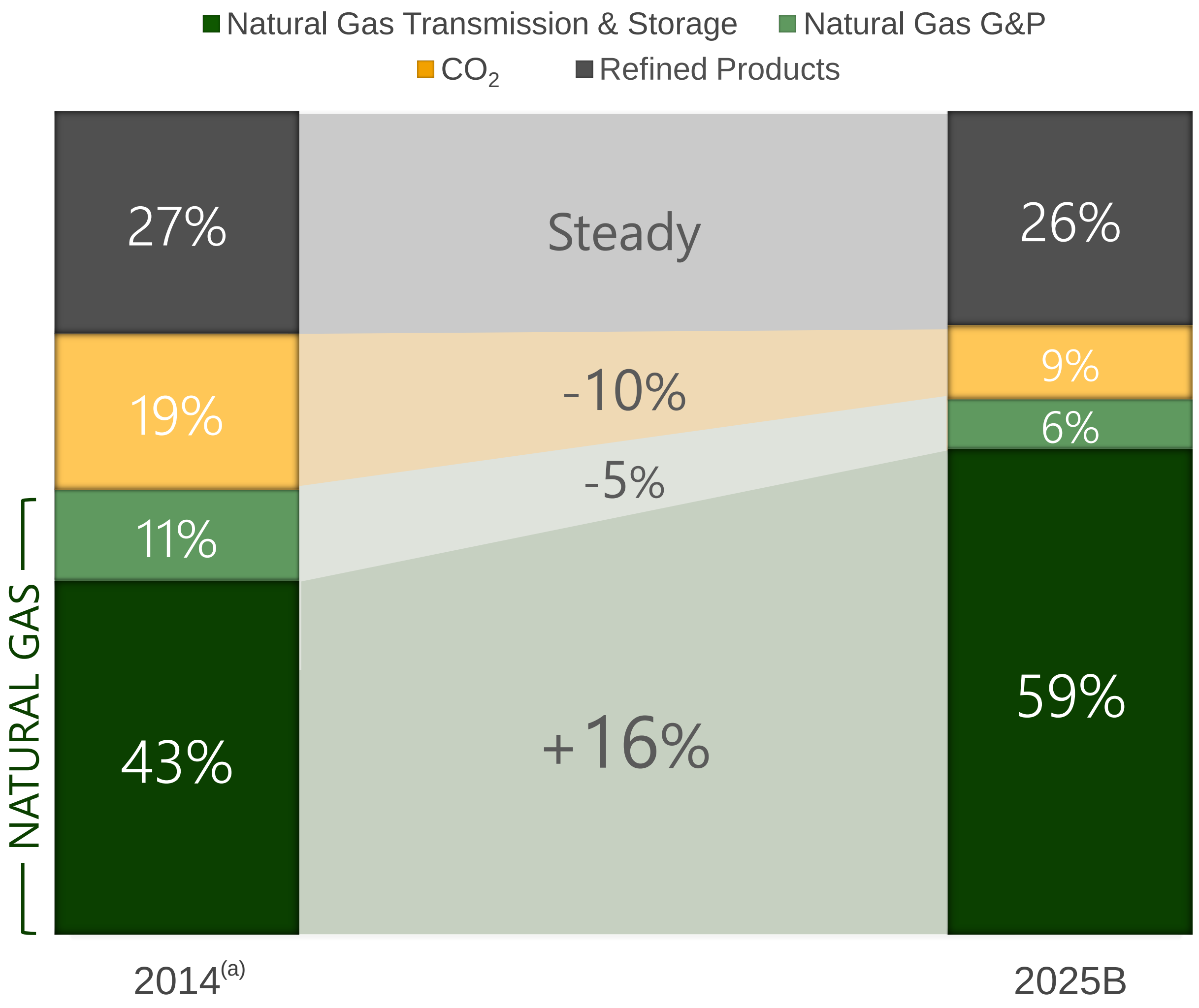
5% **Hedged**
Disciplined approach to managing price volatility
Substantially hedged near-term price exposure

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_2 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

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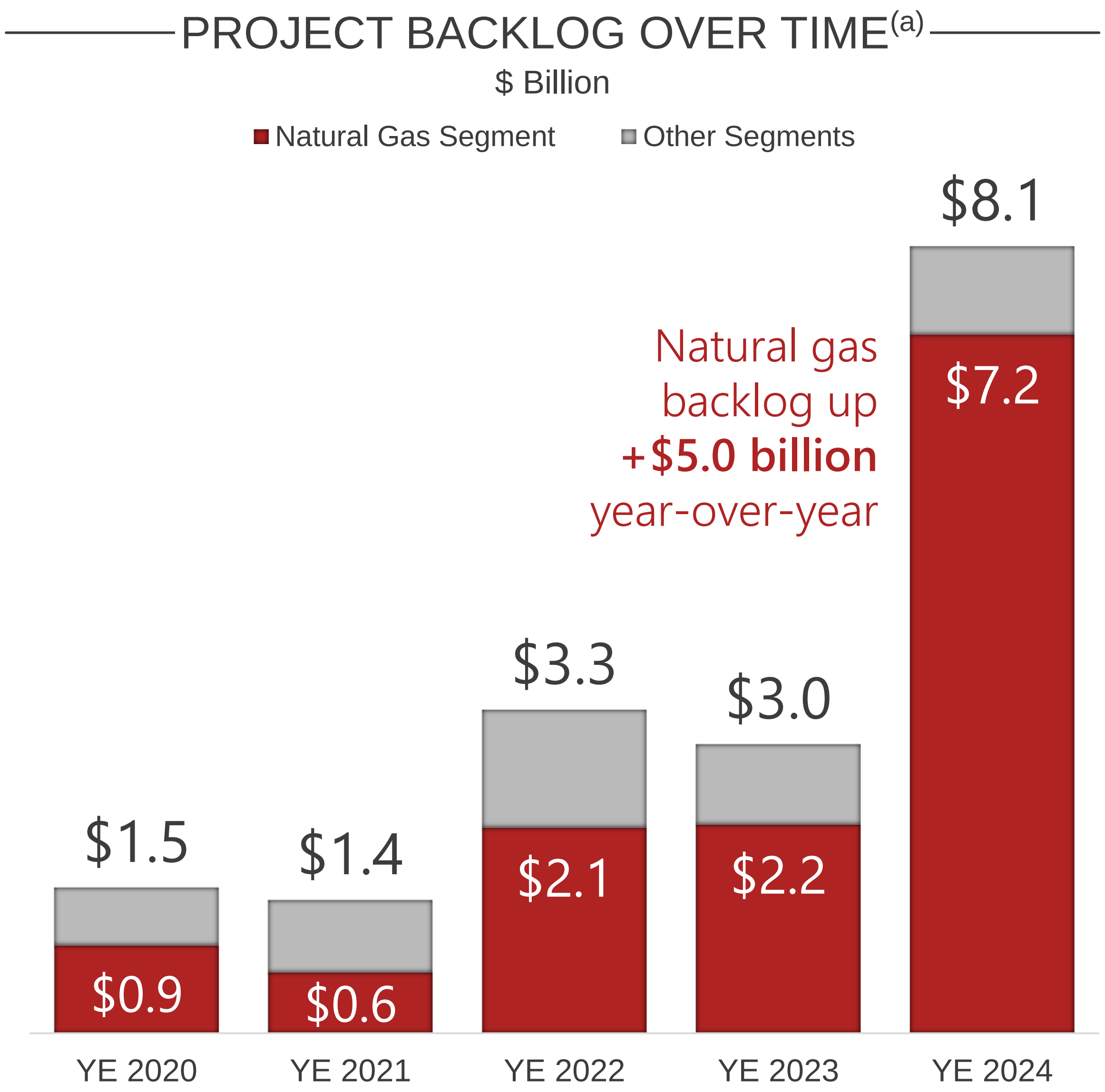

Expansive footprint creates opportunities for differentiated returns

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

Utilize a **consistent return framework**

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

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

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

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

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

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~25% of Backlog Capital in Service During 2025

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

Expect annual growth capital spend of around $2.5 billion

Natural gas investments ~90% of backlog

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

2025 Budget Highlights

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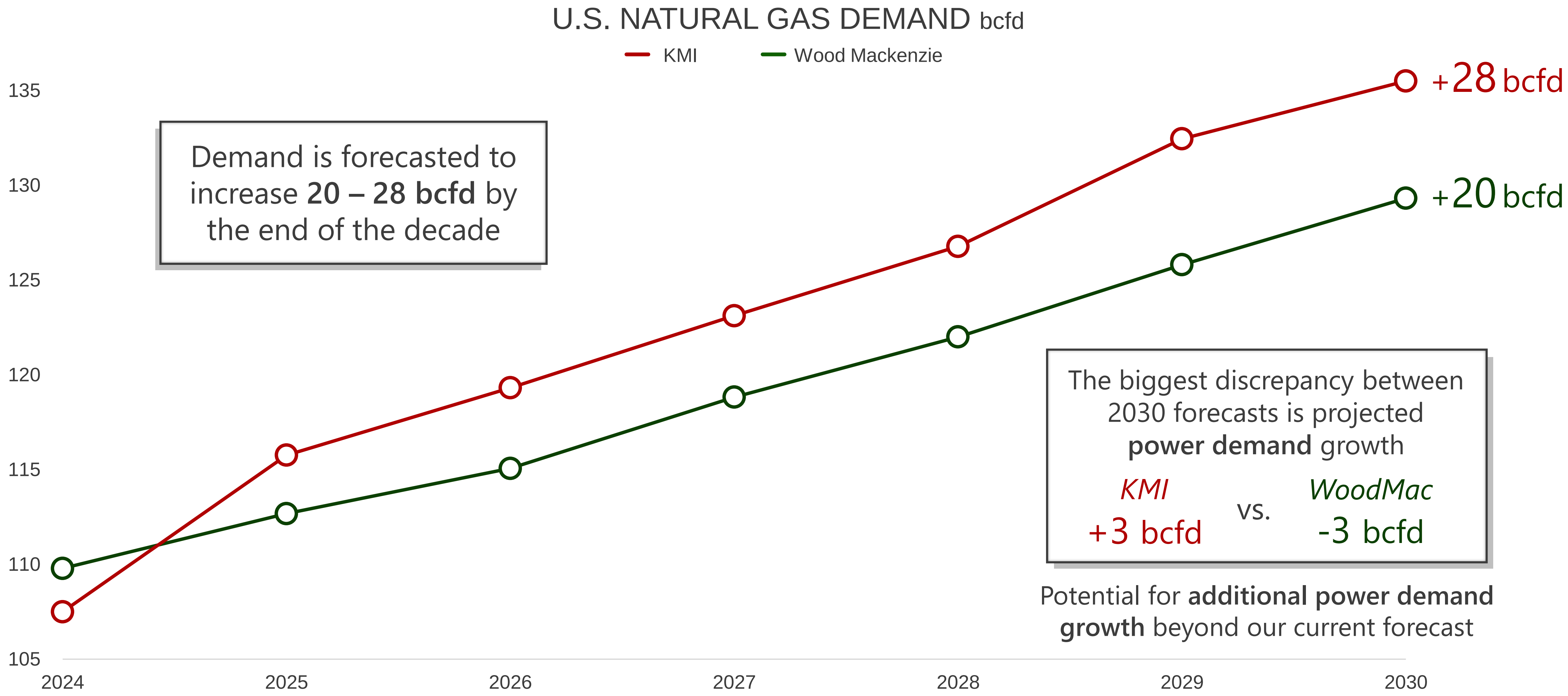
Adjusted EPS	Adjusted EBITDA	Net Debt / Adj. EBITDA	Discretionary Capital[(a)]	Cash Returns
$1.27	$8.3bn	3.8x	$2.3bn	$2.6bn
~10% increase vs. 2024	~4% increase vs. 2024	-0.2x decrease vs. year-end 2024	infrastructure projects with attractive returns	dividends expected in 2025

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



Demand is forecasted to increase **20 – 28 bcfd** by the end of the decade

The biggest discrepancy between 2030 forecasts is projected **power demand** growth

KMI +3 bcfd vs. *WoodMac* -3 bcfd

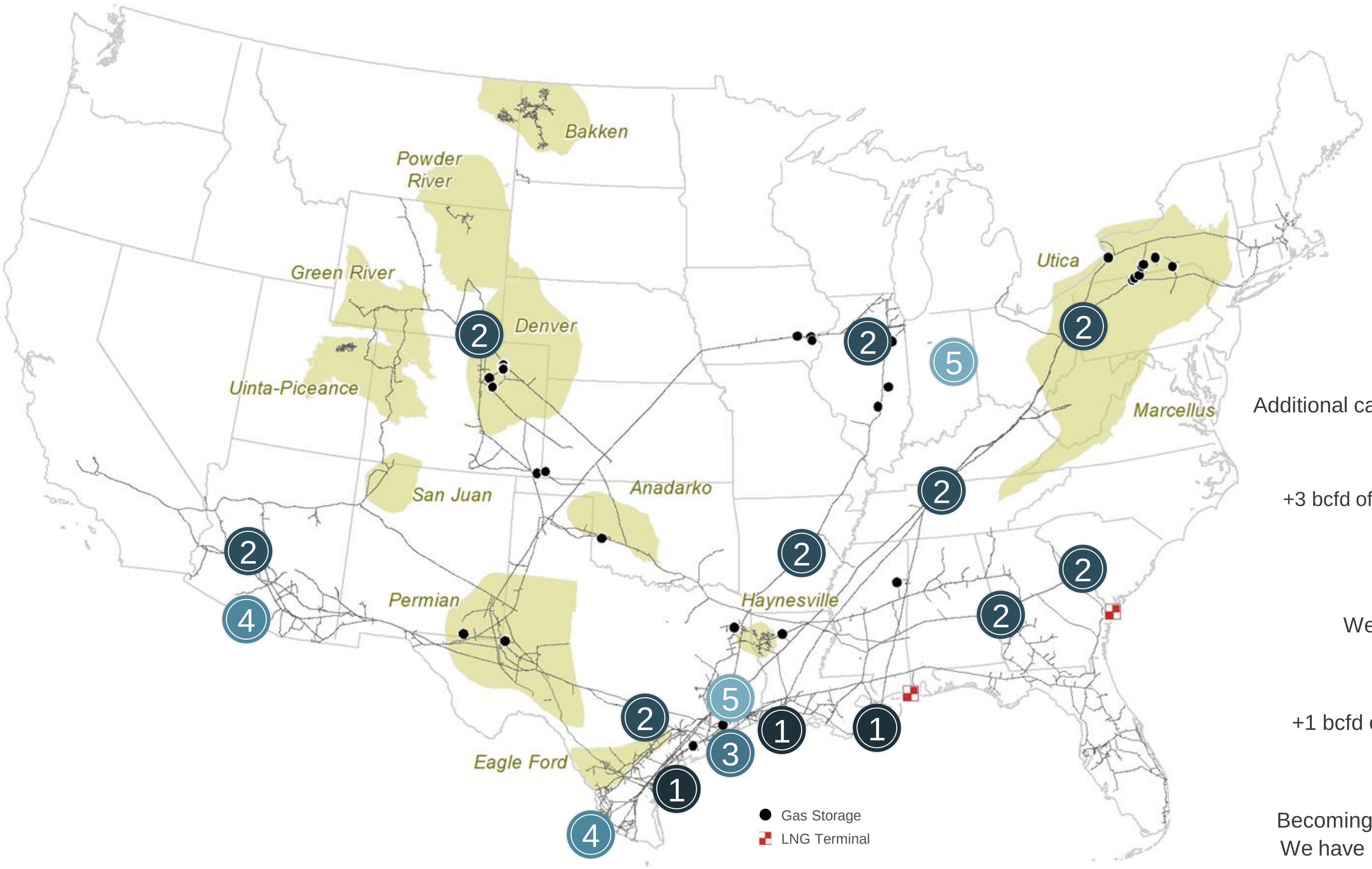
Potential for **additional power demand growth** beyond our current forecast

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 bcfd
Increase in demand by 2030
+20 bcfd

LNG Feedgas 1

+14 bcfd 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 bcfd of demand growth mainly along the TX & LA Gulf Coast

Mexico Exports 4

+1 bcfd of export demand growth
We can deliver into Mexico at multiple strategic points

Residential & Commercial 5

+1 bcfd 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

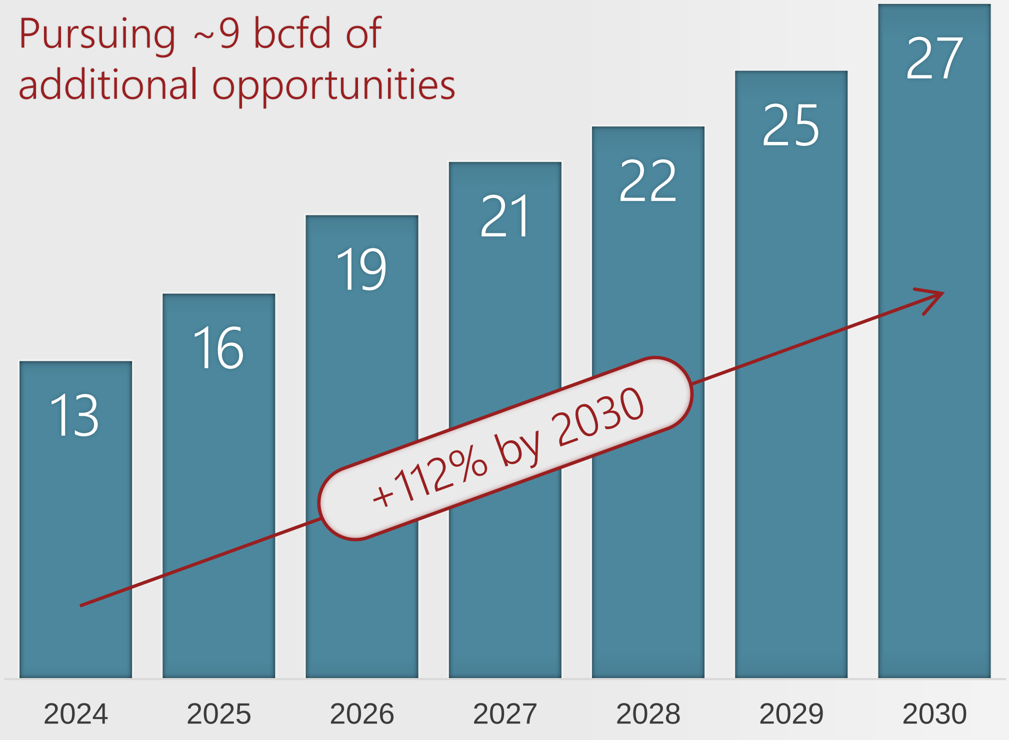
Growth Primarily Along the Texas & Louisiana Gulf Coast with Great Overlap with Our Assets

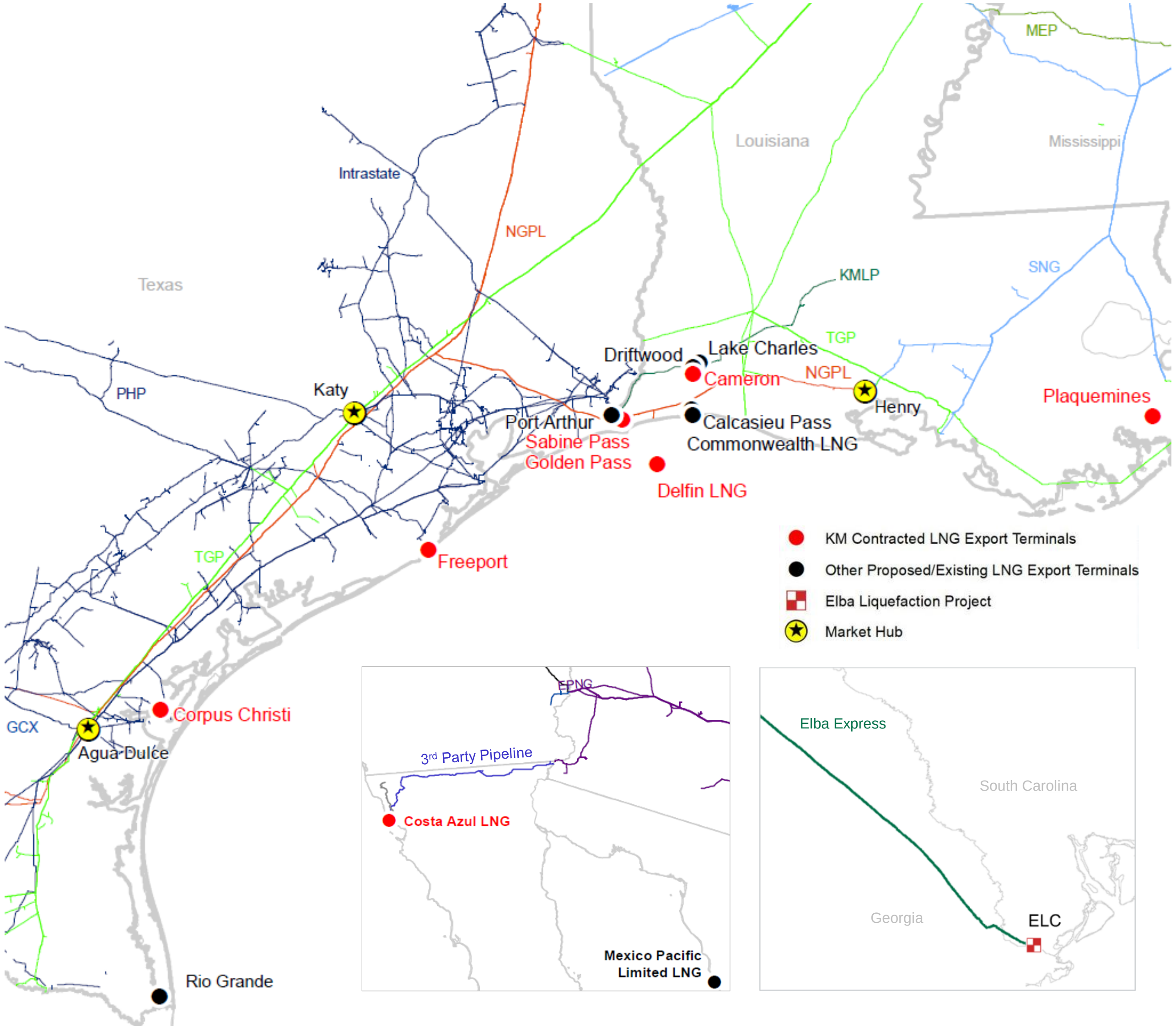
WOODMAC U.S. LNG FEEDGAS FORECAST

bcfd

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

Pursuing ~9 bcfd 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

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INCREASING NATURAL GAS FIRED POWER DEMAND DRIVEN BY

Population Migration & Economic Growth

Increases need for **reliable & scalable** power to support growing residential & commercial demand

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

Coal-to-Gas Conversions

Coal plants continue to be **retired** at a **rapid pace**

*Coal accounts for **~15%** of U.S. power generation*

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

Industrial Reshoring

Reshoring manufacturing **significantly 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, serving either primary or backup generation

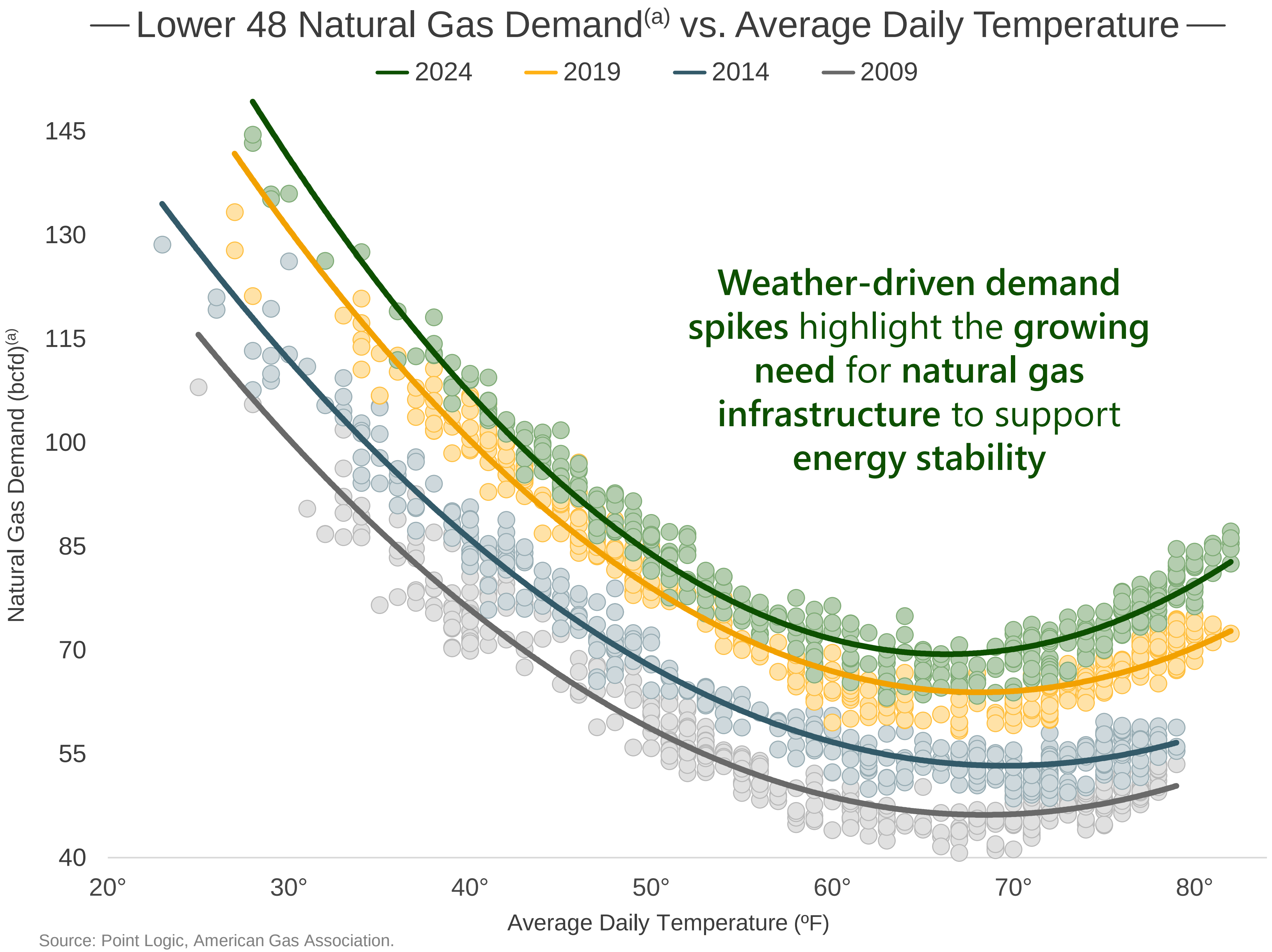
KMI forecasting **3 bcfd** increase in **natural gas fired power demand** by 2030

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

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

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

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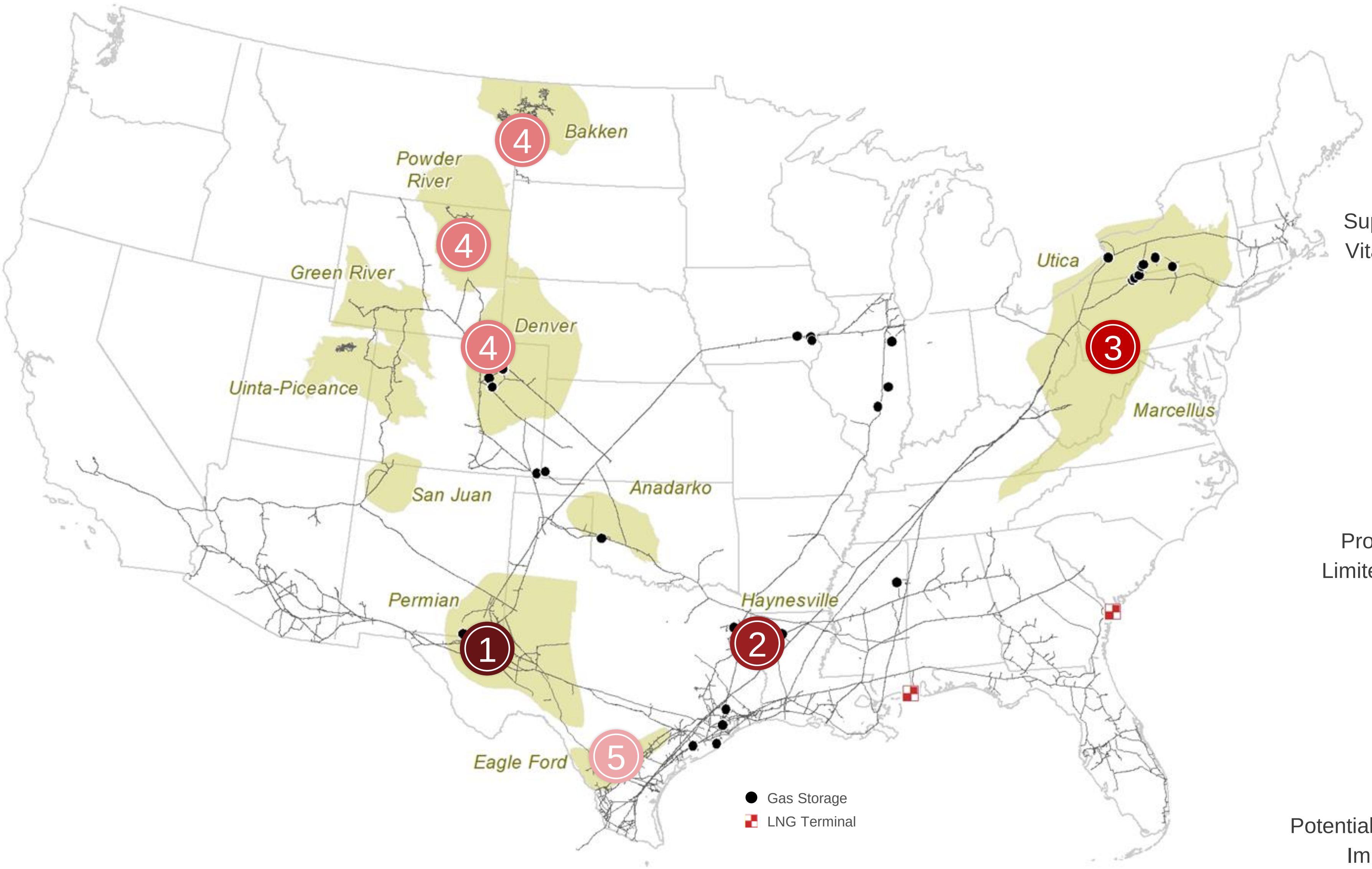
2024 U.S. Production
103 bcfd
Increase in supply by 2030
+20 bcfd



Permian +8 bcfd of associated gas growth (1)
Supply grows as oil production increases & GORs rise
Vital to supplying West Coast, Gulf Coast, and Mexico

Haynesville +6 bcfd of growth (2)
Abundant, low-cost, low-nitrogen supply
Key to serving Gulf Coast demand markets

Northeast +6 bcfd from the Marcellus/Utica (3)
Production constrained despite ample, low-cost supply
Limited infrastructure opportunity despite strong demand

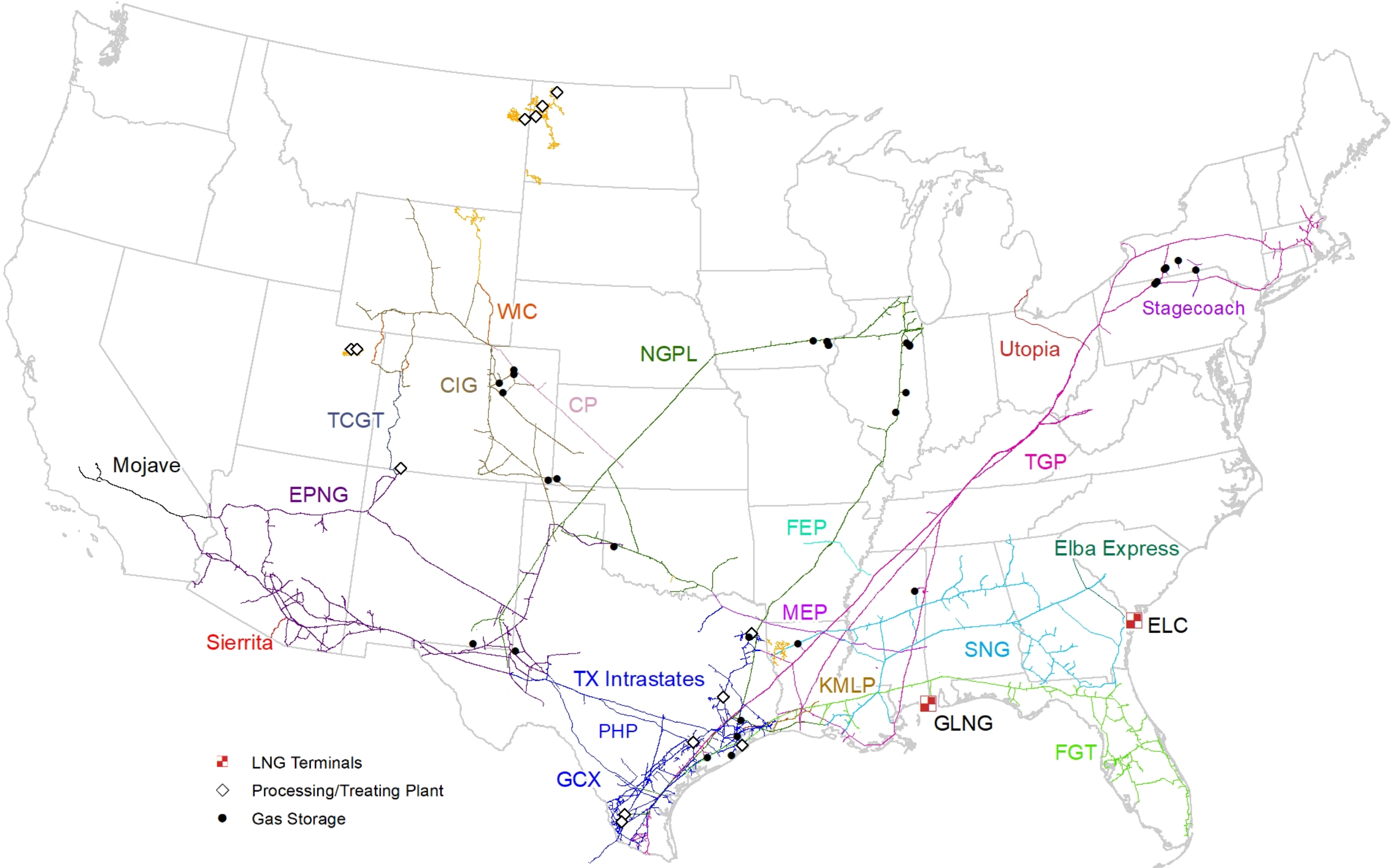
Rockies +1 bcfd Bakken/DJ/Powder River (4)
Serves Rockies and West Coast demand

Eagle Ford +0.3 bcfd of growth (5)
Potential upside to forecast; critical supply link to Gulf Coast
Important source of low-nitrogen gas for LNG facilities

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

Natural Gas Segment Overview

Connecting Key Natural Gas Resources with Major Demand Centers



66,000 miles natural gas pipelines	>700 bcf working gas storage capacity	1,200 miles NGL pipelines

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

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Largest Natural Gas Transmission Network in the U.S.

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

~45%	~50%	~45%
of all feedgas deliveries to U.S. LNG facilities	of all U.S. natural gas exports to Mexico	of all direct natural gas deliveries to Southern U.S. power plants[a] *Areas with high forecasted natural gas fired power demand growth*

Irreplaceable Assets

Long-Lived Infrastructure

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

Robust Opportunity Set for Growth

Rising Demand Benefitting Our Natural Gas Transportation Business

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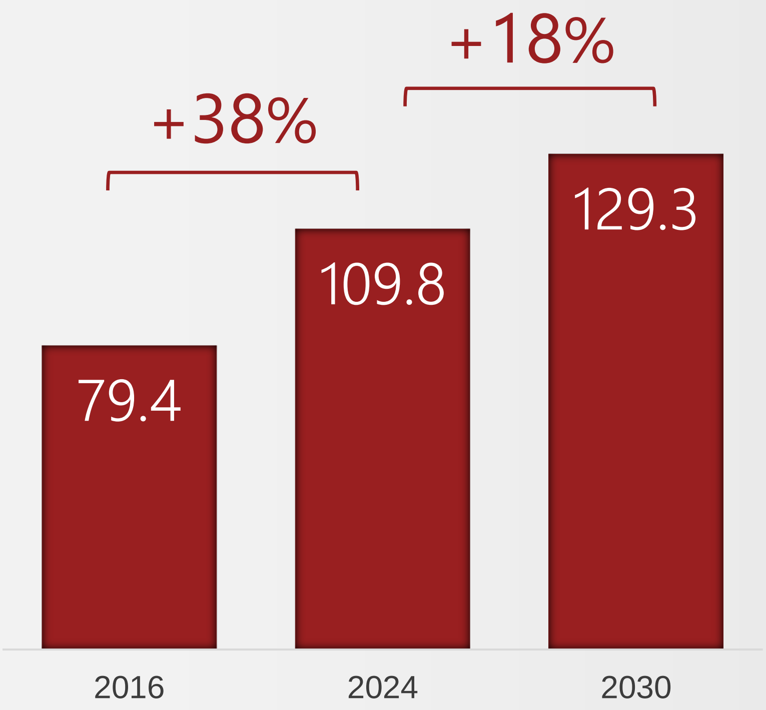
Increased Demand Leading To

WOODMAC
U.S. NATURAL GAS DEMAND
bcfd

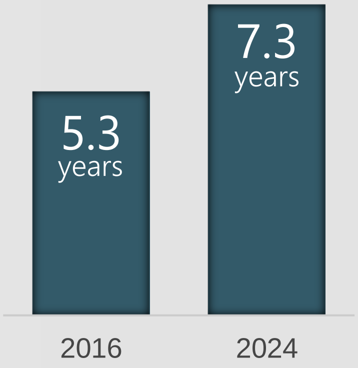


- INCREASED PIPELINE USAGE FACTOR[a]

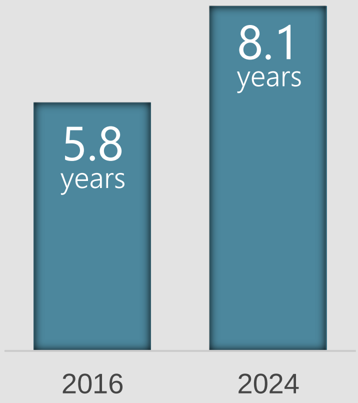
2016 5-Pipe Average	2024 5-Pipe Average
74%	⇧ 87%

- INCREASED CONTRACT TERMS AND/OR RATES

EXAMPLES



TX Intrastates[b]



EPNG

- NEW PROJECTS

~$7.2 billion of natural gas projects in our backlog; expect to continue adding projects over time[c]

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

a) Represents the capacity weighted average usage factor of TGP, EPNG, NGPL, SNG, and the Texas Intrastates. Usage factor is calculated as billed throughput divided by average annual designed pipeline capacity.
b) TX Intrastates average remaining contract life includes term sale portfolio.
c) Total includes ~$0.5bn of natural gas gathering & processing projects.

~$7.2 Billion of Approved Natural Gas Projects

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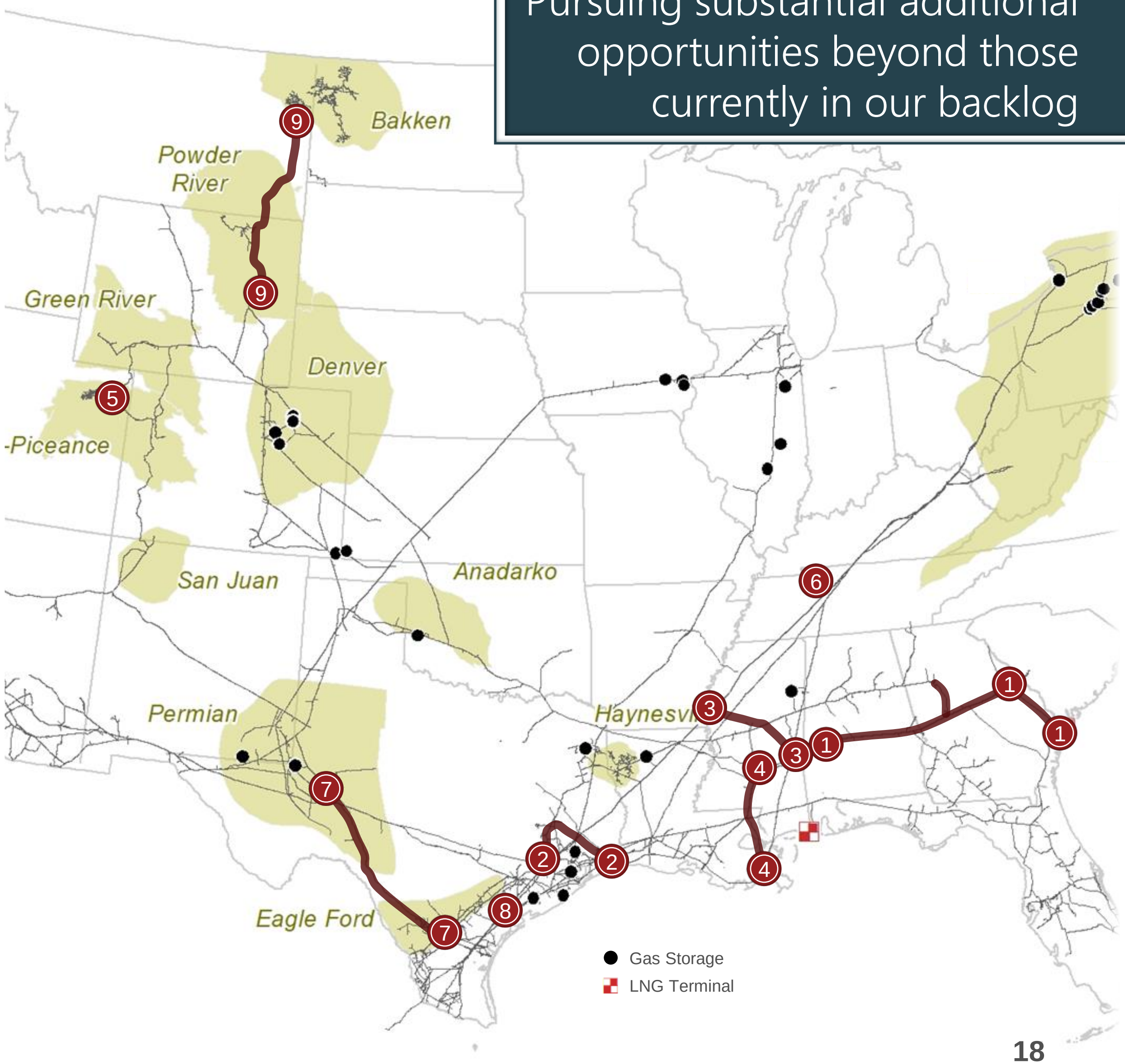
	Major Projects	Capital[a] ($mm)	Capacity (bcfd)	In-Service Date	Status
1	South System Expansion 4 *SNG & EEC*	$1,659	1.2	4Q28, 4Q29	Permitting
2	Trident *TX Intrastates*	$1,650	1.5	1Q27	Permitting
3	Mississippi Crossing *TGP*	$1,637	2.1	4Q28	Permitting
4	Evangeline Pass (Phase II) *TGP & SNG*	$389	1.1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

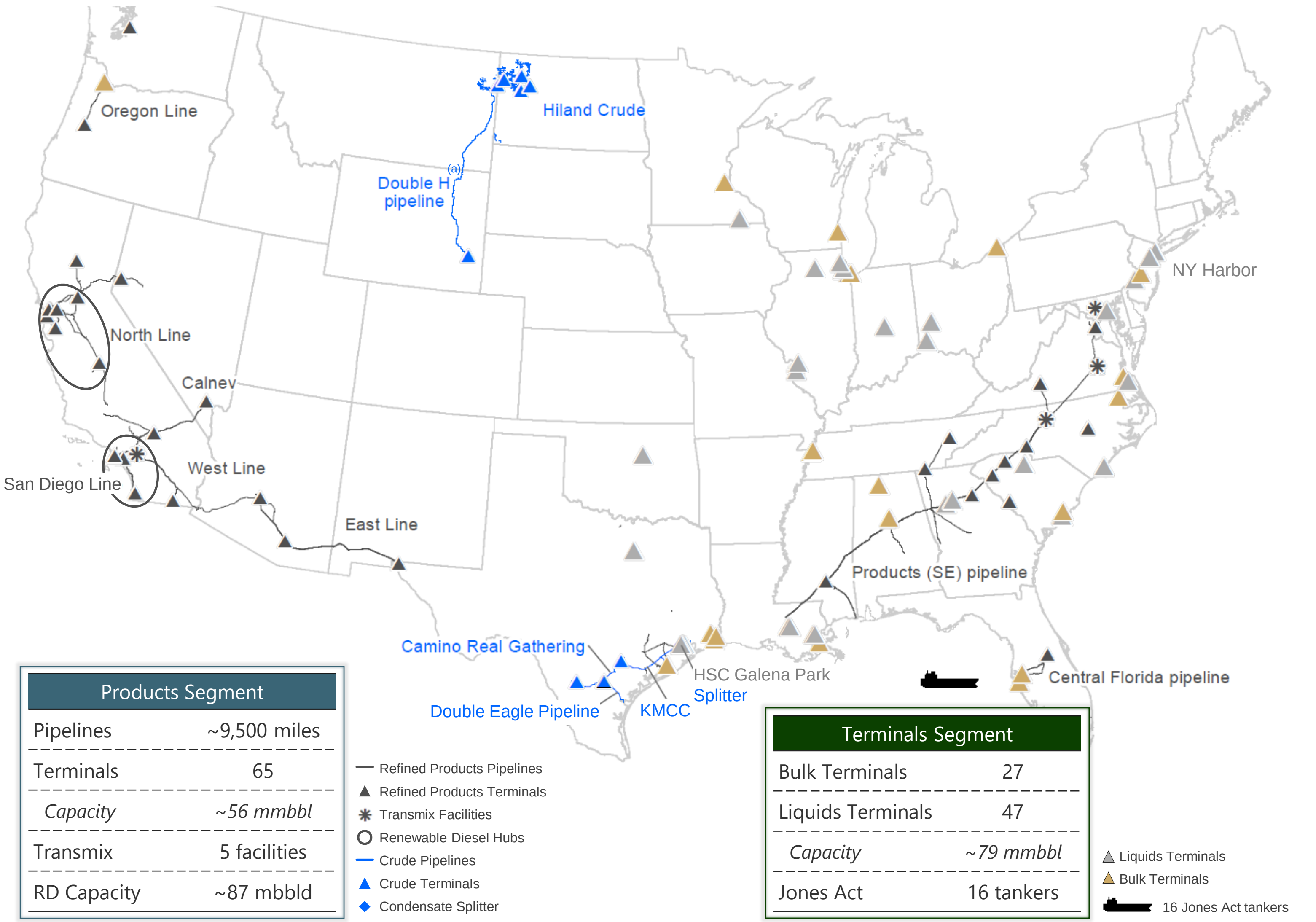
Pursuing substantial additional opportunities beyond those currently in our backlog



a) KMI share of estimated project capital.
b) Pending litigation may delay project.

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 mbbld

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

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.

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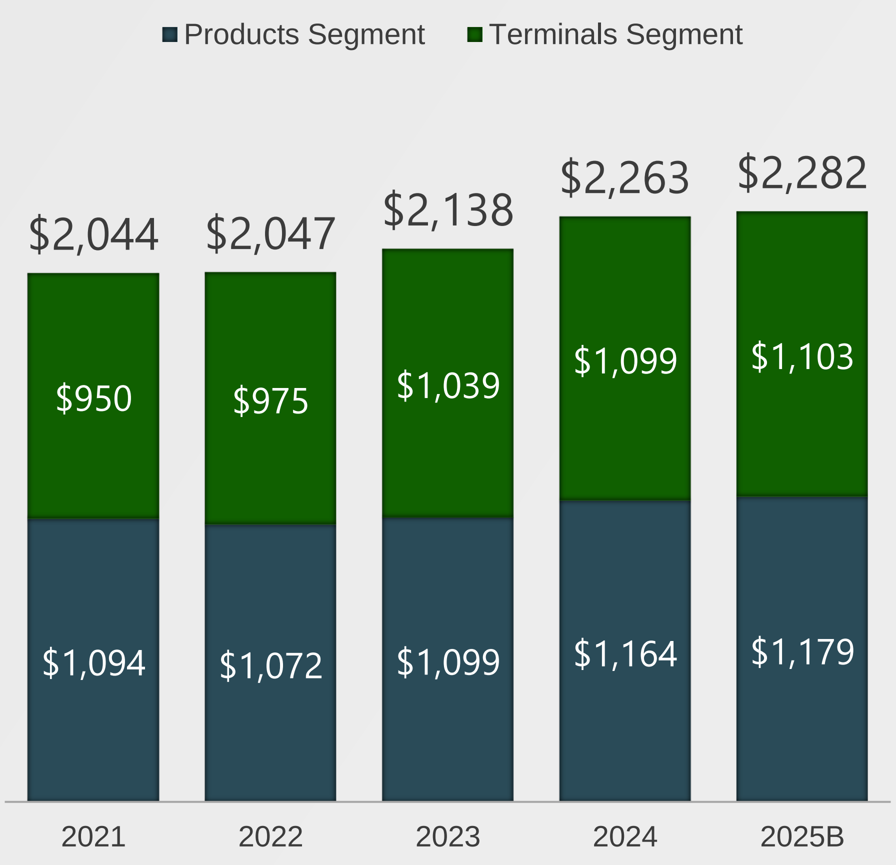
Nearly $11bn of Adjusted Segment EBDA & $8bn of FCF Generated Over 5 Years

— TERMINALS & PRODUCTS PIPELINES — ADJUSTED SEGMENT EBDA

$ Millions



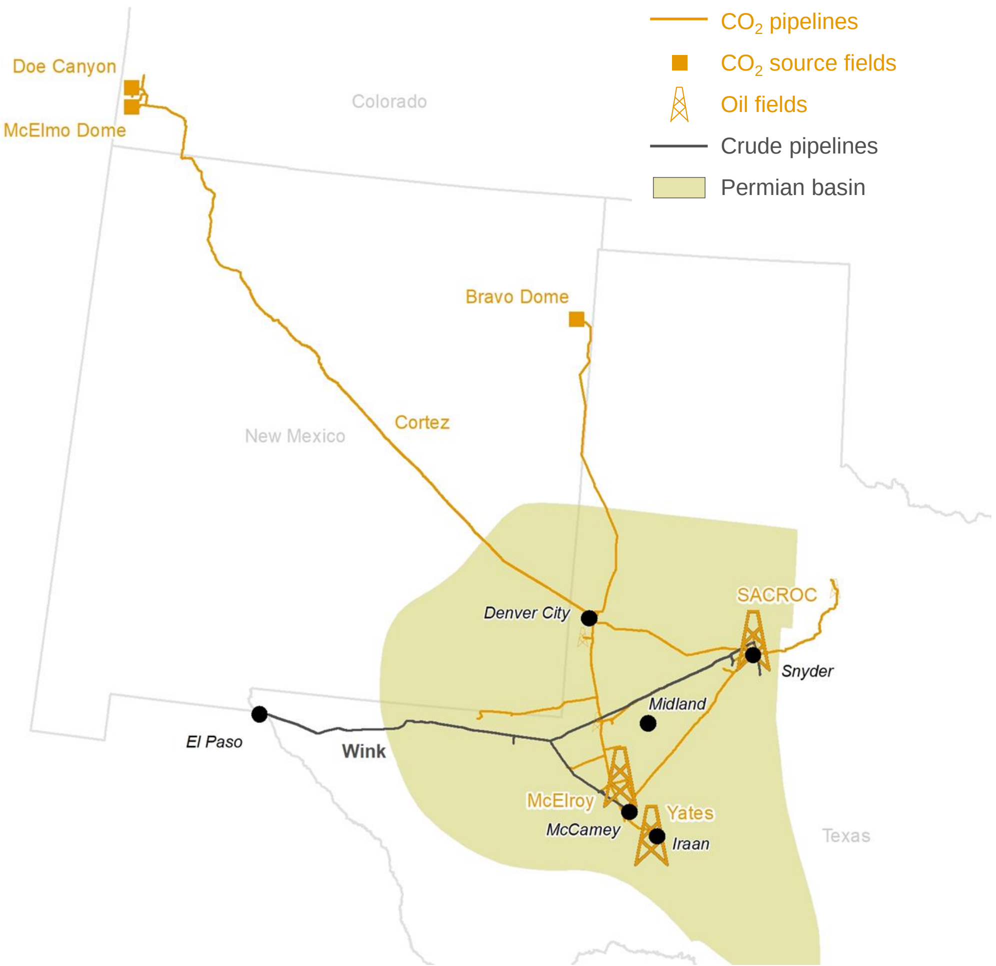
CO_2 Segment: EOR and CO_2 Transport Overview

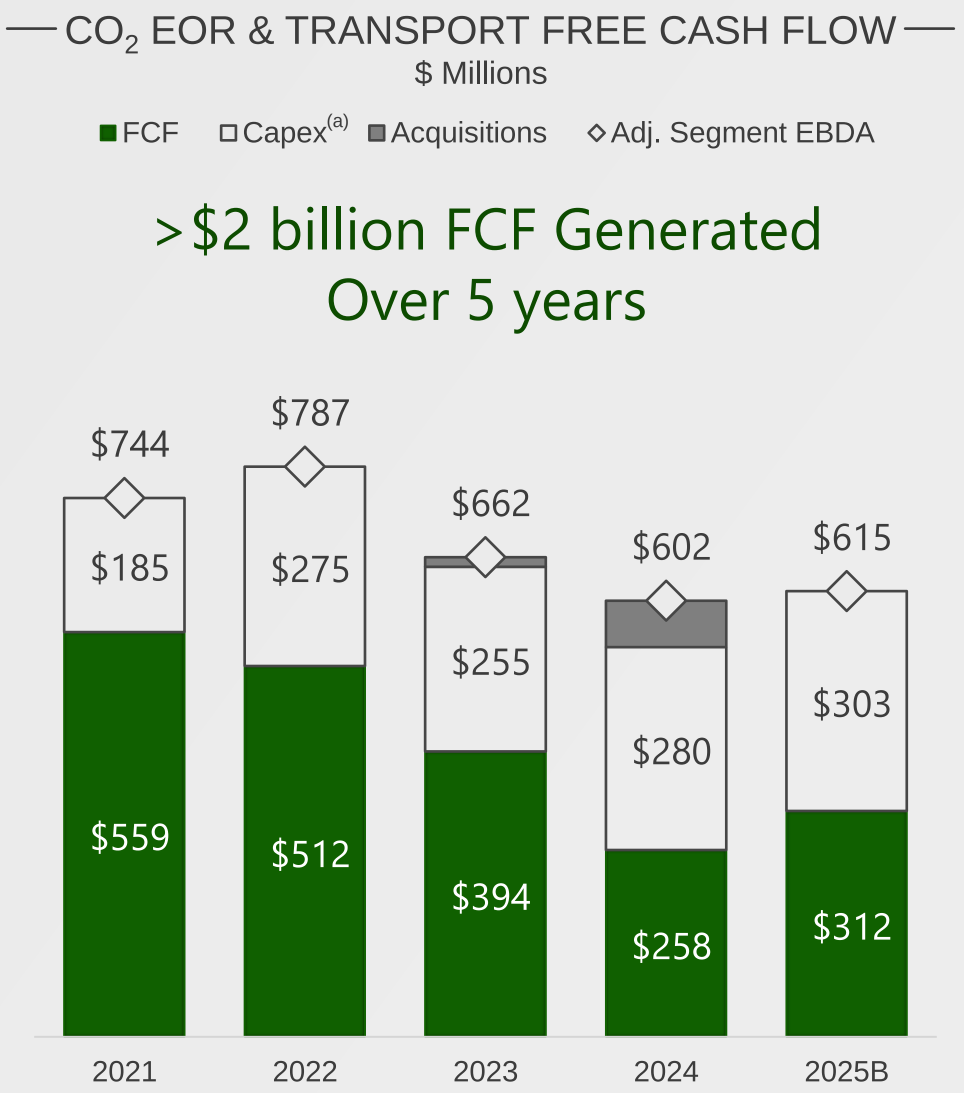
World Class, Fully-Integrated Assets Consistently Generating Robust Free Cash Flow

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. 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.

CO_2 Segment: Energy Transition Ventures (ETV) Group Overview

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Pursuing Commercial Opportunities Emerging from the Lower Carbon Energy Evolution

RNG

Established a growing RNG platform

6 facilities with 6.4 bcf[a] 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_2 experience to become a leading provider of CO_2 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 expected Q1 2025. Autumn Hills RNG facility in late stages of commissioning.

Committed to Being a Good Steward

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Reduce & Avoid Methane Emissions	Leak Detection	Safety Culture	Continuous Improvement	Diversity & Inclusion	Investing in Lower Carbon Fuels
~8%	100%	42%	BB → AAA	33%	$7.3bn
Reduction in absolute methane emissions since 2021	Of our natural gas compressor stations surveyed annually & transitioning to quarterly	Reduction in Employee TRIR 2015 – 2023[(a)]	MSCI score improvement 2018 – 2024	Total gender and minority diversity of the KMI Board	Primarily natural gas; remaining investment in RNG, renewable feedstocks, and CCS[(b)]

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

a) 2015 was first year company-wide TRIR was reported publicly in 2017 ESG Report.
b) Lower carbon projects included in our 12/31/2024 backlog.

Highly Rated by Sustainability Ratings Agencies

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Upgrade by MSCI to AAA in 2024

MSCI **AAA**

Oil & Gas Refining, Marketing, Transportation & Storage Industry

Sustainalytics **Top 15%**

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

SSGA **Top 10%**

R-Factor in Oil & Gas – Midstream sector

FTSE **#2**

of Oil & Gas Pipelines subsector

Refinitiv **#5**

of 234 Oil & Gas Related Equipment and Services Companies

S&P Global CSA

Sustainability Yearbook Member

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

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 January 2025.

APPENDIX

EPNG McClellan Creek Crossing

Contract Strategy Insulates Cash Flows Through Commodity Cycles

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Structure Long-Term Contracts That Minimize Price & Volume Volatility

		Take-or-Pay or Hedged Volumes & price are contractually fixed	Fee-Based Price is fixed, volumes are variable	Commodity-Price Based	Avg. remaining contract term as of 12/31/2024	Additional cash flow security
Natural Gas	Interstate / LNG	40%	3%		6.3 / 15.7 years	Tariffs are FERC-regulated
	TX Intrastate	12%	4%		7.3 years	
	G&P	1%[a]	4%	1%	3.9 years	Primarily acreage dedications for fee-based contracts
Products	Refined products	1%	9%	1%	generally not applicable	Pipeline tariffs are FERC-regulated ~72% of 2025B Products Adj. Segment EBDA has an annual inflation-linked tariff escalator
	Crude transport	1%			4.4 years[b]	
	Crude G&P		1%			
Terminals	Liquids terminals	5%	2%		1.8 years	~73% of 2025B Terminals Adj. Segment EBDA has annual price escalators (inflation-linked or fixed-price escalators)
	Jones Act tankers	3%			4.0 years	
	Bulk terminals	1%	2%		3.0 years	Bulk terminals: primarily minimum volume guarantee or requirements
CO_2	EOR Oil & Gas	4%[a]		1%	5.8 years	Commodity-price based contracts are mostly minimum volume committed
	CO_2 & Transport	1%	1%			
	ETV			2%		
		69%	26%	5%		

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

a) Hedged cash flows.

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

2025 Budget Sensitivities

Limited Overall Commodity Exposure

2025B Assumptions	Change	Potential Impact to Adjusted EBITDA (Full Year)				
		Natural Gas	Products	Terminals	CO_2	Total
Natural gas G&P volumes 4,125 bbtud	+/- 5%	$32.8 million				$32.8 million
Crude oil & NGL production volumes 34 mbbld net	+/- 5% in net volumes				$35.5 million	$35.5 million
$68.00/bbl WTI crude oil price	+/- $1/bbl WTI	$0.8 million	$1.1 million		$3.9 million	$5.8 million
$3.00/Dth natural gas price	+/- $0.10/Dth	$5.0 million[a]			$0.7 million	$5.7 million[a]
NGL / crude oil price ratio 55% in Natural Gas segment & 49% in CO_2 segment	+/- 1% price ratio	$1.0 million			$2.4 million	$3.4 million
$3.25/RIN D3 RIN price	+/- $0.10/RIN				$4.7 million	$4.7 million

		Potential Impact to Interest Expense (Full Year)
SOFR rate: 4.31%	+/-10-bp change in SOFR	$3.4 million[b]

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

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

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

High-Quality, Natural Gas Focused Cash Flows

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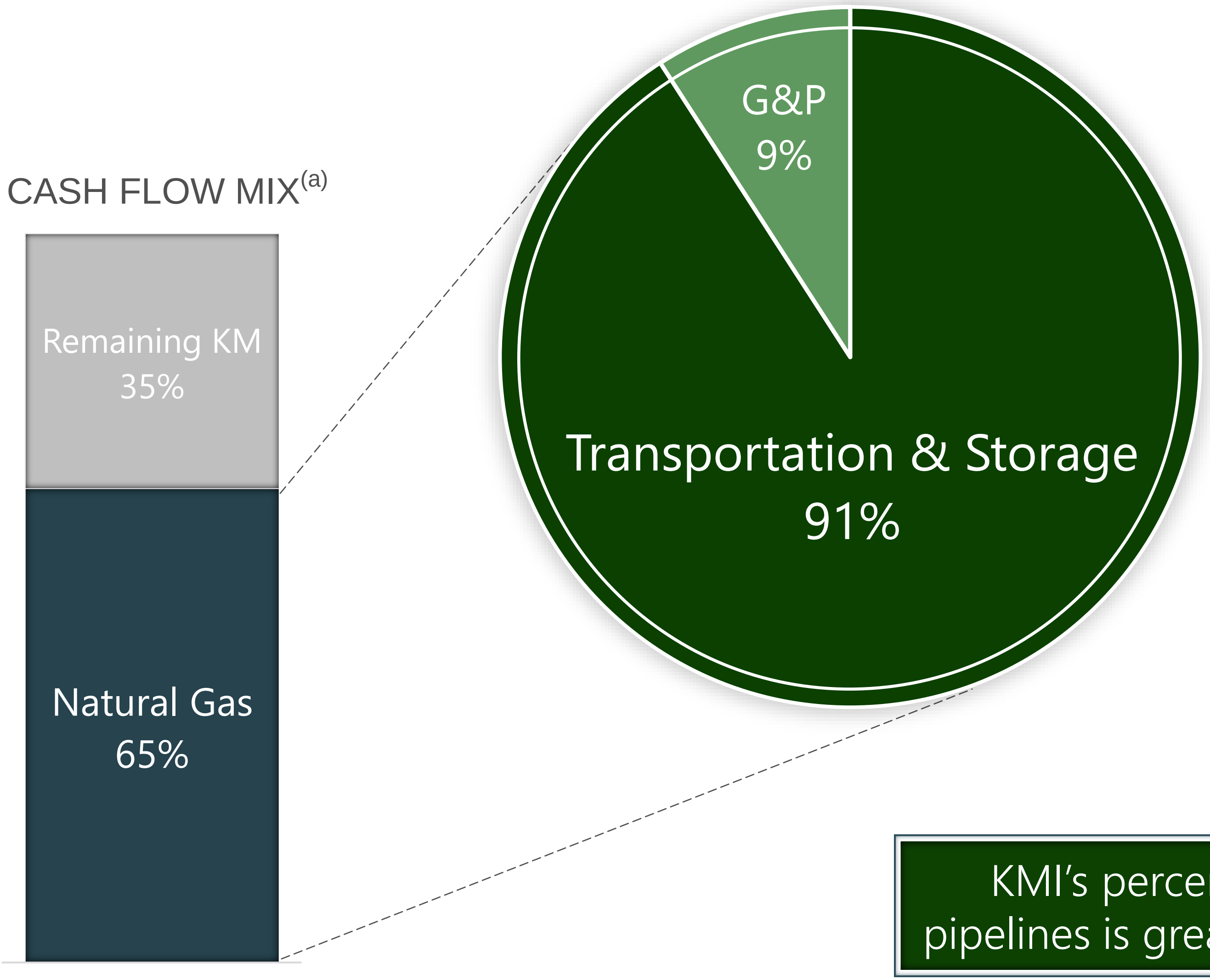
CASH FLOW MIX[a]



Natural Gas Transportation & Storage

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

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

a) Based on 2025 budgeted Total Adjusted Segment EBDA, which is a non-GAAP financial measure. See Non-GAAP Financial Measures & Reconciliations.
b) Includes U.S. based midstream companies with market capitalizations greater than $20 billion.

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

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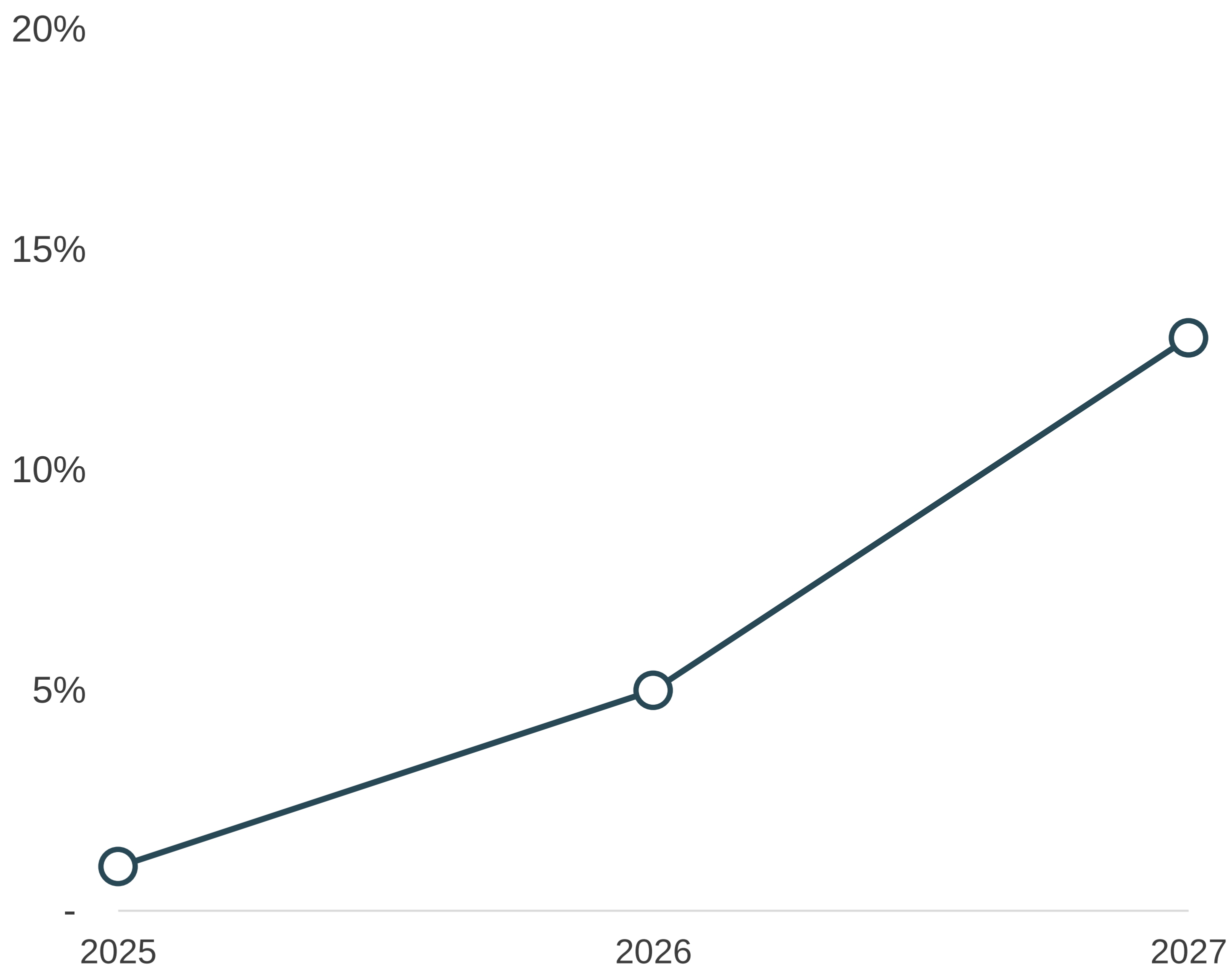
KMI PROJECTED EFFECTIVE FEDERAL CASH TAX RATE



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

$312 million of General Business Credits[a], limited to offsetting up to 75% of our annual tax liability

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

Cash tax position may be impacted by future policy changes

Note: Does not include cash taxes paid by our JVs.
a) Total as of 12/31/2024.

Use of Non-GAAP Financial Measures

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

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

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

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

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

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

Use of Non-GAAP Financial Measures (Continued)

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

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

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

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

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

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

CO_2 EOR & Transport, Terminals and Product Pipelines Free Cash Flow is calculated by reducing Segment EBDA from our CO_2 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_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 Pipeline 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

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$ in millions

	2025 Budget	2024 Actual	Change $	Change %
Net income attributable to KMI	**$ 2,829**	**$ 2,613**	**$ 216**	**8%**
Certain Items				
Change in fair value of derivative contracts	-	72	(72)	(100%)
Loss on impairment	-	(69)	69	100%
Income tax Certain Items	-	(52)	52	100%
Other	2	7	(5)	(71%)
Total Certain Items	2	(42)	44	105%
Adjusted Net income attributable to KMI	**$ 2,831**	**$ 2,571**	**$ 260**	**10%**

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

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

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

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

$ in millions

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

Segment EBDA[(a)]	2025 Budget	2014 Actual
CO_2 Segment EBDA	755	1,248
Certain Items[(b)]		
Change in fair value of derivative contracts	-	(25)
Loss on impairments, divestitures and other write-downs, net	-	243
Certain Items	-	218
CO_2 Adjusted Segment EBDA[(c)]	755	1,466
Canada Adjusted Segment EBDA	-	200
Total Adjusted Segment EBDA[(d)]	$ 8,673	$ 7,563

a) Includes revenues, earnings from equity investments, operating expenses, other (income) expense, net, and other, net. Operating expenses include costs of sales, operations and maintenance expenses, and taxes, other than income taxes. The composition of Segment EBDA is not addressed nor prescribed by generally accepted accounting principles. 2014 amounts are adjusted to reflect categorization of basis difference amortization (amortization of excess cost of equity investments) consistent with 2025 Segment EBDA accounting change.
b) See "Non-GAAP Financial Measures—Certain Items."
c) 2025 includes $140 million of EBDA associated with our ETV business. 2014 actuals consist of only our CO_2 EOR and Transport business.
d) Calculated as the sum of all our segments' respective Adjusted Segment EBDA or, to the extent that a segment has no reportable Certain Items, Segment EBDA.

2024 Reconciliation of Recasted Adjusted Segment EBDA

$ in millions

Segment EBDA[a]	2024 Actual	Adjustment[b]	2024 Recasted
Natural Gas Pipelines Segment EBDA	$ 5,427	$ (34)	$ 5,393
Certain Items[c]			-
Change in fair value of derivative contracts	75	-	75
Loss on impairments, divestitures and other write-downs, net	(29)	-	(29)
Certain Items	46	-	46
Natural Gas Pipelines Adjusted Segment EBDA	5,473	(34)	5,439
Products Pipelines Segment EBDA	1,173	(9)	1,164
Certain Items	-	-	-
Products Pipelines Adjusted Segment EBDA	1,173	(9)	1,164
Terminals Segment EBDA	1,099	(0)	1,099
Certain Items	-	-	-
Terminals Adjusted Segment EBDA	1,099	(0)	1,099
CO_2 Segment EBDA	692	(7)	685
Certain Items[c]			-
Change in fair value of derivative contracts	2	-	2
Loss on impairments, divestitures and other write-downs, net	(40)	-	(40)
Certain Items	(38)	-	(38)
CO_2 Adjusted Segment EBDA[d]	654	(7)	647
Total Adjusted Segment EBDA[e]	$ 8,399	$ (50)	$ 8,349

a) Includes revenues, earnings from equity investments, operating expenses, other (income) expense, net, and other, net. Operating expenses include costs of sales, operations and maintenance expenses, and taxes, other than income taxes. The composition of Segment EBDA is not addressed nor prescribed by generally accepted accounting principles.
b) Represents categorization of basis difference amortization (amortization of excess cost of equity investments) consistent with 2025 Segment EBDA accounting change.
c) See “Non-GAAP Financial Measures—Certain Items.”
d) Includes $45 million of EBDA associated with our ETV business.
e) Calculated as the sum of all our segments' respective Adjusted Segment EBDA or, to the extent that a segment has no reportable Certain Items, Segment EBDA.

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

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$ in millions

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

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

Reconciliations of KMI FCF and CO_2 EOR & Transport FCF

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$ in millions

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

Reconciliation of CO_2 EOR & Transport FCF	2020	2021	2022	2023	2024	2025B
EBDA for CO_2 EOR & Transport[b]	$ (294)	$ 750	$ 798	$ 658	$ 640	$ 615
Certain items:						
Change in fair value of derivative contracts	(6)	4	(11)	4	2	-
Loss (gain) on impairments, divestitures and other write-downs, net	950	(10)	-	-	(40)	-
Segment Certain Items	944	(6)	(11)	4	(38)	-
Adjusted EBDA for CO_2 EOR & Transport	**650**	**744**	**787**	**662**	**602**	**615**
Capital expenditures (GAAP)[a]	(186)	(185)	(275)	(255)	(280)	(303)
Acquisitions	-	-	-	(13)	(64)	-
CO_2 EOR & Transport FCF	**$ 464**	**$ 559**	**$ 512**	**$ 394**	**$ 258**	**$ 312**

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

Reconciliations of Terminals FCF and Products Pipelines FCF

$ in millions

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

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

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

Reconciliation of Adjusted EBITDA, Normalized for Divestitures

KINDER MORGAN

$ in millions

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

a) To avoid duplication, amounts are adjusted to exclude amounts which are already included within “Certain Items” above.
b) Includes amortization of basis differences related to our JVs.

Reconciliation of Net Debt

$ in millions

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