KINDER MORGAN

2019 Investor Day

January 23, 2019

Disclosure

Forward looking statements / non-GAAP financial measures

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Forward-Looking Statements – This presentation includes forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995 and Section 21E of the Securities and Exchange Act of 1934. Forward-looking statements include any statement that does not relate strictly to historical or current facts and include statements accompanied by or using words such as "anticipate," "believe," "intend," "plan," "projection," "forecast," "strategy," "outlook," "continue," "estimate," "expect," "may," or "long-term". In particular, statements, express or implied, concerning future actions, conditions or events, future operating results or the ability to generate revenues, income or cash flow or to pay dividends are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. There is no assurance that any of the actions, events or results of the forward-looking statements will occur, or if any of them do, what impact they will have on our results of operations or financial condition. Because of these uncertainties, you are cautioned not to put undue reliance on any forward-looking statement.

Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict. These statements are necessarily based upon various assumptions involving judgments with respect to the future, including, among others, the timing and extent of changes in the supply of and demand for the products we transport and handle; national, international, regional and local economic, competitive, political and regulatory conditions and developments; the timing and success of business development efforts; the timing, cost, and success of expansion projects; technological developments; condition of capital and credit markets; inflation rates; interest rates; the political and economic stability of oil-producing nations; energy markets; federal, state or local income tax legislation; weather conditions; environmental conditions; business, regulatory and legal decisions; terrorism; cyber-attacks; and other uncertainties. Important factors that could cause actual results to differ materially from those expressed in or implied by forward-looking statements include the risks and uncertainties described in our most recent Annual Report on Form 10-K and subsequently filed Exchange Act reports filed with the Securities Exchange Commission ("SEC") (including under the headings "Risk Factors," "Information Regarding Forward-Looking Statements" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere), which are available through the SEC's EDGAR system at www.sec.gov and on our website at www.kindermorgan.com.

GAAP – Unless otherwise stated, all historical and estimated future financial and other information and the financial statements included in this presentation have 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. Our reconciliation of non-GAAP financial measures to comparable GAAP measures can be found in this presentation under "Non-GAAP Financial Measures and Reconciliations". These non-GAAP measures do not have any standardized meaning under GAAP and therefore 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. See "Use of Non-GAAP Financial Measures" below.

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Disclosure

Forward looking statements / non-GAAP financial measures

KML FLS – Forward-looking statements in this presentation include statements, express or implied, concerning: (i) the evaluation of options in order to maximize value to KML shareholders following the Trans Mountain sale including, among others, continuing to operate as a standalone enterprise, a disposition by sale or a strategic combination with another company; (ii) KML's expected Adjusted EBITDA and DCF for 2019, expected investment in expansion projects and Adjusted EBITDA to debt at the end of 2019; (iii) the anticipated dividends and the intended payment thereof; (iv) anticipated growth and the potential growth opportunities of KML's business; (v) expected demand and market conditions and the anticipated competitive position of KML's business; and (vi) and anticipated tolls. Forward-looking statements are not guarantees of performance. They involve significant risks, uncertainties and assumptions. Any financial outlook or other forward-looking statements provided in this presentation have been included for the purpose of providing information relating to management's current expectations and plans for the future, are based on a number of significant assumptions and may not be appropriate, and should not be used, for any other purpose. Many of the factors that will determine these results are beyond the ability of KML to control or predict. In addition, given the nature of the relationships between KML and KMI, factors or events that impact KMI may have consequences for KML.

Future actions, conditions or events and future results of operations may differ materially from those expressed in forward-looking statements. Many of the factors that will determine these results, including the ability of KML to pay dividends, are beyond the ability of KML to control or predict. As noted above, the forward-looking statements in this presentation are based on a number of material assumptions, including among others those discussed in this presentation or inherent in the factors highlighted below. Among other things, specific factors that could cause actual results to differ from those indicated in the forward-looking statements include, without limitation: changes in demand for KML's services; issues, delays or stoppages associated with expansion projects; significant unanticipated cost increases or required capital expenditures; the breakdown or failure of equipment, pipelines and facilities, releases or spills, operational disruptions or service interruptions; the ability of KML's counterparties to perform; and changes in the regulatory environment.

The foregoing list should not be construed to be exhaustive. In addition to the foregoing, important factors that could cause actual results to differ materially from those expressed in or implied by forward-looking statements include the risks and uncertainties described in our most recent Annual Report on Form 10-K and subsequently filed Exchange Act reports filed with the SEC (including under the headings "Risk Factors," "Information Regarding Forward-Looking Statements" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere), which are available through the SEC's EDGAR system at www.sec.gov, under KML's profile on SEDAR at www.sedar.com and on our website at www.kindermorgancanadalimited.com.

Kinder Morgan 2019 Investor Day

Agenda and presenters

TIME	DISCUSSION	PRESENTER	
8:00 – 8:15	Compelling Investment Opportunity	**Rich Kinder** *Executive Chairman*	
8:15 – 9:15	Strategic Excellence	**Steve Kean** *CEO*	
9:15 – 9:45	Financial Excellence	**Kim Dang** *President*	
9:45 – 10:00	**BREAK**		
10:00 – 10:20	KMI: 2019 Budget	**David Michels** *VP & CFO*	
10:20 – 10:40	KML: 2019 Outlook & Budget	**Dax Sanders** *KML CFO* *KMI EVP & Chief Strategy Officer*	
10:40 – 11:30	**Q&A**		

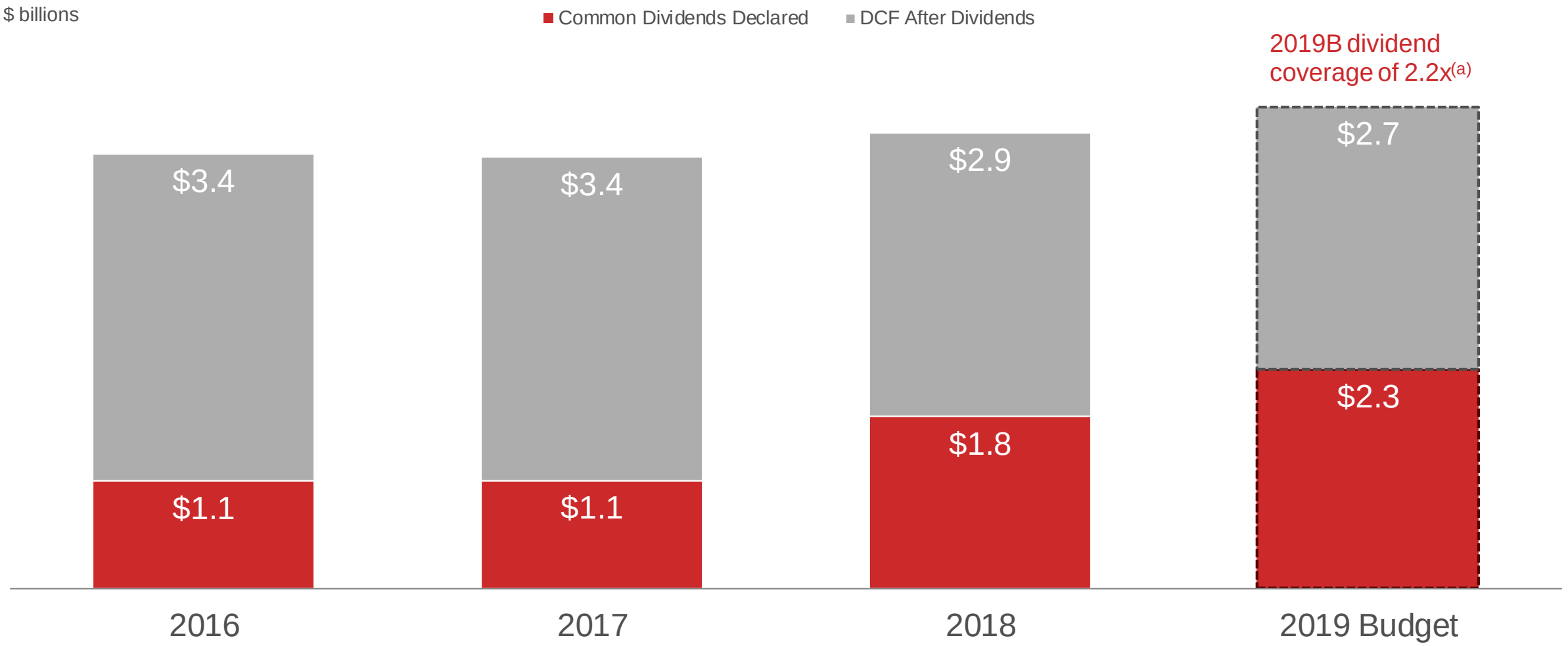
Compelling Investment Opportunity

Rich Kinder

Executive Chairman

Cash Flow Generation Machine

~$5 billion of 2019B distributable cash flow (DCF) = ~$2 billion for dividends + ~$3 billion to enhance shareholder value



Generated ~$10 billion of DCF after dividends in last 3 years

Note: See Non-GAAP Financial Measures and Reconciliations.
a) 2019B DCF divided by 2019B common dividends declared.

A Core Energy Infrastructure Holding

Significant cash flow generation, significant value to shareholders

~$40 billion market capitalization

One of the 10 largest energy companies in the S&P 500

Investment grade rated debt

Recent upgrade to BBB / Baa2 by S&P and Moody's reflects balance sheet strength

~$7.8 billion Adjusted EBITDA

budgeted for 2019

25% dividend growth in 2019 & 2020

$1.00 in 2019 and $1.25 in 2020

$2 billion share buyback program

purchased ~$525 million since December 2017

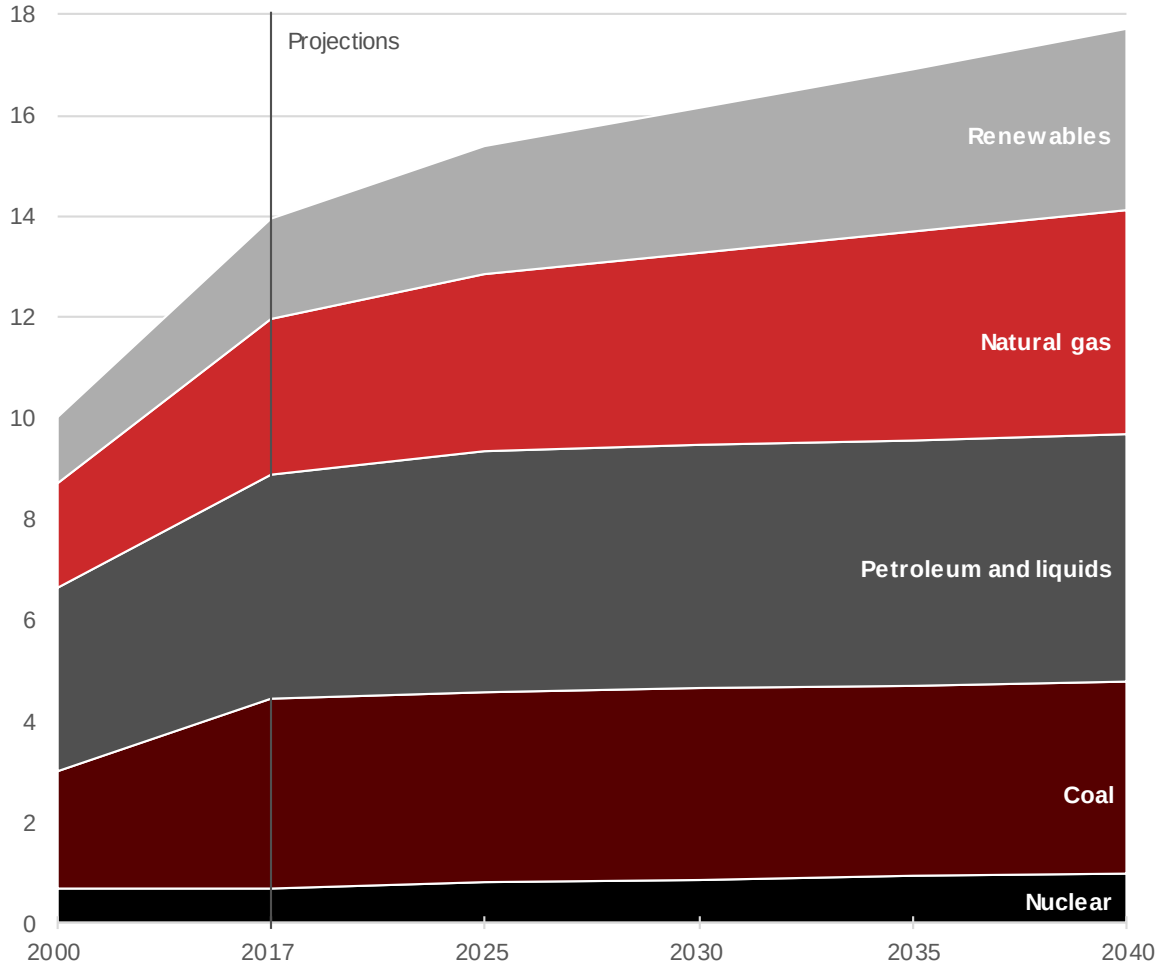
Note: Adjusted EBITDA is a non-GAAP measure. See Non-GAAP Financial Measures and Reconciliations.

Globally, the Need for Energy is Growing

Natural gas and petroleum demand expected to grow for decades to come

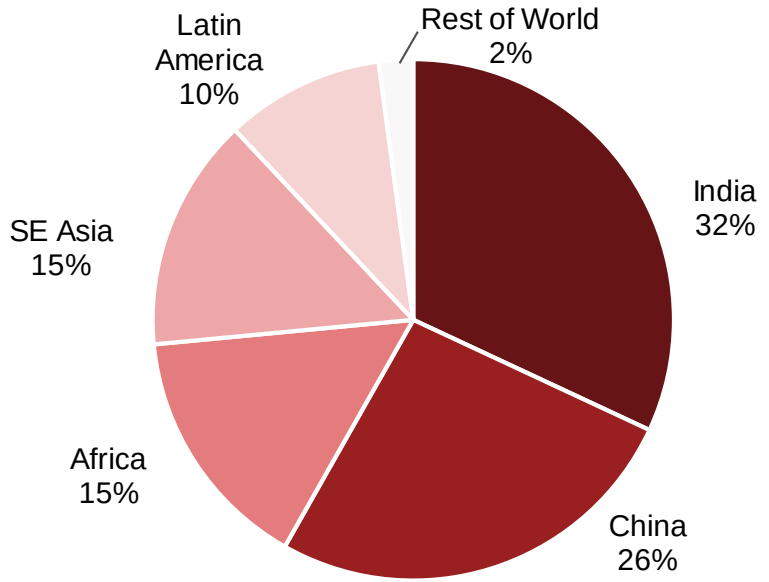
STEADY GROWTH IN GLOBAL ENERGY DEMAND

Billion tons of oil equivalent



DEMAND GROWTH DRIVEN BY DEVELOPING ECONOMIES

% of incremental demand from 2017 to 2040



- India's energy demand projected to more than double, the single largest source of global demand growth
- China projected to become the world's biggest oil consumer and the largest importer of both oil and natural gas
- Over 650 million people expected to still lack access to electricity in 2030

Population growth, urbanization and economic development create growing demand for affordable, reliable energy sources

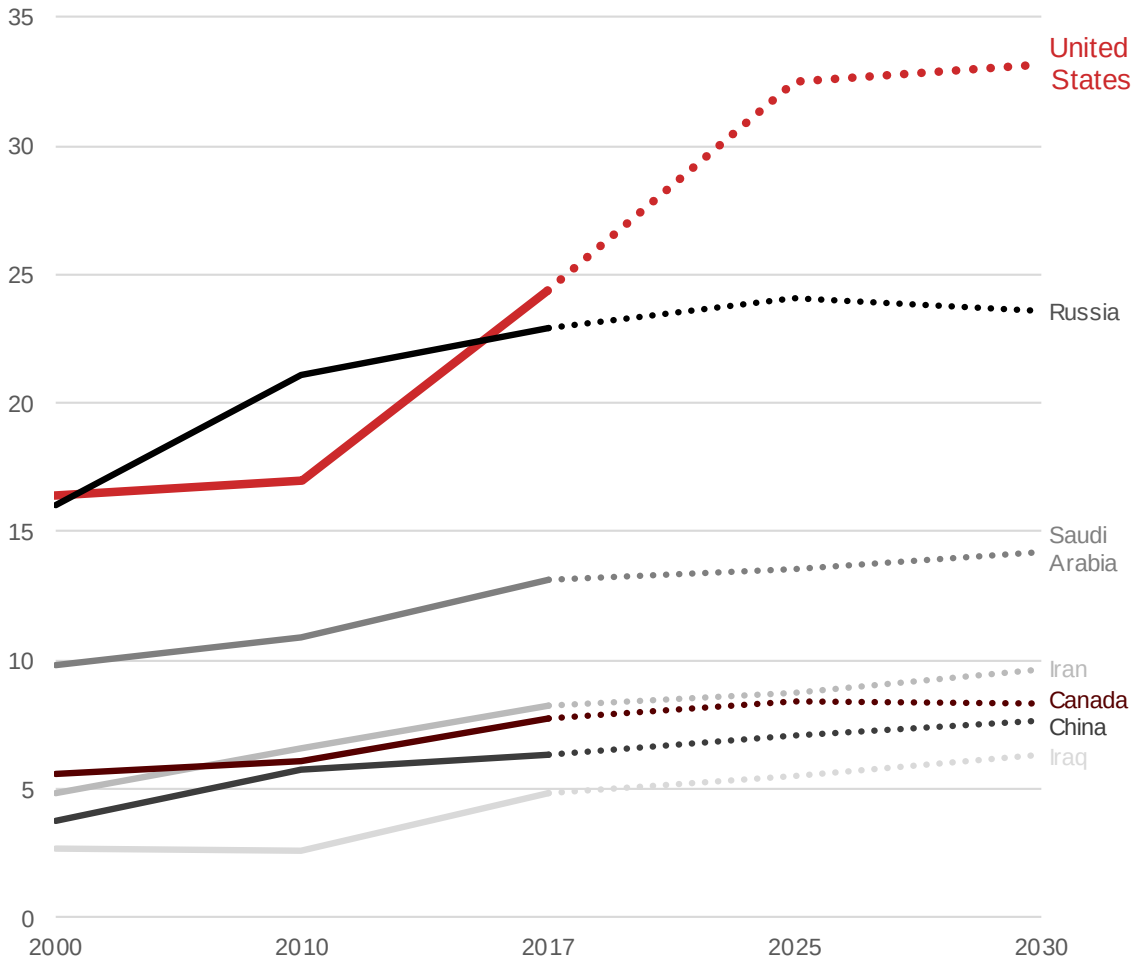
Source: International Energy Agency World Energy Outlook 2018, New Policies Scenario. New Policy Scenario considers (1) today's policy frameworks, (2) the continued evolution of known technologies and (3) policy ambitions announced as of August 2018, including commitments made under the Paris Agreement.

U.S. is the Largest Oil and Gas Producer in the World

Abundant supply enables growing U.S. role as exporter

OIL AND GAS PRODUCTION

Million barrels of oil equivalent per day



Long runway of expected growth in U.S. oil and gas production

- Current estimates for U.S. proved reserves of oil and natural gas are at record levels and approximately double estimates from a decade ago[(a)]
  - Crude oil: ~39 billion barrels
  - Natural gas: ~464 trillion cubic feet
- U.S. accounts for >50% of expected global supply increase from 2017 to 2025 given substantial growth in shale production
- In 2025, U.S. is projected to produce nearly **1/5th of every barrel of oil** and **1/4th of every cubic meter of natural gas** in the world
- ~33% expected growth in U.S. oil and natural gas production 2017 to 2025

Disparities between countries with the largest resource base and those with growing energy demand make energy security key

- Reliability and affordability are important considerations for importers
- U.S. is advantaged versus other resource-rich countries
  - Competitive marketplace driving continued innovation
  - Reliable rule of law with enforceable contracts
  - Stable regulatory environment

Connecting vast U.S. supplies to growing demand markets will drive new infrastructure and higher utilization of existing assets

Source: International Energy Agency World Energy Outlook 2018, New Policies Scenario. Scenario assumes (1) today's policy frameworks and (2) policy ambitions announced as of August 2018.
a) U.S. Energy Information Administration Proved Reserves Estimates as of YE2017 (published November 2018).

Bright Future for U.S. Natural Gas

Infrastructure is key to meet demand

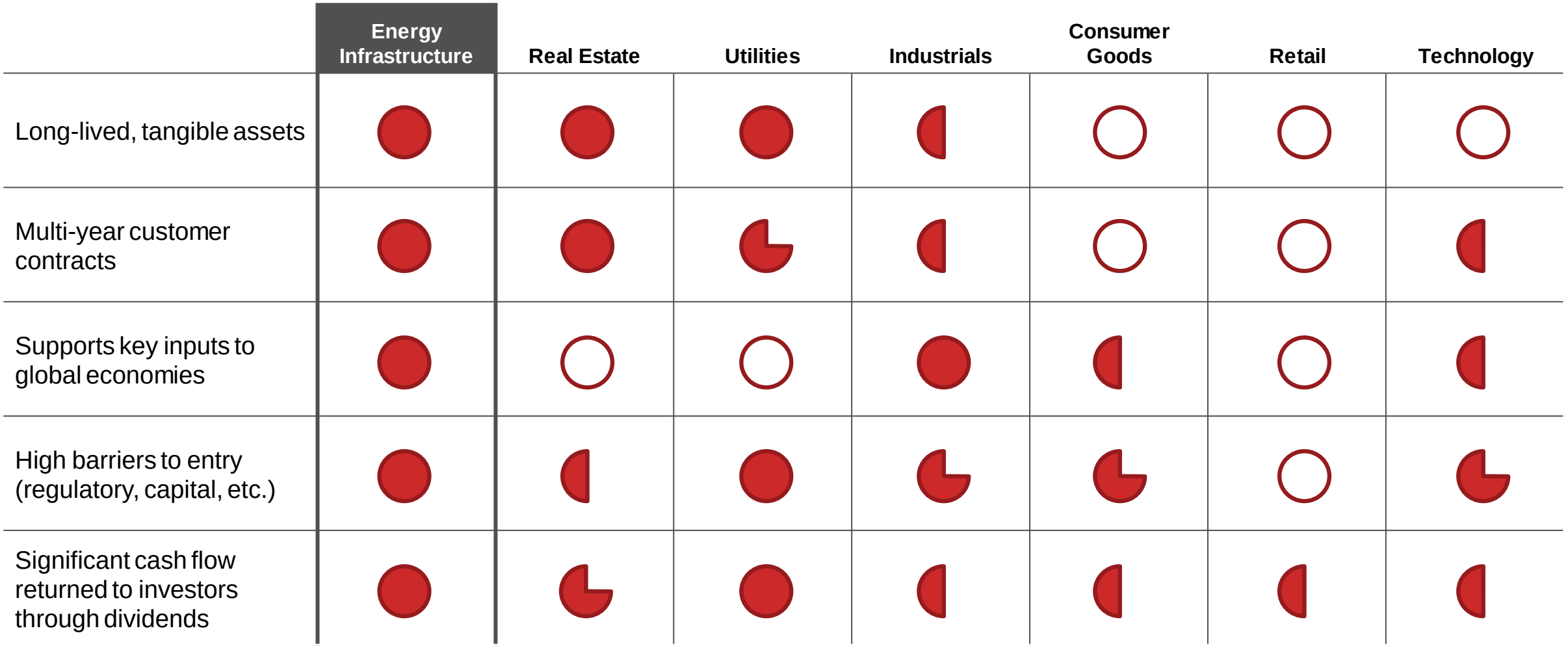
	2017 – 2018		2018 – 2030	
	Bcfd	%	Bcfd	%
Overall demand	↑ 9	12%	↑ 29	32%
Drivers of Growth:				
LNG	↑ 1	65%	↑ 14	496%
Power	↑ 4	15%	↑ 4	15%
Industrial	↑ 1	4%	↑ 4	15%
Exports to Mexico	↑ 1	10%	↑ 2	39%
Residential	↑ 2	12%	↑ 1	4%

Our expansive network is positioned to maximize current capacity and advantaged for new expansion opportunities

Source: WoodMackenzie, North America Gas Markets Long-Term Outlook, Fall 2018. LNG and exports to Mexico shown net of imports.

Attractive Attributes of Energy Infrastructure

KMI's long-lived, hard assets support key inputs to the global economy



Kinder Morgan: Leader in North American Energy Infrastructure

Unparalleled and irreplaceable asset footprint built over decades

Largest natural gas transmission network in North America

- ~70,000 miles of natural gas pipelines
- Connected to every important U.S. natural gas resource play and key demand centers
- Move ~40% of natural gas consumed in the U.S.

Largest independent transporter of refined products in North America

- Transport ~1.7 mmbbld of refined products
- ~6,900 miles of refined products pipelines
- ~5,800 miles of other liquids pipelines (crude and natural gas liquids)

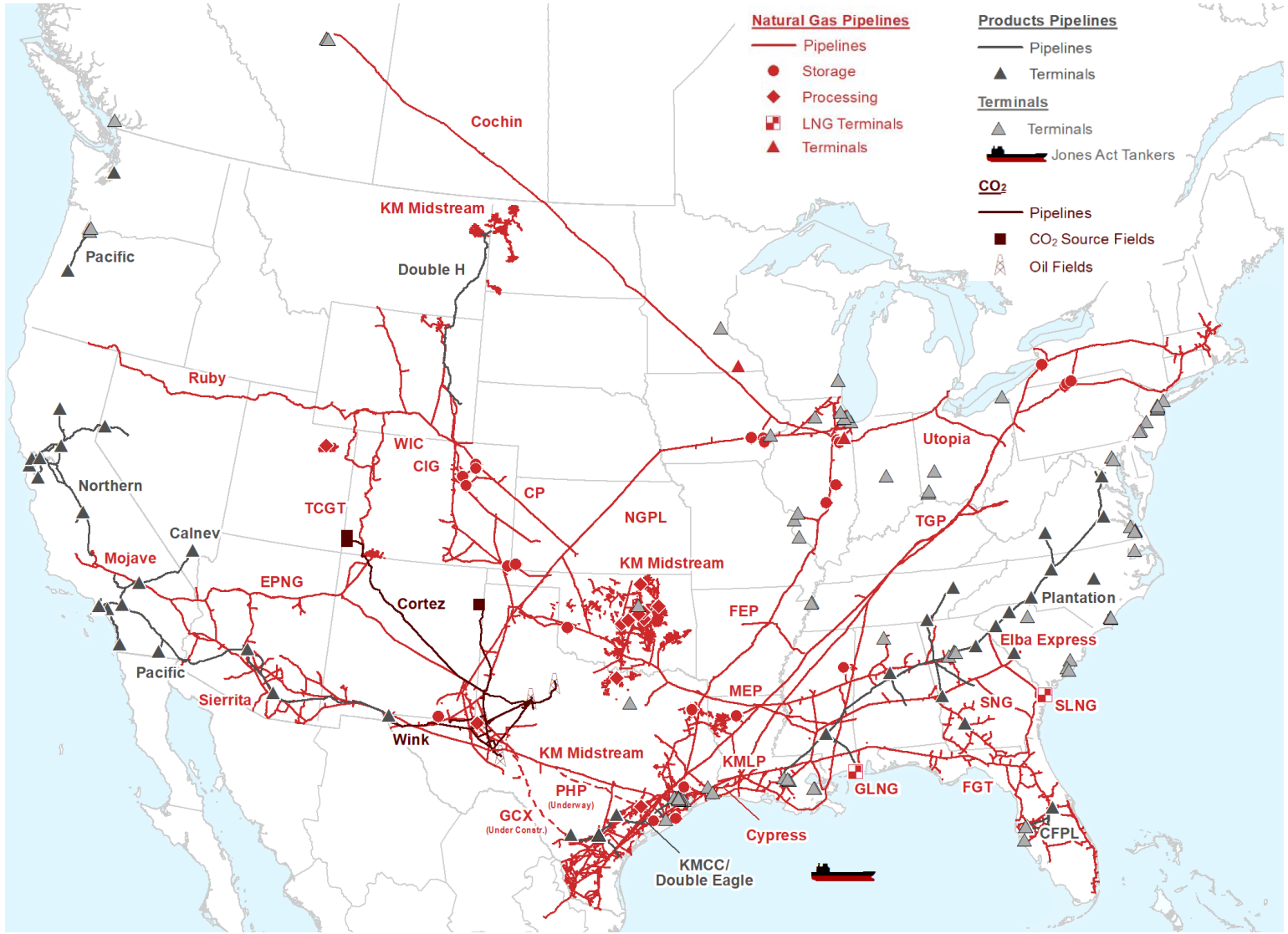
Largest independent terminal operator in North America

- 157 terminals
- 16 Jones Act vessels

Largest transporter of CO_2 in North America

- ~1.2 billion cubic feet per day (Bcfd)

Leading infrastructure provider across multiple critical energy products



Note: Mileage and volumes are company-wide per 2019 budget.

Compelling Investment Opportunity

Returning value to shareholders via significant dividend growth | Attractive valuation

DRILL-DOWN OF S&P 500 COMPANIES

411	2019E Net Debt / 2019E EBITDA <5.0x
298	Investment grade
121	Market cap >$35bn
21	18E-20E EPS CAGR >15%
2	2019E dividend yield >5%
KINDER MORGAN INC.	18E-20E dividend CAGR >20%

ENTERPRISE VALUE / 2019E EBITDA[(a)]

Attractive valuation provides upside potential



CURRENT DIVIDEND YIELD[(b)]

More than double S&P 500



Note: See Non-GAAP Financial Measures and Reconciliations.
Source: Bloomberg. Share price, market capitalization, enterprise value, ratings, and consensus estimates of S&P 500 index (SPX) as of 1/17/2019.
a) Median multiple for SPX Index.
b) Annualized last quarter dividend divided by share price.

Strategic Excellence

Steve Kean

CEO

Our Strategy

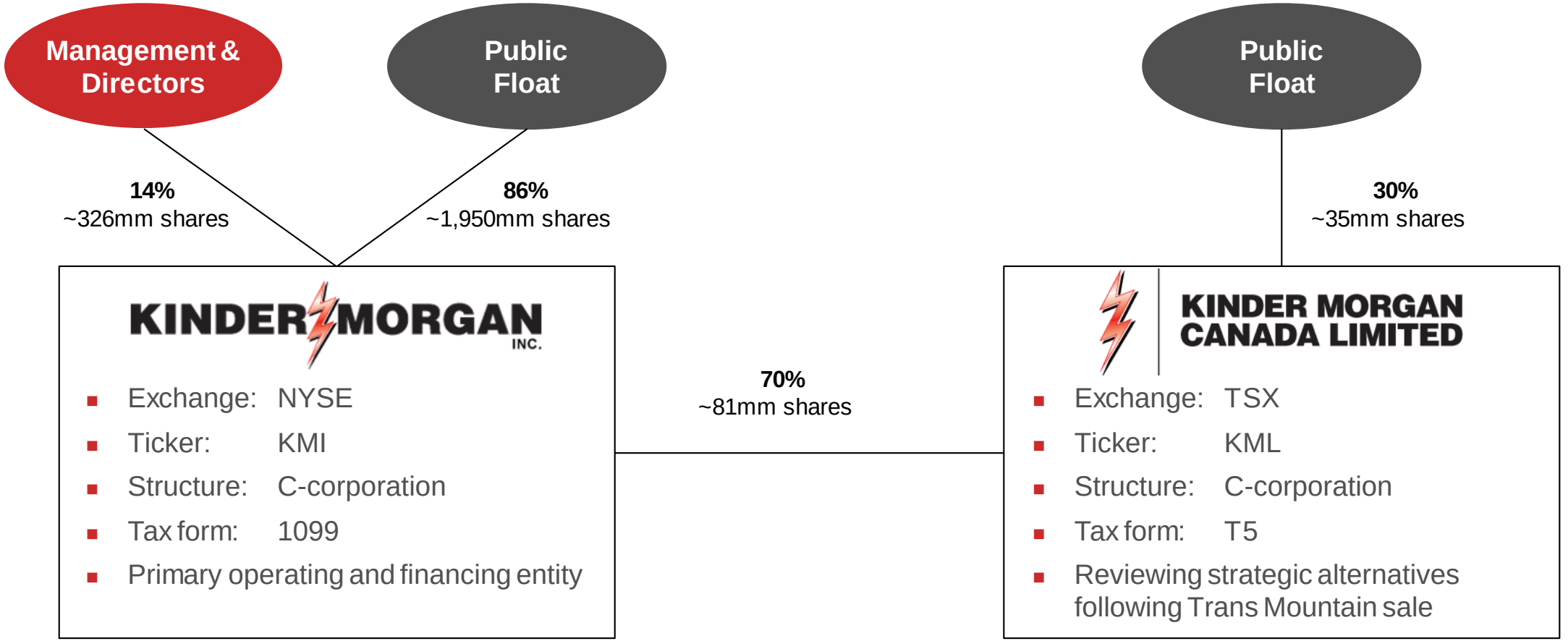
Stable, fee-based assets	Financial flexibility	Disciplined capital allocation	Enhancing shareholder value
▪ Core energy infrastructure ▪ Safe & efficient operator ▪ Multi-year contracts ▪ >90% take-or-pay and fee-based cash flows	▪ 4.5x 2019B Adjusted Net Debt / Adjusted EBITDA(a) ▪ Low cost of capital ▪ Recent credit ratings upgrades to mid-BBBs ▪ Ample liquidity	▪ Conservative assumptions ▪ High return thresholds ▪ Self-funding at least equity portion with cash flow ▪ Ongoing evaluation of best alternative for free cash flow use	▪ Attractive projects ▪ Dividend growth ▪ Share repurchases

Maximize the value of our assets on behalf of shareholders

a) See Non-GAAP Financial Measures and Reconciliations.

Simple C-Corp Structure with Highly-Aligned Leadership

14% of KMI is owned by management and board members



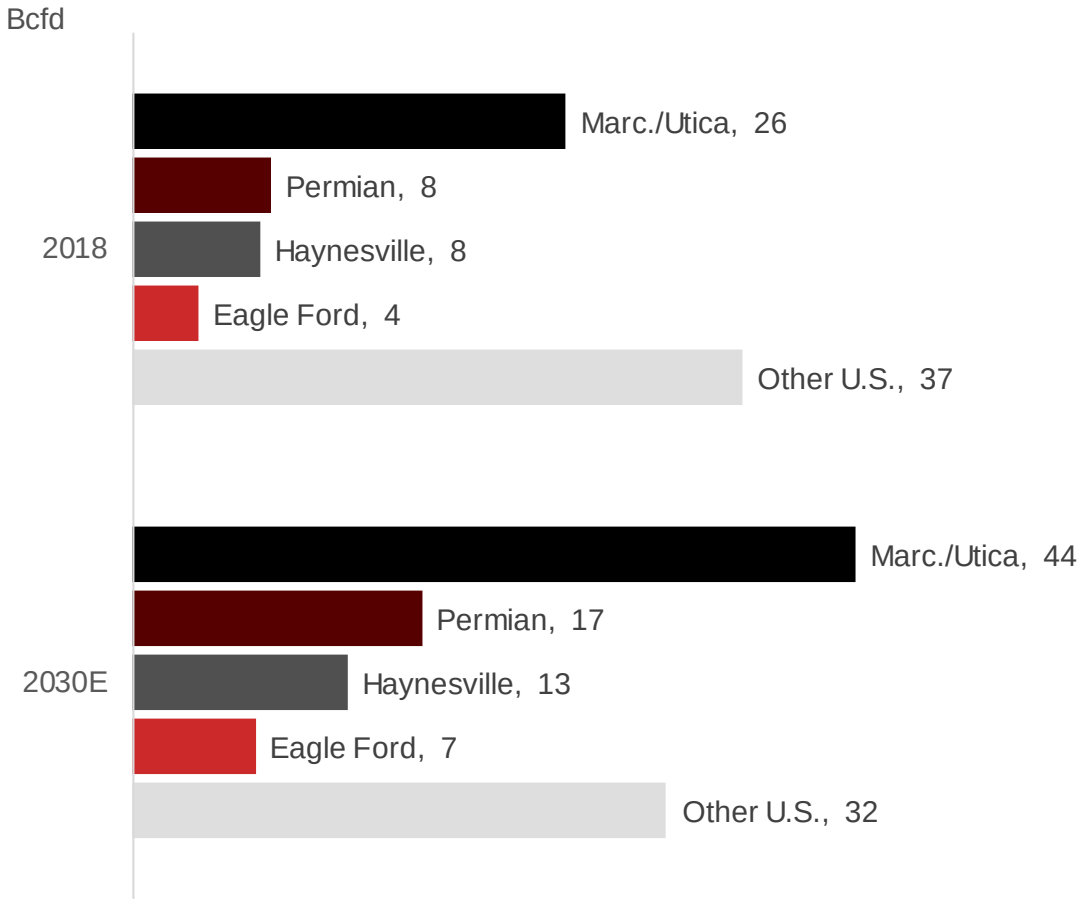
As fellow shareholders, our interests are aligned
CEO receives salary of $1 per year and no cash bonus

Note: Share count as of 12/31/2018. KMI includes Form-4 filers and management unvested restricted shares. Non-residents of Canada receive NR4 tax form from KML rather than T5 form to Canadian residents.

Positioned to Support Future of Natural Gas

Kinder Morgan transports ~40% of all natural gas consumed in the U.S.

U.S. NATURAL GAS PRODUCTION



U.S. production projected to grow by >30 Bcfd or ~37% through 2030 driven by four key basins

U.S. NATURAL GAS DEMAND

Bcfd

Sector	2018	2030E	Growth[a] Bcfd	Growth[a] %
Net LNG exports	3	17	↑ 14	496%
Power	29	33	↑ 4	15%
Industrial	23	26	↑ 4	15%
Net Mexico exports	5	6	↑ 2	39%
Transport	0	2	↑ 2	800%
Residential	14	14	↑ 1	4%
Other	17	20	↑ 3	18%
Total U.S. Natural Gas Demand	**90**	**119**	**↑ 29**	**32%**

Projected U.S. demand growth of >30% primarily from net LNG exports +14 Bcfd, power +4 Bcfd and industrial +4 Bcfd

Source: WoodMackenzie, North America Gas Markets Long-Term Outlook, Fall 2018.
a) Calculations may differ due to rounding.

U.S. Natural Gas Demand Increasingly Export Driven

Net LNG exports projected to increase 496% or 14 Bcfd by 2030

Global LNG demand is forecasted to grow from ~40 Bcfd in 2018 to ~75 Bcfd by 2030[a]

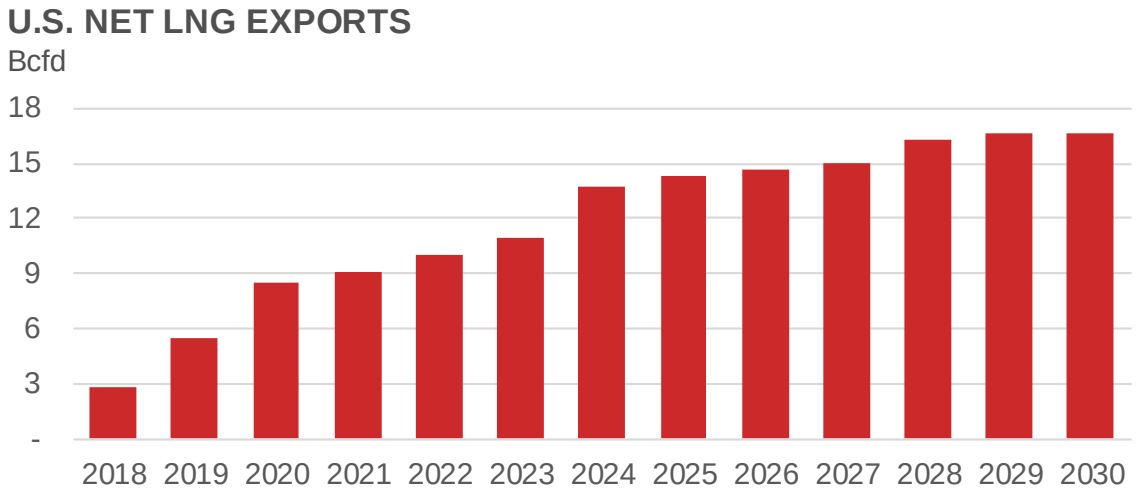
In 2017, China imported 45% more LNG than in 2016, which absorbed almost half of the new supply that came to market

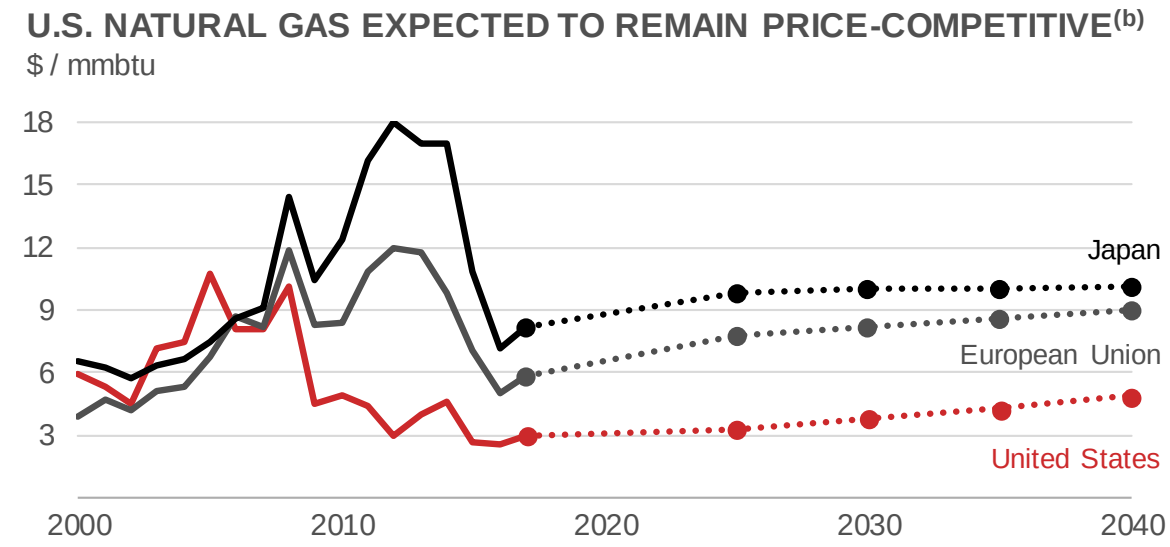
Europe is projected to become more import dependent given declining indigenous supplies

- Europe's largest gas field, Groningen (Netherlands), is forecasted to stop production by 2030

With $3/mmbtu Henry Hub, U.S. LNG projects are expected to remain competitive globally

- Global price spread justifies U.S. LNG exports even with $5/mmbtu Henry Hub





Source unless otherwise noted: WoodMackenzie, North America Gas Markets Long-Term Outlook, Fall 2018.

a) WoodMackenzie, Insight article, September 2018.

b) International Energy Agency World Energy Outlook 2018.

U.S. Natural Gas Demand for Power Generation

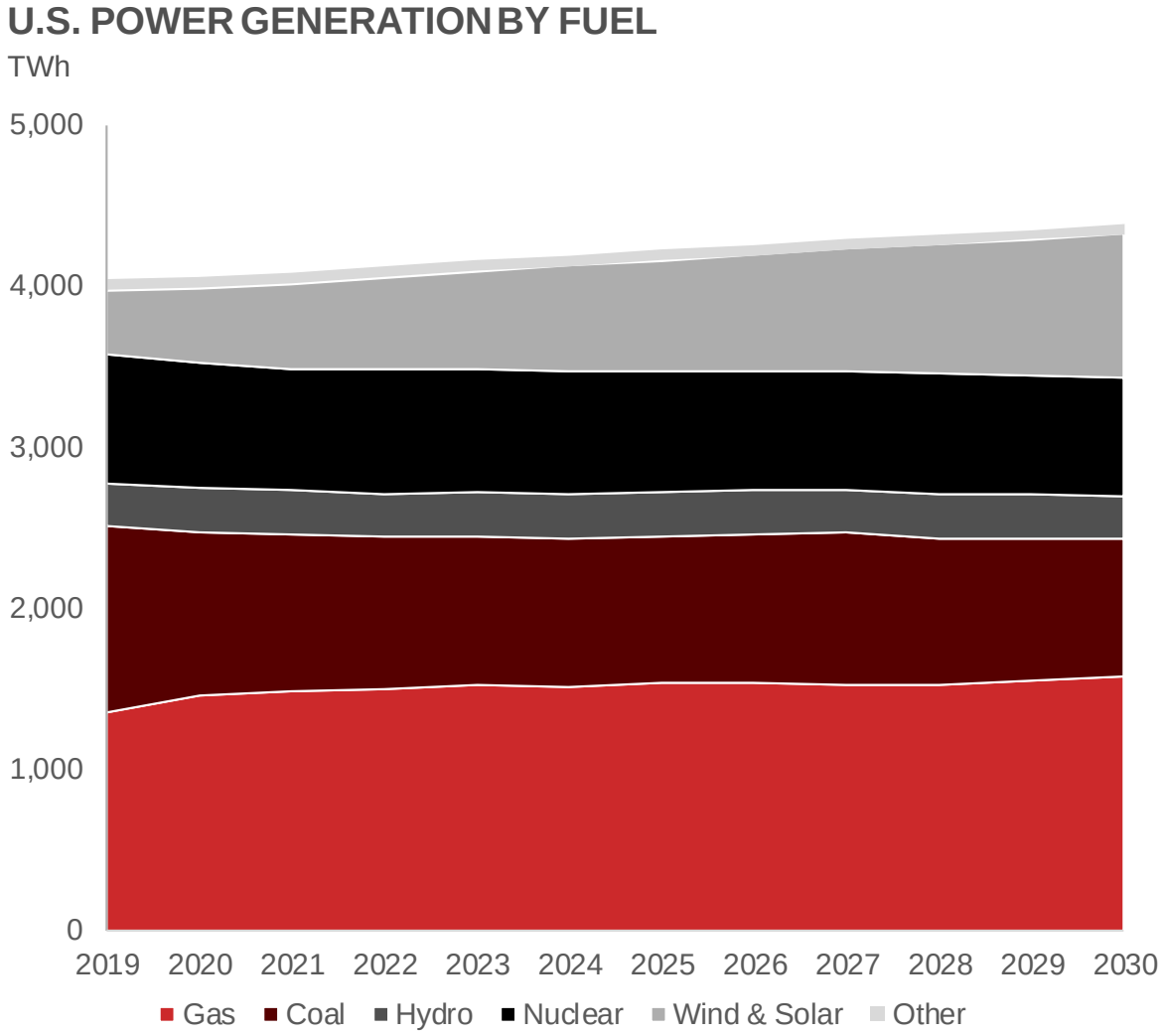
Projected to increase 15% or 4 Bcfd by 2030, representing 36% of power generation market share

Natural gas demand from the power sector is expected to have set a record in 2018 at ~29 Bcfd

- 60 GW of coal plant retirements since 2012 have contributed to a greater market share for natural gas fired generation(a)
- Lower gas prices driven by high production growth continue to incentivize fuel switching
- Increased natural gas fired capacity also driven by ability to backstop intermittent solar and wind generation capacity

Increased natural gas use has been – and will continue to be – critical to meeting climate goals

- Increased natural gas use and declining use of other hydrocarbons have reduced CO_2 emissions from the power sector by ~23% since 2005(a)
- The load-following and peaking capability of natural gas fired power generation supports growth in renewables, creating opportunities for additional pipeline and storage services



Source: WoodMackenzie, North America Gas Markets Long-Term Outlook, Fall 2018, unless otherwise noted.
a) EIA Monthly Energy Review, December 2018.

U.S. Natural Gas Industrial Demand Growth

Projected to increase 15% or 4 Bcfd by 2030

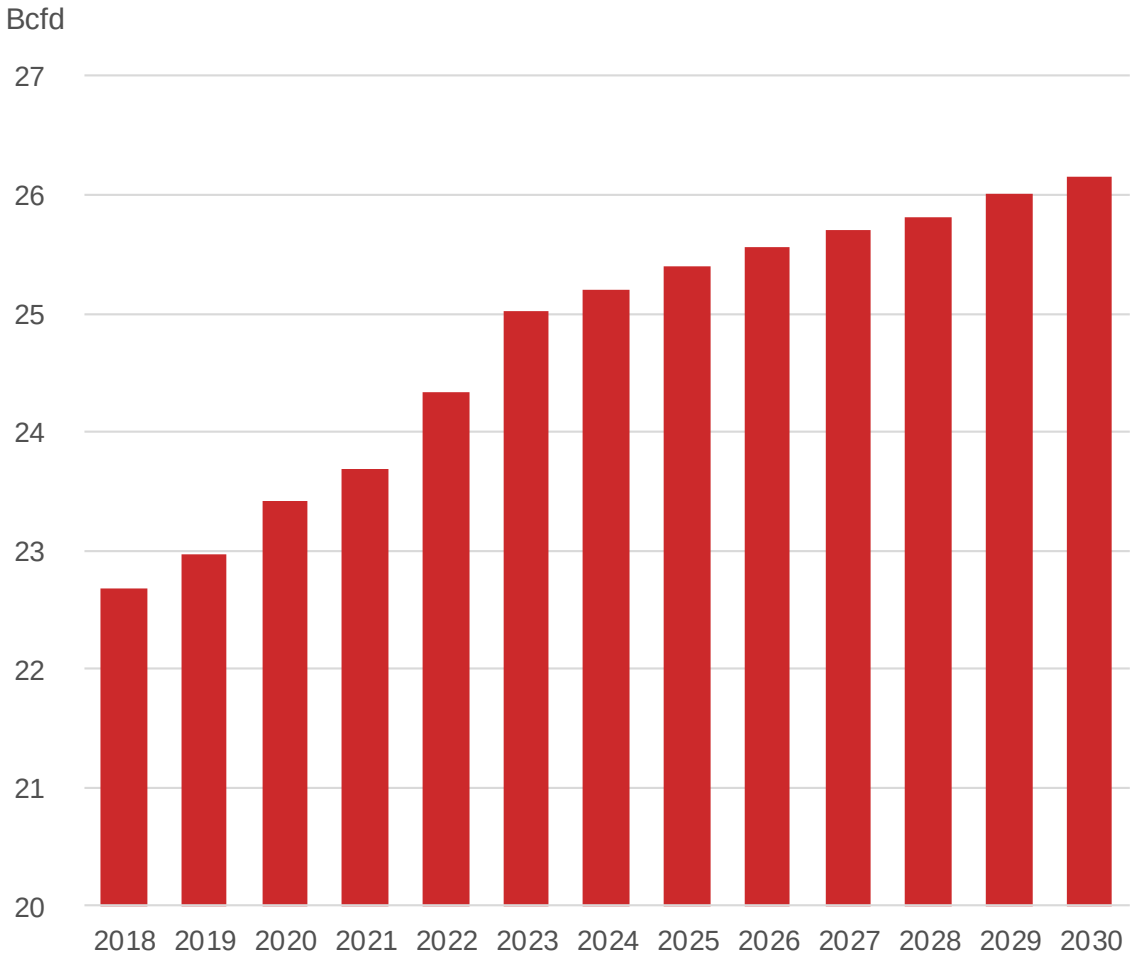
Natural gas and its derivatives are used for clothing, plastics, agriculture, medicine, petrochemicals and more

Natural gas-intensive industries such as fertilizers and petrochemicals continue to add to new natural gas demand

More than $200 billion of petrochemical projects announced since 2010 focused along the U.S. Gulf Coast[(a)]

Petrochemicals include:	Which are used to make things like:
Ethylene	Electrical cables, pipes
Butadiene	Car bumpers, rubber
Toluene	Fabric, boats
Xylene	Beverage bottles, electronics
Benzene	Insulation, phones
Propylene	Adhesives, paints

Natural gas is a key input to products we use everyday



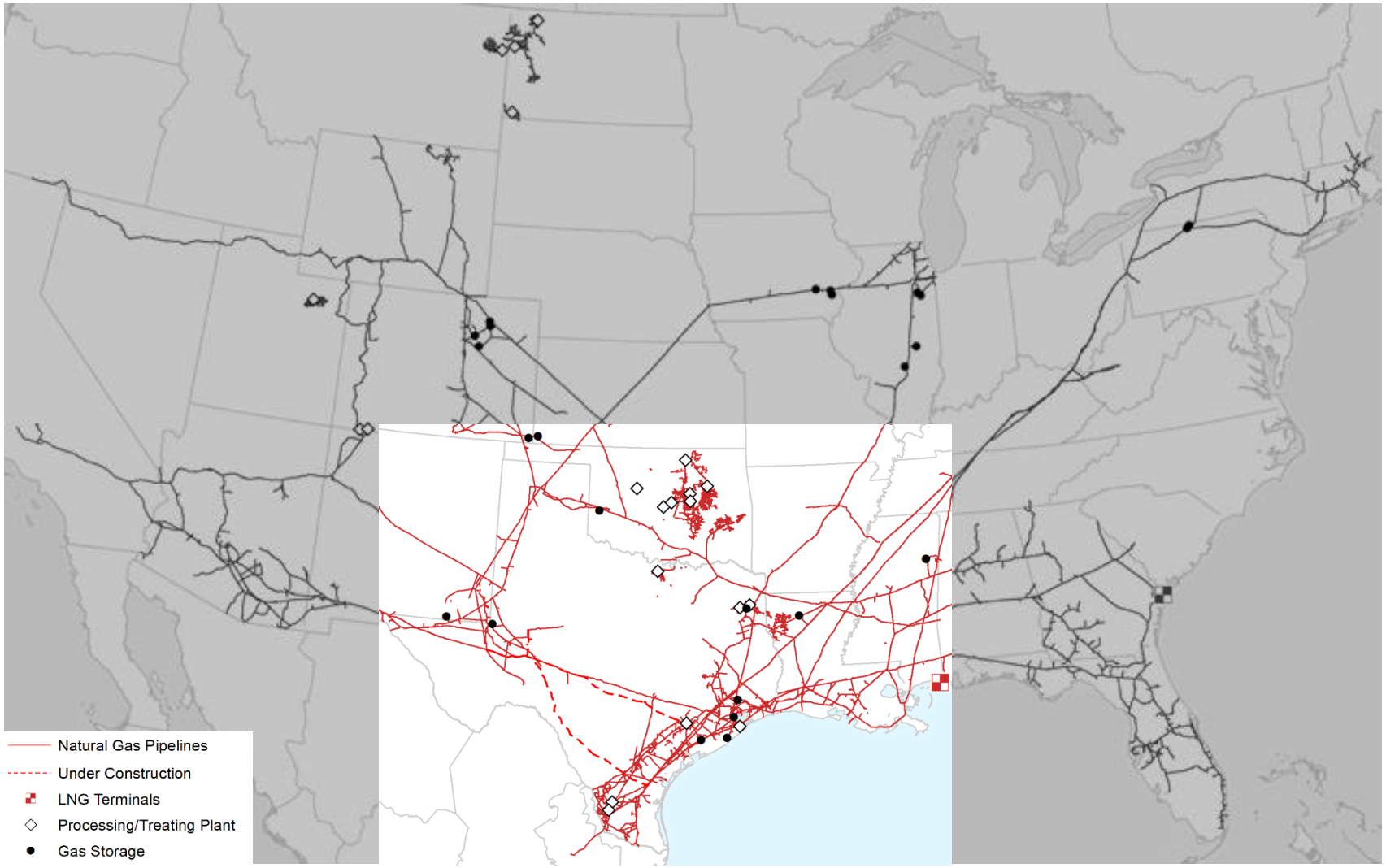
Source: WoodMackenzie, North America Gas Markets Long-Term Outlook, Fall 2018.
a) American Chemistry Council, September 2018.

U.S. Natural Gas Demand is Concentrated in Gulf Coast

>70% of forecasted 2018-2030 demand and export growth occurs in, or transits, Texas and Louisiana

Forecasted Texas and Louisiana demand and export growth between 2018 and 2030:

- LNG Export Demand +404% +13 Bcfd
- Industrial Demand +24% +2 Bcfd
- Exports to Mexico +60% +2 Bcfd
- Other Demand +99% +2 Bcfd
- Power Demand +20% +1 Bcfd
- Transport Demand +1,431% +0.4 Bcfd



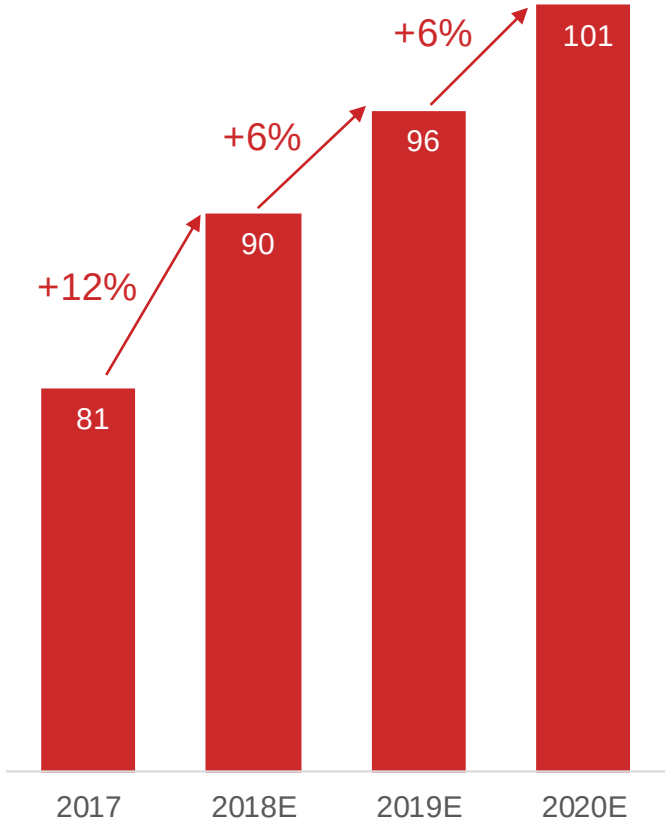
Source: WoodMackenzie, North America Gas Markets Long-Term Outlook, Fall 2018.

Our Unmatched Natural Gas Network and Deliverability

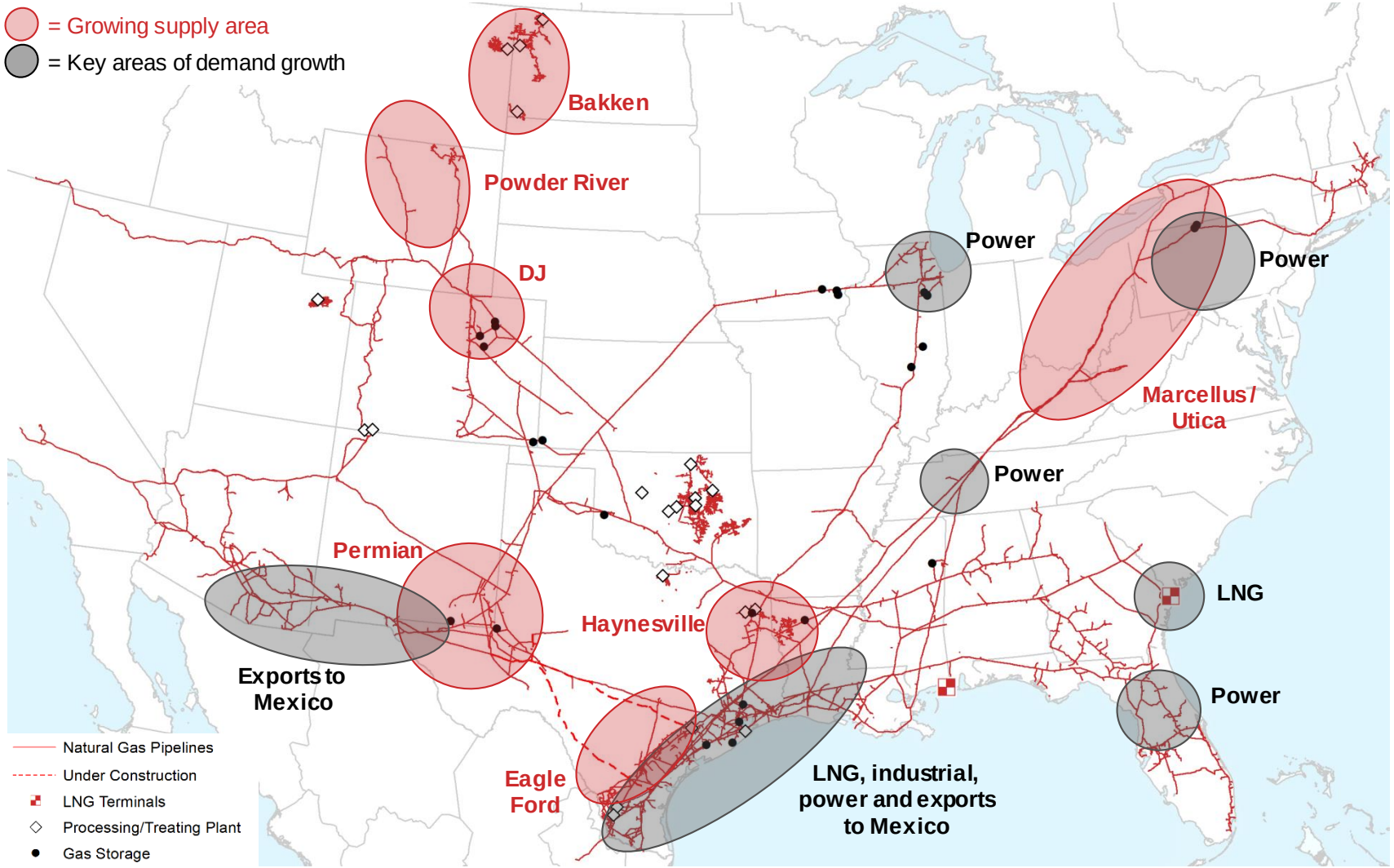
Strong fundamentals drive value on existing assets and create investment opportunities

U.S. NATURAL GAS DEMAND

Bcfd



Our network connects growing supply with key demand centers



Source: WoodMackenzie, North America Gas Short-Term Outlook, December 2018.

$5.7bn of Commercially Secured Capital Projects Underway

Significant opportunities primarily resulting from expansive natural gas footprint

Commercially Secured Capital Projects	Demand Pull / Supply Push	KMI Capital ($ billion)	Estimated In-Service Date	Capacity
Natural Gas				
Permian takeaway projects (GCX, PHP, EPNG, NGPL)		$ 1.3	Q4 2019 – 2020	5.6 Bcfd
Elba liquefaction and related terminal facilities		1.2	2019	0.4 Bcfd
Bakken G&P expansions (Hiland Williston Basin)		0.5	2019	Various
Expansions to supply LNG export (TX Intrastates, NGPL, KMLP)		0.4	2020 - 2022	2.7 Bcfd
Mexico export (EPNG, Sierrita)		0.2	2020	0.6 Bcfd
Other natural gas		0.4	Various	>2.1 Bcfd
Total Natural Gas		**$ 3.9**	**~68% of total at 5.4x EBITDA multiple**	
Other segments		1.8		
Total Backlog		**$ 5.7**		

- **Other segments' backlog includes:** $1.2 billion for CO_2 Oil & Gas, $0.4 billion for CO_2 & Transport, $0.1 billion for Products Pipelines and $0.1 billion for Terminals
  - Primarily liquids-related opportunities
- **~$2.3 billion of projects placed into service and ~$2.5 billion of new projects added during 2018**
- **Beyond the backlog, expect $2 to $3 billion per year of ongoing organic investment opportunities**:
  - Predominantly natural gas opportunities related to LNG export (supply and liquefaction), Marcellus / Utica takeaway capacity, additional power generation and incremental Gulf Coast deliverability

Note: See Non-GAAP Financial Measures and Reconciliations. EBITDA multiple reflects KM share of estimated capital divided by estimated Project EBITDA.
Numbers in table may not sum due to rounding.

Beyond the Backlog

Long-term energy fundamentals create value-enhancing opportunities for existing assets and new projects

Takeaway for significant Marcellus / Utica natural gas growth

Storage to support renewable power generation and LNG exports

Infrastructure to support U.S. energy exports

Grow crude and NGL footprints out of Bakken and elsewhere

Haynesville 2.0

Market access for surging Permian Basin production

Transport natural gas to supply LNG exports

~$800 billion of North American energy infrastructure investment required to support expected growth through 2035[a]

a) Estimate per ICF (June 2018).

501-G Process Update

Resolution expected to occur over time with opportunities to mitigate potential financial impact

Status:

- Filed a Form 501-G for 19 assets during Q4 2018[(a)]
- SNG and Young Gas Storage have entered into negotiated settlements with their customers
- Currently in settlement negotiations with customers of EPNG and TGP
- FERC initiated a Section 5 proceeding against Bear Creek Storage Company, LLC
- FERC closed the 501-G docket for Horizon Pipeline Company, LLC
- No change to estimate of $100 million total unmitigated potential impact from eventual pass through of tax rate reduction

Considerations:

- Earn meaningful % of revenues from negotiated and/or discounted rates, which should not be impacted by tariff rate changes
- Multi-year customer agreements and rate moratoria are in place on several assets, which preserve rates during those periods
- Ability to negotiate valuable service options (e.g., delivery points, pressure rates) rather than exclusively financial terms
- Incremental investments and increases in operating costs to be factored into new rates

Regulatory goal of passing on tax reduction to customers most efficiently solved with direct customer negotiations

Fully-litigated rate cases require substantial financial and human capital resources

a) FERC granted a waiver for SNG given a recent negotiated settlement with customers and an extension for TGP given ongoing settlement negotiations with customers.

Environmental, Social and Governance (ESG)

Committed to being a good corporate citizen

Prioritizing ESG Every Day

Operations Management System

- Intentional, systematic risk management activities established to maintain compliance, to reveal and manage risk and to continually improve our safety and compliance culture

Board Oversight

- KMI and KML Board Environmental, Health and Safety (EHS) Committees oversee ESG matters

Multiple policies outline our approach to Environmental and Social responsibility

- EHS Policy Statement – Reinforcement of our commitment to EHS principles
- Biodiversity – Minimize impacts on biodiversity in areas where we work and operate
- Indigenous Peoples and Aboriginal Relations – Commitment to communicate and cooperate with Indigenous and Aboriginal peoples
- Community Relations – Build and maintain healthy relationships throughout the areas where we operate through two-way engagement and dialogue to build trust and foster collaboration

For consolidated ESG information, please visit the ESG / sustainability page on KMI and KML websites

ESG-Related Achievements

Published first stand-alone ESG Report in October 2018

- Guided by the Sustainability Accounting Standards Board (SASB) standards and Task Force on Climate-related Financial Disclosures (TCFD) guidance
- Also informed by the Global Reporting Initiative (GRI) and CDP (formerly the Carbon Disclosure Project) frameworks
- Positive feedback received on report:
  - *"comprehensive, transparent, and thoughtful"* – Large Institutional Investor
  - *"Kinder Morgan's ESG report provides a clear example of improved sustainability disclosure to investors."* – SASB

Publicly reporting ESG metrics since 2007

- Have performed better than industry averages across majority of metrics reported
- Employees' - including management's - bonuses are tied to performing better than industry averages and our own 3-year averages
- **Metrics reported**: Employee Injury / Illness Rates and Avoidable Vehicle Accidents, KM Contractor Injuries / Illnesses, Gas Pipeline Incidents, Liquid Releases from Onshore Pipeline Right-of-Way
- Recognized by Environmental Defense Fund (EDF) for moving forward on methane disclosure and establishing quantitative methane targets
- Rated by EDF in the top quartile of midstream sector for methane disclosures

Leader in Methane Emission Reductions

- 20+ year involvement in EPA's voluntary Natural Gas STAR program
  - Cumulative methane emission reductions of 108 Bcf, equivalent to the CO_2 emissions from the energy used in 5.6 million homes in one year
- Founding Member of ONE (Our Nation's Energy) Future
  - KM's transmission and storage sector emissions intensity target is 0.31% by 2025

Natural Gas Segment Overview

Connecting key natural gas resources with major demand centers

Asset Summary

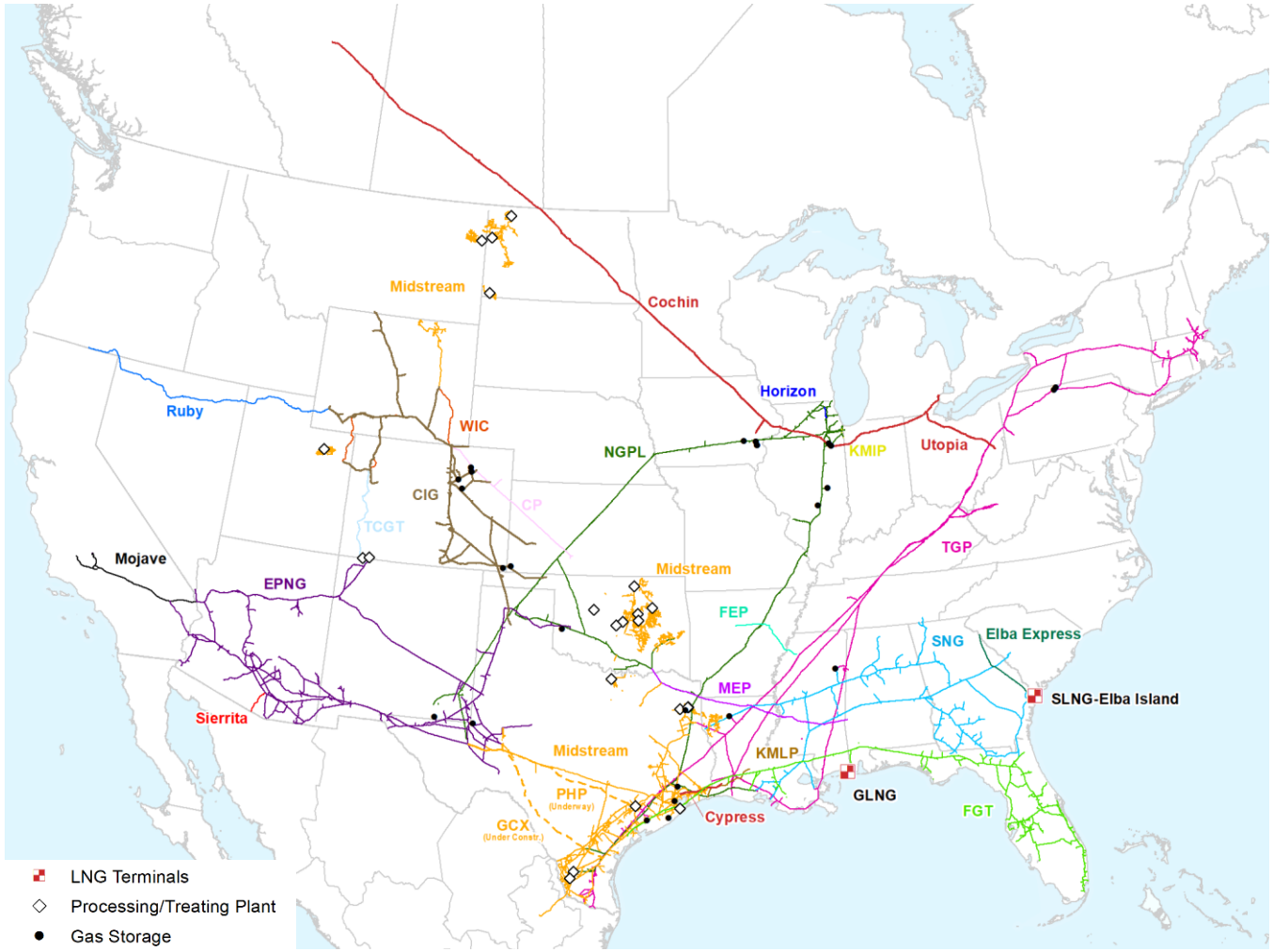
Natural Gas Pipelines:	~70,000	Miles
NGL Pipelines:	~2,700	Miles
U.S. Natural Gas Consumption Moved:		~40%
Working Gas Storage Capacity:	657	Bcf

2019B EBDA[(a)]: ~$5.1 billion

Project Backlog:

$3.9 billion of committed growth projects over the 2019-2022 time period[(b)]

- Permian takeaway, including de-bottlenecking and new builds
- LNG liquefaction (Elba Island)
- Transport projects supporting LNG exports
- Bakken G&P expansions
- Mexico



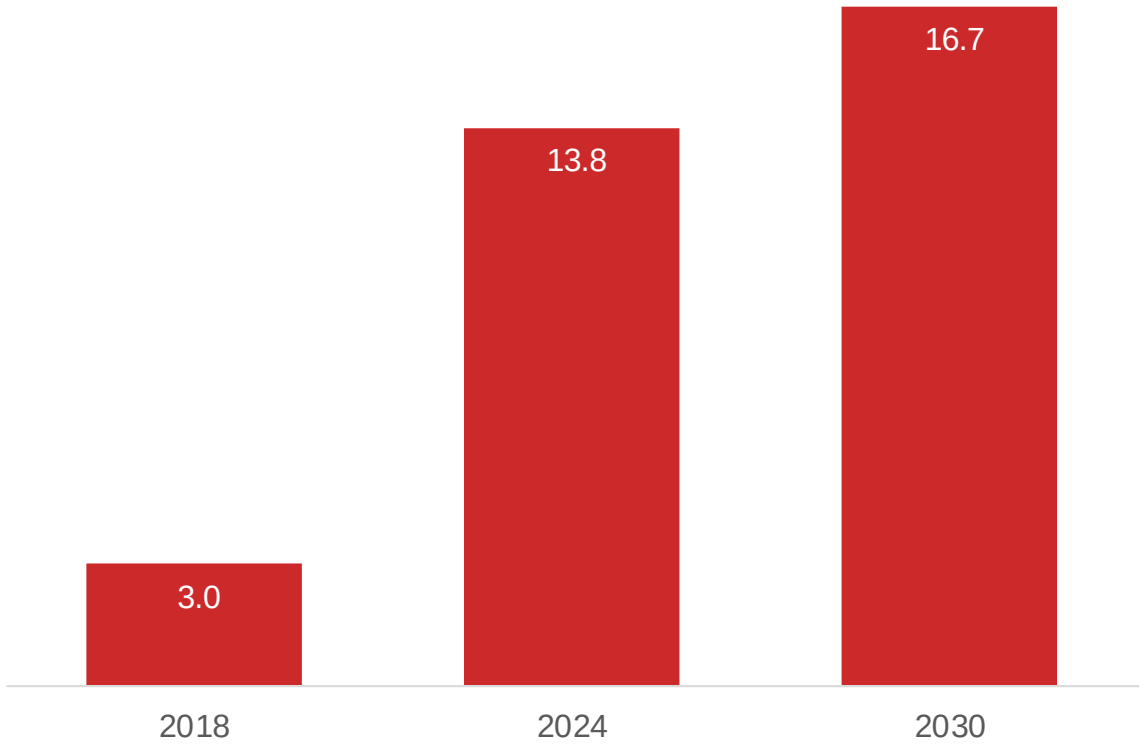
a) 2019 budgeted Segment EBDA before Certain Items plus JV DD&A. See Non-GAAP Financial Measures and Reconciliations.
b) Includes KM share of non-wholly owned projects. Includes projects currently under construction.

Growth Driver: Buildout of U.S. LNG Exports

Multiple liquefaction and natural gas transport opportunities across KM footprint

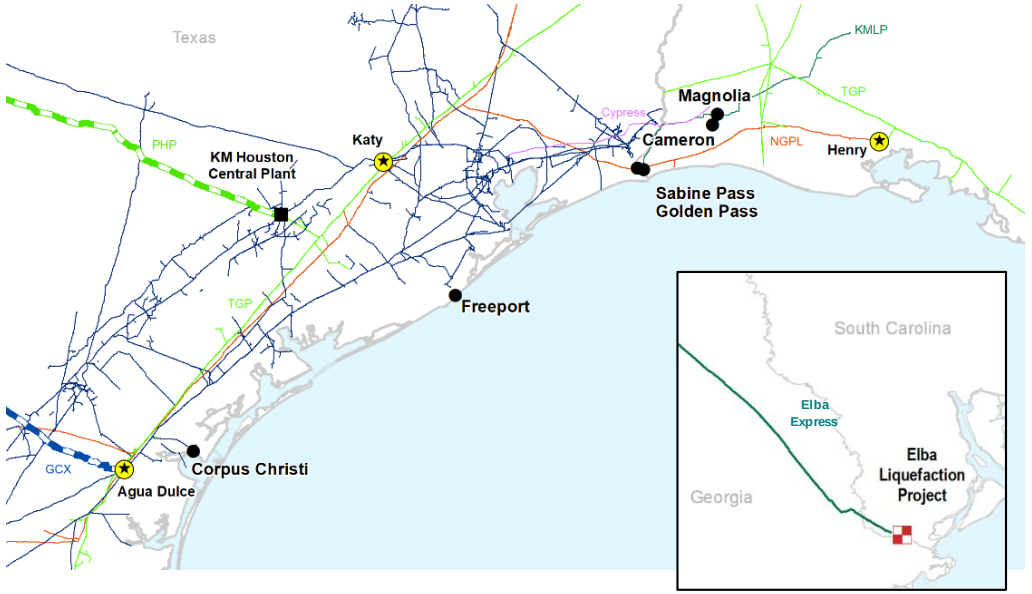
GLOBAL DEMAND DRIVING SIGNIFICANT BUILDOUT OF U.S. LNG EXPORT CAPABILITIES

Forecasted U.S. Liquefaction Capacity (Bcfd)



KM is already contracted to serve ~5.3 Bcfd (18-year average term) of U.S. liquefaction capacity and is positioned to capture more

KM NETWORK REACHES MULTIPLE EXPORT FACILITIES



KM Asset	Contracted Capacity (mDthd)	KM Capital ($mm)
TGP	1,200	$304
KMLP	1,400	$226
NGPL	1,635	$241
Intrastate	590	$134
EEC	436	$100
Subtotal:	**5,261**	**$1,006**
ELC	350 mmcfd	$1,185
Total		**$2,191**

Source: WoodMackenzie, North America Gas Markets Long-Term Outlook, Fall 2018.

Growth Driver: Surging Permian Production

KM providing additional takeaway capacity for associated natural gas production

Existing footprint reaches across Texas and connects into all major demand markets

- Interconnected deliverability to Houston markets (power, petchem), substantial LNG export capacity and Mexico

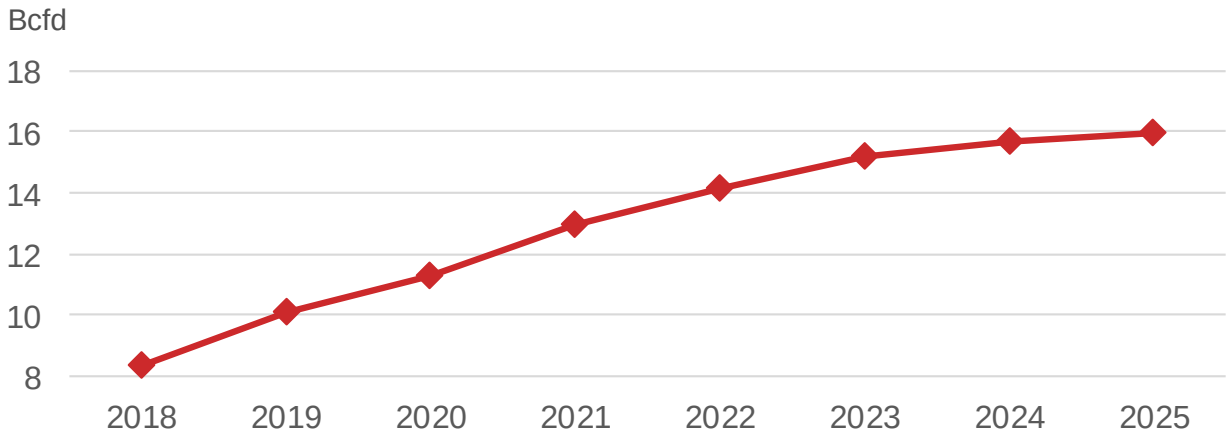
Potential to leverage existing assets into long-haul Permian crude oil pipeline projects

- KM Crude and Condensate (KMCC) pipeline to facilitate deliverability into the Houston refining and export markets

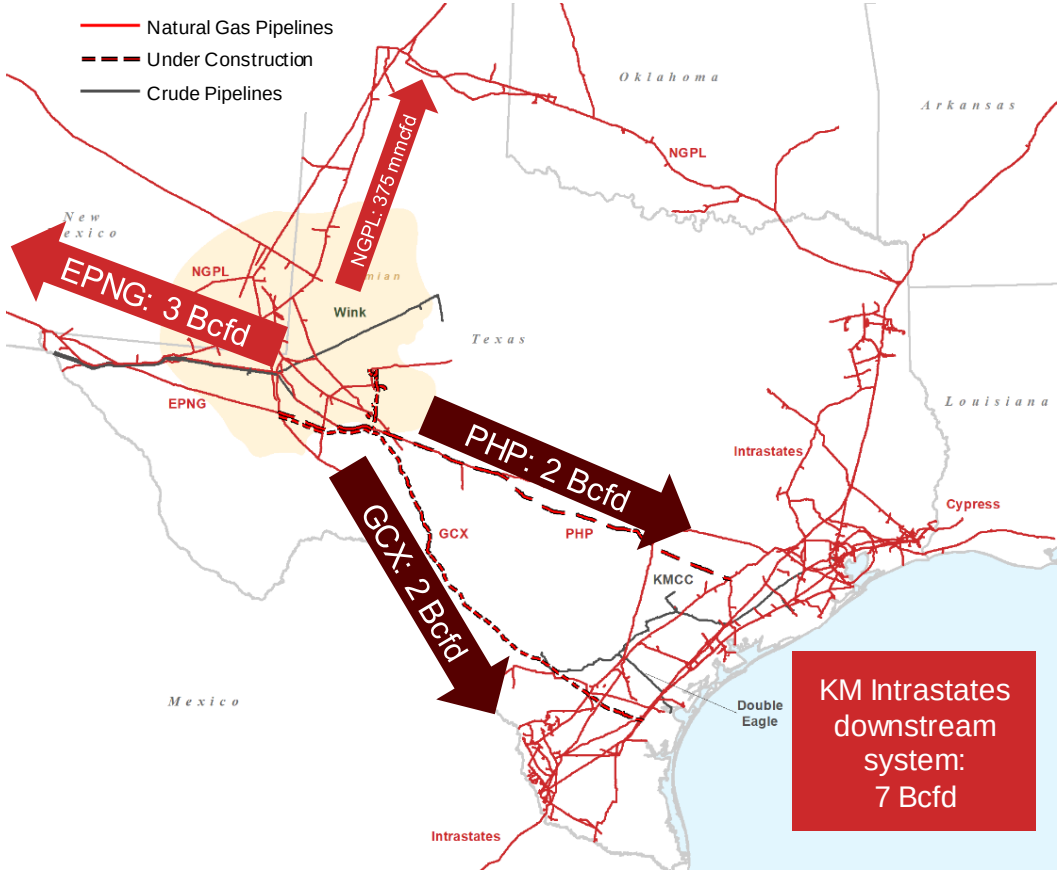
Growing Permian production will require an additional long-haul, large capacity natural gas pipeline beginning in 2021

- Gulf Coast Express (GCX) in-service Oct. 2019 and Permian Highway (PHP) in-service Oct. 2020

PERMIAN NATURAL GAS PRODUCTION FORECAST[a]



KM POSITIONED TO SERVE PERMIAN PRODUCTION



Delivering substantial Permian takeaway capacity to Midcontinent, West, and Gulf Coast markets

a) Source: WoodMackenzie, North America Gas Markets Long-Term Outlook, Fall 2018.

Project Highlight: Gulf Coast Express (GCX)

Permian direct-to-Gulf Coast project satisfying multiple growth drivers

KINDER MORGAN

Project Scope

- Mainline: 447.5 miles of 42” pipeline originating at the Waha Hub and terminating near Agua Dulce, Texas
- Midland lateral: 50 miles of 36” pipeline
- 214,280 HP of installed compression
- KM Texas Pipeline (KMTP) operator and constructor
- KM 35%, DCP 25%,Targa 25%, Altus (Apache) 15% ownership interest

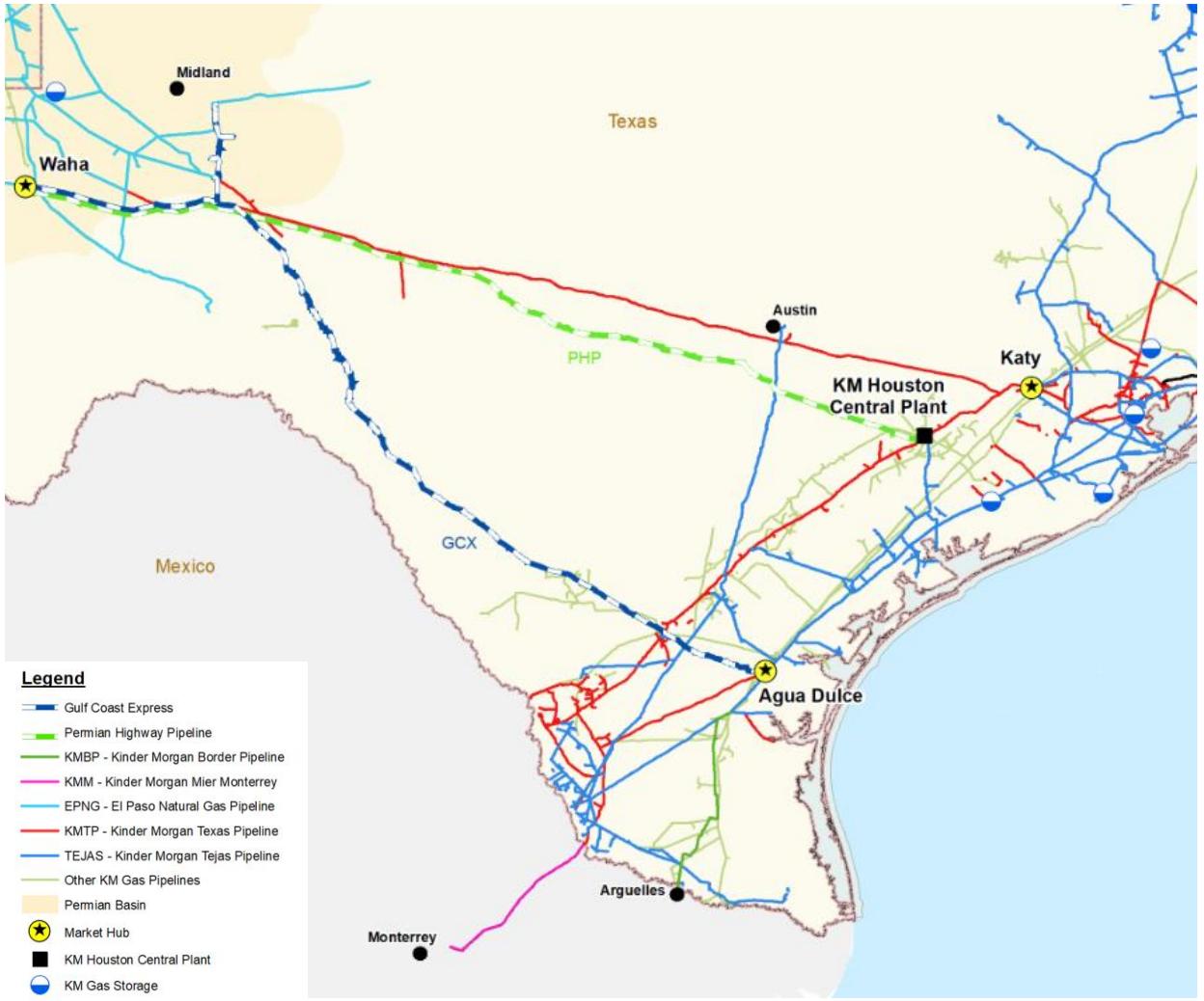
Project Statistics

- Capacity: 2.0 Bcfd
- Capital (100%): $1.75 billion
- In-Service: October 2019
- Minimum contract term: 10 years

Current Status

- Capacity fully-subscribed under long-term, binding agreements
- Construction in progress and on schedule for October 1, 2019 in-service

First-to-market Permian takeaway solution leveraging our expansive existing footprint and deliverability



Project Highlight: Permian Highway Pipeline (PHP)

PHP provides broad U.S. Gulf Coast market optionality for Permian production

Project Scope

- Mainline: ~430 miles of 42" pipeline from the Waha to Katy, Texas areas with connections to the U.S. Gulf Coast and Mexico markets
- 300,320 HP of installed compression, increased 42,870 HP from original scope at FID due to expansion
- KM Texas Pipeline (KMTP) operator and constructor
- KM 40%, EagleClaw Midstream Ventures 40%, anchor shipper affiliate 20% ownership interest[a]

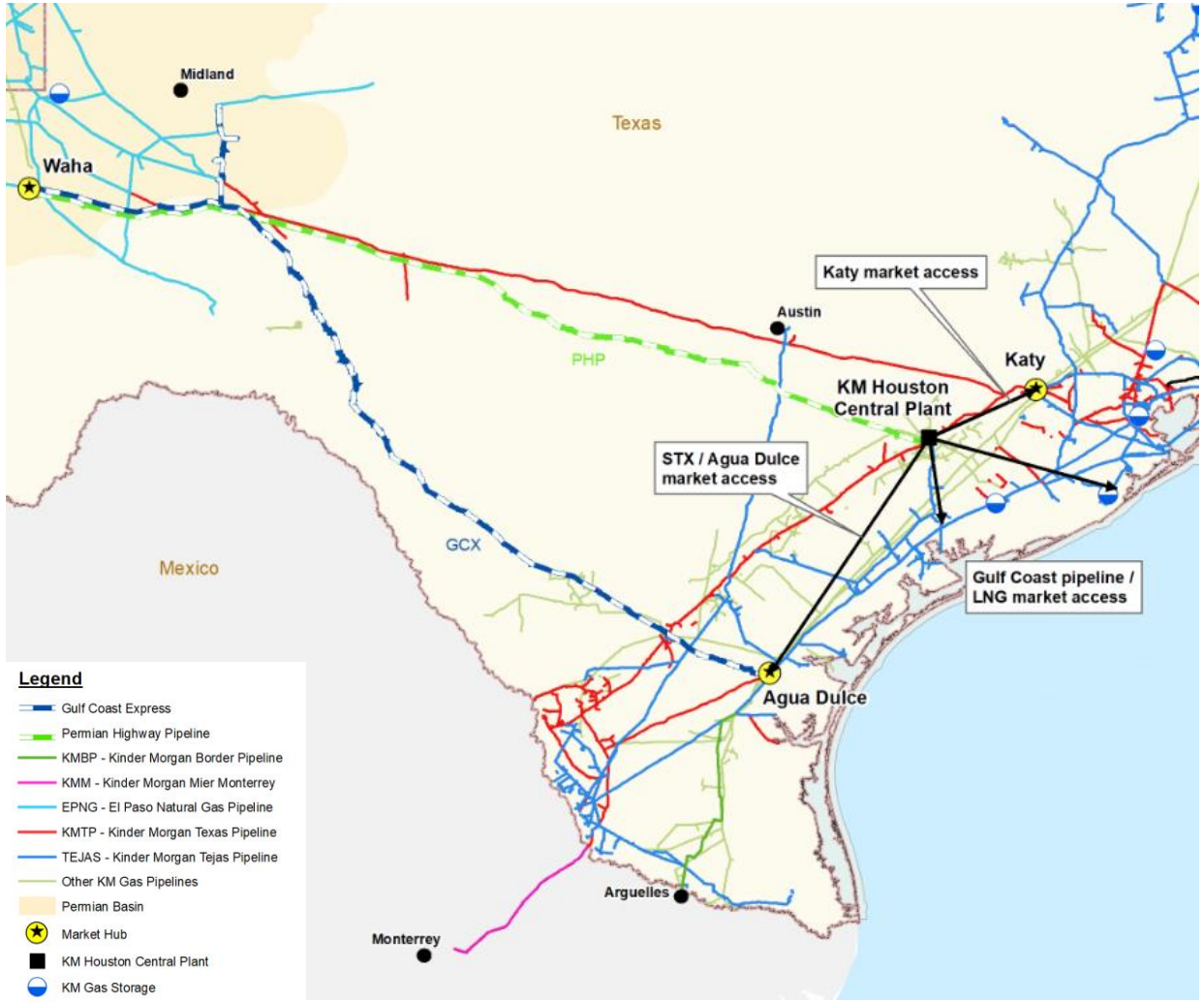
Project Statistics

- Initial Capacity: 2.0 Bcfd
- Expansion Capacity: 0.1 Bcfd
- Capital (100%): ~$2.1 billion
- In-Service: October 2020
- Minimum contract term: 10 years

Current Status

- Final investment decision to proceed made September 2018
- Initial capacity fully-subscribed and under long-term, binding agreements
- Pipeline and compression procured
- Awarded pipeline construction contracts on all spreads
- In commercial discussions with shippers for expansion capacity

Second Permian solution with unmatched market optionality expected to drive investment opportunities downstream



a) KM and EagleClaw's ultimate ownership interest may vary between ~27% and 40%, depending on outcome of equity ownership options held by an additional anchor shipper affiliate.

Key Market: Exports to Mexico

Kinder Morgan delivers ~3.1 Bcfd of U.S. natural gas exports to Mexico[a]

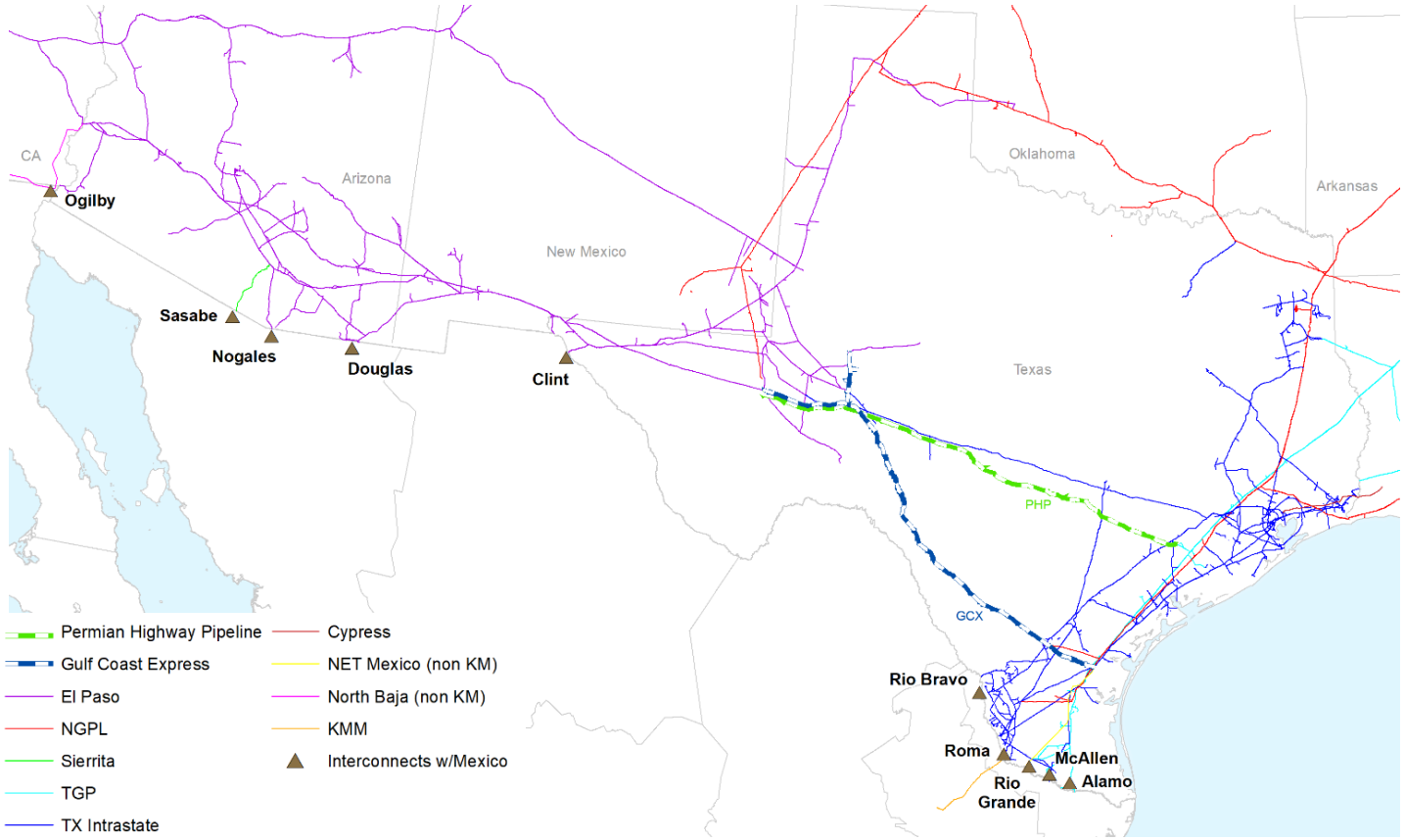
Extensive footprint offers diverse supply solutions to multiple Mexico interconnections (12 direct, 4 indirect)

- U.S. natural gas exports to Mexico are expected to grow by 36%, or ~1.6 Bcfd, to 6.1 Bcfd by 2023[b]
- Incremental opportunities include expansions of existing assets (including Monterrey and TGP), greenfield infrastructure (including GCX and PHP), new hub development, and storage near the border

~3.4 Bcfd of long term transportation contracts serving Mexico with a weighted average remaining contract term of 12.5 years

Placed ~1 Bcfd of capacity into service for ~$0.4bn since 2014

~0.6 Bcfd of capacity in the backlog for ~$0.2bn to further serve growing Mexico demand



Our network is well-positioned to serve growing Mexican demand

Note: KM Projects / Long-Term Commitments to Mexico detail available in Natural Gas Pipelines Segment Presentation.
a) 2018 calendar year average.
b) Source: WoodMackenzie, North America Gas Markets Long-Term Outlook, Fall 2018.

Products Segment Overview

Strategic footprint with significant cash flow generation

Asset Summary

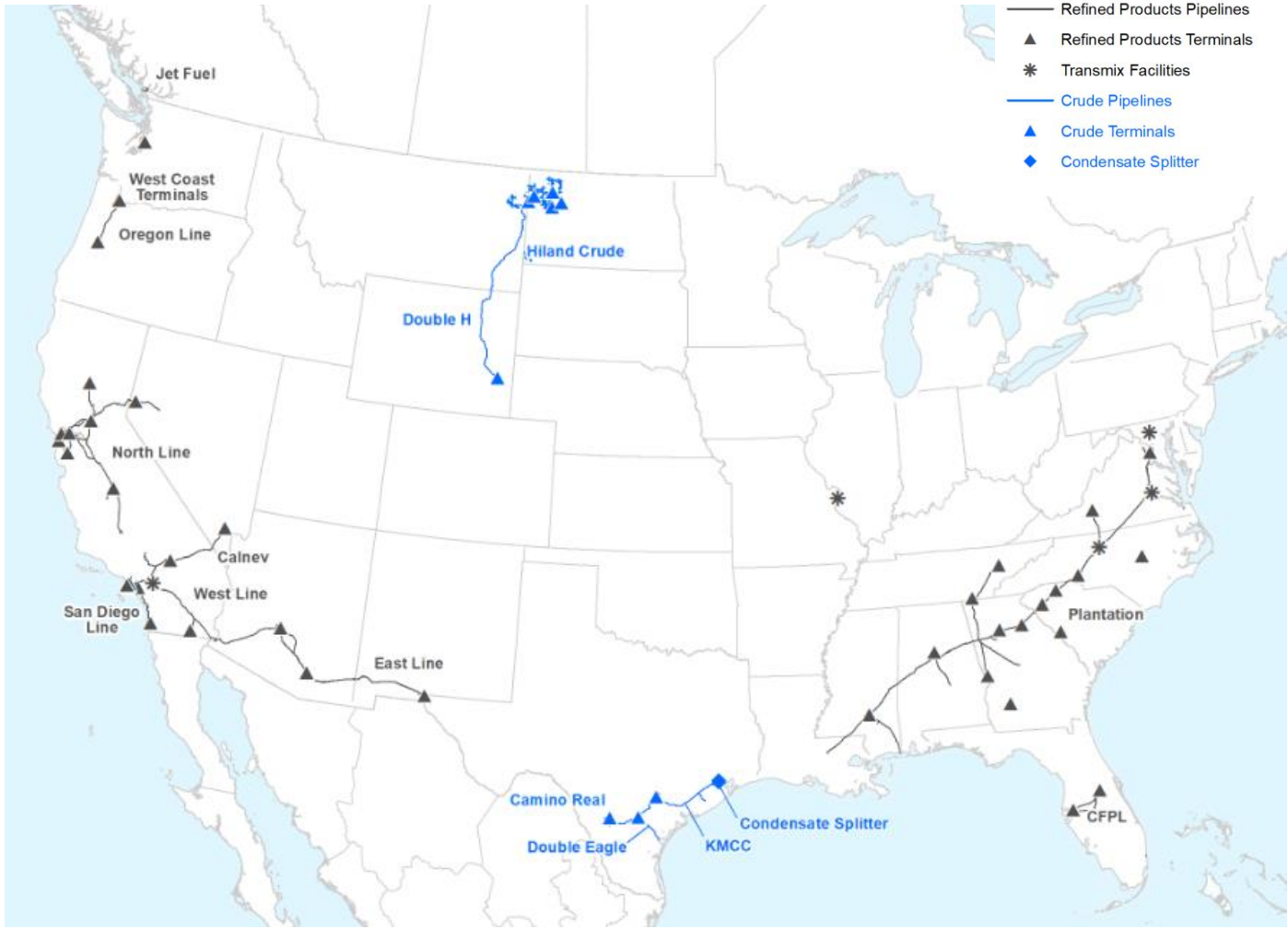
Pipelines[(a)]:	~9,500	Miles
2018 Throughput[(a)]	~2.3	mmbbld
Condensate Processing Capacity	100	mbbld
Transmix	5	facilities
Terminals:	67	Terminals
Terminals Tank Capacity	~39	mmbbls
Pipeline Tank Capacity	~15	mmbbls

2019B EBDA[(b)]: ~$1.3 billion

Project Backlog:

$0.1 billion of identified growth projects over the 2019-2020 time period[(c)]

- Plantation Roanoke expansion
- Enhanced capabilities for condensate splitter
- Multiple refined products terminaling projects
- Various Bakken crude gathering projects



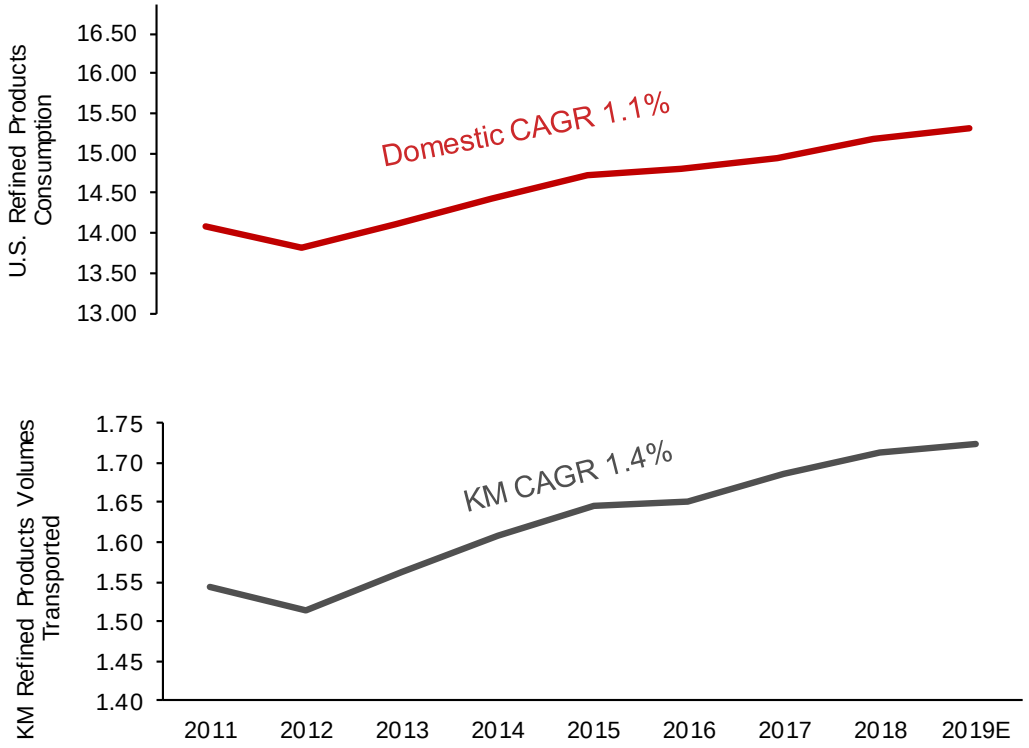
a) Volumes and mileage include SFPP, CALNEV, Central Florida, Plantation Pipe Line (KM share), KMCC, Camino Real, Double Eagle (KM share), Double H and Hiland Crude Gathering.
b) 2019 budgeted Segment EBDA before Certain Items plus KM share of JV DD&A. See Non-GAAP Financial Measures and Reconciliations.
c) Includes KM share of non-wholly owned projects. Includes projects currently under construction.

Stable U.S. Market Demand for Refined Products

Expansive footprint positioned to capture market opportunities

U.S. REFINED PRODUCTS CONSUMPTION[a] & KM REFINED PRODUCTS VOLUMES TRANSPORTED[b]

mmbbld



- Our expansive refined products footprint connects major refining centers to major consuming markets
  - Unmatched connectivity
  - Potential for market share gains in key growth areas
- Refined products fundamentals are positive
  - Steady U.S. demand for total refined products
  - FERC indexing provides predictable margin growth with 4.40% increase projected for 2019[c]

Our refined products volumes are consistent and slightly exceed domestic consumption growth

a) Source: EIA, Table 4a. U.S. Crude Oil and Liquid Fuel Supply, Consumption, and Inventories and Figure 15 U.S. Liquids Fuel Consumption Growth, December 2018.
b) Volumes include SFPP, CALNEV, Central Florida, and Plantation Pipe Line (KM share).
c) Internal projection of expected rate increase based on regulatory framework (PPI FG+1.23%).

Terminals Segment Overview

Diversified terminaling network connected to key refining centers and market hubs

Asset Summary

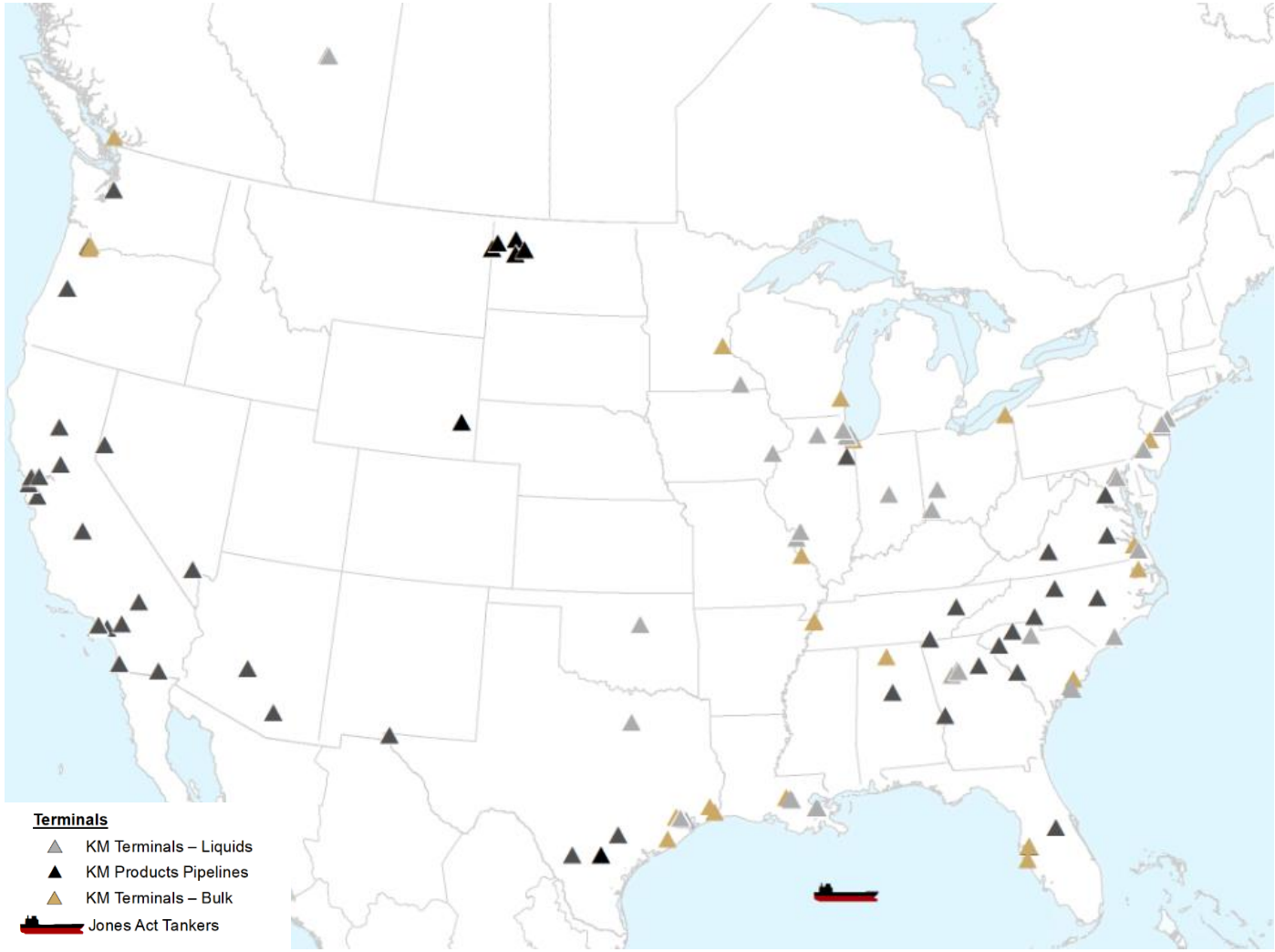
Total Kinder Morgan Terminals:	157	Terminals
Terminals Segment – Bulk	34	Terminals
Terminals Segment – Liquids	56	Terminals
Products Pipelines Segment Terminals	67	Terminals
Jones Act:	16	Tankers

2019B EBDA[(a)]: ~$1.2 billion

Project Backlog:

$0.1 billion to be completed in 2019-2021[(b)]

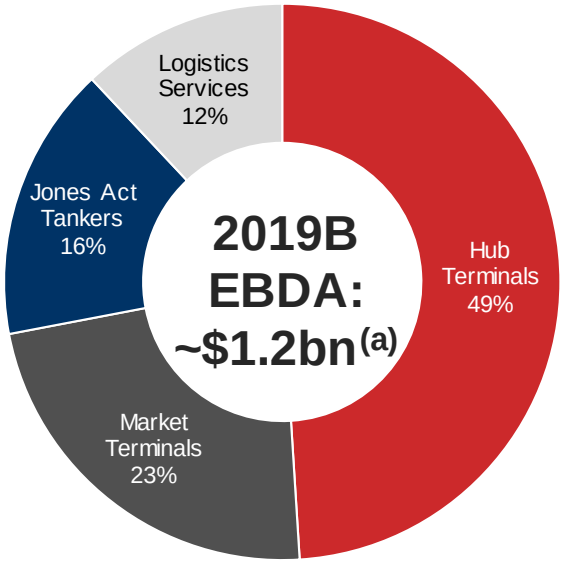
- Diesel tank expansion at Vancouver Wharves
- Investments to expand services at existing terminal facilities in Houston Ship Channel and other locations



a) 2019 budgeted Segment EBDA before Certain Items plus KM share of JV DD&A. See Non-GAAP Financial Measures and Reconciliations.
b) Includes KM share of non-wholly owned projects. Includes projects currently under construction.

Terminals Segment Strategy

Critical infrastructure and value-added service solutions



"Much more than storage"

Hub Terminals 49%

- Market clearing point between global buyers and sellers
- Multi-modal connectivity and value-added services
- Critical to our customers and their business
- KM liquids hubs: Houston, Edmonton and New York Harbor

Market Terminals 23%

- Geographic: market-specific regional product demand
- Commodity: product-specific supply chain solutions
- Trade: multi-commodity import / export infrastructure
- KM businesses: truck racks, renewables and bulk export terminals

Jones Act Tankers 16%

- 16 modern and efficient tankers
- Multi-commodity and multi-market
- Only solution for growing U.S. maritime trade
- KM's APT subsidiary: largest Jones Act tanker fleet

Logistics Services 12%

- Customer in-plant logistics solutions
- Leverage competencies in bulk and liquids
- Tankage, transloading and other services
- Nucor, Methanex and petroleum coke services

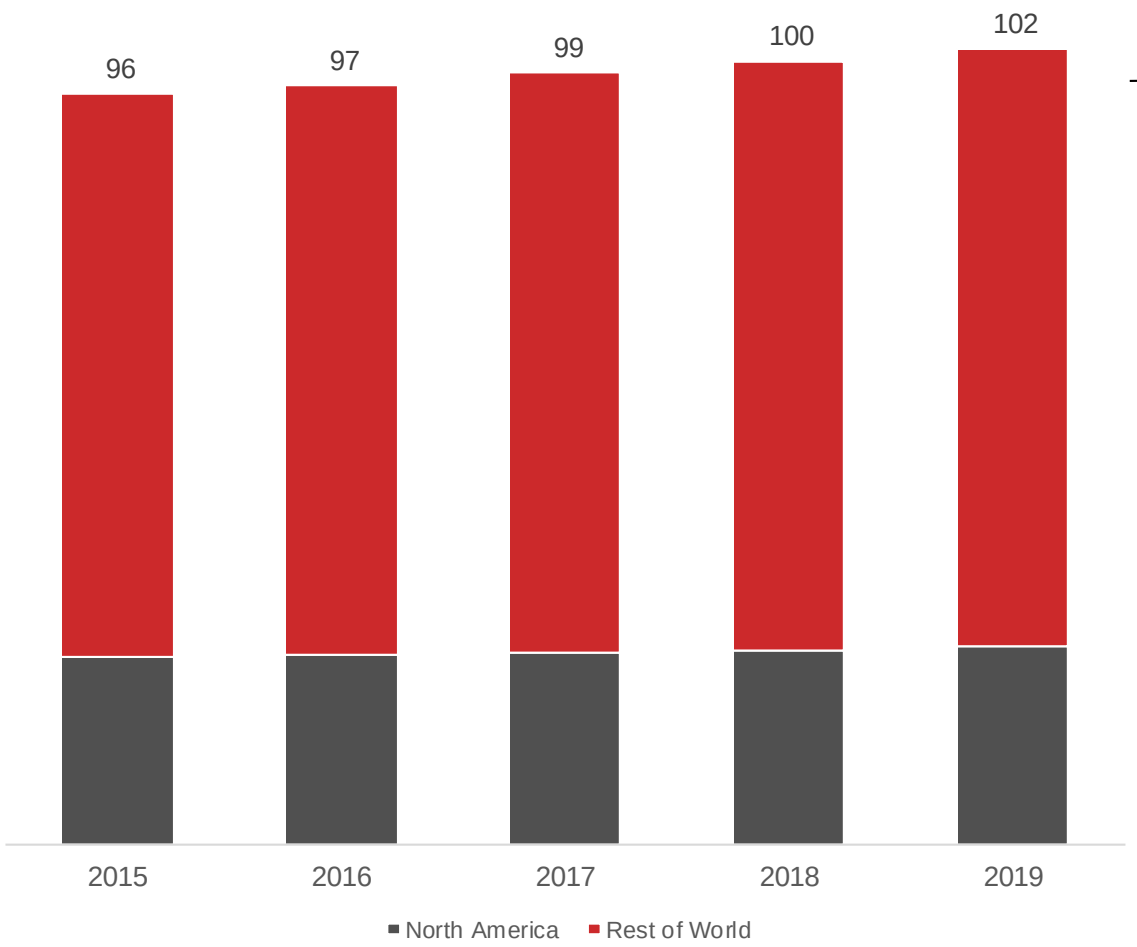
a) 2019B segment EBDA before Certain Items. See Non-GAAP Financial Measures and Reconciliations.

Strong Liquids Fundamentals

Attractive opportunities to supply U.S. products to consumers here and abroad

GLOBAL LIQUIDS CONSUMPTION EXPECTED TO EXCEED 100 MILLION BARRELS PER DAY BY 2019

World Petroleum and Other Liquids Consumption (mmbbld)



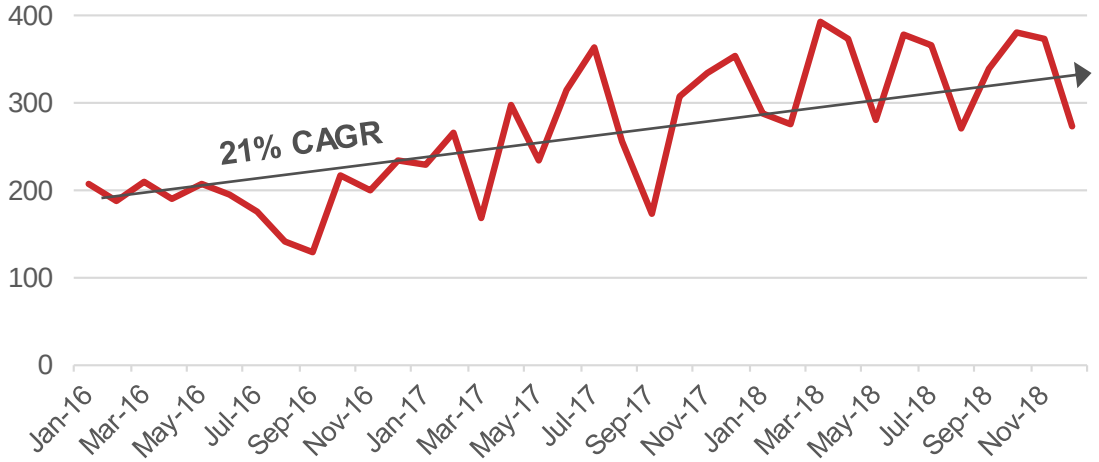
GROWTH LED BY CHINA AND INDIA (2017 – 2019)

+2.2 mmbbld — Rest of World

+0.8 mmbbld — North America

EXPORT CAPACITY REQUIRED TO DELIVER U.S. SUPPLIES TO GROWING DEMAND MARKETS

KM Liquids Exports from Gulf Coast (mbbld)



Source: U.S. Energy Information Administration, Short Term Energy Outlook (December 2018), KM internal data (CAGR calculated on a rolling 3 months basis beginning Q1 2016).

Positioned to Support U.S. Gulf Coast Exports

Houston's premier refined products aggregation and market-clearing terminaling hub

Our Houston Ship Channel position represents the largest independent refined products terminaling system in U.S.

- 43 million barrels of total capacity
- KM handles ~15% of total U.S. exports of gasoline, gasoline blend stocks and distillates[(a)]
- Unmatched pipeline connectivity
- Built for inbound / outbound flexibility
- Pipeline, rail, barge, ship and truck capabilities
- Highly-contracted, highly-utilized

Clearing point for domestic and international markets

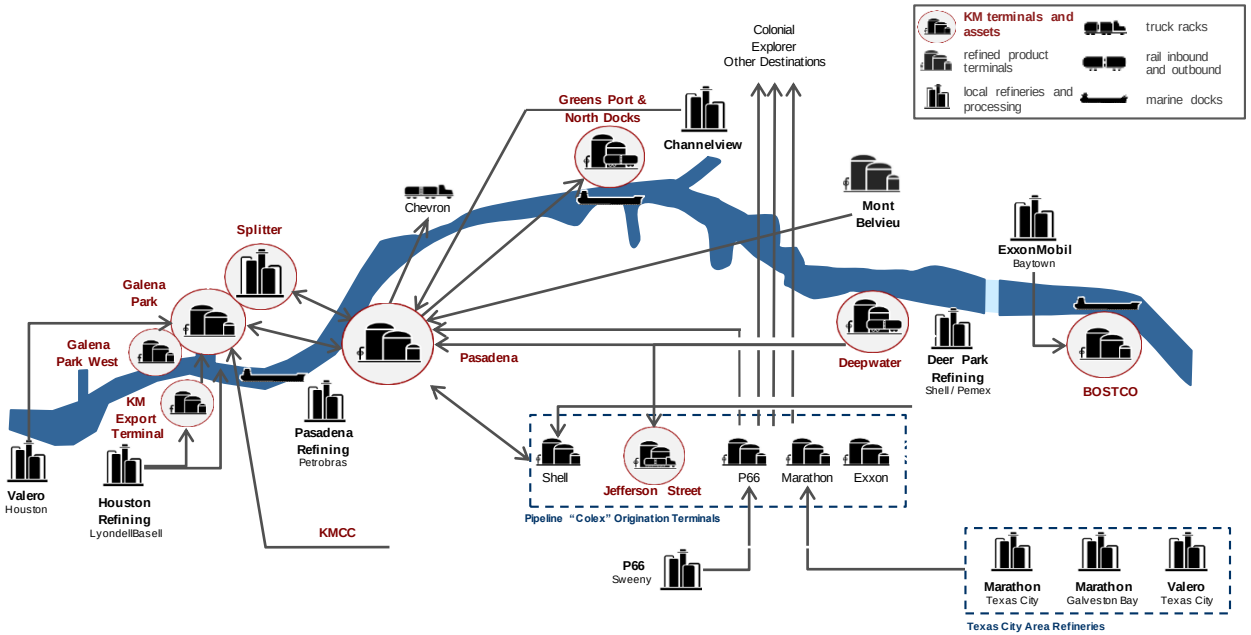
- Pipeline connectivity to domestic markets in East Coast and Midcontinent
- Marine connectivity to global markets
- Scale allows for centralized operations to maximize customer optionality

Built to serve the world's most competitive refining and petrochemical industry across multiple products

- Refined product core focus with complementary chemicals and renewables capabilities
- Difficult to replicate

Nearly $2 billion invested in our Houston hub since 2010

Integrated Houston Ship Channel Terminal Footprint



#	Asset	Connectivity
20	Inbound Pipelines	10 Houston area refineries and local chemical plants
15	Outbound Pipelines	Texas, Midcontinent, and East Coast markets
14	Cross-Channel Pipelines	Interconnecting the system
12	Barge Docks	Receipt and delivery of products and blendstocks
11	Ship Docks	Serving export and Jones Act markets
9	Bay Truck Rack	Averaging ~90 mbbld of local Houston market deliveries
3	Unit Train Facilities	Crude oil, condensate, and ethanol

a) KM market share calculated using internal data for KM export volumes and U.S. Energy Information Administration data for U.S. export volumes for the 12 months ended October 2018 (latest EIA data available).

CO_2 Segment Overview

World class, fully integrated assets — CO_2 source to crude oil production and takeaway in the Permian Basin

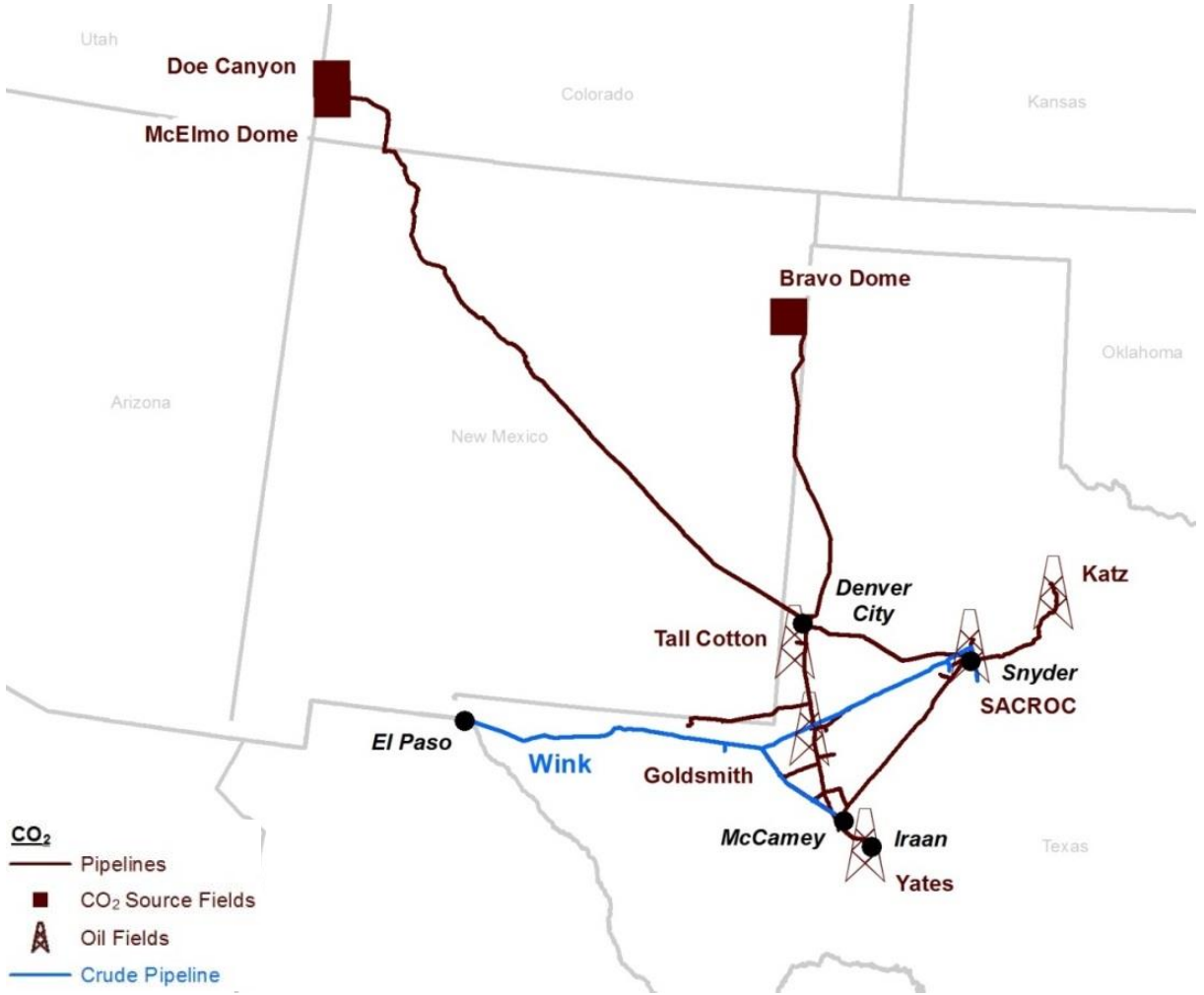
CO_2 & TRANSPORT

CO_2 Reserves	KMI Interest	NRI	Location	Remaining Deliverability	OGIP (tcf)
McElmo Dome	45%	37%	SW Colorado	20+ years	22.0
Doe Canyon	87%	68%	SW Colorado	10+ years	3.0
Bravo Dome[a]	11%	8%	NE New Mexico	10+ years	12.0

Pipelines	KMI Interest	Location	Capacity (mmcfpd)
Cortez	53%	McElmo Dome to Denver City	1,500
Bravo[a]	13%	Bravo Dome to Denver City	375
Central Basin (CB)	100%	Denver City to McCamey	700
Canyon Reef	97%	McCamey to Snyder	290
Centerline	100%	Denver City to Snyder	300
Pecos	95%	McCamey to Iraan	125
Eastern Shelf	100%	Snyder to Katz	110
Wink (crude)	100%	McCamey to Snyder to El Paso	145 mbbld

OIL & GAS

Crude Reserves[b]	KMI Interest	NRI	Location	OOIP (billion bbls)
SACROC	97%	83%	Permian Basin	2.8
Yates	50%	44%	Permian Basin	5.0
Katz	99%	83%	Permian Basin	0.2
Goldsmith	99%	87%	Permian Basin	0.5
Tall Cotton	100%	88%	Permian Basin	0.7



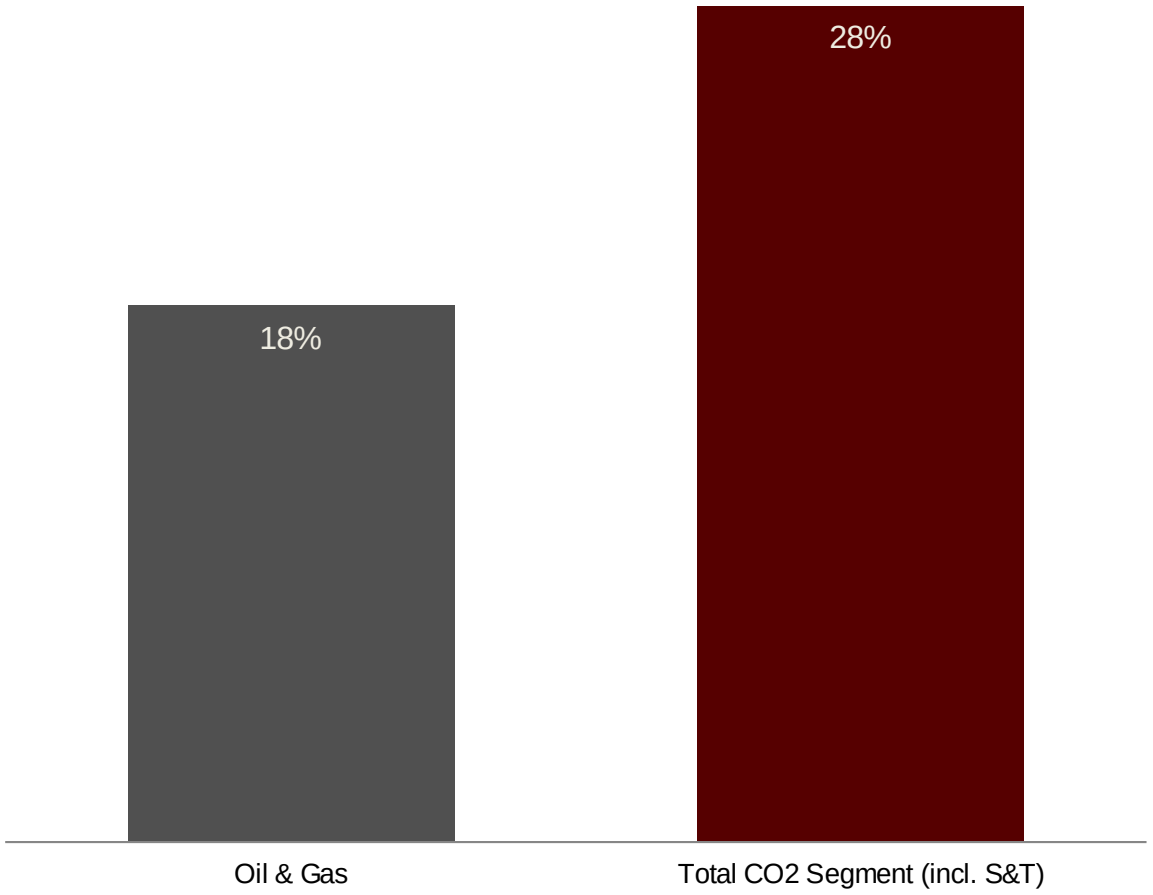
2019B EBDA[c]: ~$853 million

a) Not KM-operated.
b) In addition to KM's interests above, KM has a 22%, 51%, and 100% working interest in the Snyder gas plant, Diamond M gas plant and North Snyder gas plant, respectively.
c) 2019 budgeted Segment EBDA before Certain Items plus JV DD&A. See Non-GAAP Financial Measures and Reconciliations.

CO_2 Segment Significant Returns and Free Cash Flow

Long history of generating high returns and ~$6 billion in cumulative free cash flow

IRR% 2000-2018



CUMULATIVE FREE CASH FLOW GENERATION

$ billions



Note: Free Cash Flow calculated as segment EBDA before Certain Items less sustaining and discretionary capital expenditures. See Non-GAAP Financial Measures and Reconciliations.

Big Fields Get Bigger

Successful track record of extending productive life of mature fields

Significant amounts of recoverable oil in place

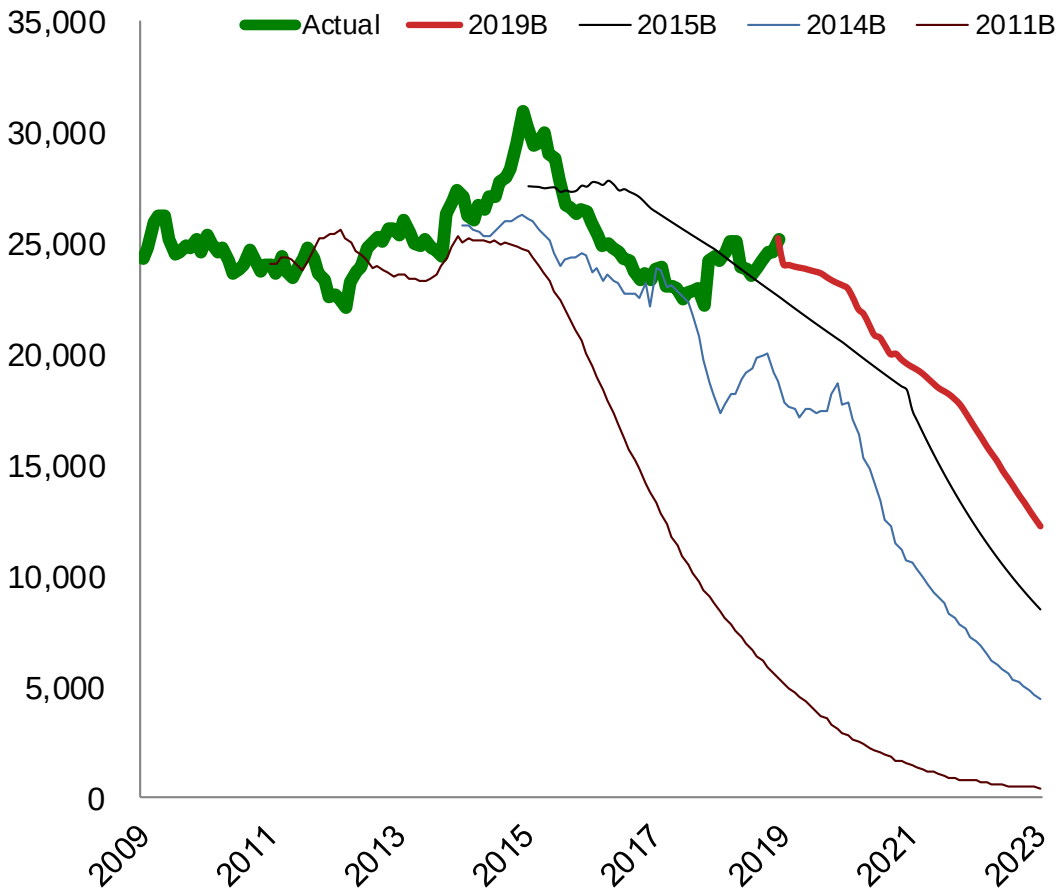
- SACROC – 2.8 billion barrels of original oil in place
  - Evaluating Transition Zone
  - Estimated incremental 700 mmbbls OOIP target
  - Delineation efforts ongoing
  - Executing two projects in 2019, East Flank and West Shore
- Yates – 5.0 billion barrels of original oil in place

Technical expertise will drive future success

- Long track record of expanding the field through advanced technology and new exploitation techniques
  - Advanced seismic reprocessing used to identify:
    - Future development projects
    - Zonal horizontal producers
    - Transition zone
  - Horizontal drilling technology
  - Conformance technologies and techniques:
    - Polymers
    - Mechanical

SACROC NET OIL PRODUCTION FORECASTS

bopd



Financial Excellence

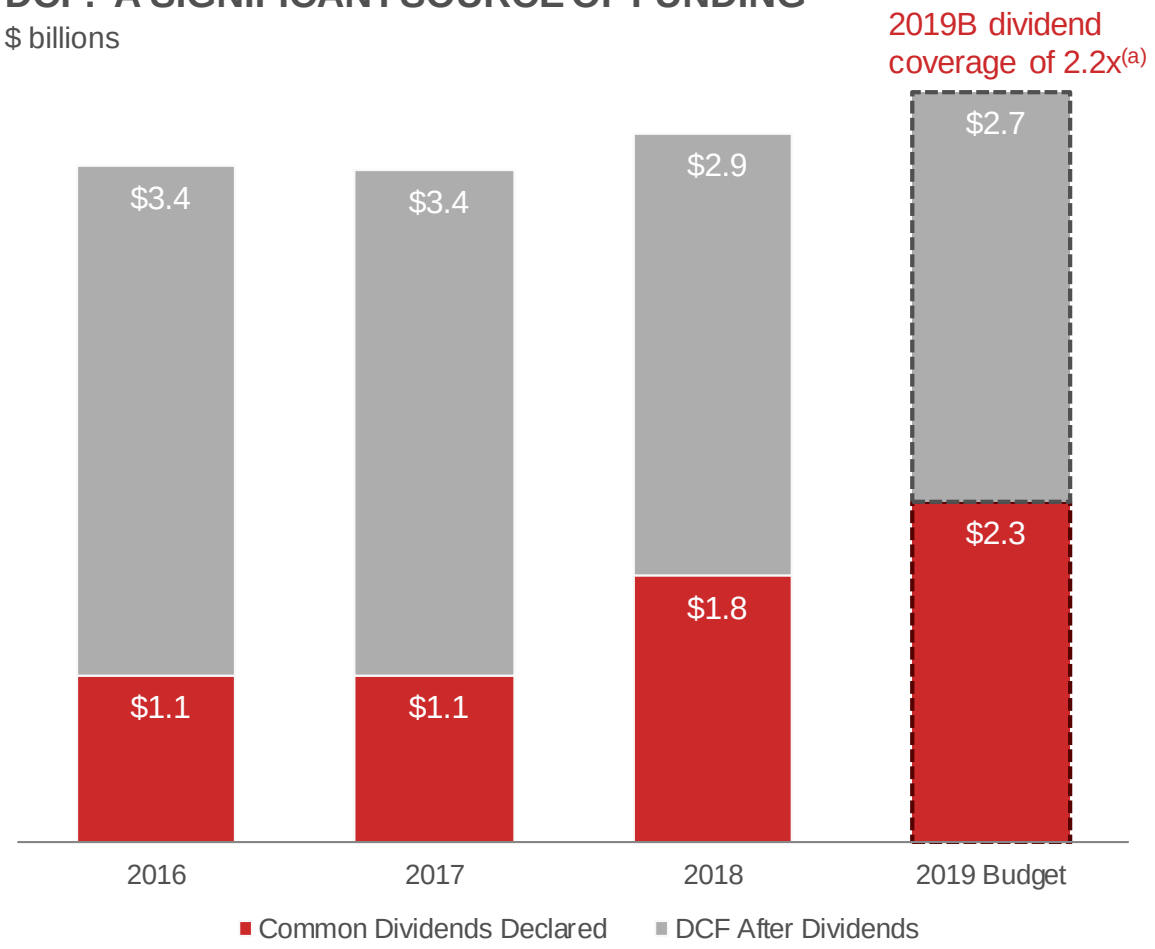
Kimberly Dang

President

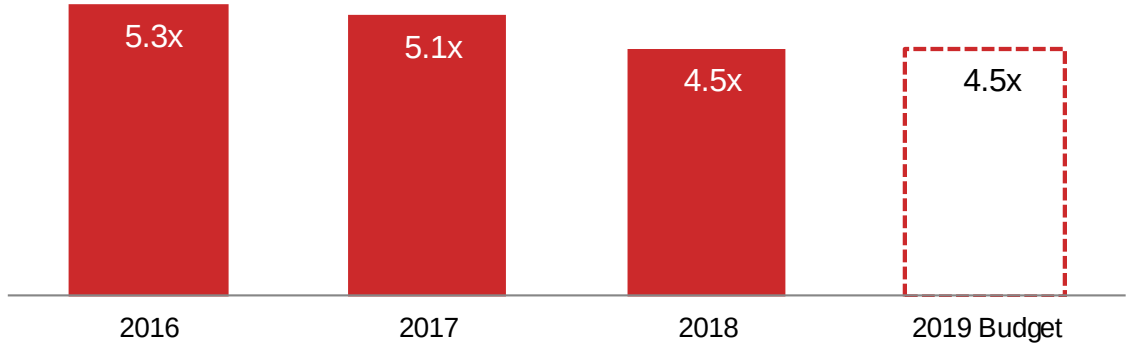
Financial Flexibility from Significant Cash Flow

DCF: A SIGNIFICANT SOURCE OF FUNDING

$ billions



YEAR-END ADJUSTED NET DEBT / ADJUSTED EBITDA



EQUITY ISSUANCE

$ millions



Generated ~$10 billion of DCF after dividends in last 3 years

Note: See Non-GAAP Financial Measures and Reconciliations.
a) 2019B DCF divided by 2019B common dividends declared.

Stable, Multi-Year Fee-Based Cash Flow

~96% of 2019B segment cash flow is from take-or-pay and other fee-based contracts or hedged[a]



66% Fee-Based Take-or-Pay: highly dependable cash flow under multi-year contracts

- Entitled to payment regardless of throughput for periods of up to 20+ years

25% Other Fee-Based: dependable cash flow, volumes largely independent from commodity price

- Supported by stable volumes, critical infrastructure between major supply hubs and stable end-user demand
- **Products Pipelines (10%):** competitively advantaged connection between refineries and end markets has resulted in stable or growing refined products piped volumes (2011-2019E CAGR of 1.4%)[b]
- **Natural Gas Pipelines (10%):** gathering and processing cash flow underpinned by dedications of economically viable acreage
- **Terminals / other (5%):** 86% of fee-based cash flow associated with high-utilization liquids assets and requirements contracts for petcoke and steel

5% Hedged: disciplined approach to managing price volatility

- CO_2 actual oil volumes produced have been within 1.4% of budget over the past 11 years
- Substantially hedged near-term exposure
- CO_2 oil production hedge schedule[c]:

Year	Hedged Vol.	% Hedged	Avg. Px.
2019	31,813	67%	$56
2020	17,000	49%	$56
2021	9,400	42%	$55
2022	3,500	31%	$57

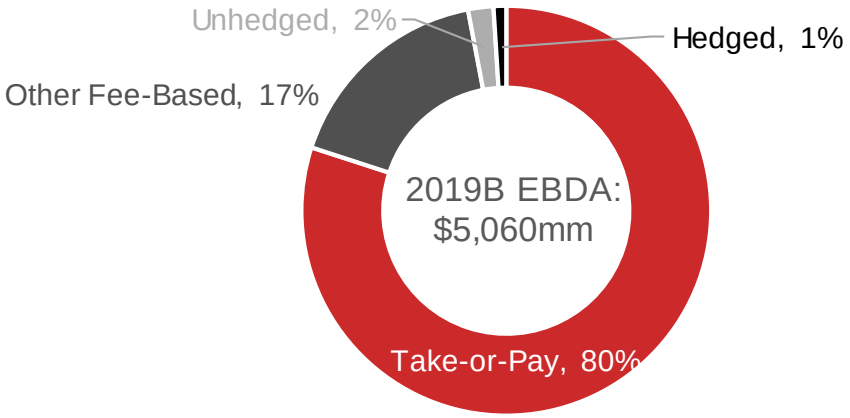
4% Commodity Based

a) Based on 2019 budgeted Segment EBDA before Certain Items plus JV DD&A. See Non-GAAP Financial Measures and Reconciliations.
b) Kinder Morgan refined products volumes transported. Volumes include SFPP, CALNEV, Central Florida, Plantation Pipe Line (KM share).
c) Percentages based on currently hedged crude oil and propane volumes as of 12/31/2018 relative to crude oil, propane and heavy NGL (C4+) net equity production projected for FY 2019, and the Ryder Scott reserve report for 2020-2022 (historically below management expectations).

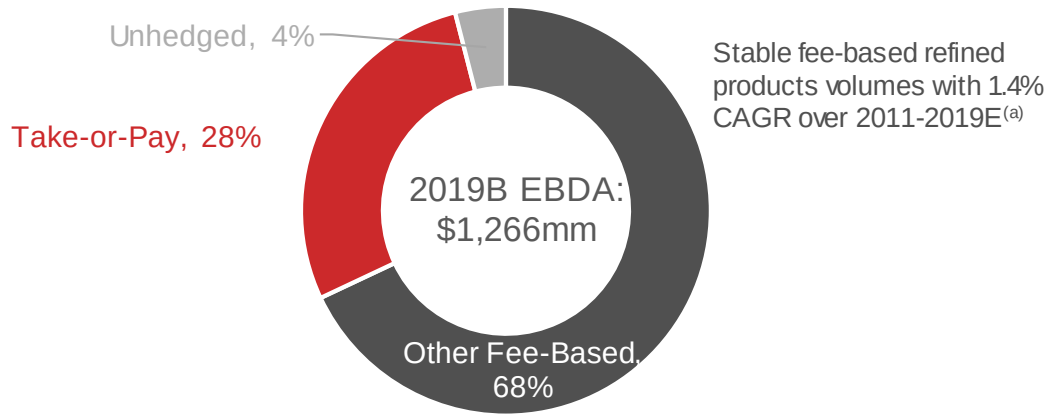
Secure Cash Flows Across Our Segments

2019 budgeted segment cash flows by contract type

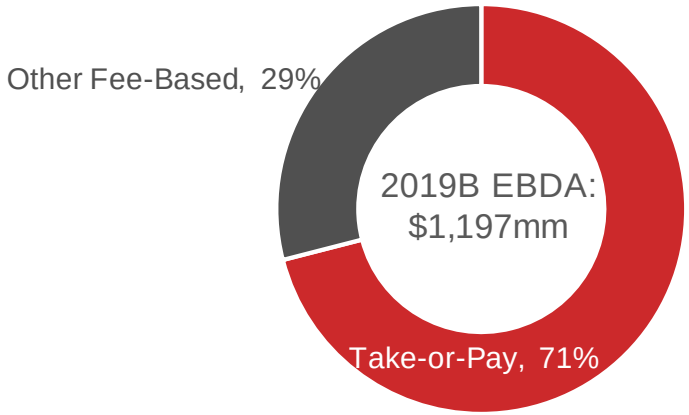
NATURAL GAS SEGMENT: 97% take-or-pay or fee-based



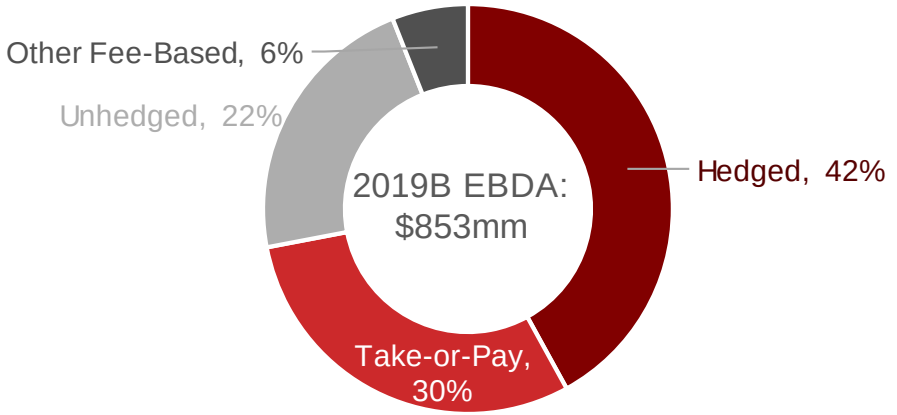
PRODUCTS SEGMENT: 96% fee-based or take-or-pay



TERMINALS SEGMENT: 100% take-or-pay or fee-based



CO_2 SEGMENT: 78% hedged, take-or-pay, or fee-based



Note: Based on 2019 budgeted Segment EBDA before Certain Items plus JV DD&A. See Non-GAAP Financial Measures and Reconciliations.
a) Volumes include SFPP, CALNEV, Central Florida, Plantation Pipe Line (KM share).

High-Quality, Diversified Customer Base

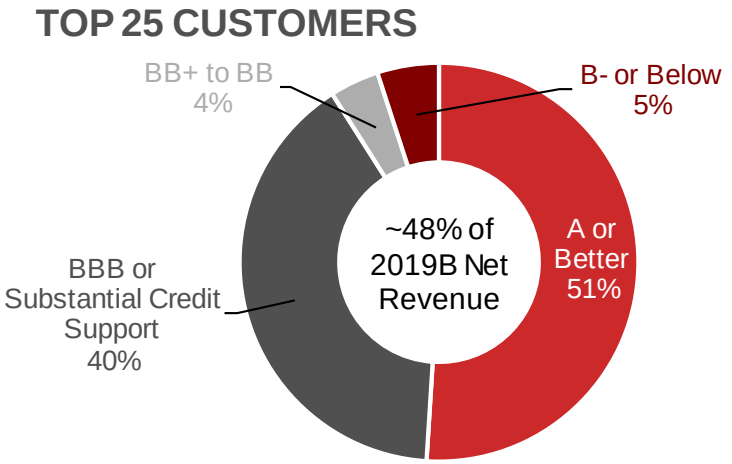
Strong customer credit, valuable services limit KMI's risk

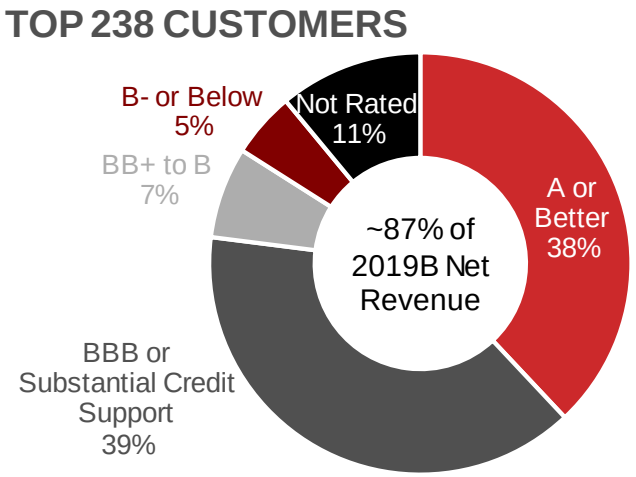
Diverse, primarily investment grade customers limit counterparty risk

- Our average customer represents less than 0.1% of 2019 budgeted net revenue
- Top 25 customers generate ~48% of KMI's 2019 budgeted net revenue
- 238 customers individually contribute at least $5mm in budgeted net revenue
  - Collectively represent ~87% of KMI's 2019 budgeted net revenue
  - ~5% from customers with B- or lower rating

~69% of 2019 budgeted net revenue generated by end-users

- Includes utilities, LDCs, refineries, chemical companies, large integrated companies, etc.





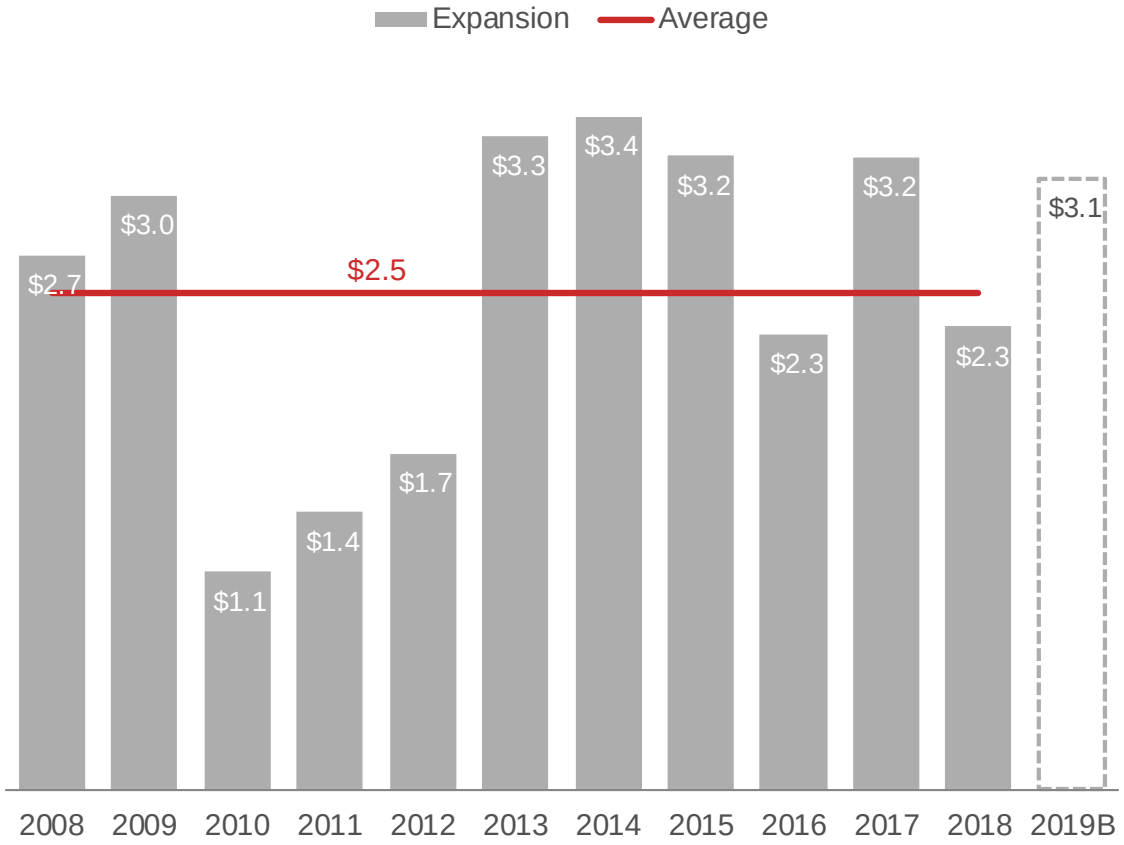
Note: Company credit ratings as of 1/9/2019 per S&P and Moody's. The charts use S&P's equivalent rating symbols utilizing a blended rate for split-rated companies. Net revenues include our share of unconsolidated joint ventures and net margin for our Texas Intrastate customers and other midstream businesses.

Averaged $2.5 Billion of Discretionary Capital since 2008

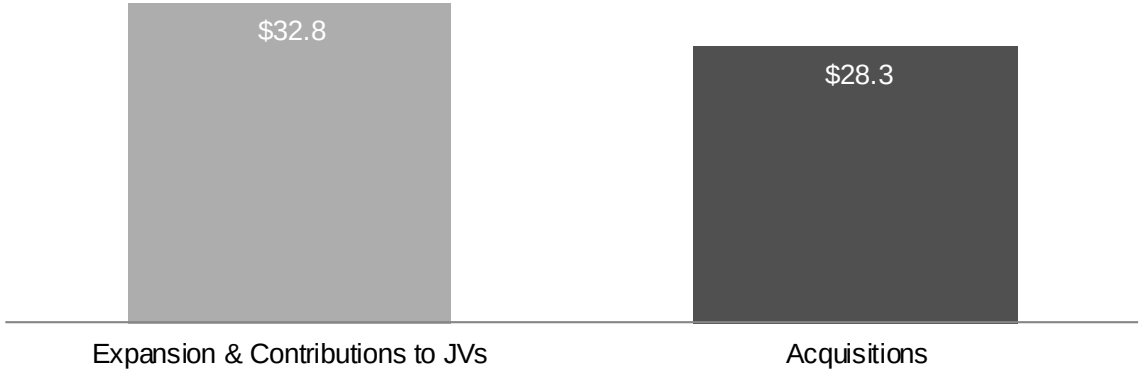
Asset investment & acquisitions over time

EXPANSION CAPITAL & CONTRIBUTIONS TO JVs BY YEAR[a,c]

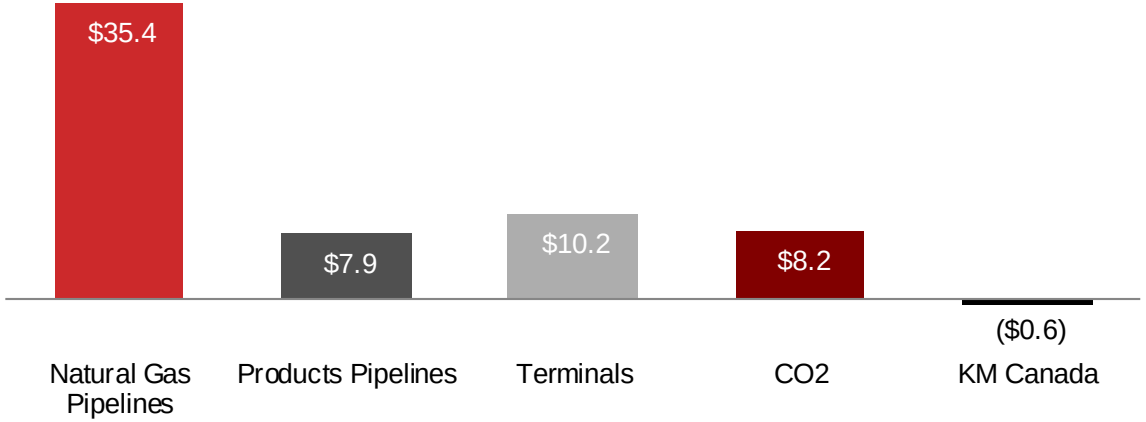
$ billions



TOTAL INVESTED BY TYPE: 1998 – 2018[b,c,d]



TOTAL INVESTED BY SEGMENT: 1998 – 2018[b,c,d]



Note: Discretionary capital includes equity contributions to joint ventures which may include debt repayments.

a) Includes KMP (2008-2014), EPB (2013-2014), and KMI (2015-2019B). Average from 2008-2018.

b) 1998-2018; includes KMP (1997-2014), EPB (2013-2014), and KMI (2015-2018).

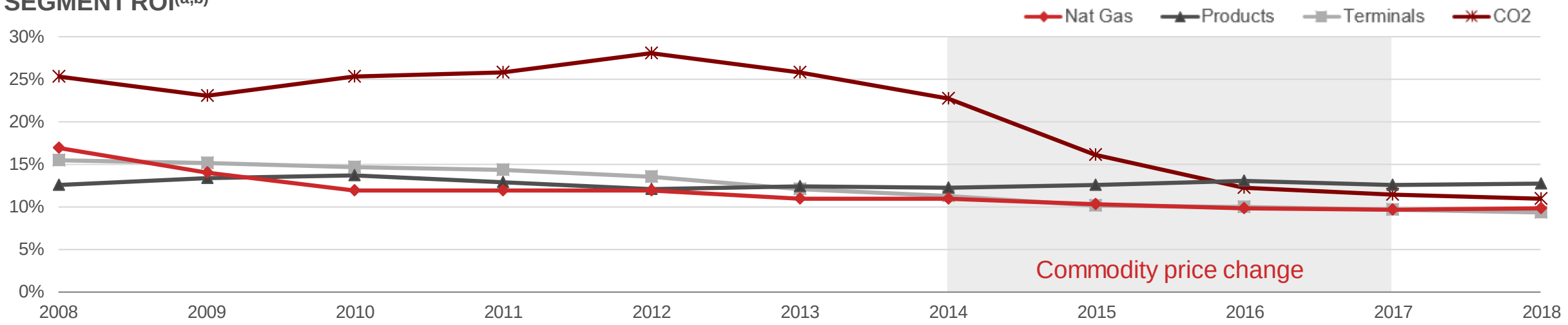
c) Excludes capital expenditures of our Canadian assets from KML IPO (May 2017) forward, though we do include these expenditures in the denominator of our ROI calculation.

d) Natural Gas Pipelines segment: Reduced by $2.6 billion and $1.8 billion for 2016 50% SNG divestiture and 2012 FTC Rockies divestiture, respectively. Excludes $11.3 billion in EPB asset acquisitions from El Paso prior to KMI's acquisition of El Paso and $2.0 billion for Citrus acquisition at KMI. Products Pipelines segment: Excludes $0.9 billion of legal and other settlements incurred over the past decade that we include in the denominator of our ROI calculation. Terminals segment: Reduced by $0.5 billion for 2018 divestiture of tanks owned by Trans Mountain. Kinder Morgan Canada segment: Reduced by $0.3 billion for 2013 divestiture of Express-Platte pipeline system, and $2.4 billion for 2018 sale of Trans Mountain.

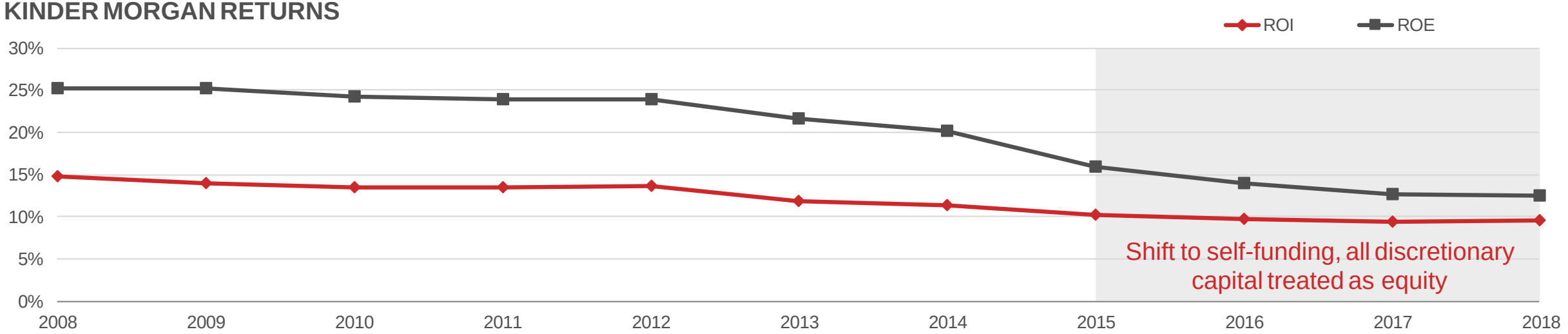
Returns on Invested Capital

Targeted returns for new capital investment are substantially above cost of capital

SEGMENT ROI[(a,b)]



KINDER MORGAN RETURNS



Notes: See Non-GAAP Financial Measures and Reconciliations. Reflects KMP (2000-2012), KMP and EPB (2013-2014) and KMI (2015-2018).

a) G&A is deducted to calculate the combined Return on Investment, but is not allocated to the segments and therefore not deducted to calculate the individual Segment ROI.

b) Natural Gas segment ROI includes NGPL and Citrus investments since 2015.

Successfully Achieving Attractive Build Multiples

Disciplined steward of capital

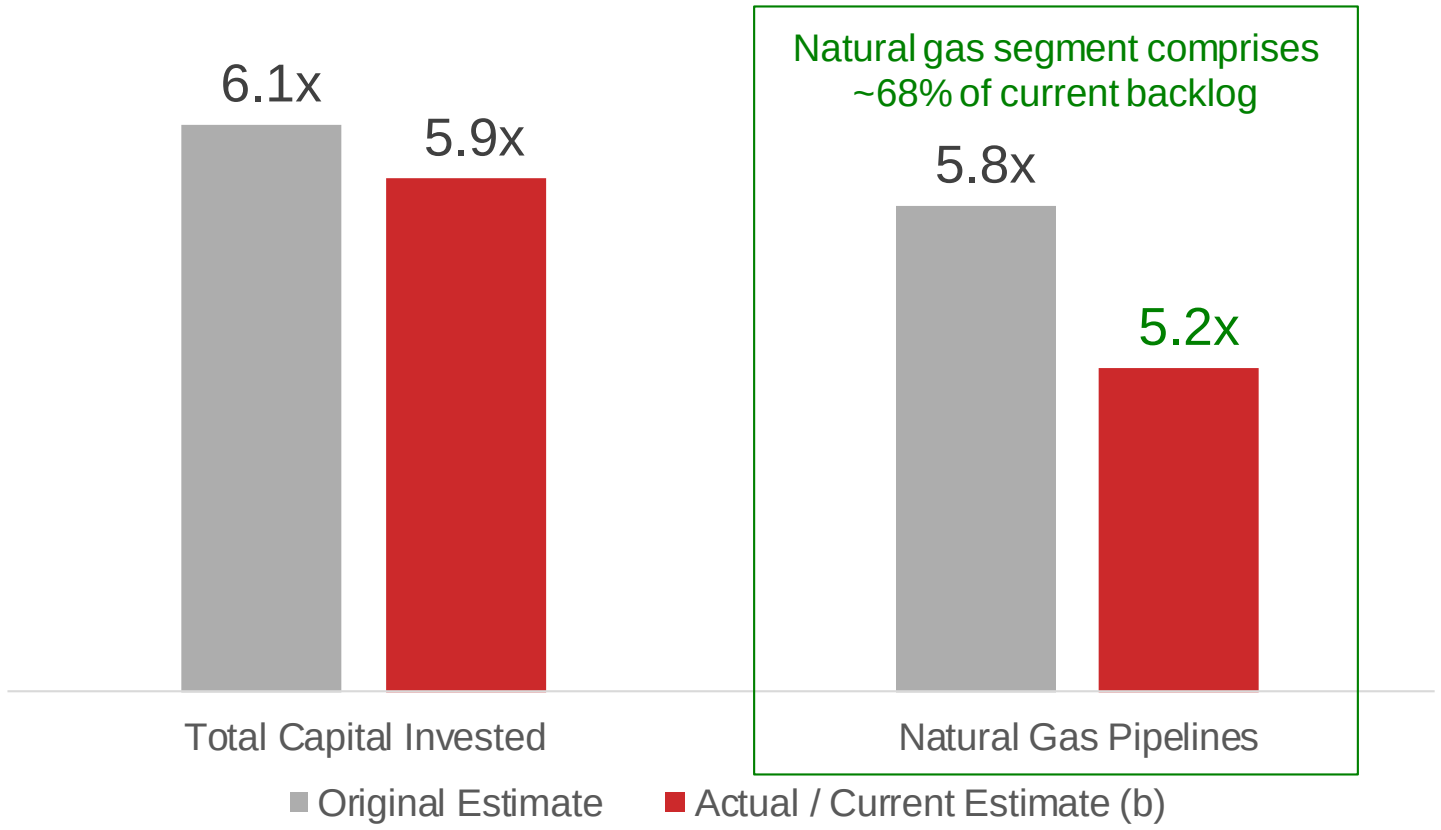
Competitive advantages:

- Expansive asset base — ability to leverage or repurpose steel already in the ground
- Connected to practically all major supply sources
- Established deliverability to primary demand centers — final mile builds typically expensive to replicate due to congestion
- Strong balance sheet and ample liquidity — internal cash flow available to fund nearly all investment needs

Expansive footprint creates opportunities for differentiated returns

INVESTMENT MULTIPLES: PROJECTS COMPLETED 2015-2018

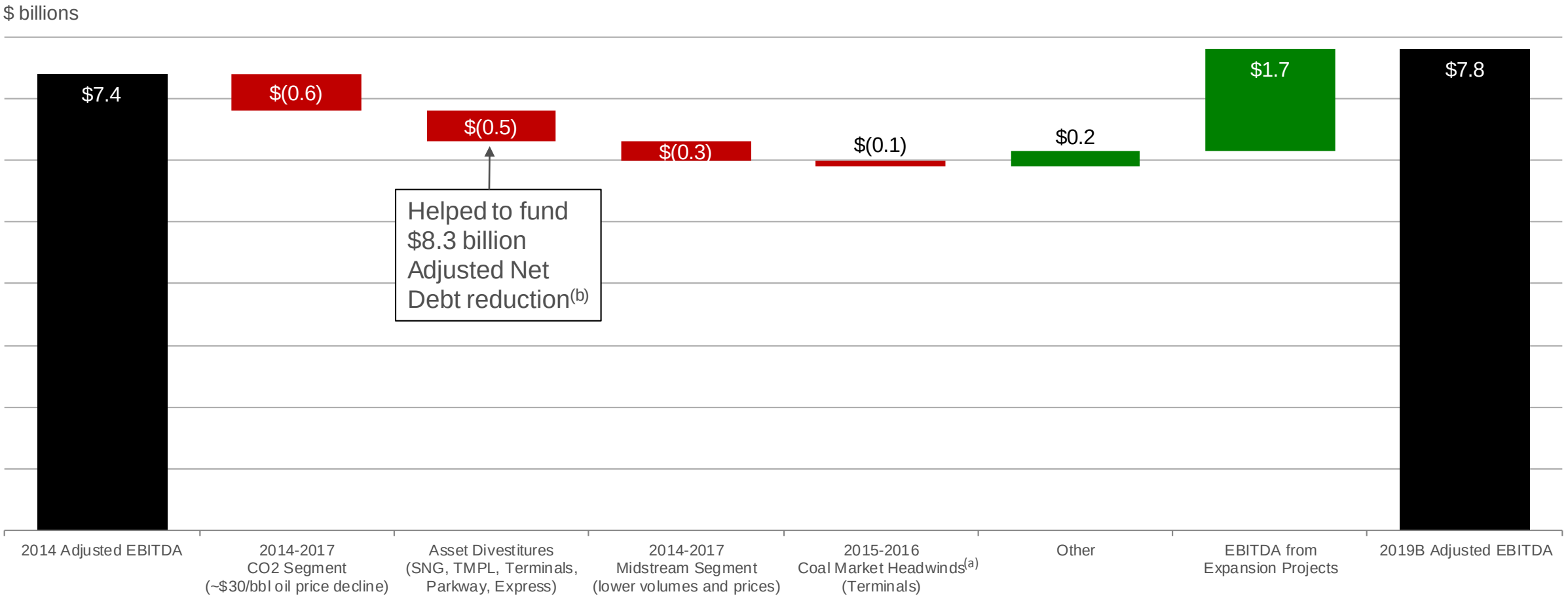
Capital invested / year 2 Project EBITDA[(a)]



Note: See Non-GAAP Financial Measures and Reconciliations.
Includes certain projects placed in commercial service prior to 2015, but were still under construction.
a) Multiple reflects KM share of invested capital divided by Project EBITDA generated in its second full year of operations. Excludes CO_2 segment projects.
b) Capital invested is actual, except for 2 projects ($444mm of capex, 4% of total capex), which are partially in service. EBITDA is actual or current estimate.

Stable Foundation of Cash Flows through Commodity Cycles

5-year change in Adjusted EBITDA



Consistently generated **over $7 billion of Adjusted EBITDA each year** through multiple market disruptions and significant strategic efforts, including asset sales and deleveraging

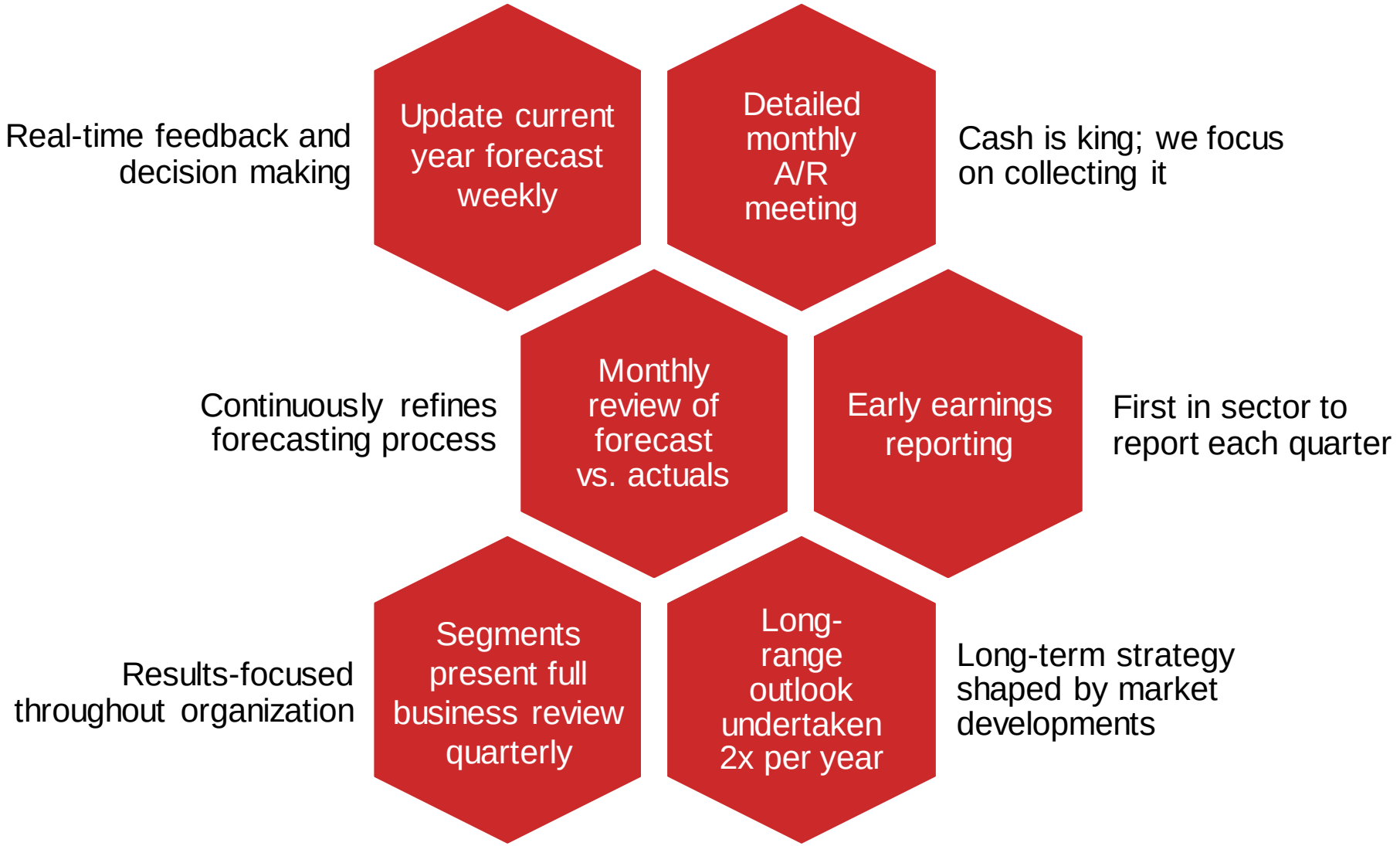
Note: See Non-GAAP Financial Measures and Reconciliations. Reconciliation for 2014 Adjusted EBITDA provided in 2015 Analyst Day slide deck available on Kinder Morgan website. EBITDA from expansion projects includes Natural Gas, Products, and Terminals segments.

a) Headwinds during 2015 and 2016 in coal market led to bankruptcy filings of three of our largest customers and the cancellation of a contract.

b) Change in consolidated Adjusted Net Debt from 9/30/2015 through 12/31/2018.

Financial Discipline is Part of Our Culture

Rigorous forecasting process enables management to react quickly and make informed decisions



Capital Allocation Priorities

Right-sized balance sheet and set dividend target through 2020; continually assessing best use of available capital

Balance Sheet

Achieved Adjusted Net Debt / Adjusted EBITDA target of ~4.5x[(a)]

Dividend

Dividend targets set through 2020 with 25% growth in each year

2019: $1.00/share

2020: $1.25/share

Capital Projects

Target return threshold well in excess of cost of capital

Given current return threshold, projects expected to generate higher returns than share repurchases

Continually re-evaluate

Share Repurchase

Expect to use cash in excess of capital projects and dividends for share repurchases

Repurchased $525mm of $2bn buyback program

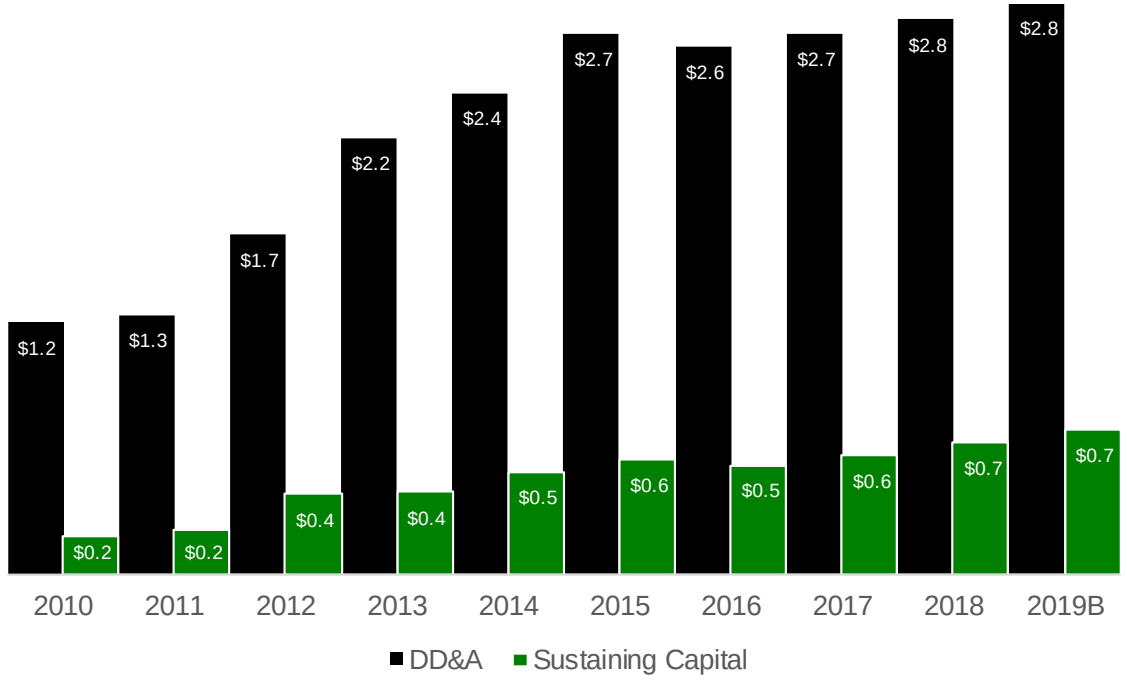
a) See Non-GAAP Financial Measures and Reconciliations.

Distributable Cash Flow (DCF) versus Net Income

Largest differences easily explainable and more reflective of cash earnings

DEPRECIATION EXPENSE VS. SUSTAINING CAPEX[(a)]

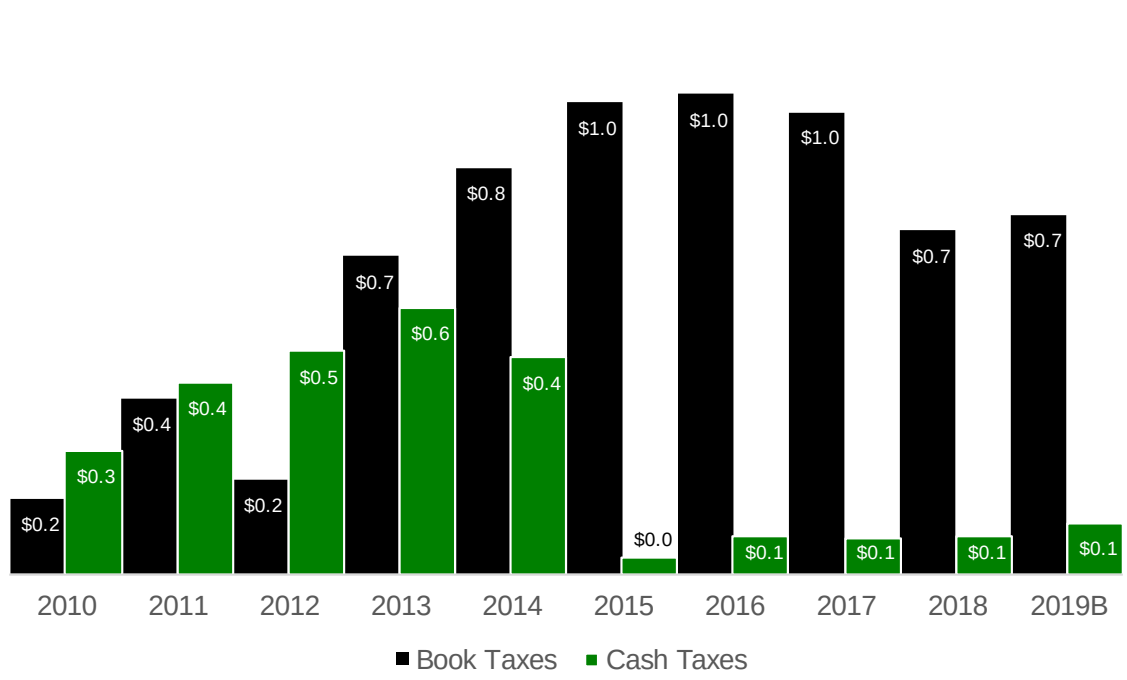
$ billions



- Our sustaining capex budget is built bottom up by operations based on need and long-term plans
- Exemplary safety record demonstrates our spending level on sustaining capex is appropriate

BOOK TAX EXPENSE VS. CASH TAXES

$ billions



- We do not expect to be a significant U.S. cash tax payer until beyond 2026

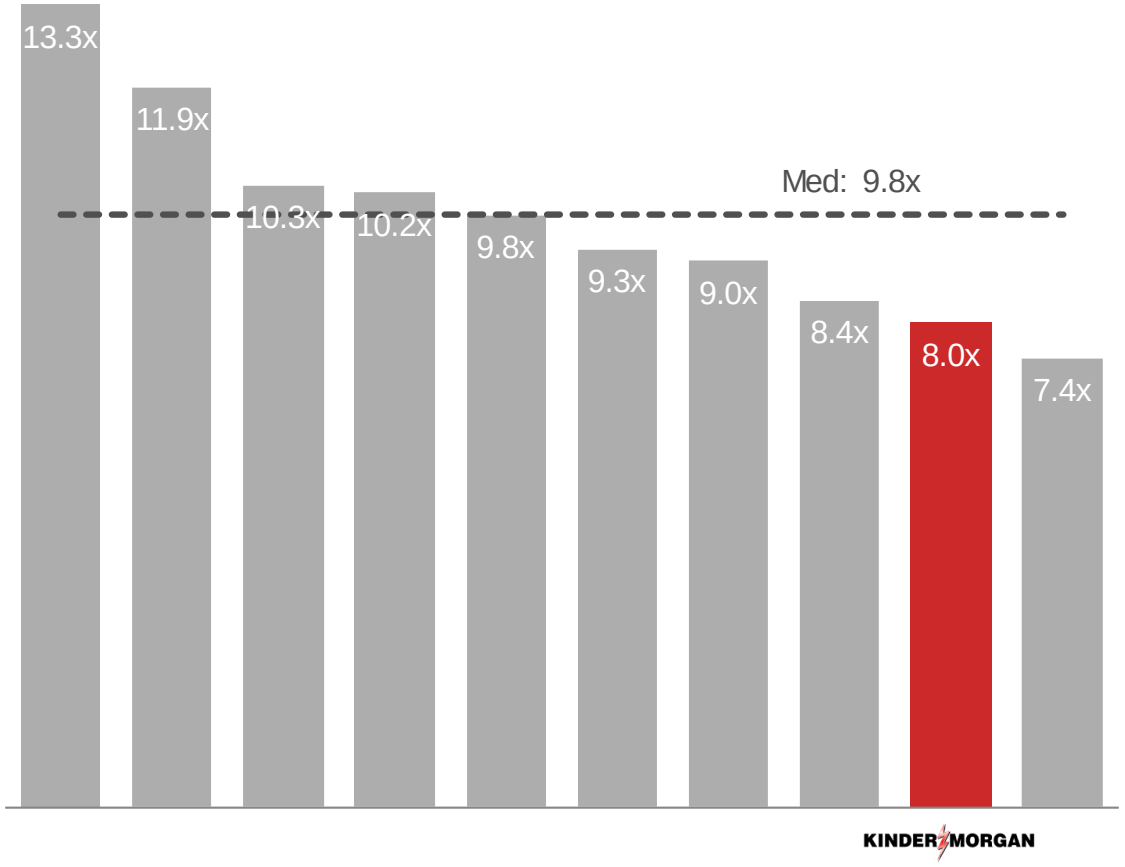
Note: 2010-2017 as presented on the distributable cash flow reconciliation to net income available to common stockholders in Forms 10-K, which includes KM's share of unconsolidated JV amounts.

a) Represents depletion, depreciation and amortization expense (DD&A), including amortization of excess cost of equity investments and JV DD&A. See Non-GAAP Financial Measures and Reconciliations.

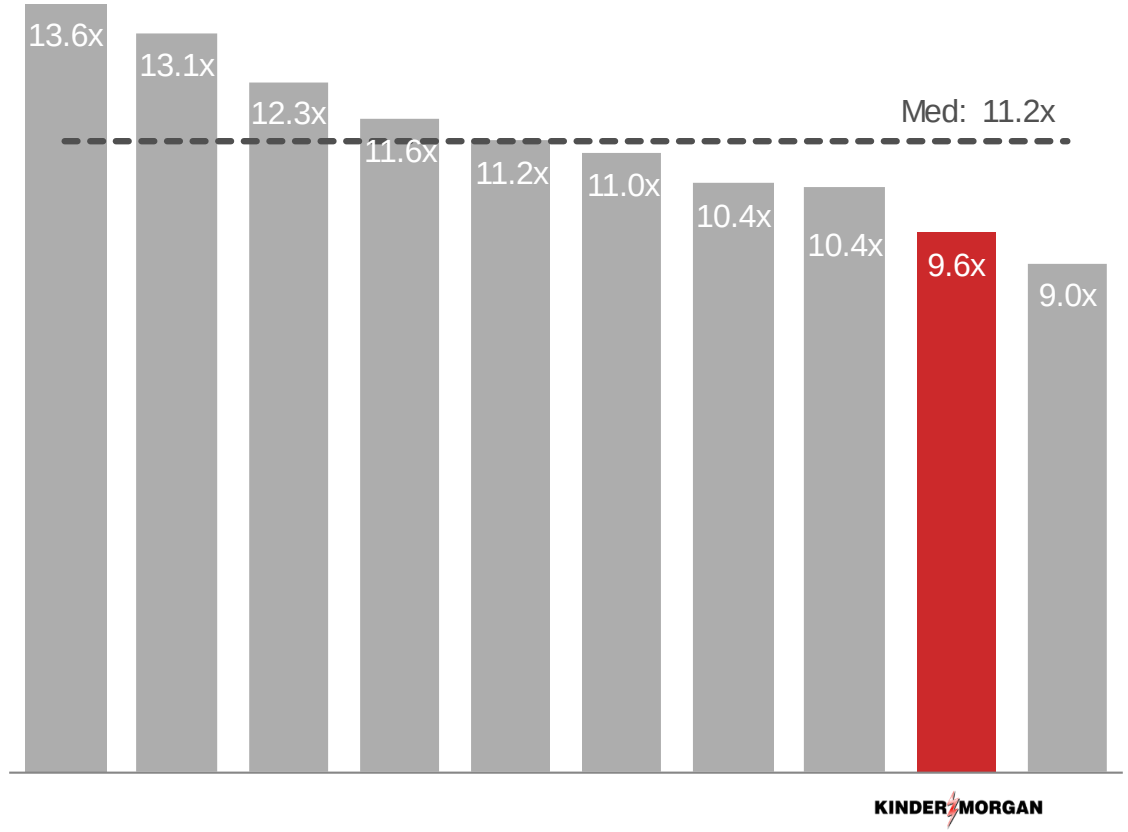
Meaningful Upside Potential

Median midstream peer valuation multiples imply ~20-30% share price upside for KMI

2019 DCF MULTIPLE[(a)]



2019 EBITDA MULTIPLE[(b)]



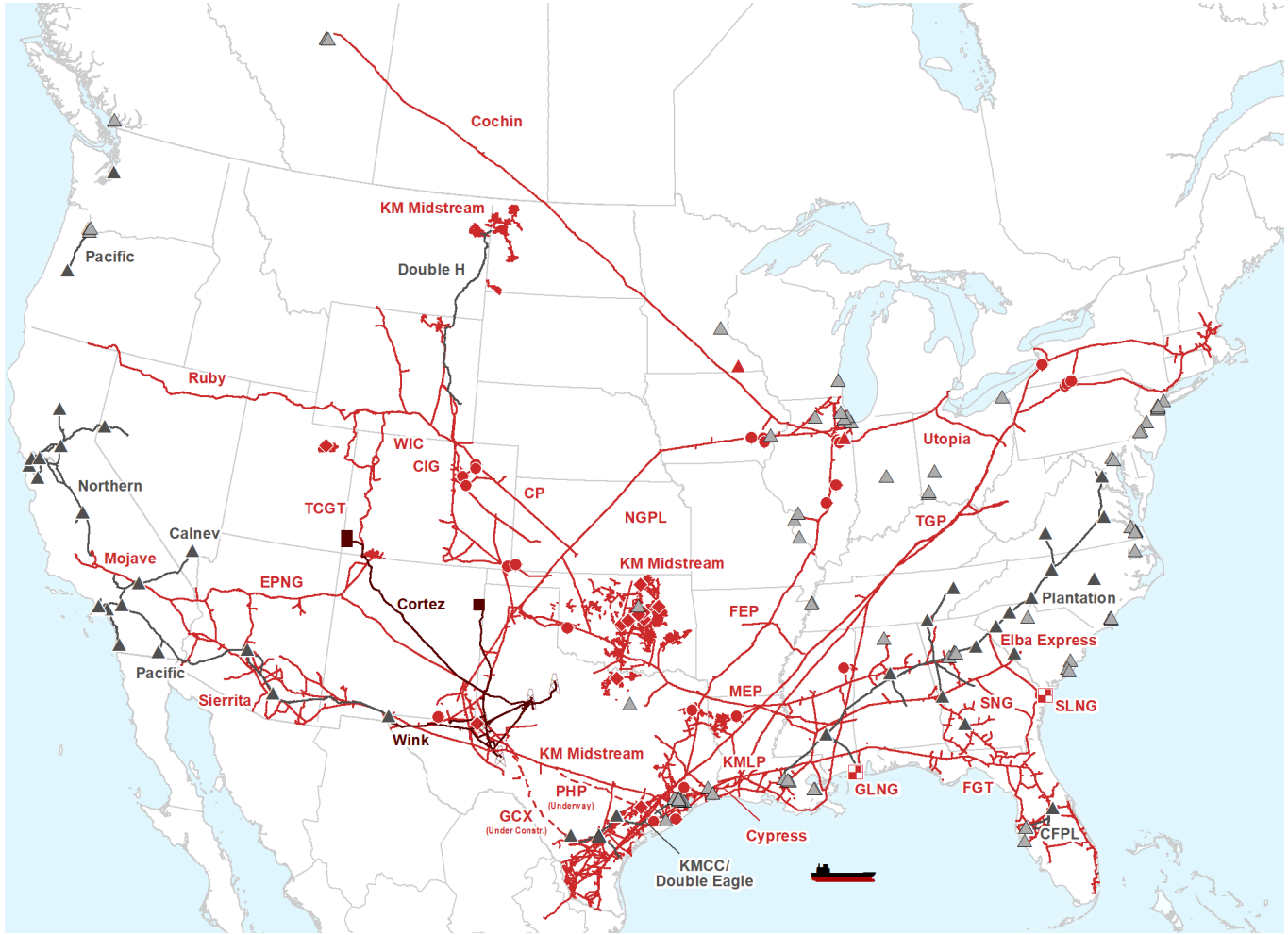
Notes: See Non-GAAP Financial Measures and Reconciliations. Market prices and Bloomberg consensus data as of 1/17/2019. Median figures are based on peer group and exclude KMI. Peer group: ENB-CN, EPD, ET, MMP, MPLX, OKE, PAA, TRP-CN and WMB.

a) 1/17/2019 share price divided by 2019E DCF per share.

b) 1/17/2019 enterprise value divided by 2019E EBITDA.

KMI: A Compelling Investment Opportunity

Strategically-positioned assets generating substantial cash flow with significant long-term growth opportunities



- ~90% take-or-pay or fee-based earnings[(a)]
- ~$7.8 billion = 2019B Adjusted EBITDA
- ~$5.0 billion = 2019B Distributable Cash Flow
- 25% dividend increase in 2019 and 2020
- Mid-BBB credit ratings
- Highly-aligned management (14% stake)
- Disciplined capital allocation
- Active stock buyback program

Market sentiment may change, but we'll stay focused on making money for our shareholders

Note: See Non-GAAP Financial Measures and Reconciliations.
a) Based on 2019B Segment EBDA plus JV DD&A.

KMI: 2019 Budget

David Michels

Vice President & CFO

KMI: 2019 Guidance – Published Budget

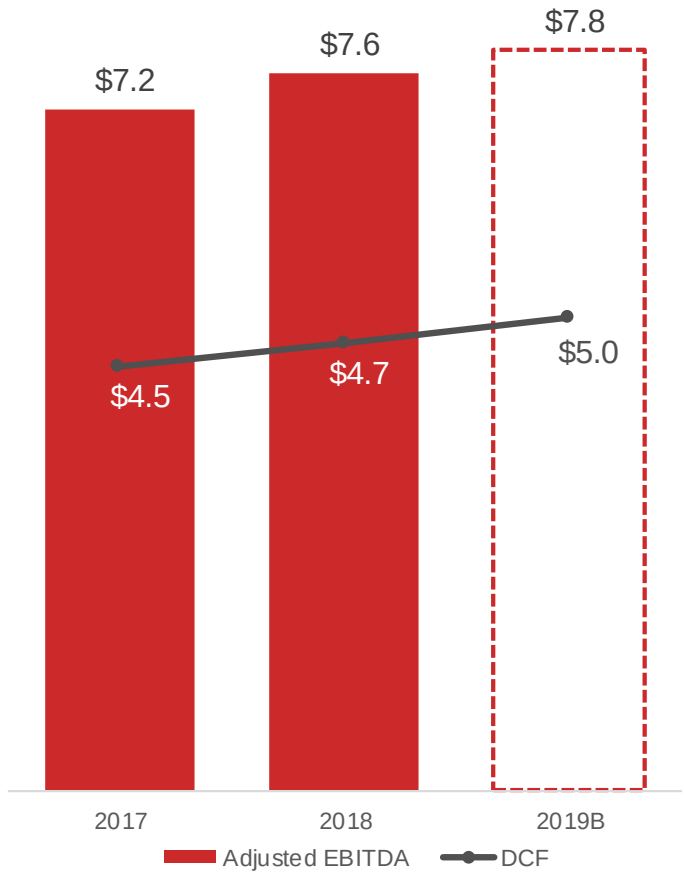
Strong fundamentals and strategic footprint support steady growth in our diversified, fee-based cash flow

Key Metrics	2019 Budget	Δ from 2018	Notes
Adjusted EBITDA	$7.8 billion	3%	
Distributable Cash Flow	$5.0 billion	6%	Meaningful increases despite sale of Trans Mountain asset
DCF per Share	$2.20	4%	
Dividend per Share	$1.00	25%	Returning additional value to shareholders via dividend increase
Growth Capex and Contributions to JVs[(a)]	$3.1 billion		
Year-end Adj. Net Debt / Adj. EBITDA	4.5x		Recently upgraded to BBB / Baa2 by S&P and Moody's; positive outlook for upgrade by Fitch

Plan to use internally generated cash flow to fully fund dividend payment and vast majority of growth capital expenditures. No need to access equity markets.

SIGNIFICANT EARNINGS POWER

$ billions



Note: See Non-GAAP Financial Measures and Reconciliations.
a) Includes JV contributions to fund expansion capital and debt repayments.

KMI: 2019B Assumptions and Highlights

EBDA growth primarily from our Natural Gas Pipelines segment

	YoY Δ in EBDA[a]	Key Developments
Natural Gas Pipelines	**+11%**	▪ Contribution from Elba Liquefaction operations starting at the end of Q1 2019 ▪ Tennessee Gas (TGP) expansion projects ▪ Increased Haynesville volumes on KinderHawk ▪ El Paso Natural Gas (EPNG) benefitting from Permian supply growth ▪ New transport contract on KM Louisiana (KMLA) to supply LNG facility
Products Pipelines	**+3%**	▪ Refined products: FERC escalator = +4.4% and flat pipeline volumes year-over-year ▪ Crude and condensate: higher volumes on Hiland assets in Bakken and through the condensate splitter, partially offset by lower rates on KM Crude & Condensate (KMCC) contract renewals
Terminals	**-1%**	▪ Full year impact of Trans Mountain tank lease expense ▪ Contributions from Base Line Tank Terminal, Gulf area expansions and contract rate escalations
CO_2	**-7%**	▪ Stable net oil production and $7.08/bbl lower oil price (driven by Mid-Cush spread) ▪ Unhedged oil price assumption = $60/bbl ▪ ~10% increase in net CO_2 volume and flat price year-over-year

- **Interest expense** – 3-month LIBOR averages 3.04% for the year, based on approximate forward curve at time of budget
- **Cash taxes** – do not expect to incur any material U.S. federal cash income taxes in 2019

a) Business segment percentage increase / (decrease) is 2018A to 2019B change in Segment EBDA before Certain Items. See Non-GAAP Financial Measures and Reconciliations.

KMI: 2019B Segment EBDA before Certain Items

in millions, except per share

	2019 Budget	2018 Actual	Change $	Change %
Natural Gas Pipelines	$ 4,682	$ 4,205	$ 477	11%
Products Pipelines	1,261	1,227	34	3%
Terminals	1,202	1,209	(7)	-1%
CO_2	848	907	(59)	-7%
Kinder Morgan Canada	-	124	(124)	-100%
Segment EBDA before Certain Items	7,993	7,672	321	4%
JV DD&A[(a)]	383	390	(7)	-2%
Segment EBDA before Certain Items plus JV DD&A	8,376	8,062	314	4%
General and administrative and corporate charges	(591)	(564)	(27)	5%
Interest, net	(1,922)	(1,891)	(31)	2%
DD&A and amortization of excess investments[(b)]	(2,856)	(2,782)	(74)	3%
Pre-tax income before Certain Items	3,007	2,825	182	6%
Book taxes	(662)	(645)	(17)	3%
Net Income before Certain Items	2,345	2,180	165	8%
Noncontrolling interests	(93)	(70)	(23)	33%
Preferred stock dividends	-	(128)	128	-100%
Adjusted Earnings[(c)]	**$ 2,252**	**$ 1,982**	**$ 270**	**14%**
Average adjusted common shares outstanding[(d)]	2,278	2,228	50	2%
Adjusted EPS[(c)]	$ 0.99	$ 0.89	$ 0.10	11%

Expect nice growth in 2019B, despite sale of Trans Mountain in 2018

Note: See Non-GAAP Financial Measures and Reconciliations. 2018 Segment EBDA before Certain Items has been reclassified between the Natural Gas Pipelines, Products Pipelines and Terminals segments to conform with 2019 presentation which reflects the January 1, 2019 transfer of certain assets between these segments.

(a) JV DD&A is not reduced by the noncontrolling interests' portion of KML DD&A of ($21) million and ($30) million in 2019 and 2018, respectively.

(b) Includes JV DD&A of $383 million and $390 million in 2019 and 2018, respectively.

(c) Adjusted Earnings is net income available to common stockholders before Certain Items. 2019 Budget represents Adjusted Earnings per share which does not include projections for certain amounts required by GAAP such as ineffectiveness on commodity, interest rate and foreign currency hedges, unrealized gains and losses on derivatives marked to market, and contingent liabilities.

(d) Includes 15 million and 12 million average unvested restricted shares that contain rights to dividends in 2019 and 2018, respectively. In addition, 2018 reflects mandatory conversion of preferred shares to common shares, net of share repurchases.

KMI: 2019B Adjusted EBITDA

$ in millions

	2019 Budget	2018 Actual	Change $	Change %
Segment EBDA before Certain Items	$ 7,993	$ 7,672	$ 321	4%
Natural Gas Pipelines JV DD&A[(a)]	378	384	(6)	-2%
Products Pipelines JV DD&A[(a)]	5	5	-	0%
Terminals JV DD&A[(a)]	(5)	(6)	1	-17%
CO2 JV DD&A	5	7	(2)	-29%
Segment EBDA before Certain Items plus JV DD&A	**8,376**	**8,062**	**314**	**4%**
JV book taxes[(b)]	90	82	8	10%
Noncontrolling interests[(c,d)]	(58)	(12)	(46)	383%
General and administrative and corporate charges	(591)	(564)	(27)	5%
Adjusted EBITDA	**$ 7,817**	**$ 7,568**	**$ 249**	**3%**

Attractive returns on recent investments drive Adjusted EBITDA growth in 2019B, more than offsetting the impact of the Trans Mountain sale

Note: See Non-GAAP Financial Measures and Reconciliations. 2018 JV DD&A has been reclassified between the Natural Gas Pipelines, Products Pipelines and Terminals segments to conform with 2019 presentation which reflects the January 1, 2019 transfer of certain assets between these segments.

(a) Includes deduction for 3rd party share of consolidated JVs. JV DD&A is not reduced by the noncontrolling interests' portion of KML DD&A of ($21) million and ($30) million in 2019 and 2018, respectively.

(b) KMI's share of unconsolidated C corp JVs' book taxes.

(c) Before Certain Items.

(d) Represents 3rd party share of consolidated JVs' earnings, excluding KML noncontrolling interests of ($35) million and ($58) million in 2019 and 2018, respectively.

KMI: 2019B Distributable Cash Flow (DCF)

in millions, except per share

	2019 Budget	2018 Actual	Change $	Change %
Net Income available to common stockholders before Certain Items	$ 2,252	$ 1,982	$ 270	14%
DD&A and amortization of excess investments[(a)]	2,835	2,752	83	3%
Total book taxes[(b)]	744	710	34	5%
Cash taxes[(c)]	(106)	(77)	(29)	38%
Sustaining capital expenditures[(d)]	(715)	(652)	(63)	10%
Other[(e)]	(4)	15	(19)	-127%
Distributable Cash Flow (DCF)	**$ 5,006**	**$ 4,730**	**$ 276**	**6%**
Average adjusted common shares outstanding[(f)]	2,278	2,228	50	2%
DCF per common share	$ 2.20	$ 2.12	$ 0.08	4%
Expected/Declared dividend per share	$ 1.00	$ 0.80	$ 0.20	25%
Excess coverage	**$ 2,728**	**$ 2,948**	**$ (220)**	**-7%**

25% increase in dividend while maintaining >2x dividend coverage

Note: See Non-GAAP Financial Measures and Reconciliations.

(a) Includes JV DD&A, reduced by the noncontrolling interests' portion of KML DD&A, of $362 million and $360 million in 2019 and 2018, respectively.

(b) Includes KMI share of unconsolidated C corp JVs' book taxes, net of the noncontrolling interests' portion of KML book taxes of $82 million and $65 million in 2019 and 2018, respectively.

(c) Includes KMI share of unconsolidated C corp JVs' cash taxes of $62 million and $68 million in 2019 and 2018, respectively.

(d) Includes JV Sustaining Capex, $127 million and $105 million in 2019 and 2018, respectively. Excludes the noncontrolling interests' portion of KML sustaining capital expenditures.

(e) Primarily pension and retiree medical contributions partially offset by non-cash compensation associated with our restricted stock program.

(f) Includes 15 million and 12 million average unvested restricted shares that contain rights to dividends in 2019 and 2018, respectively. In addition, 2018 reflects mandatory conversion of preferred shares to common shares, net of share repurchases.

KMI: 2019B Cash Tax Calculation Detail

$ in millions

	2019 Budget
Segment EBDA before Certain Items	$ 7,993
Noncontrolling interests	(93)
JV earnings from C corps	(293)
JV distributions from C corps (net of 65% Dividend Received Deduction)	88
JV book DD&A (pass-thru entities)	139
General and administrative and corporate charges	(591)
Interest, net	(1,922)
Tax DD&A from 2014 basis	(3,870)
Tax DD&A for post 2014 assets	(3,213)
Other items	(238)
Taxable loss	**$ (2,000)**

KMI U.S. federal cash taxes	$ -
Other cash taxes[(a)]	106
Total cash taxes	**$ 106**

Following the Trans Mountain sale, KMI does not expect to pay meaningful U.S. federal cash taxes until beyond 2026

Note: All items shown before certain items. See Non-GAAP Financial Measures and Reconciliations.

(a) Includes cash taxes for our share of unconsolidated C corp JVs (Citrus, Plantation, NGPL), Texas margin tax and other state income taxes.

KMI: 2019B Sustaining Capital

$ in millions

	2019 Budget	2018 Actual	Change
Natural Gas Pipelines[(a)]	$ 356	$ 316	$ 40
Products Pipelines[(a)]	79	75	4
Terminals[(a)]	226	210	16
CO_2	30	17	13
Kinder Morgan Canada[(b)]	-	10	(10)
Corporate / other	24	24	0
Total sustaining capital expenditures[(c)]	**$ 715**	**$ 652**	**$ 63**

Note: Before Certain Items.

(a) Includes KMI share of KML sustaining capital expenditures.

(b) 2018 reflects sustaining capital expenditures from TMPL and related assets prior to closing the Trans Mountain transaction on August 31, 2018.

(c) Includes KMI share of unconsolidated JVs' sustaining capital expenditures of $127 million and $105 million in 2019 and 2018, respectively.

KMI: 2019B Quarterly Profile

$ in millions, except per share

Segment EBDA before Certain Items	Q1	Q2	Q3	Q4	Total
2019 Budget	25%	24%	25%	26%	$ 7,993
2018 Actual	25%	25%	25%	25%	$ 7,672

Adjusted EBITDA					
2019 Budget	25%	24%	24%	27%	$ 7,817
2018 Actual	25%	24%	25%	26%	$ 7,568

Distributable Cash Flow (DCF)					
2019 Budget	27%	23%	23%	27%	$ 5,006
2018 Actual	26%	24%	23%	27%	$ 4,730

Adjusted EPS[(a)]					
2019 Budget	26%	23%	23%	28%	$ 0.99
2018 Actual	25%	23%	24%	28%	$ 0.89

Note: See Non-GAAP Financial Measures and Reconciliations.

(a) 2019 Budget represents Adjusted Earnings per share which does not include projections for certain amounts required by GAAP such as ineffectiveness on commodity, interest rate and foreign currency hedges, unrealized gains and losses on derivatives marked to market, and contingent liabilities.

KMI: 2019B Discretionary Capital

$ in millions

	2019 Budget	2018 Actual
Natural Gas Pipelines	$ 2,268	$ 1,767
Products Pipelines	168	126
Terminals	147	69
CO_2 - S&T	68	25
CO_2 - EOR	434	376
Total growth capital and contributions to JVs[(a)]	**$ 3,085**	**$ 2,363**

2019 budget includes:

- $0.7 billion JV expansion spending
- $0.6 billion JV debt maturities
- $(0.2) billion partner contributions for consolidated JVs

$1.1 billion of contributions to JVs

Positive market fundamentals resulting in expansion and new build opportunities across our segments and particularly in our Natural Gas segment

a) Excludes growth capital for KML as we expect KML will fund its capital needs directly.

KMI: 2019B Sources and Uses

$ in millions

Sources	2019 Budget
DCF	$ 5,006
Cash Proceeds from TMEP sale, net of KMI cash taxes[(a)]	1,965
Revolver Borrowing[(b)]/Debt Issuances	1,638
Total Sources	**$ 8,609**

Uses	2019 Budget
Dividends declared	$ 2,278
Growth capital and contributions to JVs	3,085
Debt maturities	2,813
CP/Revolver Borrowing as of 12/31/2018	433
Total Uses[(c)]	**$ 8,609**

Plan to use internally generated cash flow to fully fund dividends and the majority of growth capital expenditures and contributions to JVs

Will use the Trans Mountain sale proceeds to pay down debt

No need to access equity markets in 2019B

Note: See Non-GAAP Financial Measures and Reconciliations.

(a) Reflects KMI share of the KML return of capital distribution, net of KMI cash taxes.

(b) Excludes changes in working capital, potential rate case refunds, and KML's short-term borrowing, and will vary depending on use of discretionary free cash flow.

(c) Uses excludes funding needs for KML as we expect KML will directly fund its capital needs.

KMI: Leverage and Liquidity[a]

$ in millions

	2019 Budget
Year End 2019 Debt Outstanding	$ 35,082
50% of KML preferred equity	215
Adjusted Net Debt	$ 35,297
Adjusted EBITDA	$ 7,817
Adjusted Net Debt[b] to Adjusted EBITDA	**4.5x**

Recent credit rating upgrade at S&P and Moody's reflects balance sheet strength

Financial flexibility with ~$4 billion of capacity on our credit facilities and manageable future debt maturities

KMI revolver capacity[c]	**12/31/2018**
Committed revolving credit facilities	$ 4,500
Less:	
CP / Revolver borrowing	(433)
Letters of credit	(99)
Available capacity	**$ 3,968**

KMI long-term debt maturities[d]	
2019	$ 2,813
2020	2,198
2021	2,416
2022	2,466
2023	3,243

Note: See Non-GAAP Financial Measures and Reconciliations.

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

(b) Debt as defined in footnote above, net of cash and excluding Kinder Morgan G.P. Inc.'s $100 million preferred stock due 2057 and foreign exchange impact on Euro denominated debt. 2017 and after include 50% of KML preferred stock.

(c) Of the total $4.5 billion KMI corporate revolver facilities, $4.0 billion has a November 2023 maturity and $0.5 billion has a November 2019 maturity.

(d) 5-year maturity schedule of KMI's debt and its consolidated subsidiaries, excluding fair value adjustments, $111 million preferred securities, $76 million non-cash foreign exchange impact on Euro denominated debt, and immaterial capital lease obligations.

KML: 2019 Outlook and Budget

Dax Sanders

KML CFO
KMI EVP & Chief Strategy Officer

Overview of Kinder Morgan Canada Limited (TSX: KML)

Stable, fee-based assets central to Western Canada's energy infrastructure

Assets include integrated terminals and pipelines that support a key piece of Western Canada's economy

- Largest merchant crude oil terminal position in Alberta with ~12 million barrels of storage capacity
- Largest crude-by-rail loading terminal in North America
- Canadian portion of Cochin pipeline delivering condensate for blending
- Largest mineral concentrate export / import facility on west coast of North America located in Vancouver, British Columbia (B.C.)

Cash flows underpinned by primarily long-term, take-or-pay contracts with high-quality customers

- No direct commodity price exposure
- Long history with customers at major assets

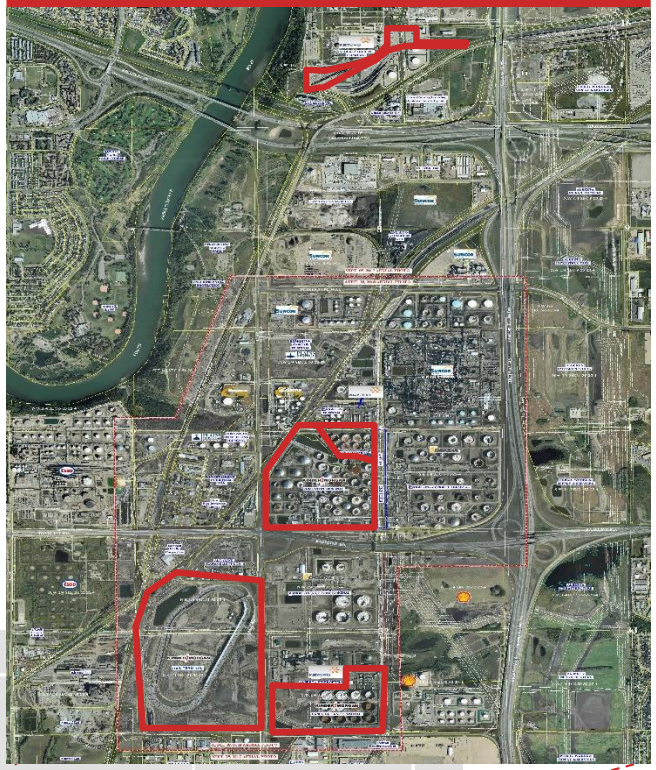
Initial Public Offering on TSX in May 2017

- Common equity is ~70% owned by KMI and ~30% owned by the public

Recently sold Trans Mountain pipeline and expansion project to the Canadian government for C$4.5 billion[(a)]

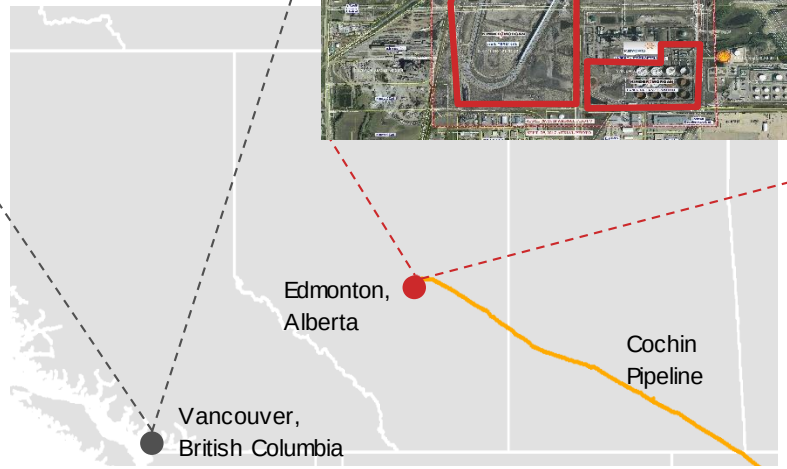
- Distributed proceeds of C$11.40 per restricted voting share as a return of capital on 1/3/2019
- Completed 1-for-3 reverse stock split following the distribution
- Expect to declare annualized dividend of C$0.65 per split-adjusted share in 2019

Edmonton Terminals



Vancouver Wharves





a) Before customary purchase price adjustments.

Asset Snapshot: Leading Crude Oil Terminal Footprint

Fully-integrated terminals in Canada's Edmonton crude oil hub | C$1.3 billion invested since 2006 with opportunities ahead

Storage Terminals

1 North 40 (N40) — 100%

- KML-owned land
- 9 tanks (1 x 150,000 bbl, 8 x 250,000 bbl)
- 2.1 mmbbl total shell capacity
- 10 inbound and 5 outbound connections (plus EST & BTT)
- External floating roof tanks

2 Edmonton South Terminal (EST) — 100%[a]

- 20 year tank lease from Trans Mountain (through 2038)
- 15 tanks (2 x 250,000 bbl, 6 x 300,000 bbl, 7 x 400,000 bbl)
- 5.1 mmbbl total shell capacity
- 15 inbound and 4 outbound connections (plus N40 & BTT)
- External floating roof tanks

3 Base Line Tank Terminal (BTT) — 50%

- 50 / 50 joint venture with Keyera (Keyera-owned land)
- 12 tanks (12 x 400,000 bbl)
- 4.8 mmbbl total shell capacity
- 10 inbound and 6 outbound connections (plus EST & N40)
- External floating roof tanks

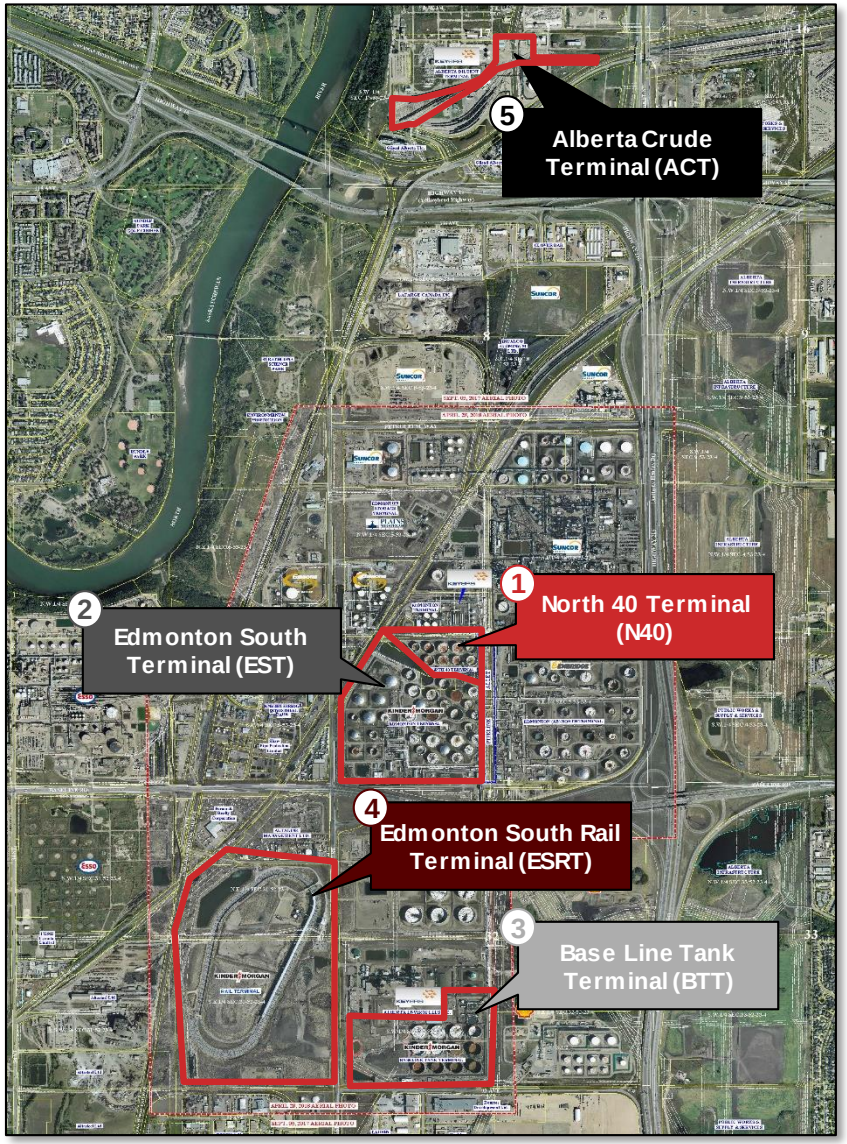
Rail Terminals

4 Edmonton South Rail Terminal (ESRT) — 50%

- 50 / 50 joint venture with Imperial (Imperial-owned land)
- 210 – 250 mbbld throughput capacity
- ~23 kilometers of track
- Directly connected to CN and CP Rail
- Can load two unit trains simultaneously, up to four trains / day
- Crude oil supplied from EST and BTT

5 Alberta Crude Terminal (ACT) — 50%

- 50 / 50 joint venture with Keyera (Keyera owned land)
- 35 – 40 mbbld throughput capacity
- 250 tank car storage
- ~6 kilometers of track
- Manifest loading
- Connected to CN and CP Rail
- Crude oil supplied from N40 and BTT



~6.7 years weighted average remaining contract life as of 12/31/2018

a) 100% economic interest in assets operated under long-term lease.

Asset Snapshot: Leading Energy Infrastructure Assets

Irreplaceable infrastructure in key markets in Western Canada

COCHIN PIPELINE (CANADIAN PORTION)

- Transports condensate from the Canada / U.S. border to Fort Saskatchewan, Alberta, for bitumen blending
- 95 mbbld of current throughput capacity (limited by capacity on U.S. portion)
  - Design capacity of 110 mbbld, which could accommodate additional receipts near the border
- Under long-term take-or-pay contracts with customers through 2024 for 85 mbbld (per 2019B)[(a)]
- Operates under joint tariff with U.S. portion
- Existing footprint extremely valuable as new cross-border pipeline projects remain challenging
  - Previously delivered propane into the U.S. and was reversed for current service

VANCOUVER WHARVES TERMINAL

- Bulk commodity marine terminal providing handling, storage, loading and unloading services
  - ~6.0 mmtpa of bulk capacity
  - Located at Canada's largest port
- Largest mineral concentrate export and import facility on the west coast of North America
- Only merchant terminal for import and export of distillates and one of two sulfur export ports in B.C.
- Majority of capacity under take-or-pay contracts with customers who have been using the terminal for an average of 13 years
- C$43mm diesel export expansion project supported by 20-year take-or-pay contract expected online Q1 2021
- Additional expansion opportunities on existing footprint, including 15-acres of developable land

JET FUEL PIPELINE

- Transports jet fuel from a Burnaby refinery and the Westridge Marine Terminal to the Vancouver International Airport
- Includes five storage tanks at the airport with ~45,000 barrels of total capacity



COCHIN PIPELINE FACILITY



VANCOUVER WHARVES TERMINAL

Key energy infrastructure assets

a) An incremental 4 mbbld is contracted through March 2019, with a one-year extension option.

Canadian Crude Oil Fundamentals

Long-term production growth, despite near-term transportation constraints, with goal to reach international markets

Western Canadian crude oil supply is projected to grow by nearly 2 mmbbld from 2017 to reach over 6 mmbbld by 2035

- Growth driven by the oil sands, which require significant upfront investment and long-term financial commitments
- Supply growth is near-term weighted as oil sands projects committed to years ago enter their production phases and ramp up

New infrastructure at Canada's key hubs is required to store, stage and transport additional volumes

- Storage acts as central aggregation and origination point for transportation
- Existing pipeline infrastructure is at capacity
- Rail serves as clearing method for incremental volumes

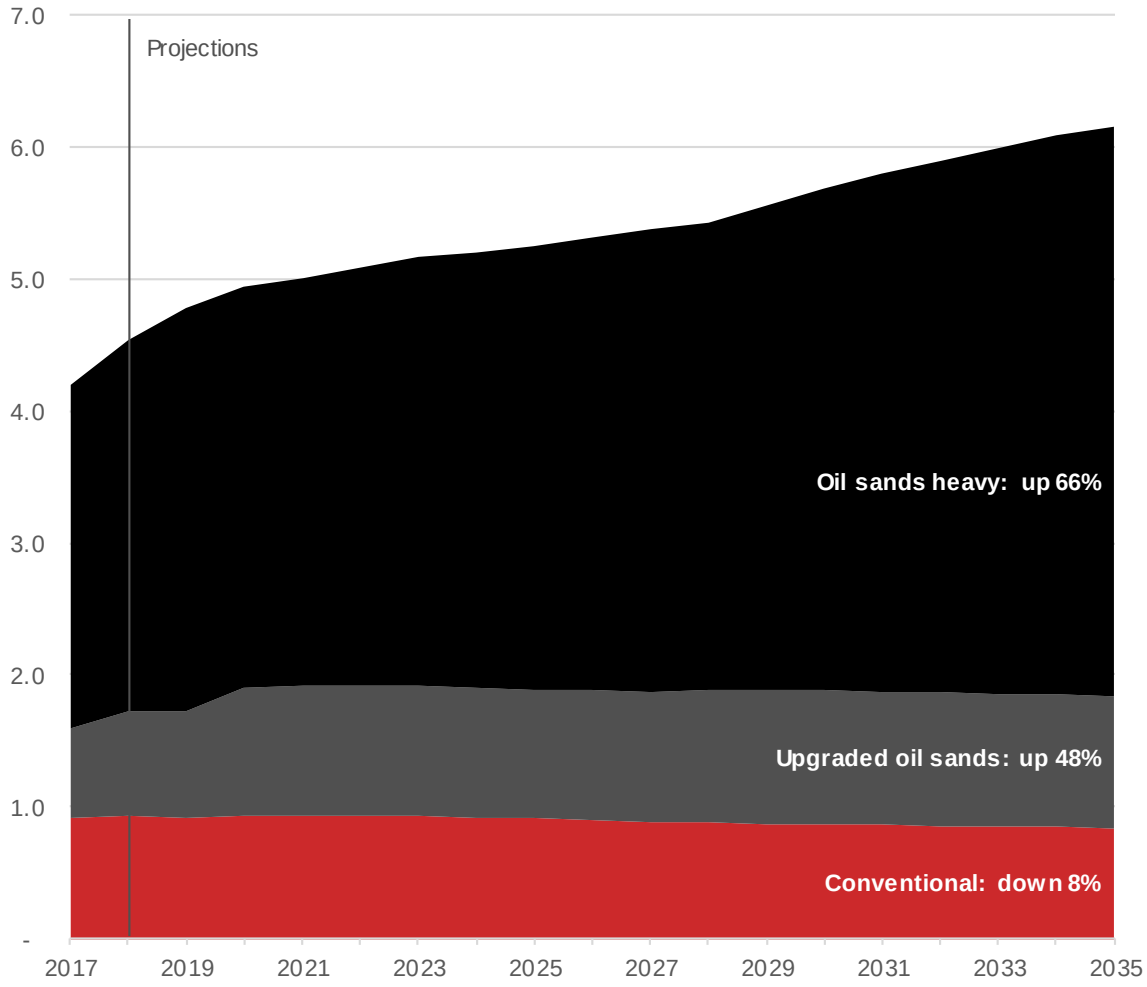
West coast access remains a priority given expected demand growth is focused in Asian markets and U.S. competition is fierce

- Edmonton hub serves the Trans Mountain pipeline, currently the only pipeline delivering crude oil to Canada's west coast for export
- Today, U.S. is the destination for ~99% of Canada's crude oil exports

Diluent from the U.S. important for bitumen blending in oil sands

- Local production of pentanes and condensate has grown substantially from liquids-rich natural gas plays
- However, ~430 mbbld of imported condensate, upgraded crude oil and butane were still required to supplement local production in 2017
- Supply optionality helps minimize impact of operational disruptions

WESTERN CANADIAN CRUDE OIL SUPPLY FORECAST



Source: Canadian Association of Petroleum Producers (CAPP), 2018 Crude Oil Forecast, Markets & Transportation, June 2018.

KML: 2019 Guidance — Published Budget

Highly contracted, fee-based cash flow

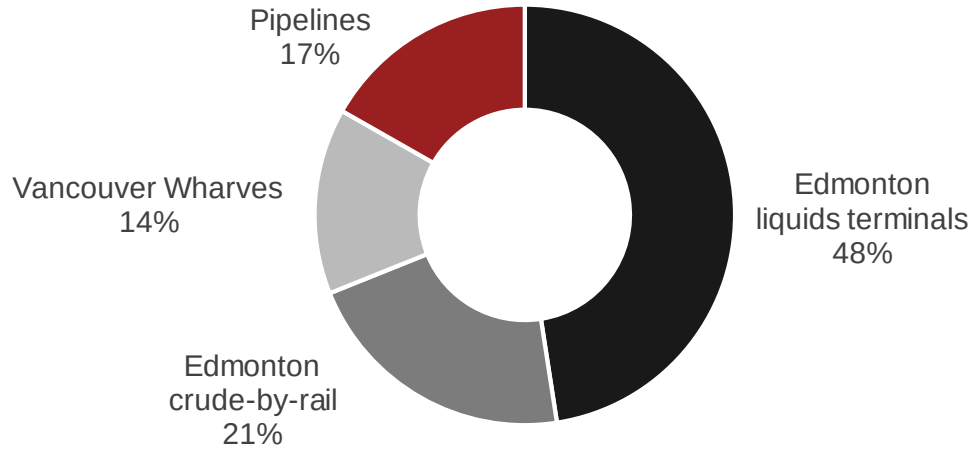
Key Metrics[a]	2019 Budget
Adjusted EBITDA	C$213 million
Distributable Cash Flow	C$109 million
DCF per Share	C$0.90
Dividend per Share	C$0.65
Growth Capex	C$32 million
Year-end Adj. Net Debt[c] / Adj. EBITDA	1.3x

Segment Highlights		YoY Δ in EBDA[b]
Terminals	▪ Full-year contribution from Base Line Tank Terminal expansion	+12%
Pipelines	▪ FERC index / contract rate increase of 4.4% for the full year	+8%

Key 2019 Budget Assumptions

- FX rate: 0.76 USD per 1.00 CAD
  - +/- 0.01 ratio change = +/- ~C$0.6 million DCF change
- Tank assets 100% leased with higher throughput year-over-year
- ~85% of Terminals segment revenue is take-or-pay
- ~98% of Cochin pipeline revenue is take-or-pay

2019B Segment EBDA by Business[a]



Note: See Non-GAAP Financial Measures and Reconciliations. See Appendix for additional key assumptions for the 2019 budget.

a) Our non-GAAP measures of DCF and Adjusted EBITDA, as well as Segment EBDA, are before Certain Items. KML's DCF per Share represents DCF available to restricted voting shareholders divided by total restricted voting shares.

b) Year-over-year change calculated using 2018 results from continuing operations which have been adjusted to reflect the sale of Trans Mountain on 8/31/2018.

c) Includes 50% of outstanding preferred stock.

KML: 2019B Segment EBDA before Certain Items

C$ in millions, except share amounts

	2019 Budget	2018 Actual[(a)]	Change $	Change %
Terminals	$ 206	$ 184	$ 22	12%
Pipelines (Cochin and Jet Fuel)	42	39	3	8%
Total Segment EBDA before Certain Items	248	223	25	11%
General and administrative and corporate charges	(35)	(34)	(1)	3%
Adjusted EBITDA	**213**	**189**	**24**	**13%**
Interest income (expense), net	(1)	29	(30)	-103%
DD&A	(90)	(83)	(7)	8%
Pre-tax income before Certain Items	122	135	(13)	-10%
Total book tax	(35)	(37)	2	-5%
Net Income before Certain Items	87	98	(11)	-11%
Preferred dividends	(29)	(29)	0	0%
Net Income attributable to KMI interest	(41)	(48)	7	-15%
Adjusted Earnings[(b)]	**$ 17**	**$ 21**	**$ (4)**	**-19%**
Adjusted Earnings per share				
Average restricted voting shares outstanding[(c)]	36	35	1	3%
Adjusted Earnings per restricted share[(b)]	$ 0.48	$ 0.62	$ (0.14)	-23%

Expansion projects drive 13% growth in Adjusted EBITDA in 2019B

2018 net income benefitted from non-recurring interest income earned on cash from sale of Trans Mountain

Note: See Non-GAAP Financial Measures and Reconciliations.

(a) 2018 reflects actual results from continuing operations, and excludes Trans Mountain operations (discontinued operations) prior to its sale on August 31, 2018.

(b) Adjusted Earnings is net income before Certain Items available to restricted voting stockholders.

(c) 2018 reflects our January 2019 1-for-3 reverse stock split for all periods presented in accordance with U.S. GAAP. Also includes stock awards of restricted voting shares that participate in dividends.

KML: 2019B Distributable Cash Flow (DCF)

C$ in millions, except share amounts

Distributable Cash Flow	2019 Budget	2018 Actual[(a)]	Change $	Change %
Net Income before Certain Items	$ 87	$ 98	$ (11)	-11%
DD&A	90	83	7	8%
Total book tax	35	37	(2)	-5%
Cash taxes	(52)	(8)	(44)	550%
Preferred dividends	(29)	(29)	0	0%
Sustaining capex	(22)	(19)	(3)	16%
Distributable Cash Flow	**$ 109**	**$ 162**	**$ (53)**	**-33%**
Distributable Cash Flow attributable to KMI interest	(76)	(114)	38	-33%
Distributable Cash Flow available to restricted voting stockholders	**$ 33**	**$ 48**	**$ (15)**	**-31%**

Average restricted voting shares outstanding	36
DCF per restricted share	$ 0.90

We expect to declare a dividend of C$0.65 per share for 2019

Note: See Non-GAAP Financial Measures and Reconciliations.

(a) 2018 reflects actual results from continuing operations, and excludes Trans Mountain operations (discontinued operations) prior to its sale on August 31, 2018.

KML: 2019B Cash Tax Calculation Detail

C$ in millions

		2019 Budget
Segment EBDA before Certain Items	$	248
General and administrative and corporate charges		(35)
Interest, net		(1)
Tax depreciation		(86)
Other items		3
Taxable income	**$**	**129**

KML Canadian cash taxes[(a)]	$	52
Other cash taxes		-
Total cash taxes	**$**	**52**

2019B includes payment for 2019 & taxes deferred from 2018

Note: Before Certain Items. See Non-GAAP Financial Measures and Reconciliations.

(a) Total cash tax of $52 million is comprised of $17 million from 2018 and $35 million for 2019.

KML: 2019B Capital Expenditures and Sources / Uses

C$ in millions

Sustaining Capital Expenditures	2019 Budget	2018 Actual[(a)]	Change
Terminals	$ 19	$ 16	$ 3
Pipelines (Cochin and Jet Fuel)	3	3	0
Total Sustaining Capital Expenditures[(b)]	**$ 22**	**$ 19**	**$ 3**

Growth Capital	2019 Budget	2018 Actual[(a)]	Change
Terminals	$ 32	$ 53	$ (21)
Pipelines (Cochin and Jet Fuel)	-	(11)	11
Total Growth Capital	**$ 32**	**$ 42**	**$ (10)**

Sources	2019 Budget
DCF	$ 109
Excess cash	(1)
Total Sources	**$ 108**

Uses	2019 Budget
Dividends declared	$ 76
Growth capital	32
Total Uses	**$ 108**

2019B assumes dividend and capital needs are funded with internally generated cash flow

Note: See Non-GAAP Financial Measures and Reconciliations.

(a) 2018 reflects actual results from continuing operations, and excludes Trans Mountain operations (discontinued operations) prior to its sale on August 31, 2018.

(b) Before Certain Items.

KML: Leverage and Liquidity[(a)]

C$ in millions

	2019 Budget
Revolver balance	$ 5
50% of KML preferred equity balance	275
Less: Cash	-
Net Debt including 50% of KML preferred equity balance	280
Adjusted EBITDA	213
Adjusted Net Debt to Adjusted EBITDA	**1.3x**

Financial flexibility to pursue accretive opportunities

Revolver Capacity[(b)]	**12/31/2018**
Committed revolving credit facility	$ 500
Less:	
CP / revolver borrowing	-
Letters of credit[(c)]	(11)
Available capacity	**$ 489**

No long-term debt outstanding as of 12/31/2018

Note: Before Certain Items. See Non-GAAP Financial Measures and Reconciliations.

(a) Debt of KML and its consolidated subsidiaries.

(b) KML revolving credit facility has an August 2022 maturity.

(c) Includes approximately $8 million of Letters of Credit issued on behalf of Trans Mountain for which it has issued a backstop letter of credit to KML.

KML Long-term Opportunities and Risks

Established footprint provides attractive opportunities to serve growing Canadian crude oil production

OPPORTUNITIES

- Rate improvements on re-contracting
- Incremental rail business given pipeline constraints
- Add-on Base Line Tank Terminal expansion
- Additional storage capacity for growing production
- Solutions for heavy bitumen

RISKS

Edmonton South Rail Terminal contract reset

- Original contract provided minimum monthly payments to underwrite investment in the facility (return on and of capital)
- After initial 5-year term expiry in April 2020, commercial arrangement expected to shift to a cost-plus structure
- Unmitigated, full-year revenue impact of ~C$54mm

Edmonton South Terminal tank recall

- 2 of 15 tanks leased at Edmonton South expected to be recalled to regulatory service upon in-service of Trans Mountain expansion
- Earnings impact varies by specific tanks' commercial arrangements offset by reduction in lease payment

Uncertainty around incremental pipeline takeaway capacity

- Short-term benefit of increased storage and rail demand
- Prolonged regulatory uncertainty and transportation constraints could impact projected growth in crude oil production
- Additional takeaway originating in Hardisty would likely draw incremental barrels towards that hub

Natural Gas Pipelines

Segment Presentation

Natural Gas Segment Overview

Connecting key natural gas resources with major demand centers

Asset Summary

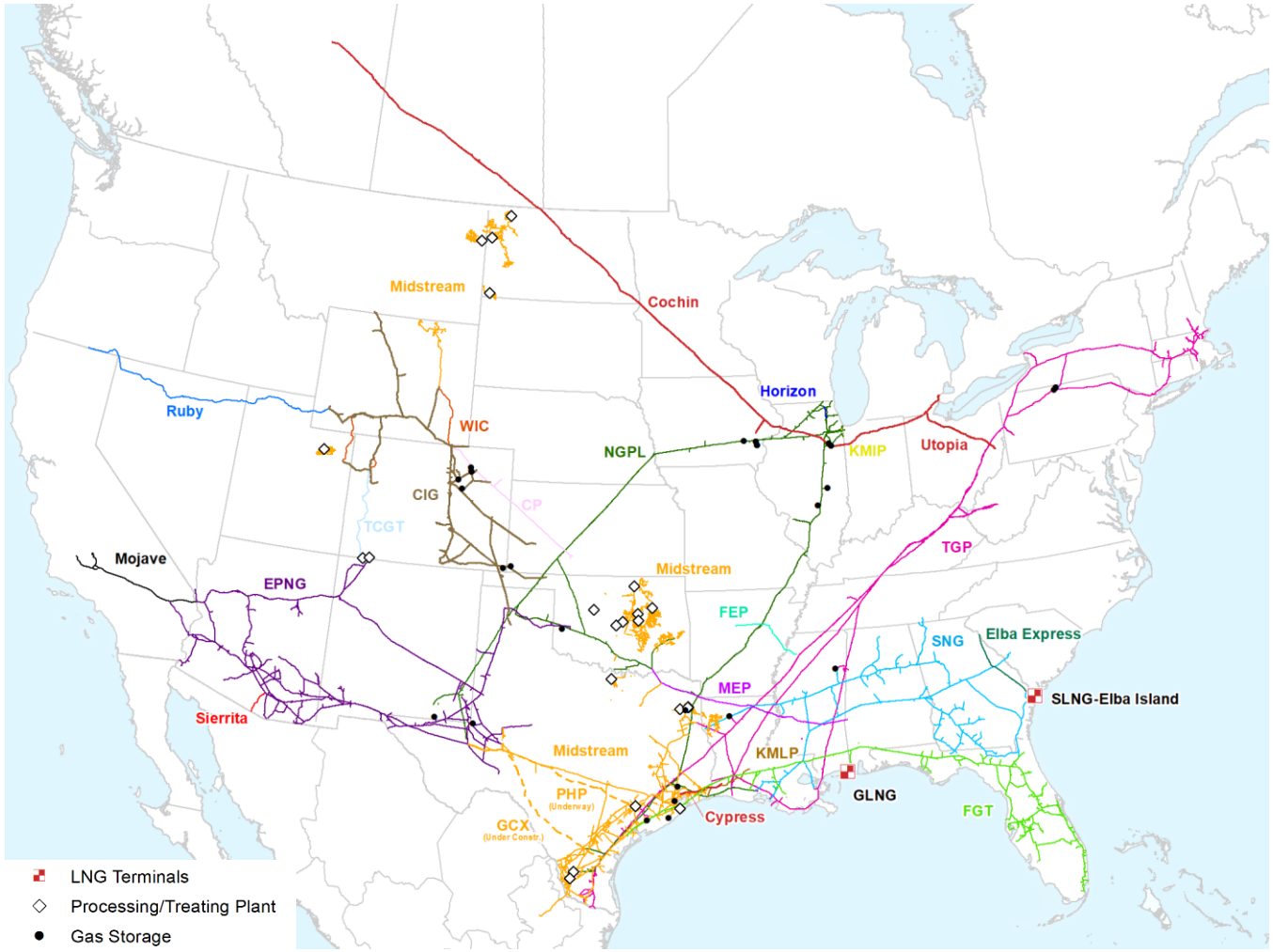
Natural Gas Pipelines:	~70,000	Miles
NGL Pipelines:	~2,700	Miles
U.S. Natural Gas Consumption Moved:		~40%
Working Gas Storage Capacity:	657	Bcf

2019B EBDA[(a)]: ~$5.1 billion

Project Backlog:

$3.9 billion of committed growth projects over the 2019-2022 time period[(b)]

- Permian takeaway, including de-bottlenecking and new builds
- LNG liquefaction (Elba Island)
- Transport projects supporting LNG exports
- Bakken G&P expansions
- Mexico



a) 2019 budgeted Segment EBDA before Certain Items plus JV DD&A. See Non-GAAP Financial Measures and Reconciliations.
b) Includes KM share of non-wholly owned projects. Includes projects currently under construction.

Long-Term Growth Drivers: Natural Gas Pipelines

Kinder Morgan capitalizes on industry trends

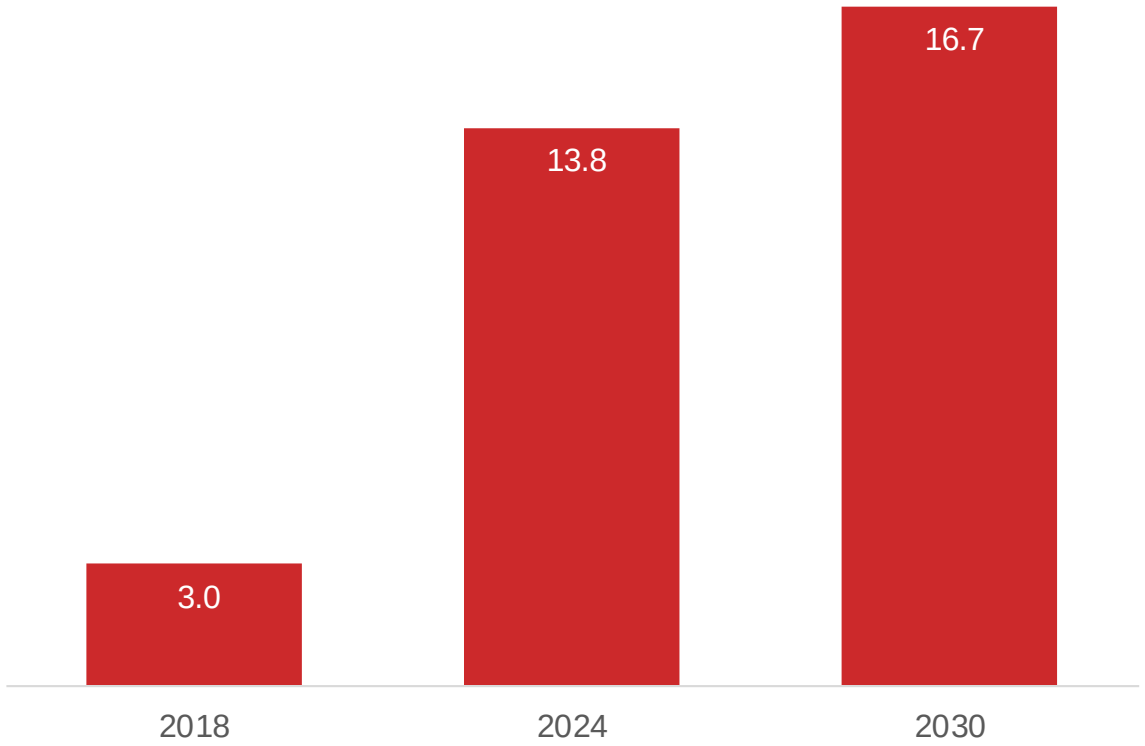
Exports	▪ LNG exports: liquefaction facilities and pipeline infrastructure ▪ Exports to Mexico
Shale-driven expansions / extensions	▪ Expansions / extensions off existing footprint ▪ Midstream gathering and processing expansions ▪ Greenfield projects
End-user / LDC demand growth	▪ Gulf Coast industrial growth ▪ Regional power generation opportunities, baseload growth and peaking ▪ Enhanced access to LDC markets
Pipeline conversions	▪ Repurpose assets to achieve greater value
Support for increasing variable demand	▪ Support LNG liquefaction (interruptions / outages) ▪ Backstop variable renewable generation ▪ Support daily and seasonal variability in exports to Mexico ▪ Meet peak summer / winter demand

Growth Driver: Buildout of U.S. LNG Exports

Multiple liquefaction and natural gas transport opportunities across KM footprint

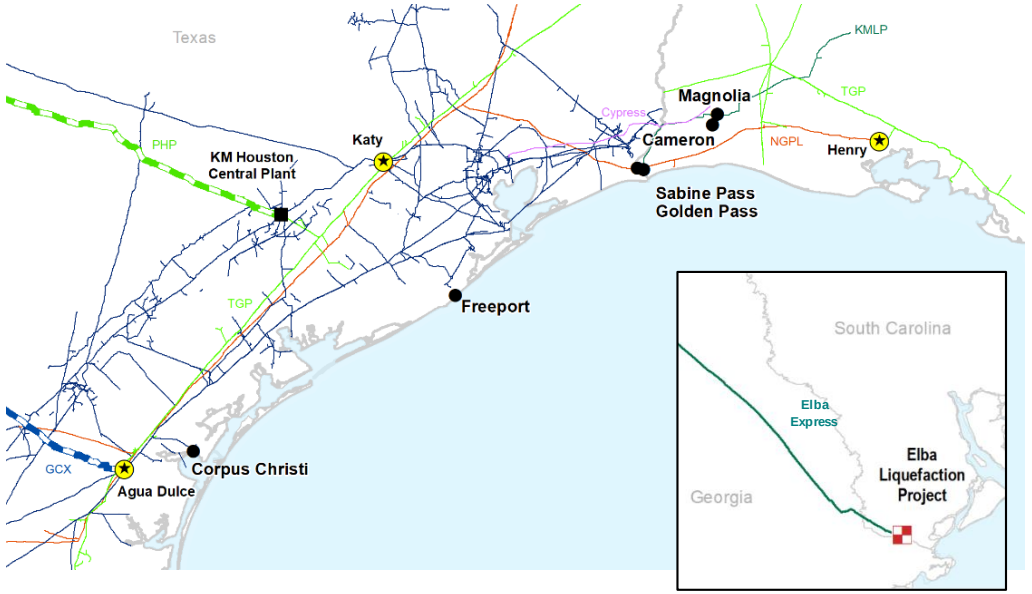
GLOBAL DEMAND DRIVING SIGNIFICANT BUILDOUT OF U.S. LNG EXPORT CAPABILITIES

Forecasted U.S. Liquefaction Capacity (Bcfd)



KM is already contracted to serve ~5.3 Bcfd (18-year average term) of U.S. liquefaction capacity and is positioned to capture more

KM NETWORK REACHES MULTIPLE EXPORT FACILITIES



KM Asset	Contracted Capacity (mDthd)	KM Capital ($mm)
TGP	1,200	$304
KMLP	1,400	$226
NGPL	1,635	$241
Intrastate	590	$134
EEC	436	$100
Subtotal:	**5,261**	**$1,006**
ELC	350 mmcfd	$1,185
Total		**$2,191**

Source: WoodMackenzie, North America Gas Markets Long-Term Outlook, Fall 2018.

Project Highlight: Elba Island LNG Export Terminal

Elba Liquefaction Company (ELC)[a] / Southern LNG Company (SLNG)

Project Scope

- Liquefaction facilities (10 small-scale modular units)
- Ship loading facilities; boil-off gas compression
- Located on Elba Island near Savannah, Georgia

Project Statistics

- Liquefaction Capacity: 2.5 mtpa or ~350 mmcfd
- Capital (100%):
  - ELC: ~$1,400 million[b] / ~$750 million KM share
  - SLNG: ~$430 million
- In-service: Q1 2019 through Q4 2019 (phased)
- Contract term: 20 years

Current Status

- FERC certificate issued June 2016
- DOE FTA and non-FTA authorizations received
- Construction ongoing and first unit expected online end of Q1 2019

Fully-contracted under 20-year take-or-pay agreement with Shell and ~70% of the revenue expected with in-service of the first unit





a) ELC is a 51 / 49 joint venture of Kinder Morgan and investment funds managed by EIG Global Energy Partners (EIG).
b) Excludes non-KM capitalized interest cost.

Key Market: Exports to Mexico

Kinder Morgan delivers ~3.1 Bcfd of U.S. natural gas exports to Mexico[a]

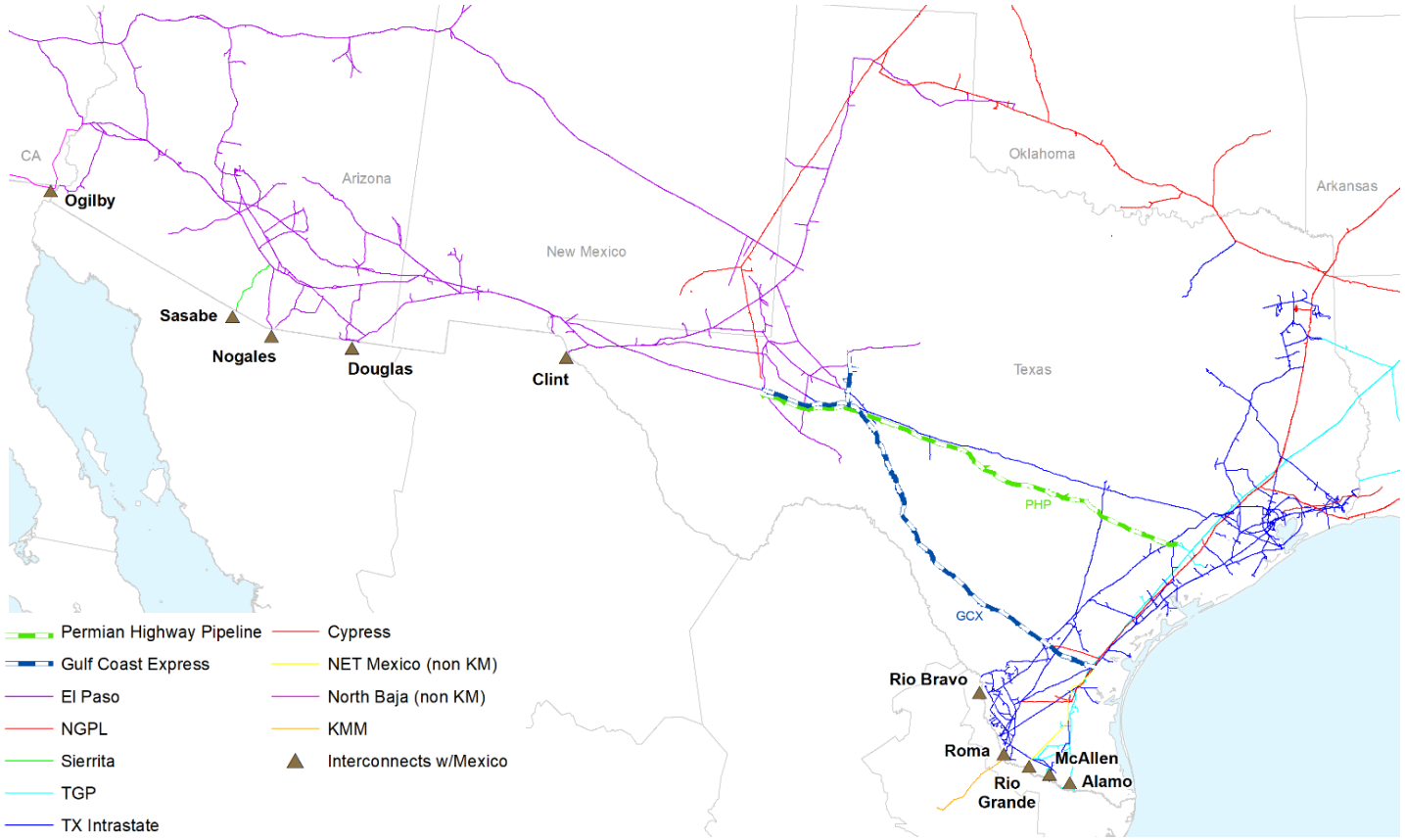
Extensive footprint offers diverse supply solutions to multiple Mexico interconnections (12 direct, 4 indirect)

- U.S. natural gas exports to Mexico are expected to grow by 36%, or ~1.6 Bcfd, to 6.1 Bcfd by 2023[b]
- Incremental opportunities include expansions of existing assets (including Monterrey and TGP), greenfield infrastructure (including GCX and PHP), new hub development, and storage near the border

~3.4 Bcfd of long term transportation contracts serving Mexico with a weighted average remaining contract term of 12.5 years

Placed ~1 Bcfd of capacity into service for ~$0.4bn since 2014

~0.6 Bcfd of capacity in the backlog for ~$0.2bn to further serve growing Mexico demand



Our network is well-positioned to serve growing Mexican demand

Note: KM Projects / Long-Term Commitments to Mexico detail available in Natural Gas Pipelines Segment Presentation.
a) 2018 calendar year average.
b) Source: WoodMackenzie, North America Gas Markets Long-Term Outlook, Fall 2018.

Growth Driver: Surging Permian Production

KM providing additional takeaway capacity for associated natural gas production

Existing footprint reaches across Texas and connects into all major demand markets

- Interconnected deliverability to Houston markets (power, petchem), substantial LNG export capacity and Mexico

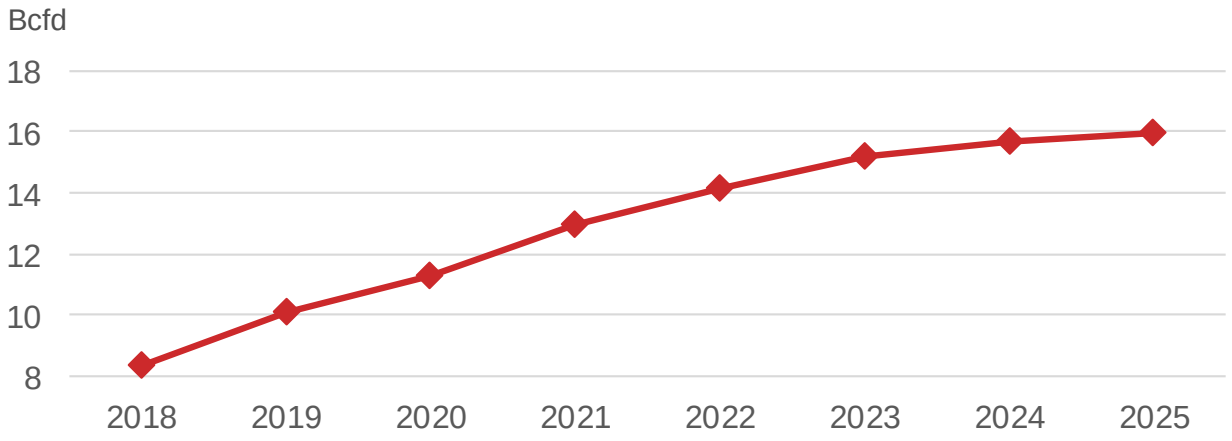
Potential to leverage existing assets into long-haul Permian crude oil pipeline projects

- KM Crude and Condensate (KMCC) pipeline to facilitate deliverability into the Houston refining and export markets

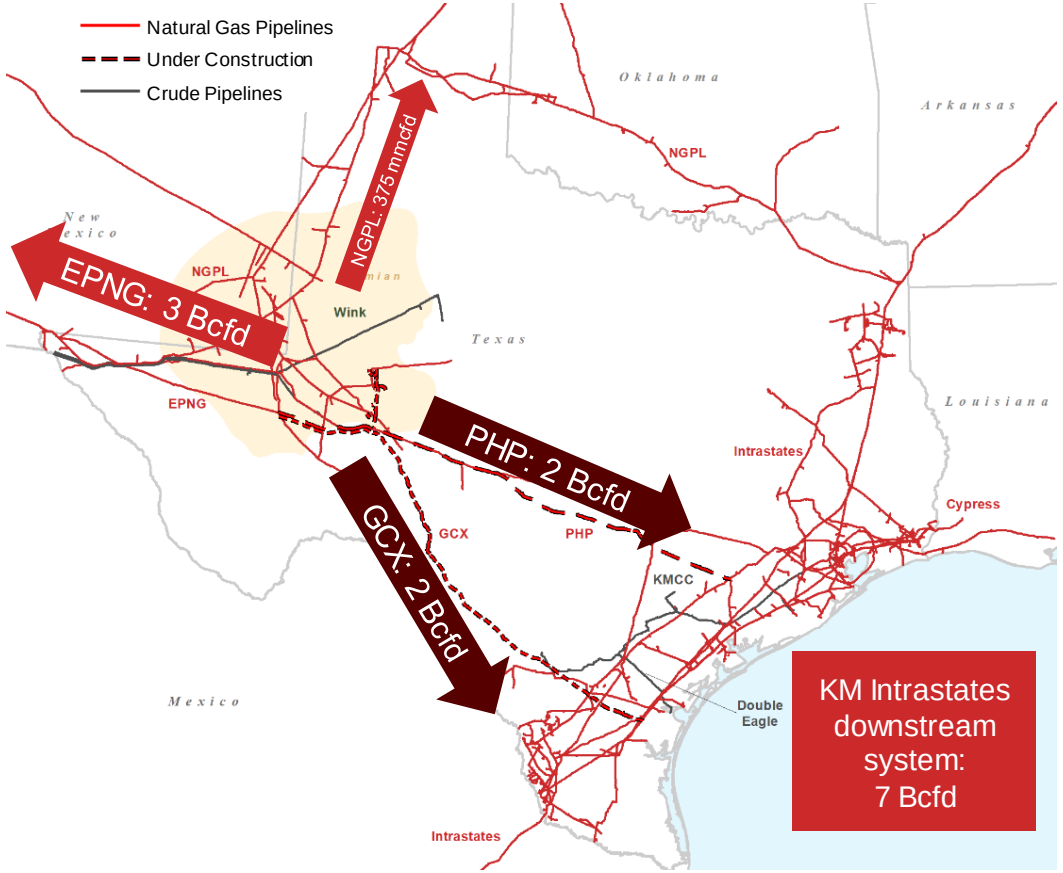
Growing Permian production will require an additional long-haul, large capacity natural gas pipeline beginning in 2021

- Gulf Coast Express (GCX) in-service Oct. 2019 and Permian Highway (PHP) in-service Oct. 2020

PERMIAN NATURAL GAS PRODUCTION FORECAST[a]



KM POSITIONED TO SERVE PERMIAN PRODUCTION



Delivering substantial Permian takeaway capacity to Midcontinent, West, and Gulf Coast markets

a) Source: WoodMackenzie, North America Gas Markets Long-Term Outlook, Fall 2018.

Project Highlight: Gulf Coast Express (GCX)

Permian direct-to-Gulf Coast project satisfying multiple growth drivers

KINDER MORGAN

Project Scope

- Mainline: 447.5 miles of 42” pipeline originating at the Waha Hub and terminating near Agua Dulce, Texas
- Midland lateral: 50 miles of 36” pipeline
- 214,280 HP of installed compression
- KM Texas Pipeline (KMTP) operator and constructor
- KM 35%, DCP 25%,Targa 25%, Altus (Apache) 15% ownership interest

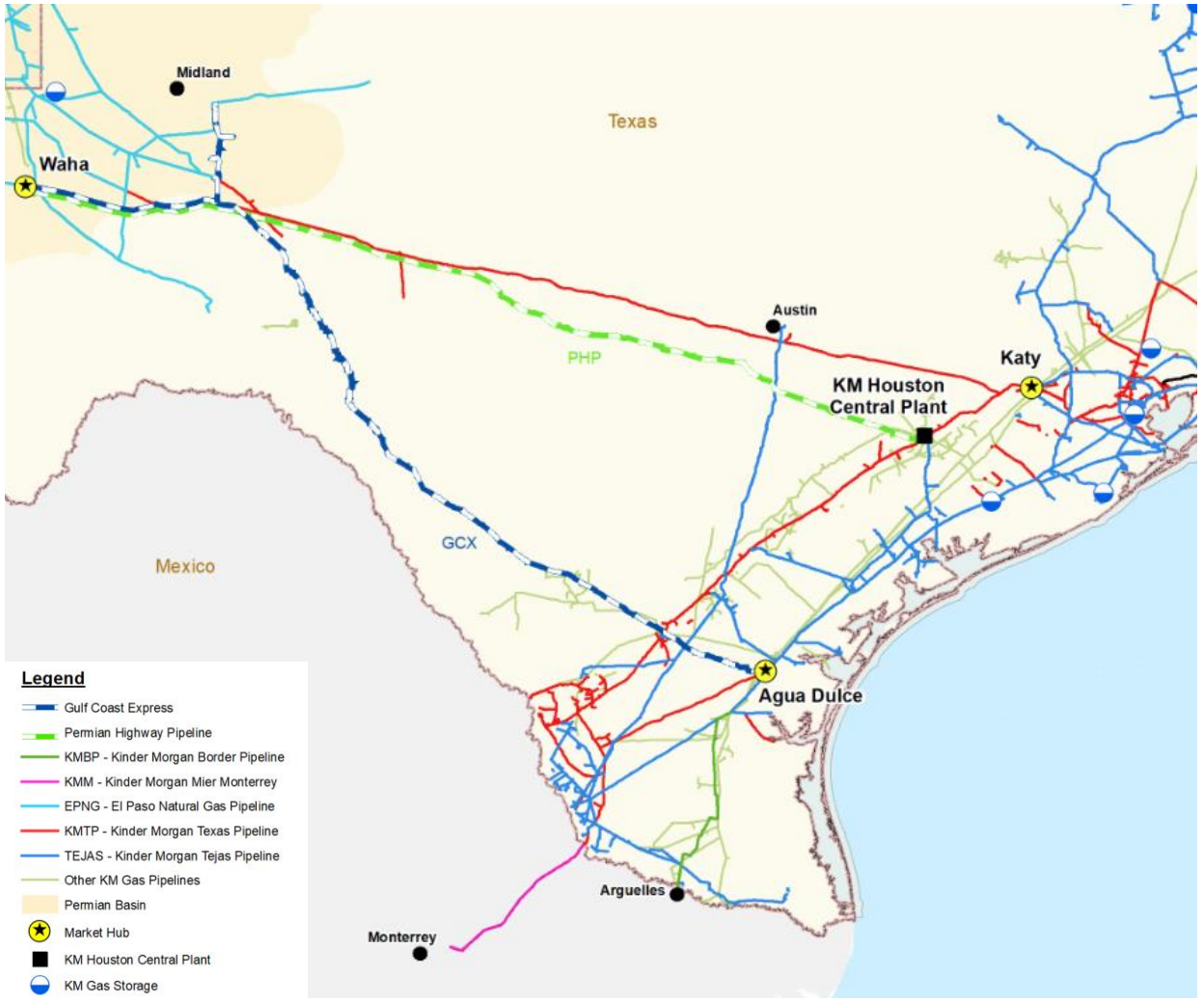
Project Statistics

- Capacity: 2.0 Bcfd
- Capital (100%): $1.75 billion
- In-Service: October 2019
- Minimum contract term: 10 years

Current Status

- Capacity fully-subscribed under long-term, binding agreements
- Construction in progress and on schedule for October 1, 2019 in-service

First-to-market Permian takeaway solution leveraging our expansive existing footprint and deliverability



Project Highlight: Permian Highway Pipeline (PHP)

PHP provides broad U.S. Gulf Coast market optionality for Permian production

Project Scope

- Mainline: ~430 miles of 42" pipeline from the Waha to Katy, Texas areas with connections to the U.S. Gulf Coast and Mexico markets
- 300,320 HP of installed compression, increased 42,870 HP from original scope at FID due to expansion
- KM Texas Pipeline (KMTP) operator and constructor
- KM 40%, EagleClaw Midstream Ventures 40%, anchor shipper affiliate 20% ownership interest[a]

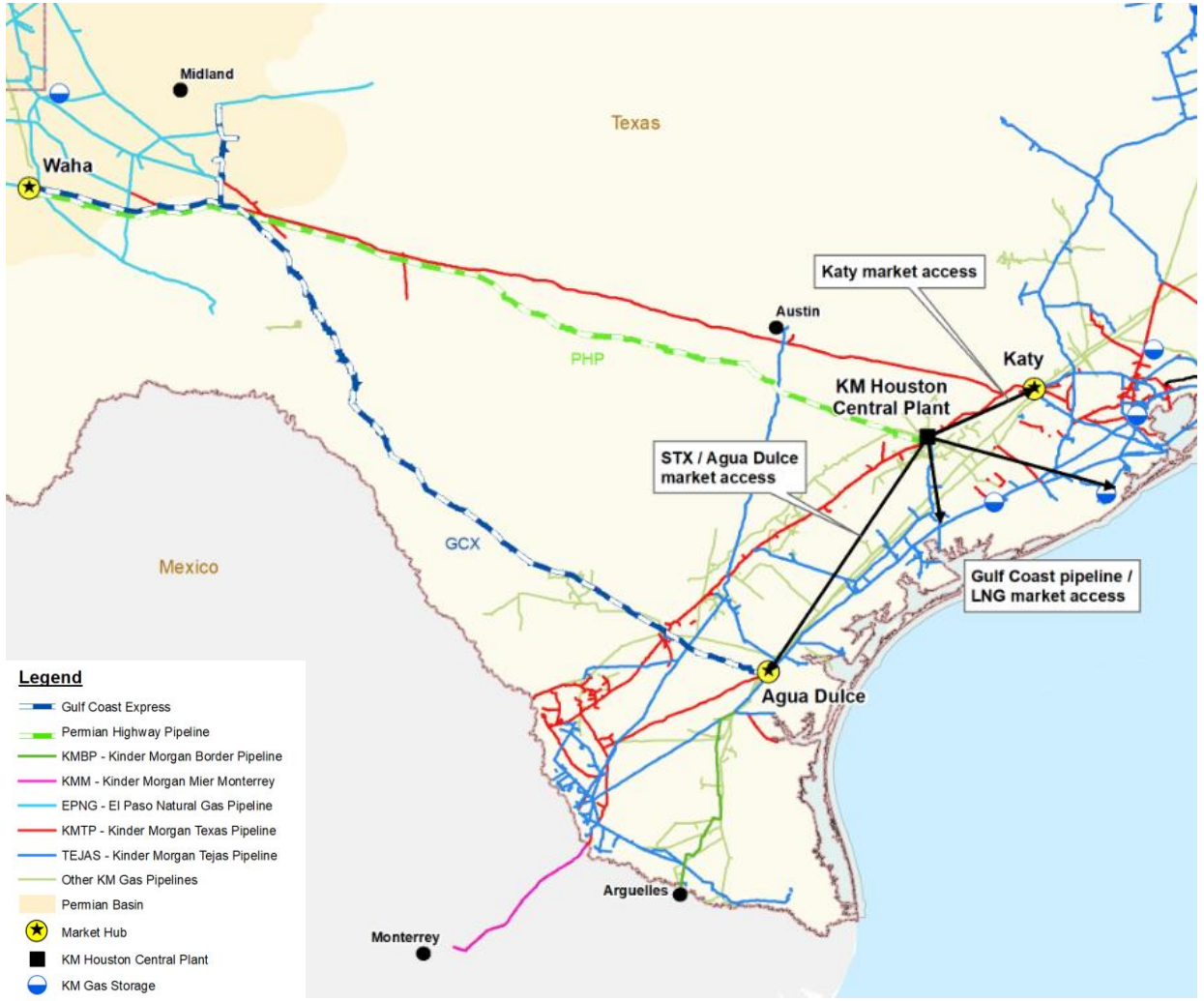
Project Statistics

- Initial Capacity: 2.0 Bcfd
- Expansion Capacity: 0.1 Bcfd
- Capital (100%): ~$2.1 billion
- In-Service: October 2020
- Minimum contract term: 10 years

Current Status

- Final investment decision to proceed made September 2018
- Initial capacity fully-subscribed and under long-term, binding agreements
- Pipeline and compression procured
- Awarded pipeline construction contracts on all spreads
- In commercial discussions with shippers for expansion capacity

Second Permian solution with unmatched market optionality expected to drive investment opportunities downstream



a) KM and EagleClaw's ultimate ownership interest may vary between ~27% and 40%, depending on outcome of equity ownership options held by an additional anchor shipper affiliate.

Growth Driver: G&P Upside from Continued Shale Growth

Opportunities from both operating leverage and capital projects

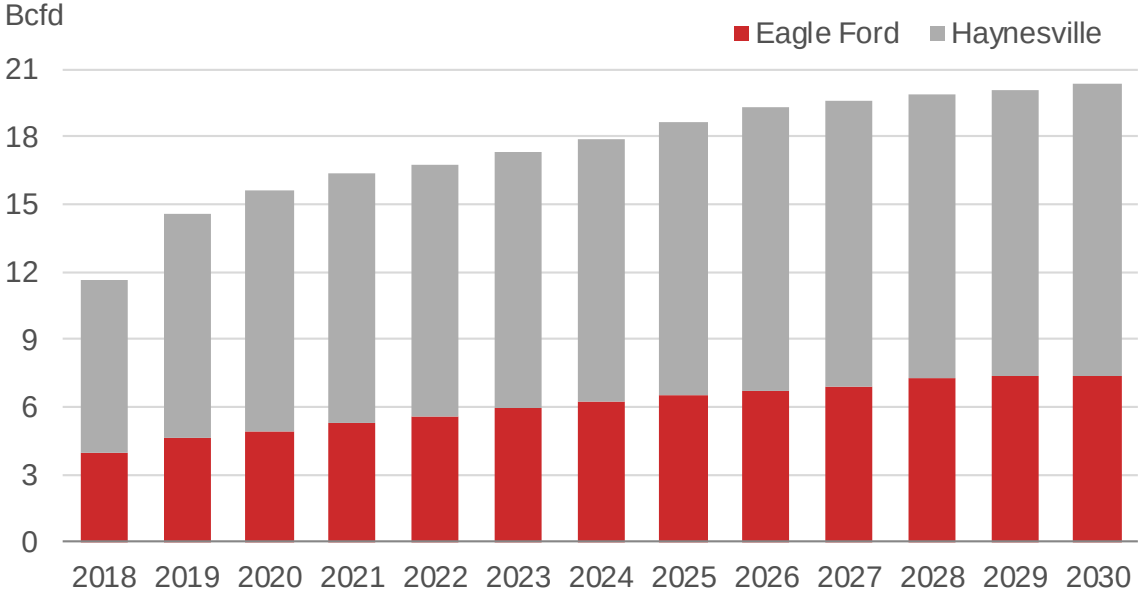
EAGLE FORD & HAYNESVILLE

- 70% of forecasted 2018-2030 demand and export growth occurs in, or transits, Texas and Louisiana
  - Both basins are well positioned for serving growing demand
- Rising production provides additional gathering and takeaway opportunities
- ~0.5 Bcfd of available gathering and processing capacity to handle incremental volume in the Eagle Ford
- ~1 Bcfd of available gathering capacity with minimal capital investment to unlock potential, incremental value in the Haynesville

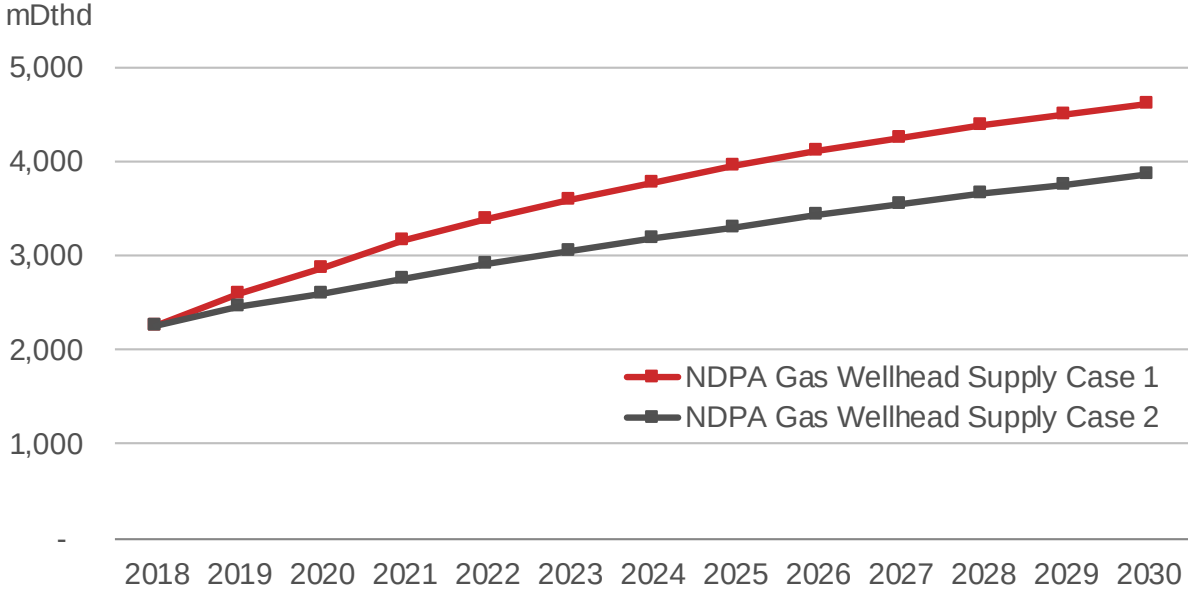
BAKKEN

- $500 million of Bakken G&P projects in Project Backlog
  - Includes construction of 200 mmcfd plant to be placed in service late 2019
- Rising associated gas production will strain existing residue gas / NGL infrastructure, providing additional gathering and takeaway opportunities
  - The Bakken as a whole is currently at a Gas Oil Ratio (GOR) of 2, with new wells now approaching a GOR of 3
  - North Dakota Industrial Council flaring goals of decreasing from 12% to 9% by Nov. 2020
- Processing capacity projected to be constrained by 2021, provides for expansions and new build opportunities

FORECASTED NATURAL GAS PRODUCTION



NORTH DAKOTA GAS PRODUCTION FORECAST



Source: WoodMackenzie, North America Gas Markets Long-Term Outlook, Fall 2018; North Dakota Pipeline Authority (NDPA).

Growth Driver: Support for Increasing Variable Demand

Expect greater daily and seasonal demand volatility from renewable / gas generation, exports and winter conditions

Demand drivers requiring enhanced deliverability

- Opportunities for increased throughput, short notice high deliverability services including gas storage

Renewable generation

- As renewable generation increases, pipeline deliverability becomes increasingly important to natural gas-fired generation for backstopping intermittent renewables
  - Battery storage cannot provide the duration of gas generation for backstopping
  - Opportunities for KM to reconfigure services to provide required deliverability

Growing gas capacity

- U.S. has ~200 GW of operating gas peaker capacity and ~12 GW of planned additions targeting areas with high renewable penetration
- U.S. has ~263 GW of operating gas baseload capacity, ~33 GW of new planned capacity

Export demand

- Increased export related demand, LNG terminal liquefaction interruptions and minimal storage capability in Mexico

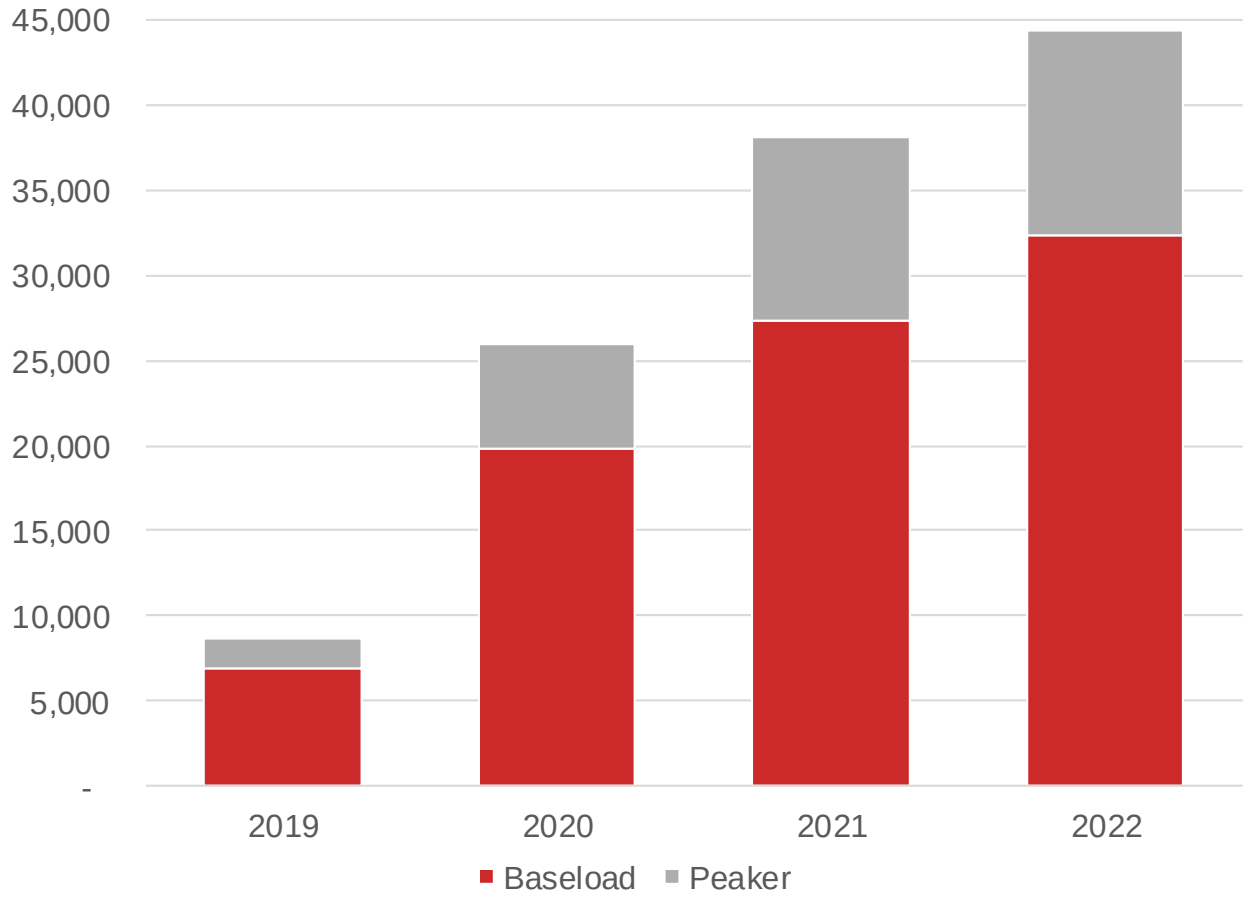
Deliverability opportunities in the Northeast

- Continued winter reliance on fuel oil due to insufficient gas pipeline capacity to the market

PLANNED NEW GAS FIRED GENERATION CAPACITY THROUGH 2022:

GW, shown on a cumulative basis

~12 GW of peaking capacity
~33 GW of baseload capacity



Source: U.S. Energy Information Administration

Natural Gas: Interstate Pipelines

Key statistics

		Ownership	Miles	Capacity (bcfd)	Storage (bcf)	Avg. Remaining Contract Term (yrs)	Effective Date of Next Rate Case
100% KMI-owned:							
TGP	Tennessee Gas Pipeline	100%	11,800	12.1	110	8.4 / 3.8[a]	NA
EPNG	El Paso Natural Gas + Mojave	100%	10,660	5.7	44	5.2	NA
CIG	Colorado Interstate Gas	100%	4,300	5.2	38	6.2 / 6.4[a]	4/1/2022
WIC	Wyoming Interstate	100%	850	3.8	–	3.5	4/1/2022
KMLP	Kinder Morgan Louisiana Pipeline	100%	135	3.0	–	0.8	NA
CP	Cheyenne Plains	100%	410	1.2	–	1.7	NA
TCGT	TransColorado	100%	310	0.8	–	0.9	NA
EEC	Elba Express	100%	200	1.1	–	18	NA
Jointly-owned (asset stats shown at 100%):							
NGPL	Natural Gas Pipeline Co. of America	50%	9,100	7.6	288	5.4 / 4.0[a]	NA
SNG	Southern Natural Gas	50%	6,950	4.3	69	6.2 / 2.8[a]	9/1/2024
FGT	Florida Gas Transmission	50%	5,350	3.9	–	9.2	2/1/2021
FEP	Fayetteville Express	50%	185	2.0	–	2.2	NA
MEP	Midcontinent Express	50%	510	1.8	–	1.7	NA
	Ruby	50%[b]	680	1.5	–	3.5	NA
	Sierrita	35%	60	0.2	–	20.8	NA
Storage and LNG (asset stats shown at 100%):							
	Keystone Gas Storage	100%	15	0.4	6	2.1	NA
SLNG	Southern LNG Co. (Elba Island)	100%	–	1.8	12	13.8	NA
GLNG	Gulf LNG	50%	5	1.5	7	12.8	NA
YGS	Young Gas Storage (CIG)	47.5%			6	6.4	NA

a) Transport / Storage.
b) Reflects third party ownership of a 50% preferred interest.

Natural Gas: G&P and Intrastate Assets

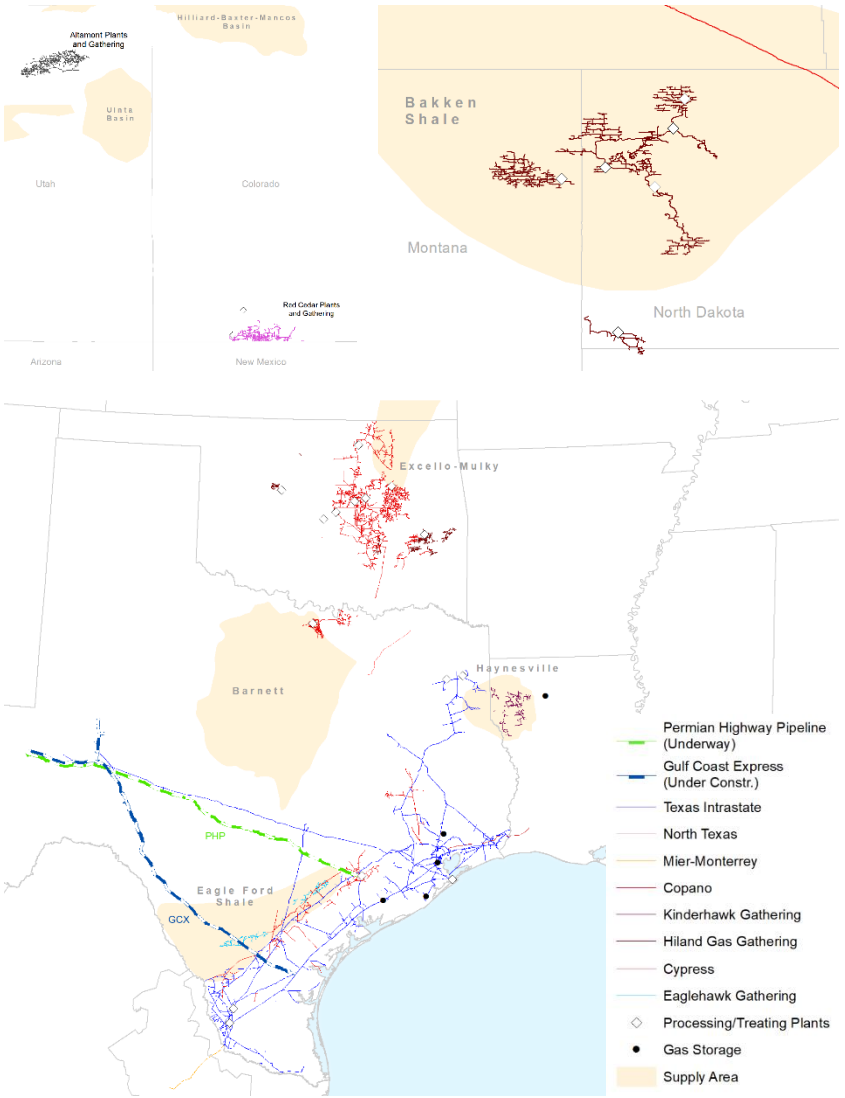
Key statistics

	Ownership	Miles	Capacity (bcfd)	Avg. Remaining Contract Term (yrs)	Storage (Bcf)	Treating (GPM)	Processing (Bcfd)
100% KMI-owned natural gas pipelines:							
KMTP / Tejas	100%	5,640	7.0	4.7	132	1,680	0.5
Copano - gas	100%	6,800	4.8	3.6		4,100	1.3
KinderHawk Gathering	100%	520	2.4	Life of Lease		2,960	
Mier-Monterrey	100%	90	0.7	9.0			
North Texas Pipeline	100%	80	0.3	14.6			
Hiland (Williston Basin) - gas	100%	2,030	0.4	14.4		80	0.2
Camino Real Gathering - gas	100%	70	0.2	3.8			
Altamont Gathering	100%	1,370	0.1	3..3			0.1
Jointly-owned natural gas pipelines (asset stats shown at 100%):							
Eagle Hawk Gathering - gas	25%	530	1.2	Life of Lease			
Red Cedar Gathering	49%	900	0.6	5.6		4,600	
Treating - Leased Units	100%		Plants in service: 52 Amine / 69 MRU / 16 Dew Point				

	Ownership	Miles	Capacity (mbbld)	Avg. Remaining Contract Term (yrs)	Storage (mbbl)
100% KMI-owned liquids pipelines:					
Copano - liquid	100%	430	115	5.1	
Cochin	100%	1,525	95	5.5	900
Jointly-owned liquids pipelines (asset stats shown at 100%):					
Cypress	50%	100	56	2.3	
Utopia	50%	270	50	20.0	
Eagle Hawk Gathering- condensate	25%	400	220	Life of Lease	60

2019 Commodity Price Exposure

Price Δ and Commodity	DCF impact Unhedged / Hedged ($mm)
$1/bbl WTI	$2.2 / $1.4
1% NGL / crude ratio[a]	$1.3 / $0.9
1¢/gal ethane frac spread[b]	$1.4 / $0.6
$0.10/Dth natural gas[c]	$1.7 / $0.7



a) Excluding ethane. Budgeted NGL / crude ratio = 60%.
b) An unfavorable impact can be limited by reducing ethane equity volumes through operational changes and contractual elections.
c) Assumes constant ethane frac spread vs. natural gas prices.

Highly-Contracted Natural Gas Pipelines

Contracted capacity and term by region

NET ANNUAL INCREMENTAL RE-CONTRACTING EXPOSURE (KM SHARE):

% of $8.4bn 2019B Total Segment EBDA[a]

	2020	2021
Interstate pipelines	-0.7%	-2.3%
G&P and Intrastates	-0.2%	-0.3%
Total Natural Gas Pipeline Segment	**-0.9%**	**-2.6%**

Assumptions

- Negative figures represent unfavorable re-contracting exposure based on November 2018 market assumptions
- Excludes contracted cash flow associated with new growth projects
- Assumes evergreen contracts are renewed at market rates
- Interstate transport contracts average remaining term of 6 years 4 months

Re-contracting exposure of base business relatively limited and expected to be more than offset by growth projects underway, continued increases in usage, volume growth and improved storage values

a) 2019 budgeted Segment EBDA before Certain Items plus JV DD&A. See Non-GAAP Financial Measures and Reconciliations.

Projects Placed Into Service During 2018

New natural gas projects expected to generate $327 million of annual EBITDA

Asset	Project	In-service Date	Capacity (mDthd)	Capital, KM Share ($mm)	EBITDA ($mm)
TGP	Broad Run Expansion	Oct 2018	200	463.2	
	SW Louisiana Supply (Cameron)	Mar 2018	900	174.6	
	Lone Star	Dec 2018	300	106.4	
	Triad (Invenergy)	Jun 2018	180	52.8	
KMLP	Cheniere Sabine Pass LNG	Dec 2018	600	132.8	
SNG	Fairburn Expansion	Dec 2018	370	122.4	
EEC	Elba Express Modification Project	Nov 2018	245	83.7	
NGPL	Gulf Coast Expansion - Phase I	Oct 2018	385	87.8	
EPNG	Various Expansions	1Q 2018 - 4Q 2018	529	19.6	
CIG	High Plains & 5AB Expansions	Nov - Dec 2018	452	18.9	
Texas Intrastates	Border Pipeline Expansion	3Q 2018	100	13.8	
	Intrastate well / market connects	1Q 2018 - 4Q 2018	Various	12.8	
Gathering / Other	Williston Basin (Hiland Gas)	1Q 2018 - 4Q 2018	Various	67.2	
	Williston Basin (Hiland Crude)	1Q 2018 - 4Q 2018	Various	61.7	
	Kinderhawk Field Services	1Q 2018 - 4Q 2018	Various	25.5	
	Oklahoma well connects / expansions	1Q 2018 - 4Q 2018	Various	24.0	
	Altamont well connects / expansions	1Q 2018 - 4Q 2018	Various	20.2	
	Other	1Q 2018 - 4Q 2018	Various	16.1	
Total Natural Gas Pipeline Segment:				**$1,503.5**	**$327.5**

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

Project Backlog: Interstate Pipelines

Natural Gas

Asset	Project	Capital, KM Share ($mm)	Capacity (mDthd)	In-service Date	Project Status
ELC / SLNG	Elba Liquefaction	$752	357	1Q 2019	Construction near completion. Commissioning in process. Schedule is dependent on commissioning.
	SLNG Ship Loading	$433			
NGPL	GC Southbound Phase II (Cheniere C.C.)	$114	300	6/2021	FERC filing expected 1Q/2019
	Sabine Pass Compression Expansion	$31	400	2Q 2020	FERC 7(c) application filed 2Q 2018
	Lockridge Lateral Extension	$26	500	4Q 2020	FERC filing expected 1Q/2019
	NIPSCO	$8	75	4/2019	Project engineering underway
EPNG	South Mainline Expansion	$138	271	7/2020	FERC 7(c) application filed, EA issued 11/2018
	XTO / Matador Permian Expansion	$33	415	10/2019	Prior notice FERC filing made 12/2018
	Line 1600 to Waha Phase II	$2	577	10/2019	Project execution underway
	Targa Expansion / Sweetie Peck	$1	100	10/2019	Project execution underway
KMLP	LNG Expansion	$100	800	2Q 2022	FID expected 2Q/3Q 2019
FGT	Seminole Electric	$52	136	6/2018, 4/2022	FERC filing made
	East West	$40	275	1/2019, 2/2019	FERC Certificate received 4/5/2018
	Sanford	$4	400	7/2019	Board approved, preparing regulatory
	South Alabama	$3	60	12/2018, 10/2019	FERC filing made
TGP	Line 261 Upgrade	$58	128	11/2019, 11/2021	FERC 7C Application filed 10/19/2018
Sierrita	Sierrita Gas Pipeline Expansion	$20	323	4/2020	Received FERC 7(c) 10/2018
CIG	Discovery Midstream - New CO/WYCO	$14	410	6/2019	Under development
	Western Sugar Expansion	$2	6	9/2019	Under development
	Black Hills Cody Expansion	$1	15	7/2019	Project underway
	DCP LaSalle 2 O'Connor Meter Upgrade	$1	150	4/2019	Project underway
SNG	Plant Miller	$1	5	2/2019	Initial modifications complete. Other work to be completed by June.
Total Interstate		**$1,835**	**EBITDA = $319 mm**		

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

Project Backlog: G&P and Intrastates

Natural Gas

Asset	Project	Capital, KM Share ($mm)	Capacity (mDthd)	In-service Date	Project Status
Texas Intrastate	Gulf Coast Express	$637	1,980	4Q 2019	Under construction
	Permian Highway	$572	2,100	4Q 2020	Construction contractors secured and surveys underway
	TX Intrastate Combined Crossover Project	$134	1,200	2Q 2020	Construction ongoing.
	Dayton Storage Loop Line	$69	275	11/2019	Construction to commence
	Hilcorp Supply - Texas City Expansion	$19	45	1Q 2019	Construction ongoing
	Intrastate - well/market connects *	$19	Various	2019	Expansions / extensions of existing gathering systems
Gathering / Other	Williston Tier I Gas Expansion	$355	200	11/2019	Processing plant and system gathering expansions ongoing
	Hiland Gas Pasadena Projects / Wild Basin Offload	$73	Various	1Q 2019	Construction ongoing
	Altamont - Bluebell Processing	$31	30	1Q 2019	Construction ongoing
	Hiland Gas Pontiac Project	$30	16	10/2019	Construction to commence
	Other system expansion and well connects *	$99	Various	2019	Expansions / extensions of existing gathering systems
Total Midstream		**$2,038**	**EBITDA = $401 mm**		
Total Natural Gas Pipeline Segment		**$3,872**	**EBITDA = $720 mm**		

Note: EBITDA is a non-GAAP financial measure. See Non-GAAP Financial Measures and Reconciliations.
All projects have KMI Board approval. All projects have executed customer contracts, except where * denotes.

FERC-Regulated Natural Gas Assets

Summary statistics, including remaining contract term and rate moratorium dates (where applicable)

#	Asset Name (Nickname)	KM Ownership	Miles	Transport Capacity (Bcfd)	Storage Capacity (Bcf)	Avg. Remaining Contract Term (years)	% of 2017 Revenues from Negotiated or Discounted Rates	Rate Moratorium through Date
1	Tennessee Gas Pipeline (TGP)	100%	11,800	12.1	110	8.4 / 3.8 (a)	61%	Under negotiation
2	El Paso Natural Gas (EPNG)	100%	10,200	5.7	44	5.5	76%	—
3	Natural Gas Pipeline (NGPL)	50%	9,100	7.6	288	5.4 / 4.0 (a)	80%	6/30/2022
4	Southern Natural Gas (SNG)	50%	6,950	4.3	69	6.2 / 2.8 (a)	29%	8/31/2021
5	Florida Gas Transmission (FGT)	50%	5,350	3.9	—	9.2	46%	1/31/2021
6	Colorado Interstate Gas (CIG)	100%	4,300	5.2	38	6.2 / 6.4 (a)	30%	9/30/2020
7	Wyoming Interstate (WIC)	100%	850	3.8	—	3.5	68%	12/31/2020
8	Ruby Pipeline	50% (b)	680	1.5	—	3.5	95%	—
9	Midcontinent Express (MEP)	50%	510	1.8	—	1.7	96%	—
10	Mojave Pipeline	100%	470	0.4	—	1.0	1%	—
11	Cheyenne Plains (CP)	100%	410	1.2	—	1.7	95%	—
12	TransColorado (TCGT)	100%	310	0.8	—	0.9	93%	—
13	Elba Express (EEC)	100%	200	1.1	—	18.0	100%	—
14	Fayetteville Express Pipeline (FEP)	50%	185	2.0	—	2.2	100%	—
15	KM Louisiana Pipeline (KMLP)	100%	135	3.0	—	0.8	100%	—
16	Sierrita Pipeline	35%	60	0.2	—	20.8	100%	—
17	Horizon Pipeline	25%	30	0.4	—	5.5	77%	—
18	KM Illinois Pipeline (KMIP)	50%	3	0.2	—	3.0	100%	—
19	Southern LNG Co. (SLNG)	100%	—	1.8	12	13.8	78%	—
20	Bear Creek Storage	75%	—	—	59	n.a.	0%	—
21	Young Gas Storage	47.5%	—	—	6	6.4	0%	Pending FERC approval

Significant assets under multi-year agreements and/or rate moratorium

Meaningful % of 2017 revenues from negotiated or discounted rates

a) Average remaining contract term shown for transport / storage contracts.
b) Reflects third party ownership of a 50% preferred interest.

Products Pipelines

Segment Presentation

Products Segment Overview

Strategic footprint with significant cash flow generation

Asset Summary

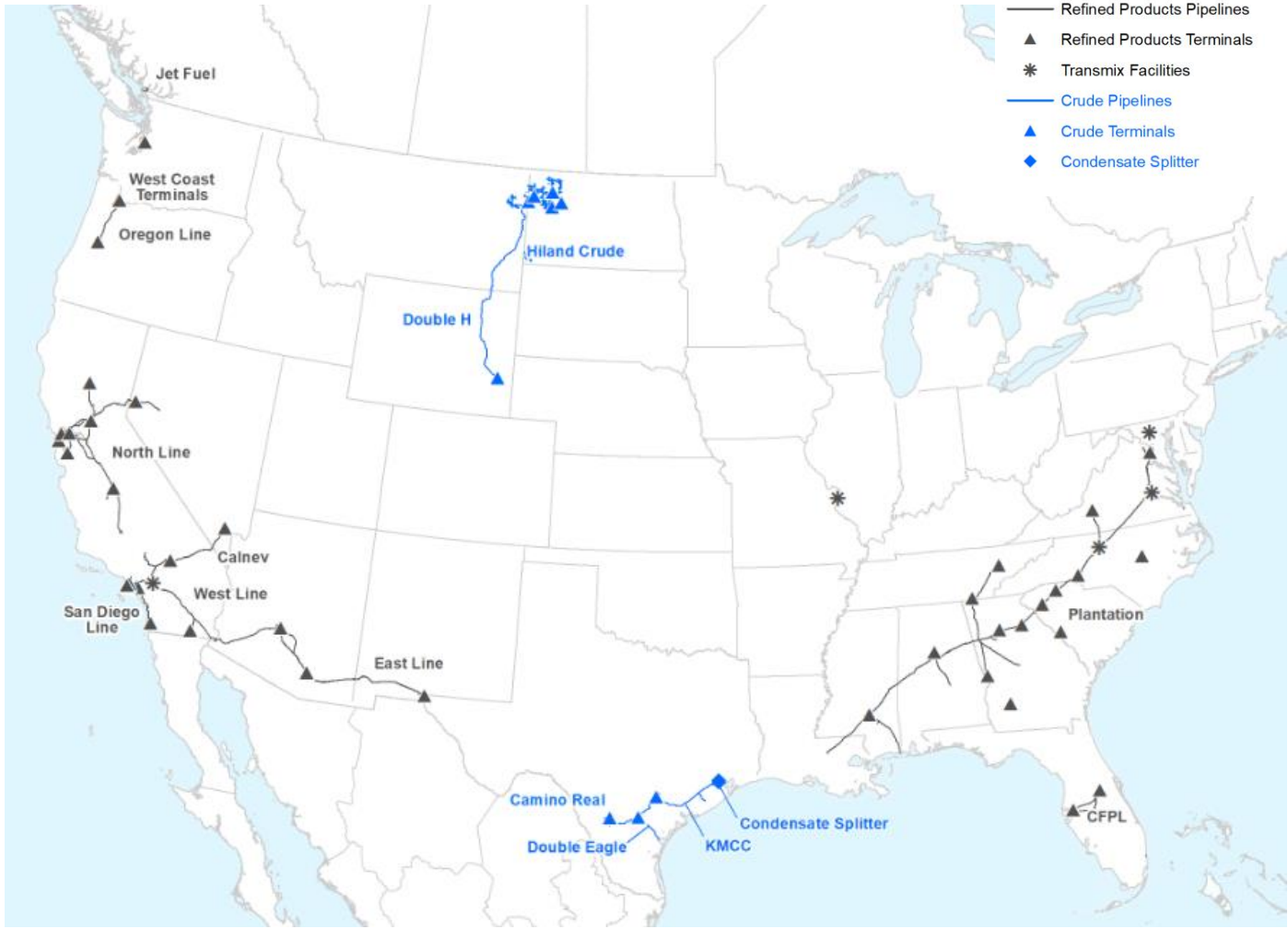
Pipelines[(a)]:	~9,500	Miles
2018 Throughput[(a)]	~2.3	mmbbld
Condensate Processing Capacity	100	mbbld
Transmix	5	facilities
Terminals:	67	Terminals
Terminals Tank Capacity	~39	mmbbls
Pipeline Tank Capacity	~15	mmbbls

2019B EBDA[(b)]: ~$1.3 billion

Project Backlog:

$0.1 billion of identified growth projects over the 2019-2020 time period[(c)]

- Plantation Roanoke expansion
- Enhanced capabilities for condensate splitter
- Multiple refined products terminaling projects
- Various Bakken crude gathering projects



a) Volumes and mileage include SFPP, CALNEV, Central Florida, Plantation Pipe Line (KM share), KMCC, Camino Real, Double Eagle (KM share), Double H and Hiland Crude Gathering.
b) 2019 budgeted Segment EBDA before Certain Items plus KM share of JV DD&A. See Non-GAAP Financial Measures and Reconciliations.
c) Includes KM share of non-wholly owned projects. Includes projects currently under construction.

KMCC and Double Eagle Update

Valuable connectivity to Corpus Christi and the Houston Ship Channel

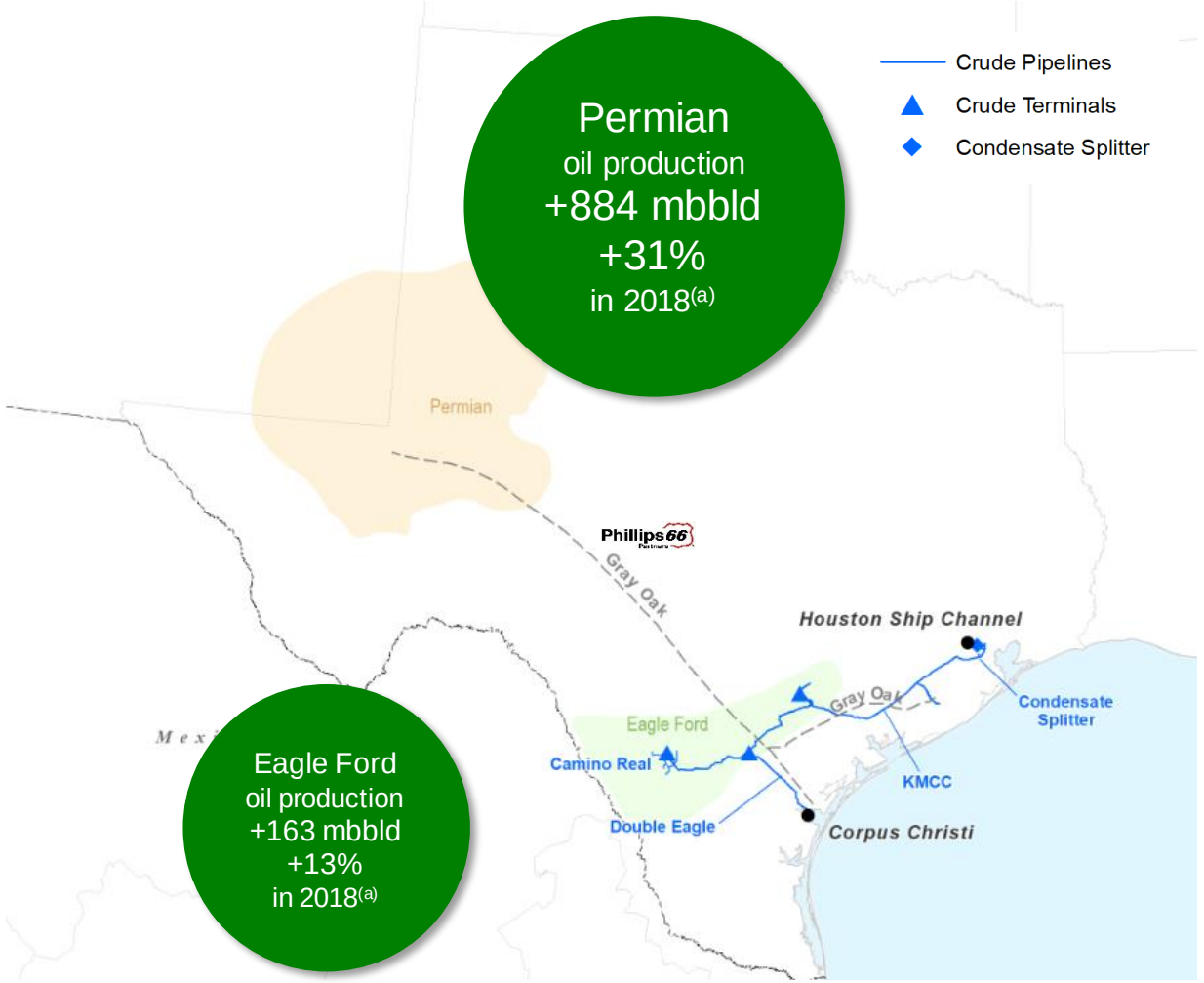
Strong Permian and Eagle Ford production growth driving new projects and increased utilization on existing assets

2019B assumes 7% year-over-year increase in volumes transported from the Eagle Ford and Permian on our assets

KMCC and Double Eagle are connected to Corpus Christi and the Houston Ship Channel markets, which offer key access to domestic refining capacity and export facilities

KMCC currently working towards open season with P66 Partners' Gray Oak pipeline to offer joint tariff service from the Permian Basin to the Houston market

- Not currently in backlog
- Connects KMCC to new supply basin
- Expansion provides up to 100 mbbld of incremental capacity on KMCC



a) EIA Short Term Energy Outlook, Drilling Productivity Report, December 2018.

Bakken Crude Update

Strong production growth in the Bakken translating into higher transport volumes

2019B estimates 21% year-over-year increase in volumes transported on our assets from the Bakken

KMI benefitting from premier gathering system

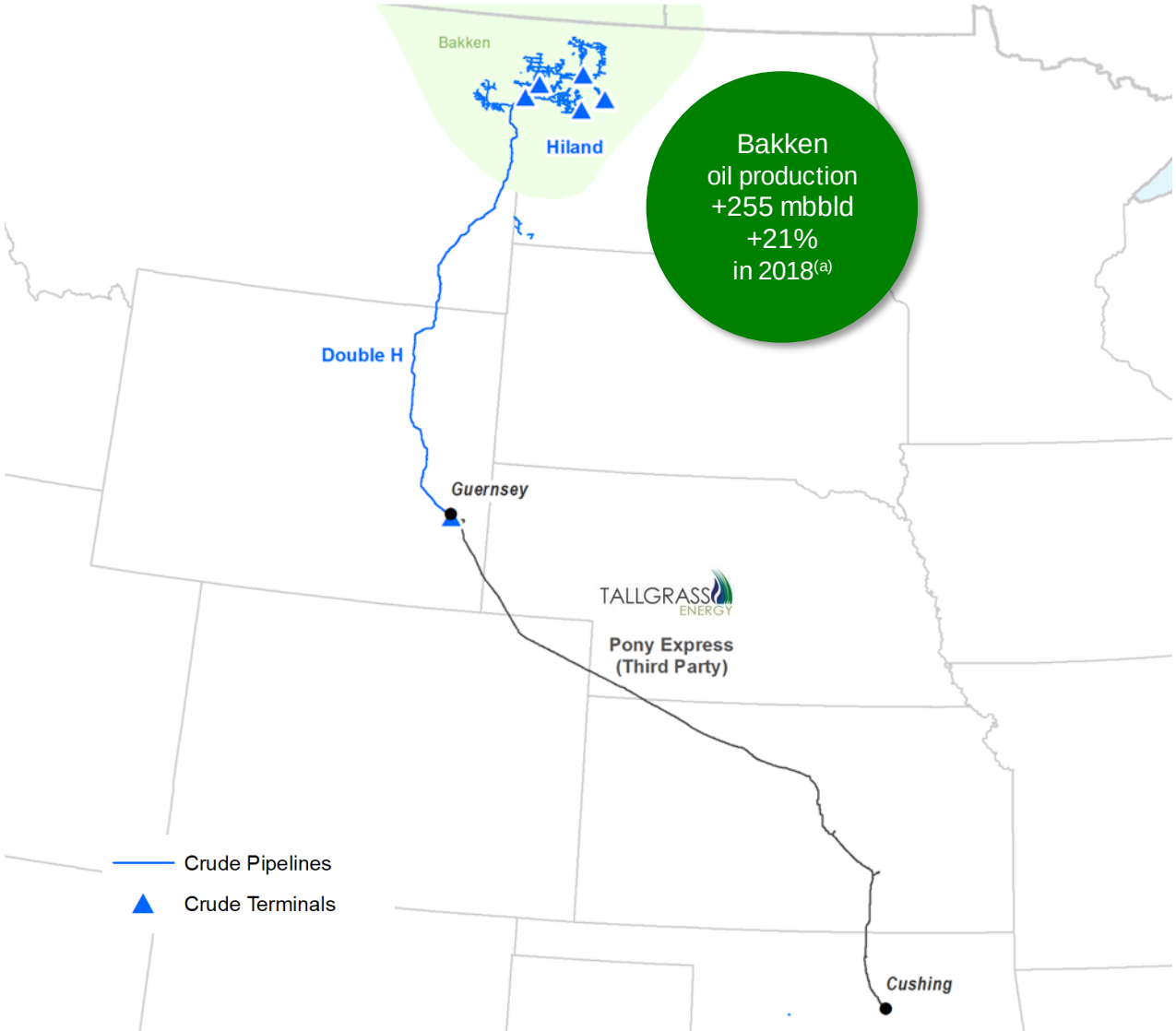
- Backed by dedications from key producers in the basin
- Well positioned to capture incremental production
- Joint tariff with Pony Express provides access to Cushing

Potential Double H expansion (not currently in backlog)

- Would streamline structure to access Cushing and U.S. Gulf Coast markets
- Option to increase pumping capability would yield 30 mbbld in incremental capacity

KMI – Tallgrass Rockies Project (not currently in backlog)

- Potential conversion of KMI gas assets to crude service and new build to Cushing as part of joint offering with Pony Express Pipeline
- Industry solution for growing Rockies production, plus incremental takeaway for Bakken and Canadian production
- Combined system would have capability to transport 800 mbbld of light crude oil and 150 mbbld of heavy crude oil from Wyoming and Colorado to Cushing, Oklahoma



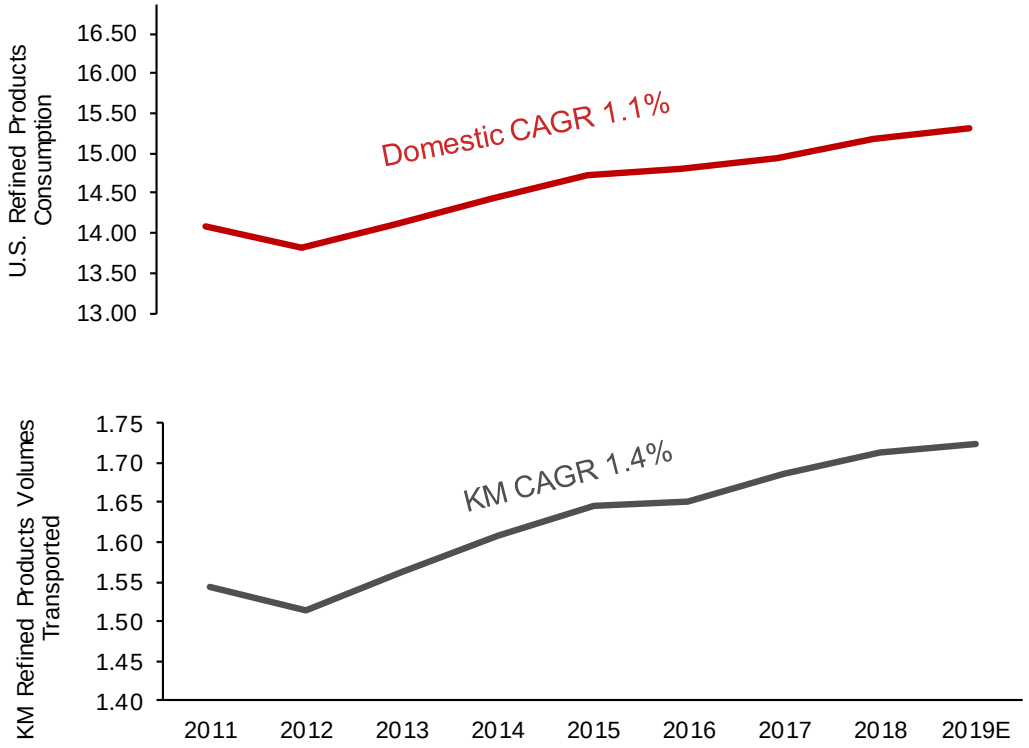
a) EIA Short Term Energy Outlook, Drilling Productivity Report, December 2018.

Stable U.S. Market Demand for Refined Products

Expansive footprint positioned to capture market opportunities

U.S. REFINED PRODUCTS CONSUMPTION[(a)] & KM REFINED PRODUCTS VOLUMES TRANSPORTED[(b)]

mmbbld



- Our expansive refined products footprint connects major refining centers to major consuming markets
  - Unmatched connectivity
  - Potential for market share gains in key growth areas
- Refined products fundamentals are positive
  - Steady U.S. demand for total refined products
  - FERC indexing provides predictable margin growth with 4.40% increase projected for 2019[(c)]

Our refined products volumes are consistent and slightly exceed domestic consumption growth

a) Source: EIA, Table 4a. U.S. Crude Oil and Liquid Fuel Supply, Consumption, and Inventories and Figure 15 U.S. Liquids Fuel Consumption Growth, December 2018.
b) Volumes include SFPP, CALNEV, Central Florida, and Plantation Pipe Line (KM share).
c) Internal projection of expected rate increase based on regulatory framework (PPI FG+1.23%).

Project Highlight: Roanoke Expansion

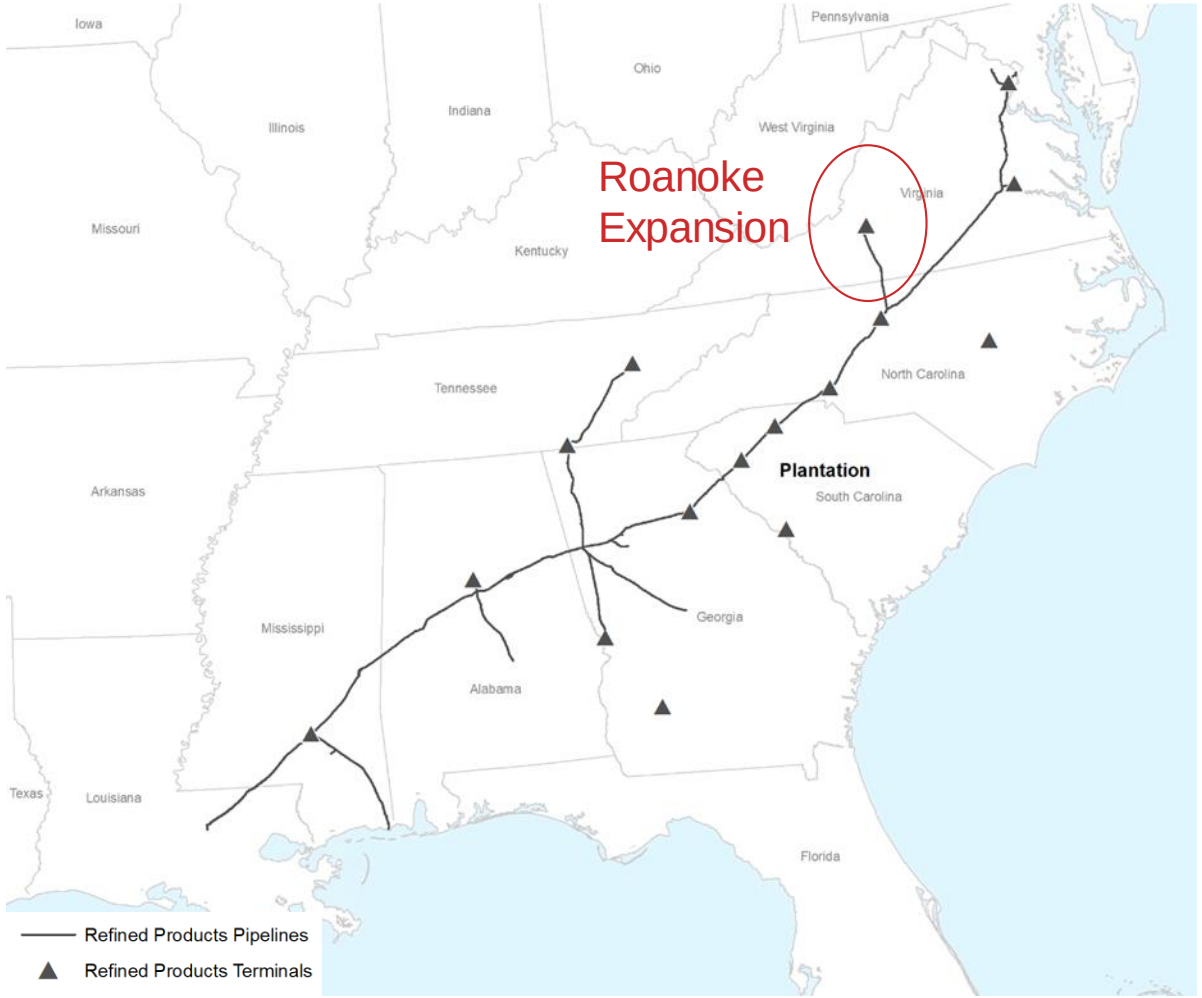
Securing refined products delivery for the Roanoke / Montvale area

Market Drivers

- Historically, both the Colonial Pipeline Montvale Lateral and Plantation Roanoke Lateral have served the Roanoke, Virginia market
- Abandonment of the Colonial Montvale Lateral has displaced 30-50 mbbld in the Roanoke / Montvale area, creating opportunity for Plantation

Project Scope

- ~21 mbbld expansion on Plantation Pipeline system (mainline and delivery lateral)
  - Secured by 20 mbbld 10-year contracts with strong credit-worthy counterparties
- Serving the Roanoke / Montvale market in Virginia with origin points in Louisiana and Mississippi
- Also expanding terminals at Roanoke locations to handle additional throughput
- ~$34 million investment (KM share)
- Expected expansion to Greensboro in service by May 2019, expected in service to Roanoke by April 2020



Products Pipelines Segment Snapshot

Asset statistics

Crude oil assets:	Statistics	Origin	Destination
KM Crude & Condensate pipeline (KMCC)	264 miles	Eagle Ford Shale Field in South TX (Dewitt, Karnes, Gonzales Counties)	Houston Ship Channel Refining Complex
Camino Real Gathering	70 miles	South Texas, Eagle Ford shale formation	
Double Eagle pipeline (50 / 50 JV Magellan)	204 miles	Eagle Ford	Corpus Christi and KMCC
Double H pipeline	512 miles	Bakken shale in Montana and North Dakota	Guernsey, WY
Hiland (Williston Basin)	1,587 miles	Bakken / Three Forks shale formations (North Dakota / Montana)	
Condensate Splitter	Two 50 mbbld units which split condensate into its various components; located in the Houston Ship Channel		
Refined products assets:			
Plantation Pipeline Company	3,182 miles	Louisiana & Mississippi	From Mississippi through Virginia incl. Tennessee
SFPP Pipeline System	2,845 miles	North Line: San Fran Bay area refineries Oregon Line: Portland Marine terminals West Line: Los Angeles Basin East Line: El Paso, TX	North Line: Northern CA and NV Oregon Line: Eugene, OR West and East Lines: Arizona San Diego Line: serves major population areas in Orange County and San Diego
CALNEV Pipeline System	566 miles	Colton, CA	Las Vegas, NV
Central Florida Pipeline (CFPL)	206 miles	Tampa, FL	Orlando, FL
Southeast Terminals	27 locations ~9 mmbbls capacity	From Mississippi through Virginia incl. Tennessee	
West Coast Terminals	64 miles 7 locations ~10 mmbbls storage capacity	Seattle, Portland, San Francisco, and Los Angeles area terminals; Vancouver Jet Fuel pipeline	
Transmix Facilities	~0.6 mmbbls tankage capacity	Colton, CA; St Louis, MO; Greensboro, NC; Woodbine, MD; Richmond, VA	

Terminals

Segment Presentation

Terminals Segment Overview

Diversified terminaling network connected to key refining centers and market hubs

Asset Summary

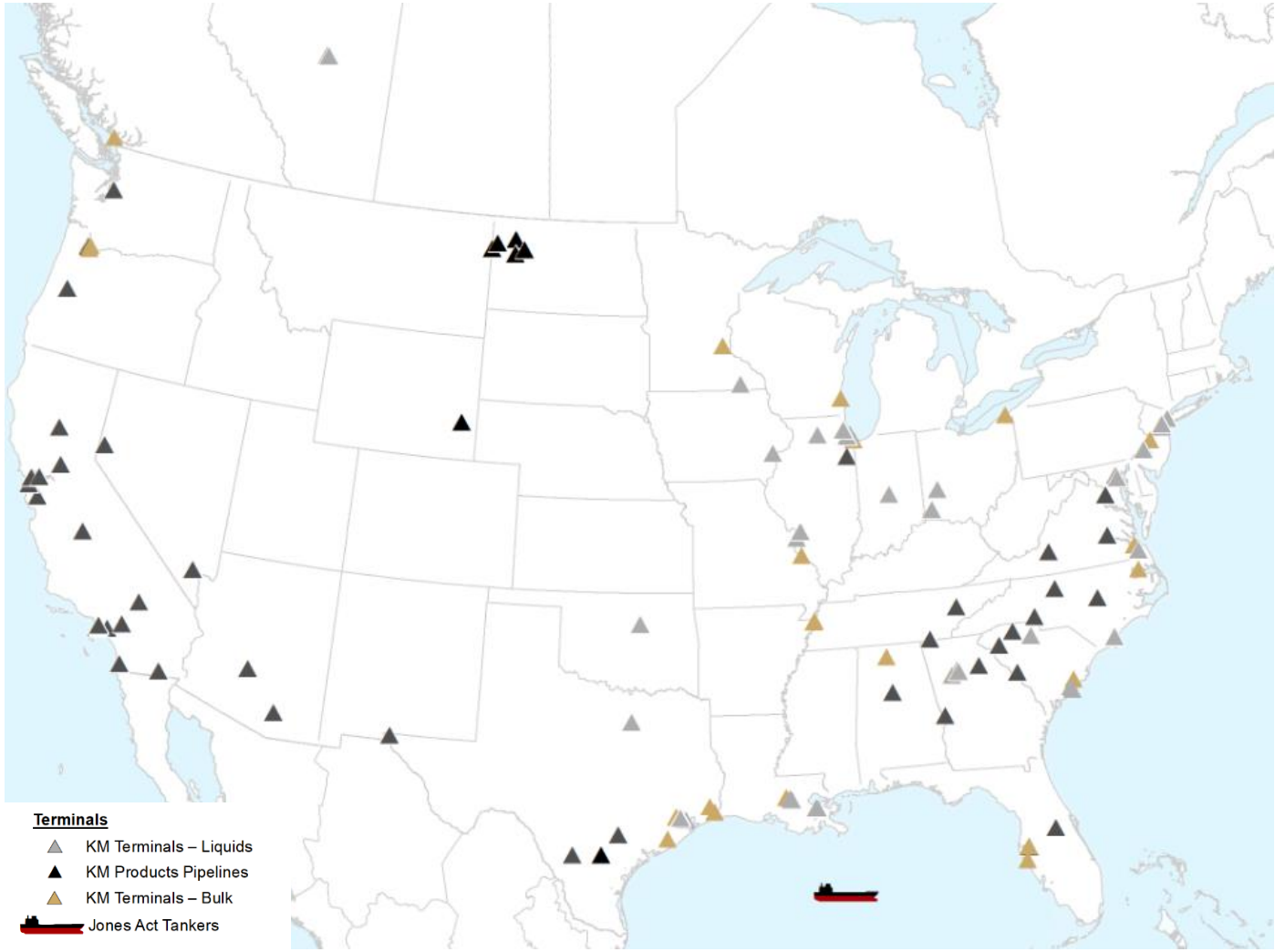
Total Kinder Morgan Terminals:	157	Terminals
Terminals Segment – Bulk	34	Terminals
Terminals Segment – Liquids	56	Terminals
Products Pipelines Segment Terminals	67	Terminals
Jones Act:	16	Tankers

2019B EBDA[(a)]: ~$1.2 billion

Project Backlog:

$0.1 billion to be completed in 2019-2021[(b)]

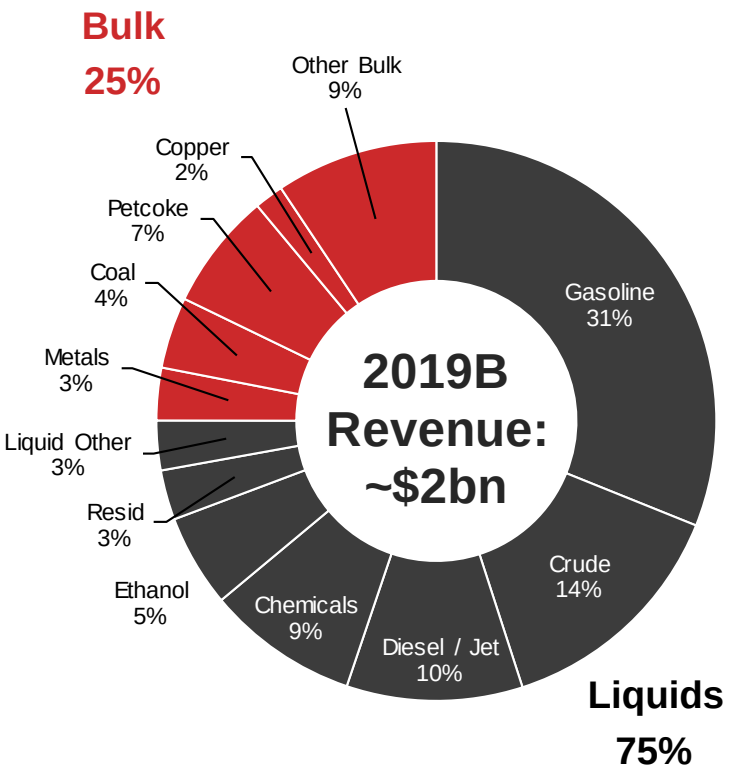
- Diesel tank expansion at Vancouver Wharves
- Investments to expand services at existing terminal facilities in Houston Ship Channel and other locations



a) 2019 budgeted Segment EBDA before Certain Items plus KM share of JV DD&A. See Non-GAAP Financial Measures and Reconciliations.
b) Includes KM share of non-wholly owned projects. Includes projects currently under construction.

Terminals Segment Product Mix

Commodities serving the world's most advantaged petroleum and petrochemical industry



Diverse product mix underpinning stable business profile

Refined Products / Renewables 52%

- Houston Ship Channel position is the largest single refined products and renewables terminaling system worldwide
- Organic growth through continued unmatched service offerings and flexibility to domestic and international markets

Crude Oil 14%

- Canada's premier merchant terminaling system allowing Alberta producers access to both U.S. pipeline and international markets
- Organic growth with enhanced customer inbound and outbound multi-modal customer market options and opportunities.

Chemicals 9%

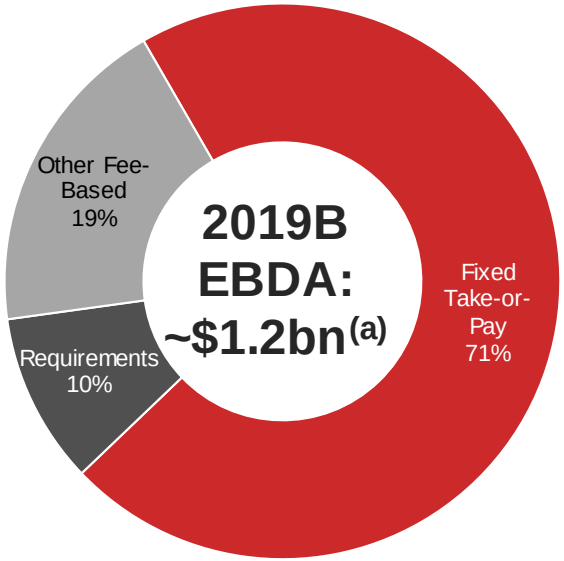
- U.S. crude, condensate, NGL and natural gas production growth continues to promote world-scale, cost-advantaged domestic expansion
- Organic growth both through current terminal services and expansions as well as new plant logistics solutions

Bulk 25%

- KM export / import capabilities in multiple bulk commodity products, including petroleum coke, coal, copper, ores, soda ash and other
- Organic growth with increasing international trade across multiple commodities

Terminals Segment Contract Model

Stable, fee-based business model



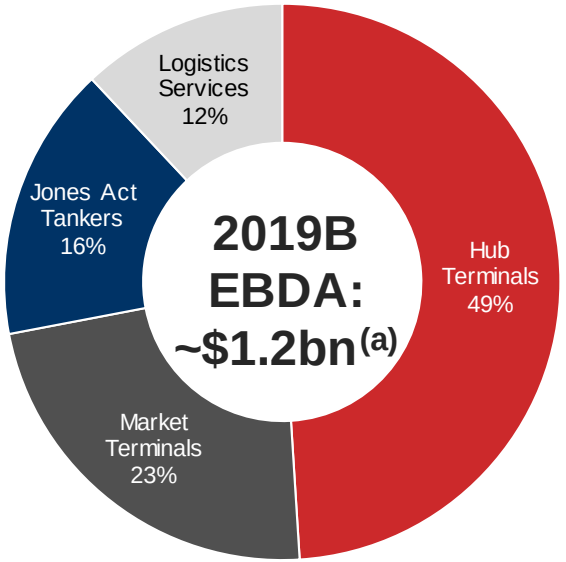
Fee-based business model underpinned by take-or-pay contracts

Take-or-Pay 71%	▪ Leased tank capacity (pre-paid monthly) ▪ Jones Act tanker charters (pre-paid monthly) ▪ Minimum volume commitments (per bbl or ton)
Requirements(b) 10%	▪ Fee-based ▪ Ratable – tied to customer production levels ▪ Refineries – petroleum coke production ▪ Steelmaking – Nucor in-plant services
Other Fee-Based 19%	▪ Ancillary services (e.g., vessel loading and blending) ▪ Based on customer use (per bbl or ton) ▪ Secured by customer and market needs
Other <1%	▪ Other ancillary services ▪ No KM marketing or equity barrels at our facilities ▪ Not competing with our customers

a) 2019B segment EBDA before Certain Items. See Non-GAAP Financial Measures and Reconciliations.
b) Customer has a physical requirement and, in almost all cases, contractual obligation to exclusively use our facility or services.

Terminals Segment Strategy

Critical infrastructure and value-added service solutions



"Much more than storage"

Hub Terminals 49%

- Market clearing point between global buyers and sellers
- Multi-modal connectivity and value-added services
- Critical to our customers and their business
- KM liquids hubs: Houston, Edmonton and New York Harbor

Market Terminals 23%

- Geographic: market-specific regional product demand
- Commodity: product-specific supply chain solutions
- Trade: multi-commodity import / export infrastructure
- KM businesses: truck racks, renewables and bulk export terminals

Jones Act Tankers 16%

- 16 modern and efficient tankers
- Multi-commodity and multi-market
- Only solution for growing U.S. maritime trade
- KM's APT subsidiary: largest Jones Act tanker fleet

Logistics Services 12%

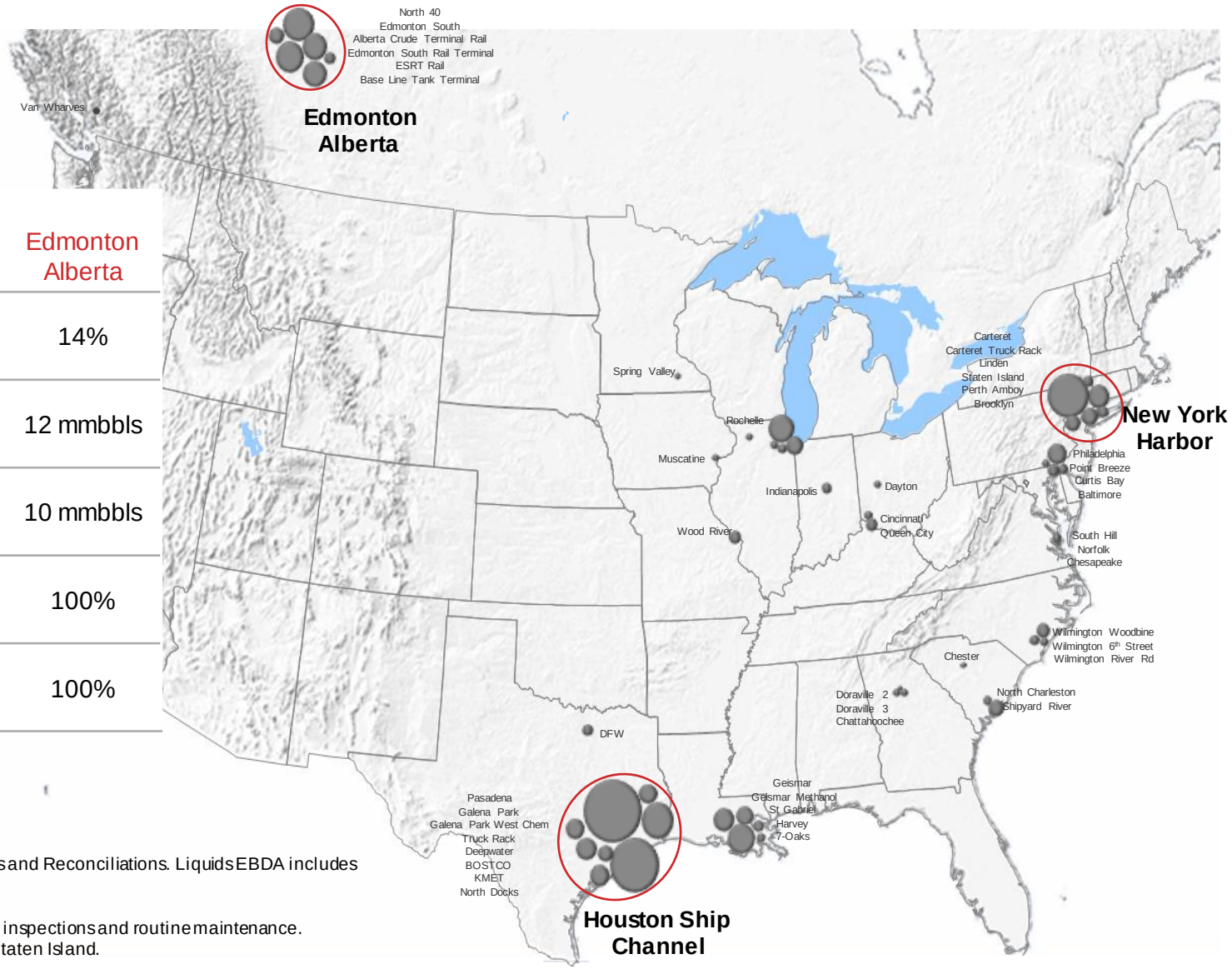
- Customer in-plant logistics solutions
- Leverage competencies in bulk and liquids
- Tankage, transloading and other services
- Nucor, Methanex and petroleum coke services

a) 2019B segment EBDA before Certain Items. See Non-GAAP Financial Measures and Reconciliations.

Terminals Liquids Hubs

Houston, Edmonton, and New York Harbor

	Houston Ship Channel	New York Harbor	Edmonton Alberta
% of 2019B Liquids EBDA[a]	39%	10%	14%
Total Terminal Capacity[b]	43 mmbbls	16 mmbbls	12 mmbbls
New Capacity since 2010	17 mmbbls	3 mmbbls	10 mmbbls
5-yr Average Utilization[c]	95%	93%	100%
2019B Utilization[d]	95%	90%	100%



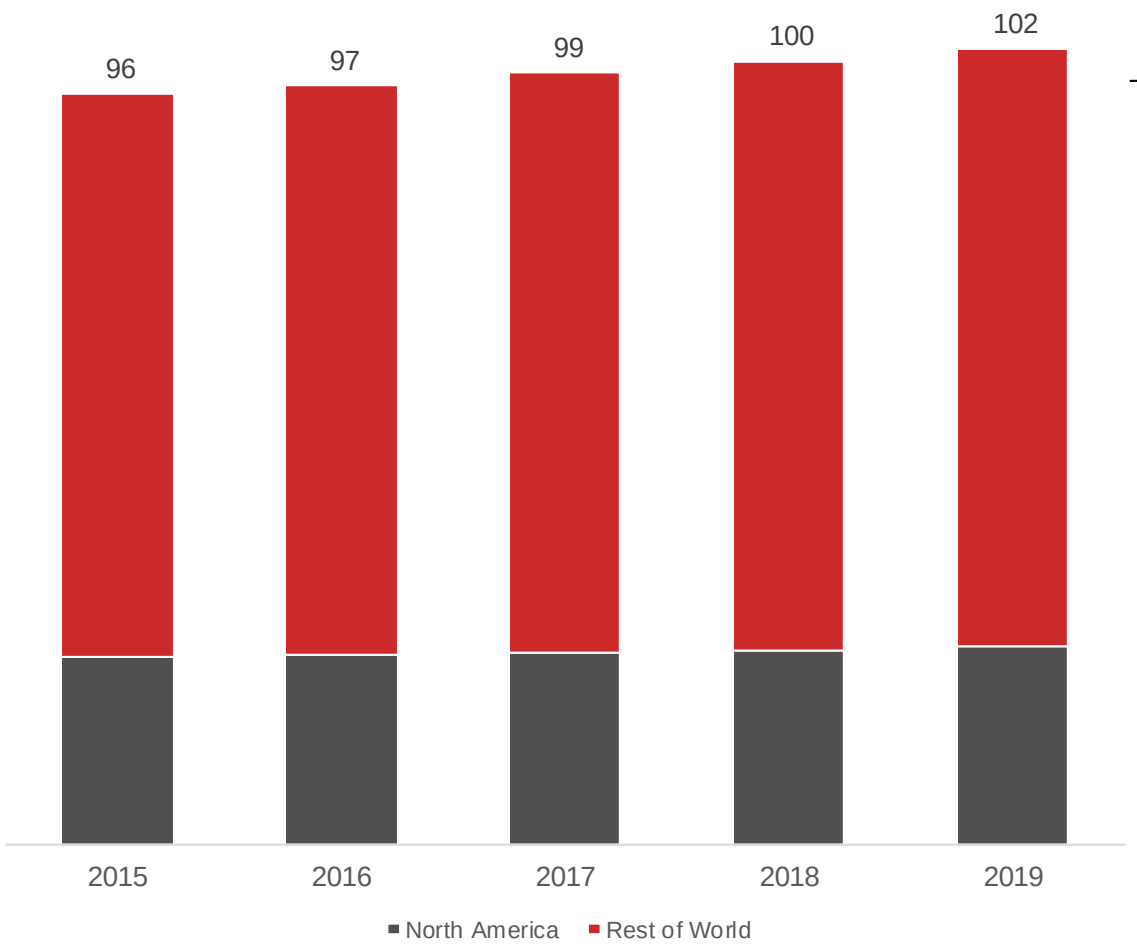
a) 2019B segment EBDA before Certain Items. See Non-GAAP Financial Measures and Reconciliations. Liquids EBDA includes Jones Act Tankers.
b) Total capacity, including JV Partner interests.
c) 2014-2018 average; utilization reflects tankage unavailable for lease due to API inspections and routine maintenance.
d) All Houston and Edmonton tankage fully leased in 2019B; available tankage at Staten Island.

Strong Liquids Fundamentals

Attractive opportunities to supply U.S. products to consumers here and abroad

GLOBAL LIQUIDS CONSUMPTION EXPECTED TO EXCEED 100 MILLION BARRELS PER DAY BY 2019

World Petroleum and Other Liquids Consumption (mmbbld)



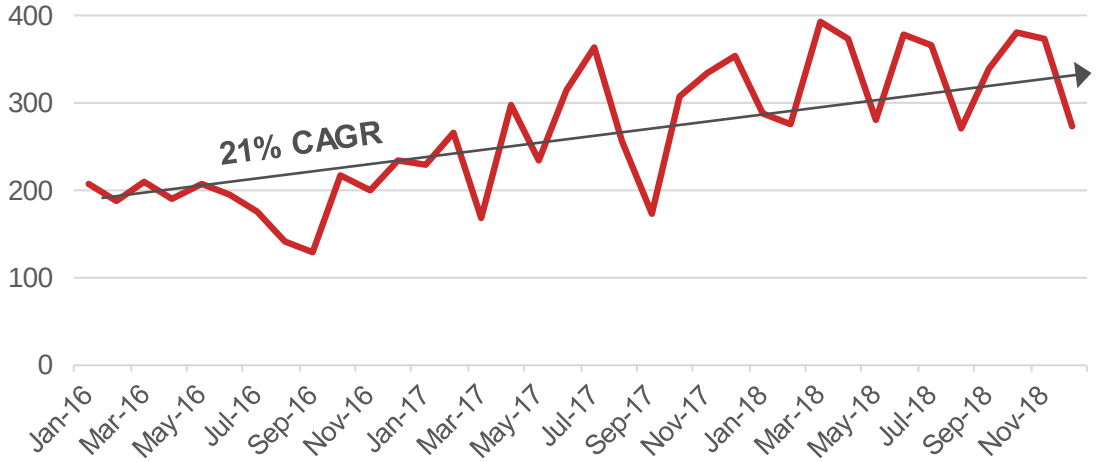
GROWTH LED BY CHINA AND INDIA (2017 – 2019)

+2.2 mmbbld — Rest of World

+0.8 mmbbld — North America

EXPORT CAPACITY REQUIRED TO DELIVER U.S. SUPPLIES TO GROWING DEMAND MARKETS

KM Liquids Exports from Gulf Coast (mbbld)



Source: U.S. Energy Information Administration, Short Term Energy Outlook (December 2018), KM internal data (CAGR calculated on a rolling 3 months basis beginning Q1 2016)..

Positioned to Support U.S. Gulf Coast Exports

Houston's premier refined products aggregation and market-clearing terminaling hub

Our Houston Ship Channel position represents the largest independent refined products terminaling system in U.S.

- 43 million barrels of total capacity
- KM handles ~15% of total U.S. exports of gasoline, gasoline blend stocks and distillates[(a)]
- Unmatched pipeline connectivity
- Built for inbound / outbound flexibility
- Pipeline, rail, barge, ship and truck capabilities
- Highly-contracted, highly-utilized

Clearing point for domestic and international markets

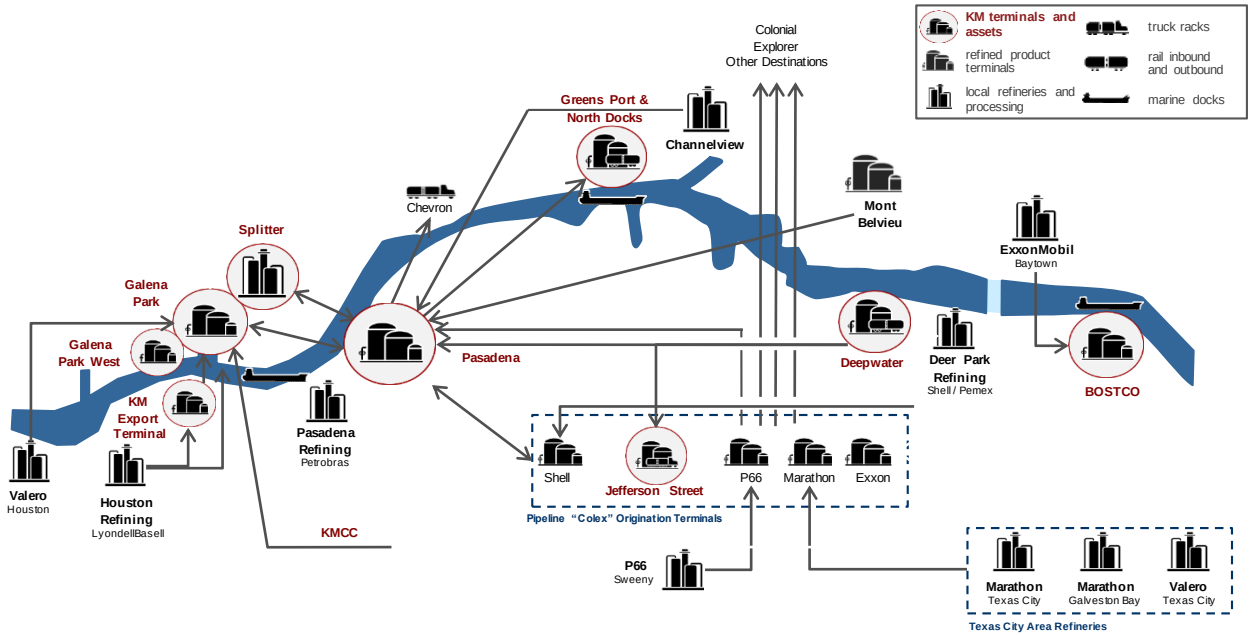
- Pipeline connectivity to domestic markets in East Coast and Midcontinent
- Marine connectivity to global markets
- Scale allows for centralized operations to maximize customer optionality

Built to serve the world's most competitive refining and petrochemical industry across multiple products

- Refined product core focus with complementary chemicals and renewables capabilities
- Difficult to replicate

Nearly $2 billion invested in our Houston hub since 2010

Integrated Houston Ship Channel Terminal Footprint



#	Asset	Connectivity
20	Inbound Pipelines	10 Houston area refineries and local chemical plants
15	Outbound Pipelines	Texas, Midcontinent, and East Coast markets
14	Cross-Channel Pipelines	Interconnecting the system
12	Barge Docks	Receipt and delivery of products and blendstocks
11	Ship Docks	Serving export and Jones Act markets
9	Bay Truck Rack	Averaging ~90 mbbld of local Houston market deliveries
3	Unit Train Facilities	Crude oil, condensate, and ethanol

a) KM market share calculated using internal data for KM export volumes and U.S. Energy Information Administration data for U.S. export volumes for the 12 months ended October 2018 (latest EIA data available).

Positioned to Meet Domestic Maritime Demand

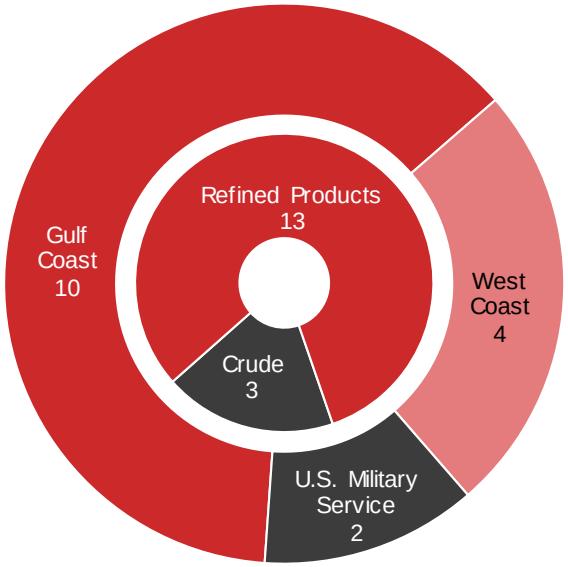
American Petroleum Tankers (APT) fleet of 16 MR-tankers

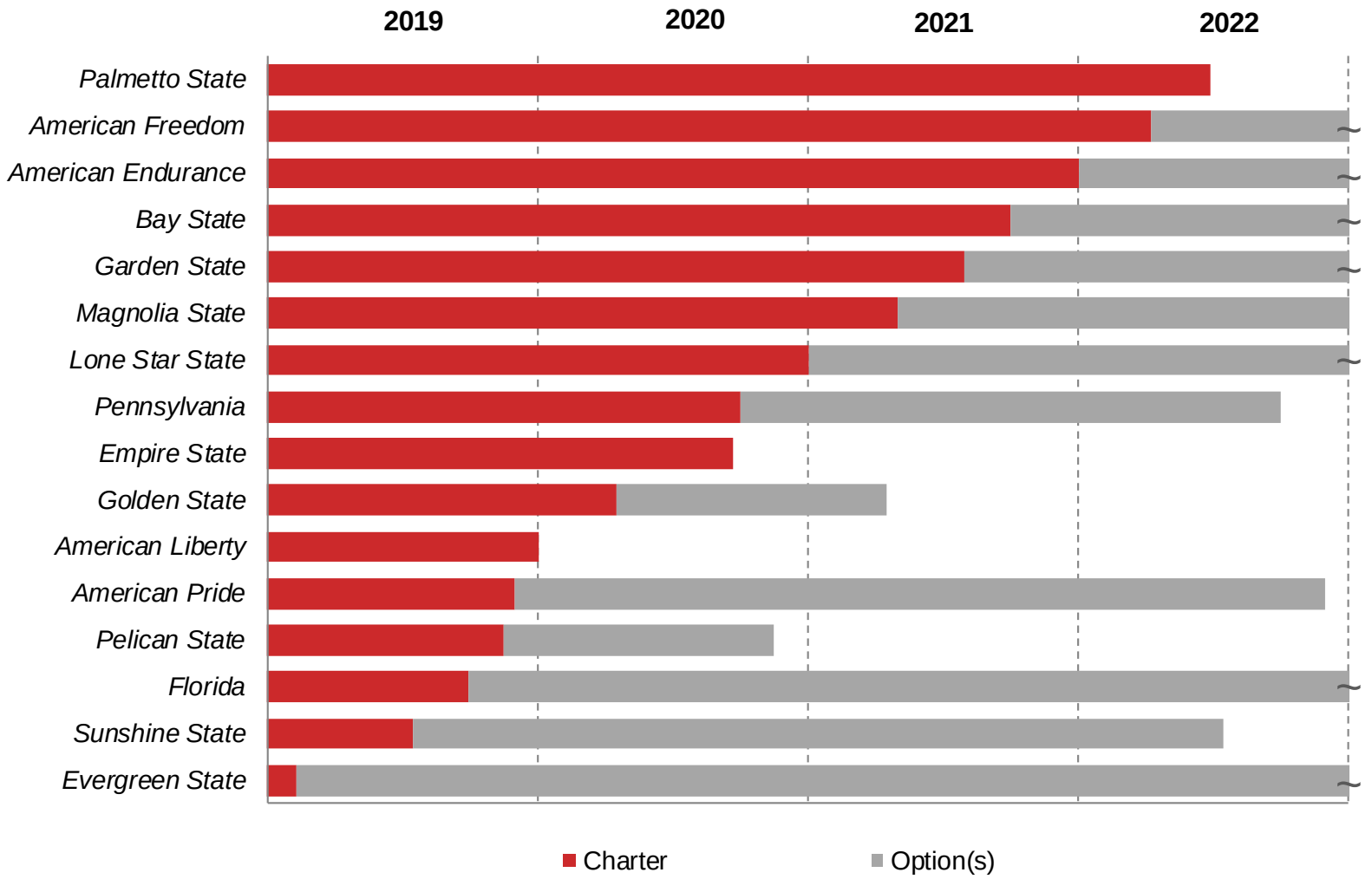
All 2019 charter expirations are expected to renew with current customers

No exposure to IMO 2020

- APT's tankers currently fueled by 0.1% sulfur marine distillate as required in coastal waters
- 9 of APT's vessels are designed to facilitate conversion to LNG fuel if warranted

KMT Jones Act Tanker Trade:





Most modern and efficient industry offering in both refined product and crude oil service

Positioned to Serve International Bulk Trade

Complementary services supporting multiple bulk commodities

Petroleum Coke

- One of the nation's largest handlers of petroleum coke
  - Handle ~40% of Midcontinent and Gulf Coast production
  - In-plant refinery bulk-handling and export terminaling services
  - Complementary full value chain services to key refining customers

Coal

- Advantaged U.S. export position in our Norfolk, VA Pier IX terminal
  - Continued demand for U.S. coal exports
  - Steam coal as well as metallurgical coking coal grades
  - Additional asset capabilities on the Mississippi River (IMT) and Houston (HBT & Deepwater)

Vancouver Wharves

- Premier Canadian commodity import / export terminal
  - Western Canadian gateway to world markets for multiple commodities
  - Minerals, sulfur, grain and distillates
  - 6 million tons of export capacity
  - Key exports of zinc, copper concentrate, and canola





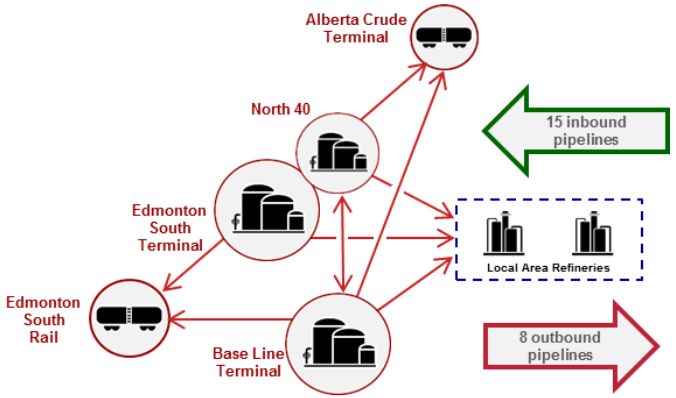


Positioned to Support Alberta Crude Exports

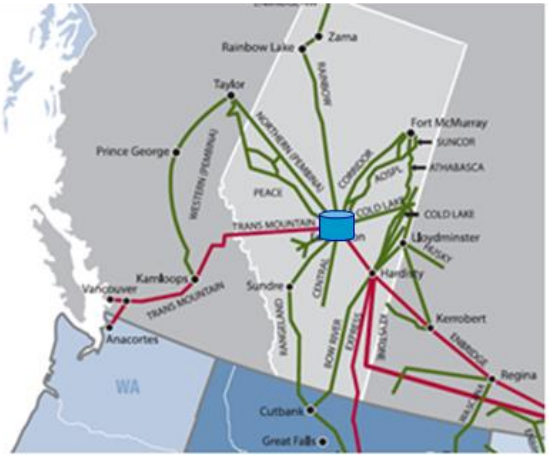
Alberta crude oil aggregation and market-clearing terminaling hub

Industry's preferred Canadian merchant (i.e. non-regulated) crude oil terminal solution

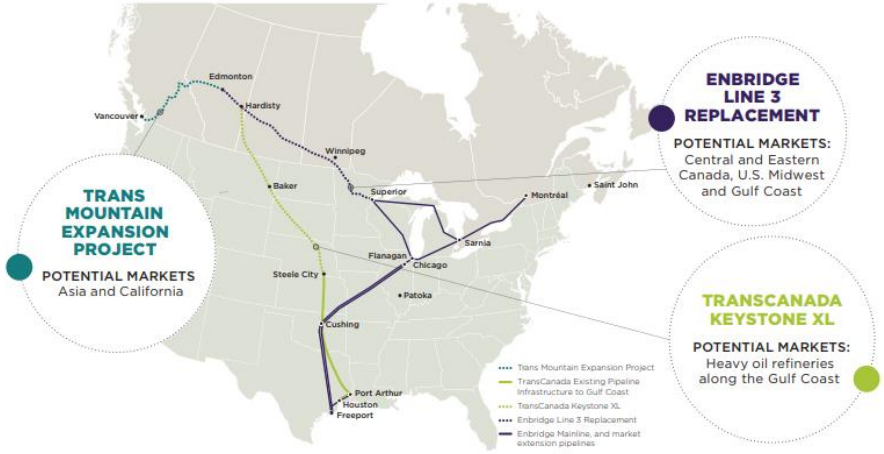
- Matches oil sands production with Canadian, U.S. and world markets
- Inbound connections to a majority of Canadian oil sands production
- Outbound pipeline connects to all Alberta export markets
- North America's largest crude-by-rail loading facilities



#	Asset	Connectivity
15	Inbound Crude Pipelines	Total pipeline connections vary by individual facility
8	Outbound Connections	Including Trans Mountain and Trans Mountain Expansion
2	JV Crude-by-Rail Facilities	Key crude takeaway capacity alongside Imperial and Keyera
2	Refinery Connections	Local refinery demand



Source CAPP



Source CAPP



Project Highlight: Base Line Terminal

4.8 million barrel Edmonton merchant crude oil terminal

Project Scope

- 12-tank crude oil merchant storage terminal in Edmonton, Alberta
- KM 50% and Keyera 50% ownership interest
- Fully contracted with long-term, firm take-or-pay agreements with creditworthy customers

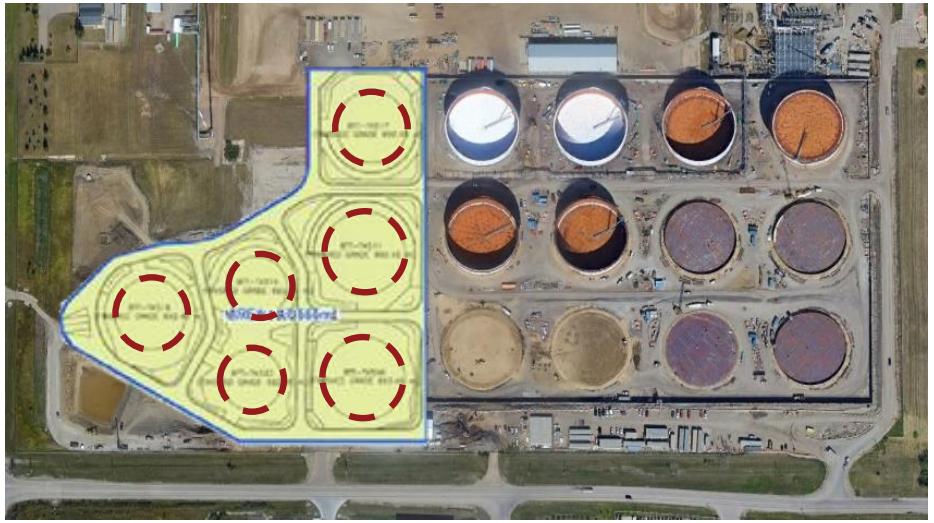
Project Statistics

- Capacity: 4.8 million barrels
- Capital (net to KM): C$357 million
- KML-led project completed on-time and under-budget

Phase II Expansion

- Demand for merchant storage in Edmonton market remains elevated
- Expansion could add up to 1.8 million barrels of additional storage
- New tanks would be connected to existing manifold, offering a full suite of best-in-market connectivity
- Not in backlog





Beyond the Backlog

Long-term liquids fundamentals drive value on existing assets and new projects

Domestic crude & NGL liquids production growth

Refinery industry - customer expansion

Petrochemical industry - customer expansion

Crude export demand

NGL export demand

Refined product hub infrastructure

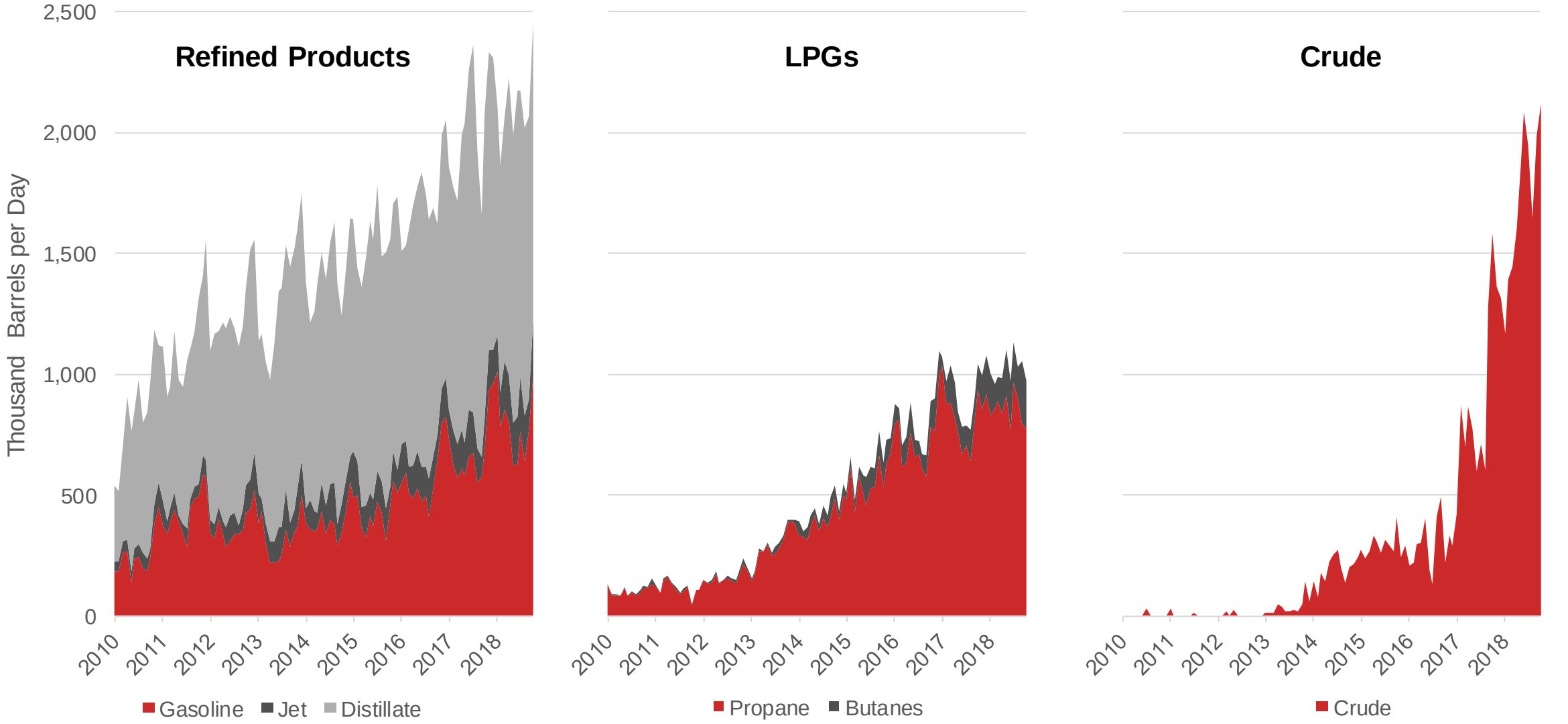
Chemical plant infrastructure & export demand

KM Terminals' Advantaged Position:

- ✓ Current key-asset footprint
- ✓ Existing key-customer relationships
- ✓ Fee-based services contracting
- ✓ Non-competing customer solutions
- ✓ Preferred infrastructure provider

U.S. Gulf Export Demand

Continued industry demands with Shale production development



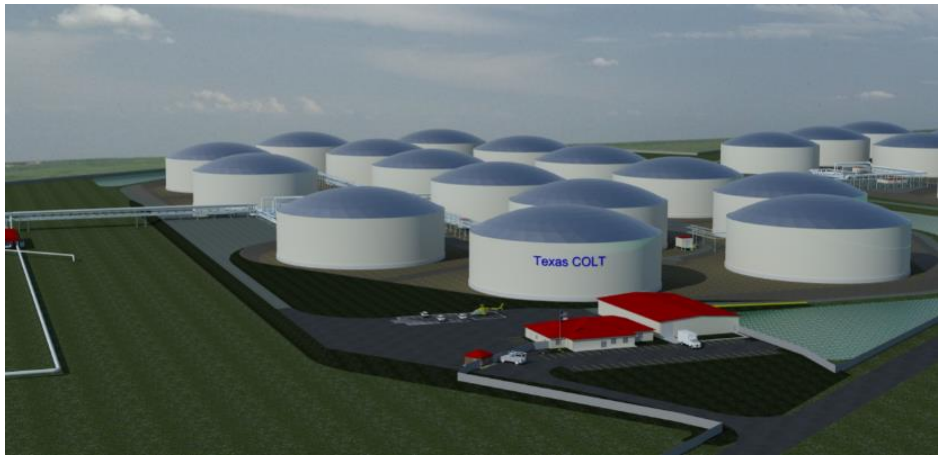
Source EIA USGC PADD III exports.

Texas COLT

Crude Offshore Loading Terminal

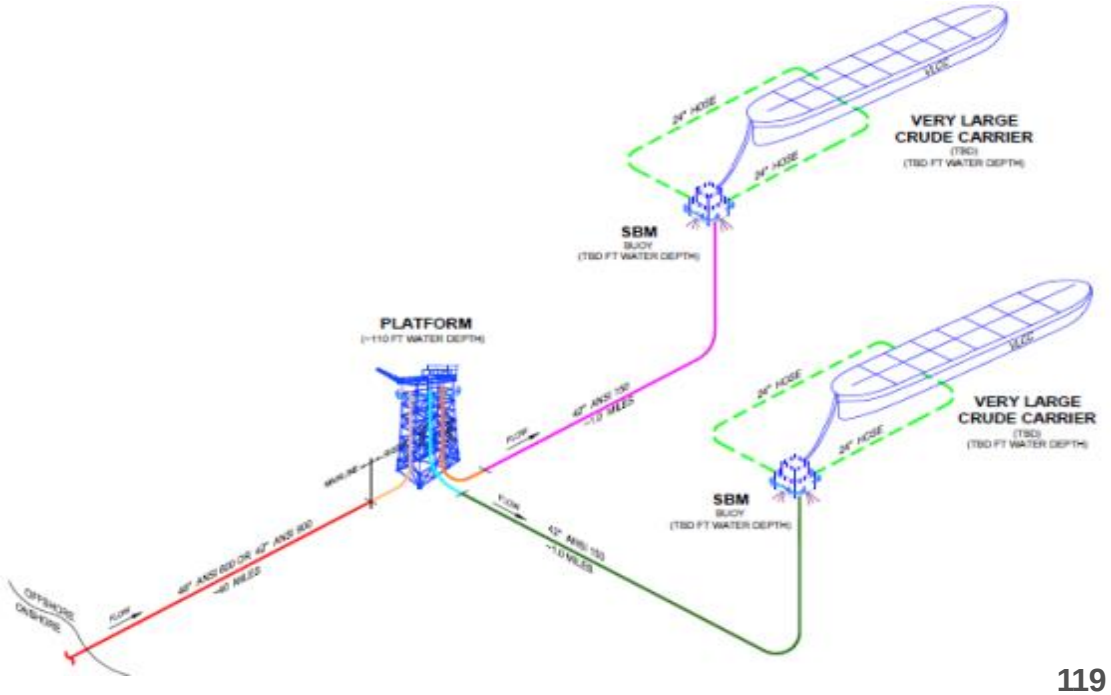
Project Scope

- ~9 million barrel onshore crude storage terminal
- Connectivity to inbound Houston pipelines
- Pipeline to a platform located 35 miles offshore of Freeport, TX
- 2 Single Buoy Mooring (SBM) VLCC loading positions
- ~85,000 bph loading (one VLCC per day)



Advantages

- Operational and commercial competencies of Kinder Morgan, Enbridge and Oiltanking
- Direct access / connections to major U.S. shale basins, Cushing and Canadian crudes



Milestones

- MARAD Deepwater permit application filings being finalized
- Not in backlog, pending customer commitments
- Expected in-service 2022

Terminals Throughput and Tonnage Statistics

2018A vs. 2019B

Liquids Throughput

	Throughput		Variance	
mmbbls	**2018**	**2019B**	**mmbbls**	**%**
Gasoline	463.6	511.9	48.4	10 %
Petroleum	160.2	193.5	33.3	21 %
Distillate (incl. jet fuel)	151.3	146.4	(4.9)	(3)%
Ethanol	61.7	54.8	(6.9)	(11)%
Chemicals	47.0	49.6	2.6	6 %
Vegetable Oil	6.1	6.9	0.8	13 %
Liquids Other	3.9	3.6	(0.3)	(8)%
	893.8	**966.7**	**73.0**	**8 %**

Bulk Tonnage

	Tonnage		Variance	
tons (millions)	**2018**	**2019B**	**mm tons**	**%**
Ores / Metals (Bulk)	17.8	17.6	(0.2)	(1)%
Coal	13.8	15.1	1.4	10 %
Petroleum Coke	14.4	14.3	(0.1)	(1)%
Soda Ash	4.4	4.2	(0.2)	(5)%
Aggregate	3.7	3.4	(0.4)	(10)%
Bulk Other	2.6	3.3	0.6	25 %
Road Salt	2.5	2.4	(0.1)	(4)%
Fertilizers	2.3	2.4	0.1	6 %
Ores / Metals (Break-Bulk)	1.8	1.8	0.1	4 %
Cement (including Clinker)	0.8	0.8	(0.0)	(1)%
	64.2	**65.4**	**1.3**	**2 %**

Notes: Does not reflect refined product or crude oil volumes through Jones Act tankers.
Petroleum includes crude oil and black oil (e.g., residual fuel oils).
Does not include assets held for sale.
2018 does not include transfer of Products Pipelines terminals.

CO_2

Segment Presentation

CO_2 Segment Overview

World class, fully integrated assets — CO_2 source to crude oil production and takeaway in the Permian Basin

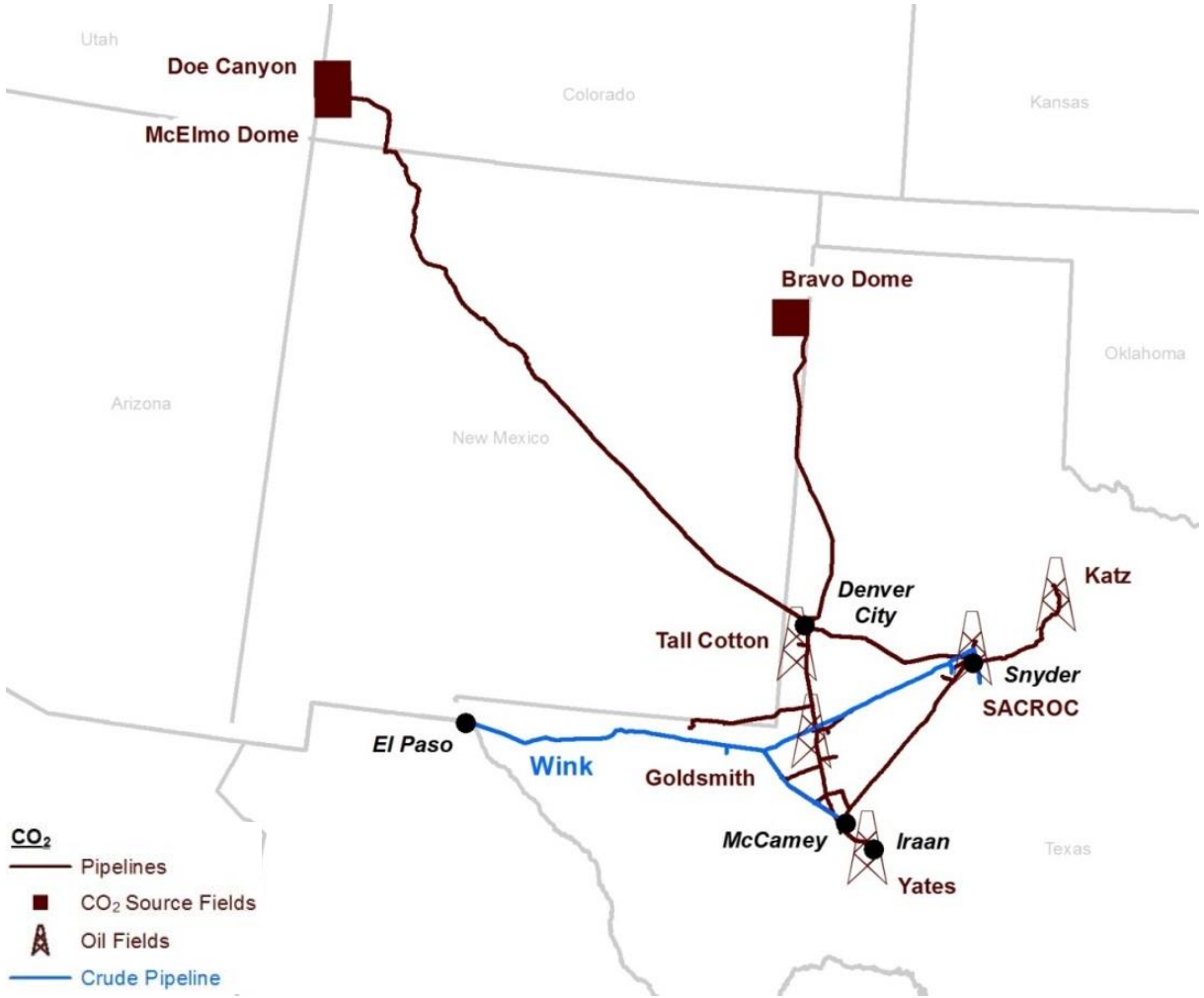
CO_2 & TRANSPORT

CO_2 Reserves	KMI Interest	NRI	Location	Remaining Deliverability	OGIP (tcf)
McElmo Dome	45%	37%	SW Colorado	20+ years	22.0
Doe Canyon	87%	68%	SW Colorado	10+ years	3.0
Bravo Dome[a]	11%	8%	NE New Mexico	10+ years	12.0

Pipelines	KMI Interest	Location	Capacity (mmcfpd)
Cortez	53%	McElmo Dome to Denver City	1,500
Bravo[a]	13%	Bravo Dome to Denver City	375
Central Basin (CB)	100%	Denver City to McCamey	700
Canyon Reef	97%	McCamey to Snyder	290
Centerline	100%	Denver City to Snyder	300
Pecos	95%	McCamey to Iraan	125
Eastern Shelf	100%	Snyder to Katz	110
Wink (crude)	100%	McCamey to Snyder to El Paso	145 mbbld

OIL & GAS

Crude Reserves[b]	KMI Interest	NRI	Location	OOIP (billion bbls)
SACROC	97%	83%	Permian Basin	2.8
Yates	50%	44%	Permian Basin	5.0
Katz	99%	83%	Permian Basin	0.2
Goldsmith	99%	87%	Permian Basin	0.5
Tall Cotton	100%	88%	Permian Basin	0.7

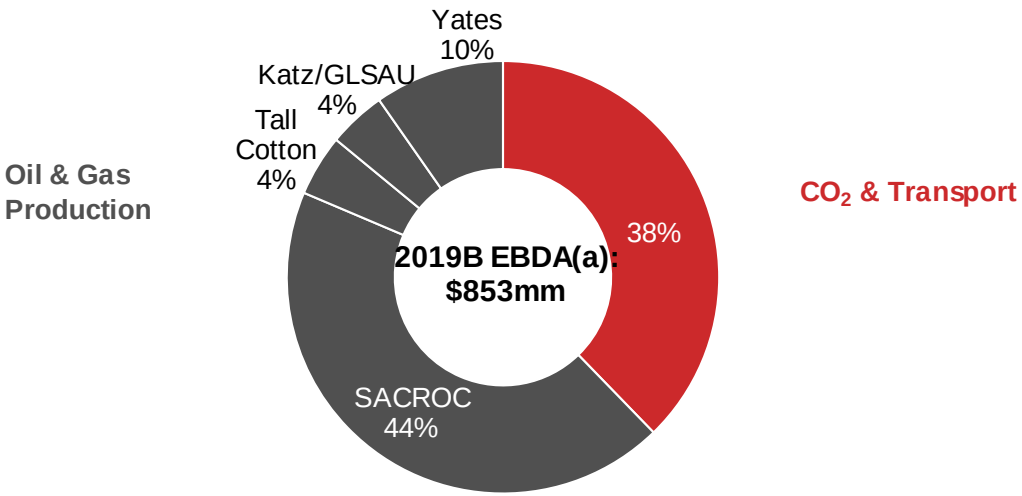


2019B EBDA[c]: ~$853 million

a) Not KM-operated.
b) In addition to KM's interests above, KM has a 22%, 51%, and 100% working interest in the Snyder gas plant, Diamond M gas plant and North Snyder gas plant, respectively.
c) 2019 budgeted Segment EBDA before Certain Items plus JV DD&A. See Non-GAAP Financial Measures and Reconciliations.

CO_2 Segment Key Budget Assumptions

Kinder Morgan is the largest producer and transporter of CO_2 in North America



CO_2 & TRANSPORT

- Budgeted 2019 SW Colorado CO_2 production: 1,289 mmcfd gross / 614 mmcfd net
- Our O&G group is projected to consume ~47% of our entitled CO_2 production in 2019
- 100% of CO_2 production is contracted in 2019, of which 83% is at Minimum Volume Commitments
- Weighted average contract life with third parties is ~9 years
- We produce and transport ~82% of CO_2 delivered to the Permian

EBDA Sensitivity: Impact of Oil Price / Volume on 2019B

Δ	EBDA impact
$1/bbl WTI	NGL: $2.0mm CO_2: $1.4mm Crude: $2.9mm **Total: $6.3mm**
1% NGL / crude ratio[b]	$2.2mm
$0.01/bbl Mid / Cush Diff	$0.1mm
1,000 bopd in SACROC, Katz, GLSAU, or Tall Cotton	$16.0mm
1,000 bopd in Yates	$8.2mm
50 mmcfd in CO_2	$7.7mm

Oil & Gas Production Group

	Net Prod. (mboepd)		EBDA ($mm)	
	2018	2019B	2018	2019B
SACROC Group	35.2	34.9	$435	$372
Yates	7.4	7.2	$107	$83
Katz	3.0	2.9	$32	$27
GLSAU	1.7	1.5	$15	$10
Tall Cotton	2.4	3.6	$22	$39
Total	49.6	50.1	$611	$531

Note: 2019B segment EBDA before Certain Items plus JV DD&A. See Non-GAAP Financial Measures and Reconciliations.

a) Segments shown without elimination. We view our CO_2 & Transport and O&G businesses independently, values shown above excludes intercompany eliminations.

b) Budgeted NGL / crude ratio = 54%.

CO_2 Segment 2019 Expansion Program Summary

$502 million capex program, flexibility to adjust given dynamic commodity price environment

Asset	Capex ($mm)[a]	% of Total Capex	Commentary	CO_2 Purchased (mmcfd)	Net Oil Produced (mbopd)
SACROC	186	37%	■ Activate 21 Transition Zone East Flank Patterns ■ Continue Bullseye redevelopment Phase I and II ■ Expand Center Ring Bypassed Pay project, 11 pattern equivalent ■ Drill 5 Bypassed Pay zonal horizontal producers	142	24.1 oil[a] 10.4 NGL
Tall Cotton	70	14%	■ Complete analysis and commence Phase 3 expansion, utilizing existing facilities as much as possible ■ Activate 15 of 15 patterns in 225 Acre Phase 3 expansion project area ■ Evaluate 415 acre Phase 3B Project	56	3.6
Yates	24	5%	■ Drill 40 Horizontal Drain Hole wells ■ Continue Waterflood expansion ■ Continue testing cationic surfactant pump and soak stimulations	80	7.2
Katz	0	0%	■ Continue conformance activity and optimize flood performance	32	2.9
GLSAU	0	0%	■ Continue optimizing active flood area	18	1.4
EOR Total:	**$280**	**56%**			
CO_2 & Transport	$60	12%	■ Expand production capacity in McElmo Dome / Doe Canyon ■ CO_2 net production of 629 mmcfd		
Total Segment:	**$339**	**68%**			
Capitalized CO_2 / Overhead	$162	32%	■ Capitalized CO_2 $119MM (SACROC $66, Tall Cotton $19, Yates $9, Katz $18, and GLSAU $6) ■ Overhead $44MM (SACROC $24, Tall Cotton $9, Yates $3, and CO_2 & Transport $8)		
Total Segment:	**$502**	**100%**			

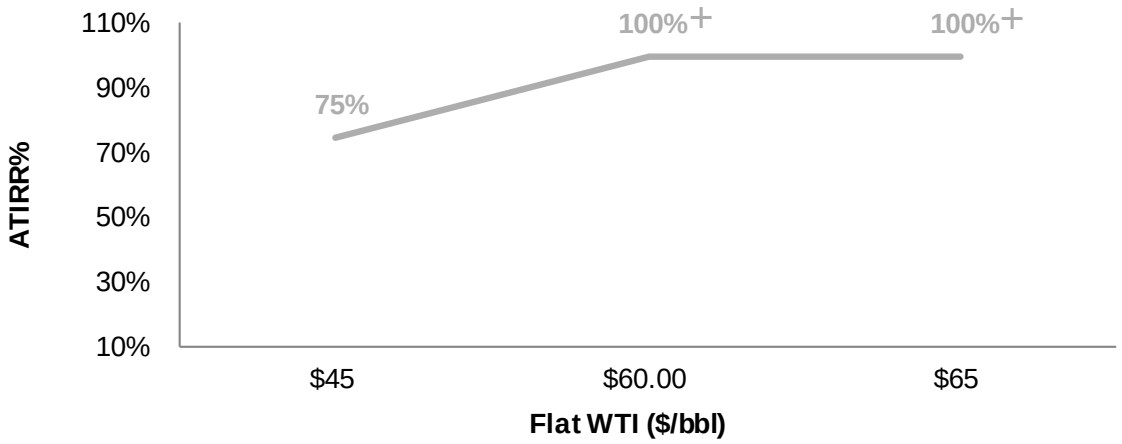
a) Net oil for SACROC Group which includes SACROC unit, Kelly Snyder Strawn (81 bopd), Cisco Sands (5 bopd), Midcross (49 bopd), Reinecke (153 bopd) and Sharon Ridge (186 bopd).

CO_2 Segment 2019 Project Returns at Various Flat Prices

Projects expected to generate attractive returns in multiple commodity price environments

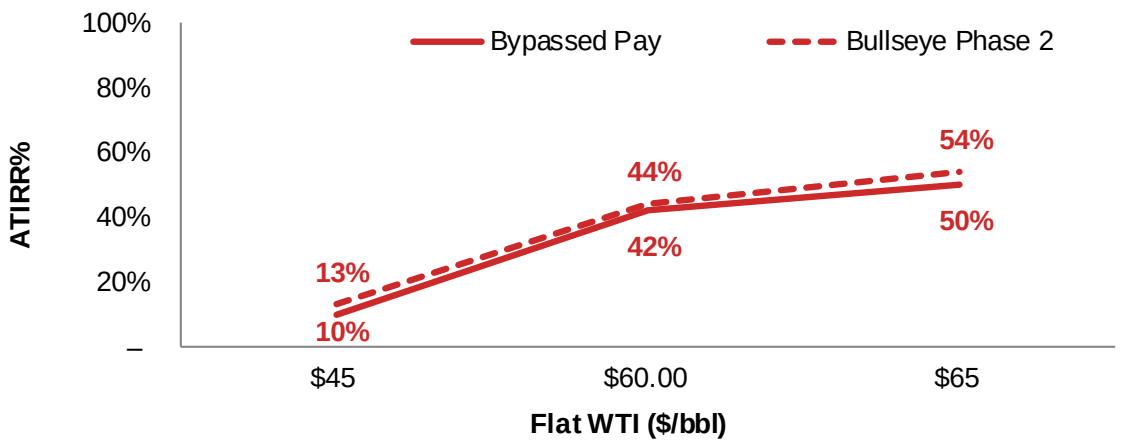
YATES HZ DRAIN HOLE PROGRAM

ATIRR%



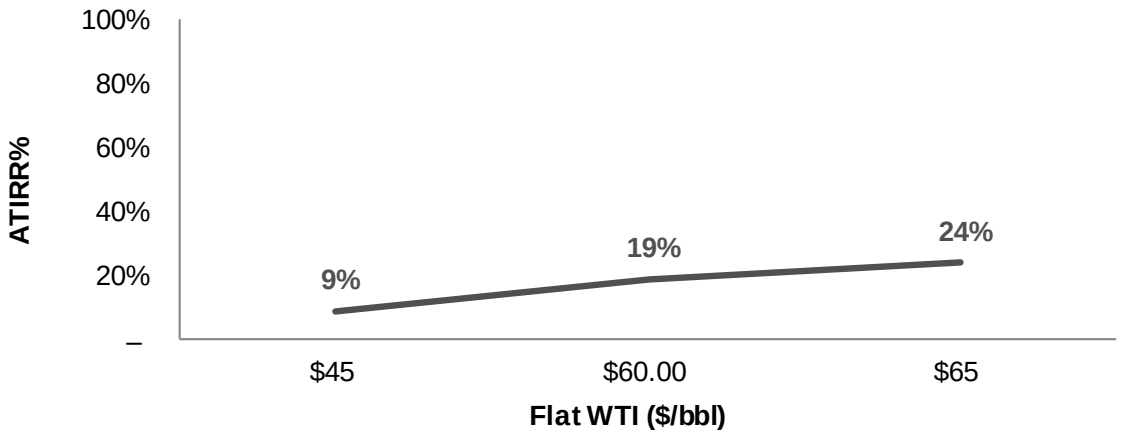
SACROC CONVENTIONAL

ATIRR%



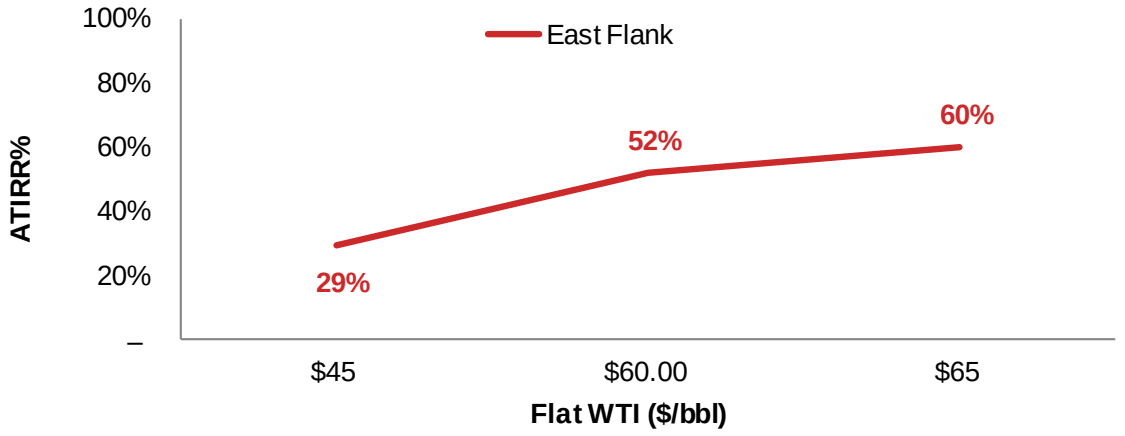
TALL COTTON

ATIRR%



SACROC TRANSITION ZONE

ATIRR%



CO_2 Segment 10 Year Development Plan

2019 — 2028: Maximizing returns and recoverability

KINDER MORGAN

Keys to Success:

- Robust portfolio that is profitable through commodity cycles
- Operational synergies from integrated asset model
- Long-term track record of extending productive life of fields
- Highly-skilled team with decades of experience with these assets
  - Consistently execute with production and capex within 1.4% of expectations (2008-2018)
- Continual pursuit of technological advances
- Attractive consolidation opportunities

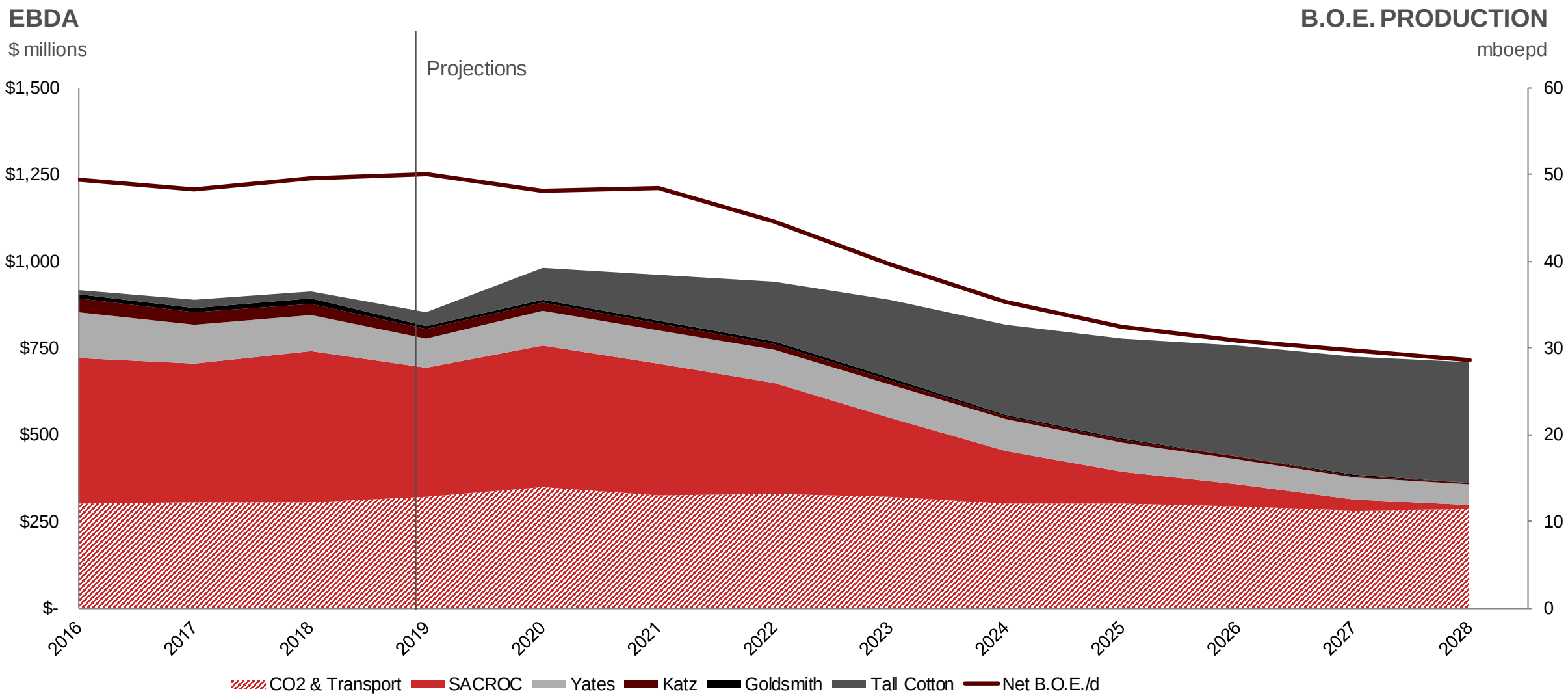
Innovation will continue to drive results

Asset	Total Net Production (mmboe)[a]	KM Share CapEx[b] ($mm)	Expansion Program Plans
SACROC	65	$916	■ Complete East Flank development ■ Bullseye redevelopment into Phase 3 ■ Develop West Shore ■ Exploit transition zone expansion ■ Expand zonal horizontal producer program
Tall Cotton	48	1,556	■ Commence Phase 3 expansion ■ Engineering, Planning and Development of future Phases
GLSAU	3	40	■ Optimize flood performance ■ Evaluate expansion opportunities
Yates	22	162	■ Continue Horizontal Drain Hole programs and gravity drainage depletion plan ■ Initiate additional water flood phases ■ Evaluate Hydrocarbon Miscible pilot and cationic surfactant stimulations
Katz	6	35	■ Continue conformance program ■ Optimize flood performance
O&G Total:	**144**	**$2,708**	
CO_2 & Transport		585	■ Maintain capacity in existing source fields (McElmo & Doe Canyon) ■ Optimize production and increase efficiency ■ Manage source development to be prepared for increase in demand
Total Segment:		**$3,293**	

a) Net BOE = Net Crude plus Net NGLs plus Net Residue Gas divided by 6.
b) Inclusive of capitalized CO_2 and capitalized overhead.

CO_2 Segment Long-Term Growth Outlook

Projected EBDA and B.O.E. production

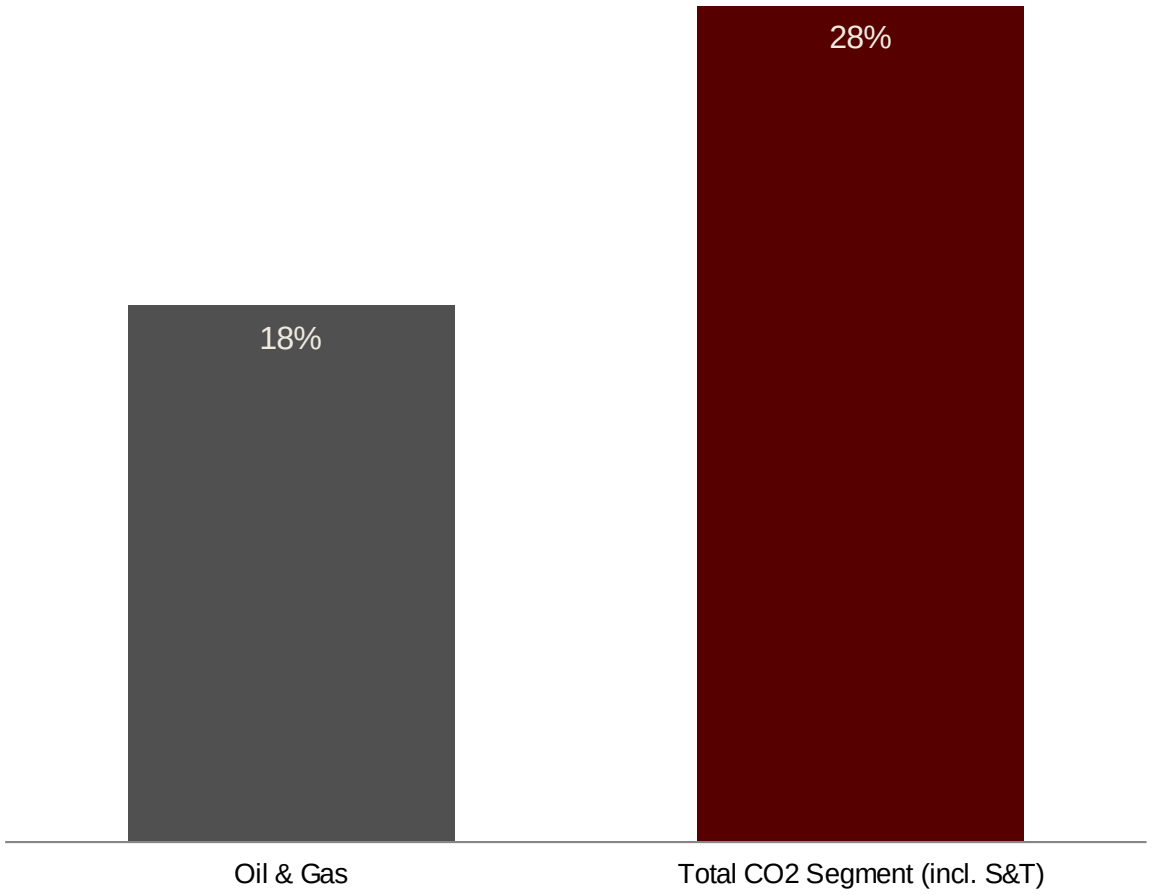


Note: 2019B segment EBDA before Certain Items. See Non-GAAP Financial Measures and Reconciliations.

CO_2 Segment Significant Returns and Free Cash Flow

Long history of generating high returns and ~$6 billion in cumulative free cash flow

IRR% 2000-2018



CUMULATIVE FREE CASH FLOW GENERATION

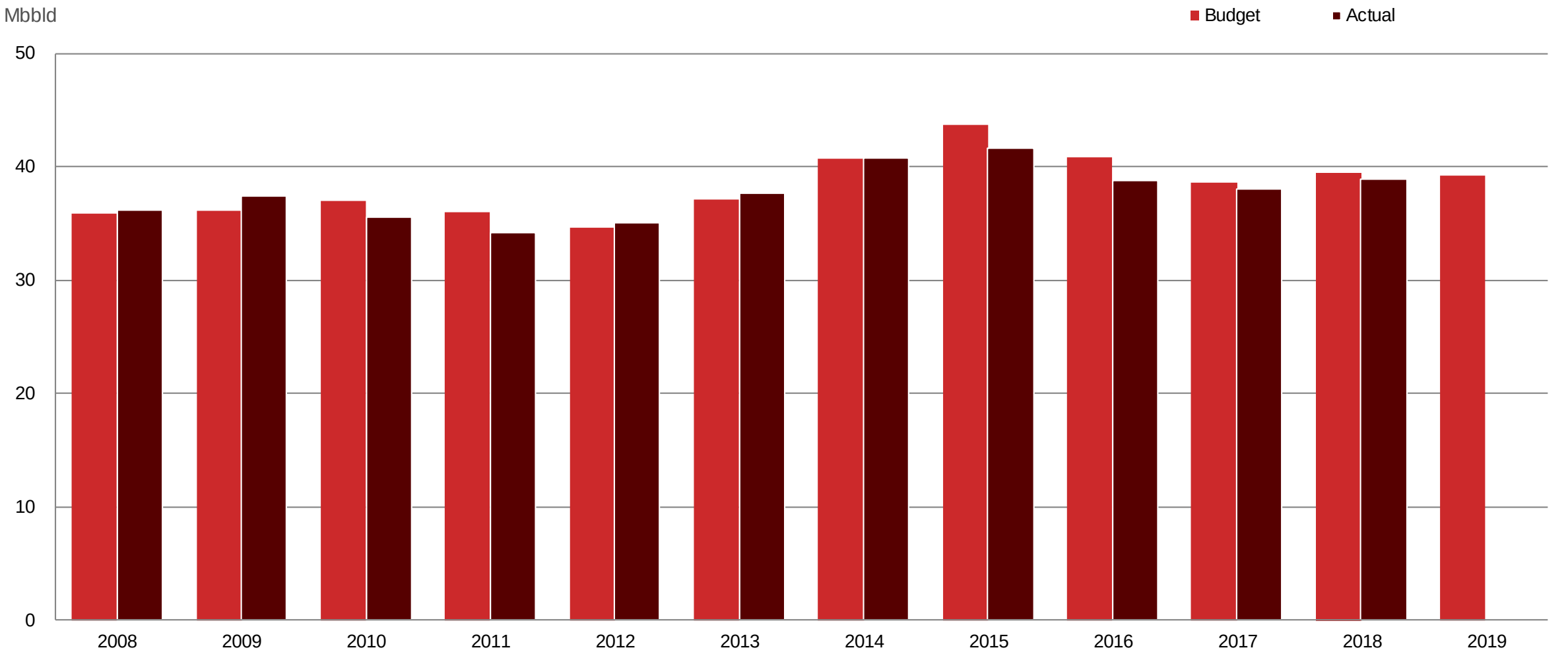
$ billions



Note: Free Cash Flow calculated as segment EBDA before Certain Items less sustaining and discretionary capital expenditures. See Non-GAAP Financial Measures and Reconciliations.

History of Predictable and Stable Oil Volumes

Actual oil production within 1.4% of budget 2008-2018 | Capex within 0.6% of budget for projects completed

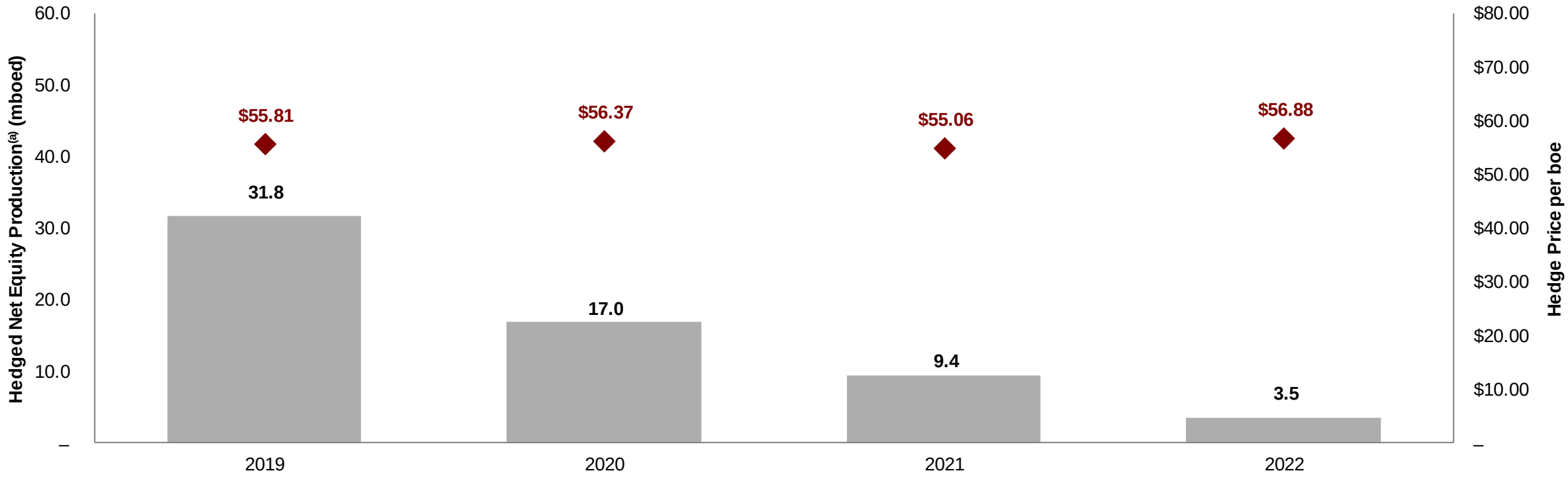


Disciplined Approach to Managing Price Volatility

Hedge profile: Limited near-term price risk

WTI: 2019 ~67% hedged at $55.81/bbl as of 12/31/2018, 5-year hedge policy requires additional hedges on a rolling basis

MIDLAND-CUSHING DIFFERENTIAL: ~94% hedged at $(8.08)/bbl in 2019, with limited hedges beyond given expected takeaway capacity



Consistent hedge policy mitigates near-term price volatility and secures expected cash flows

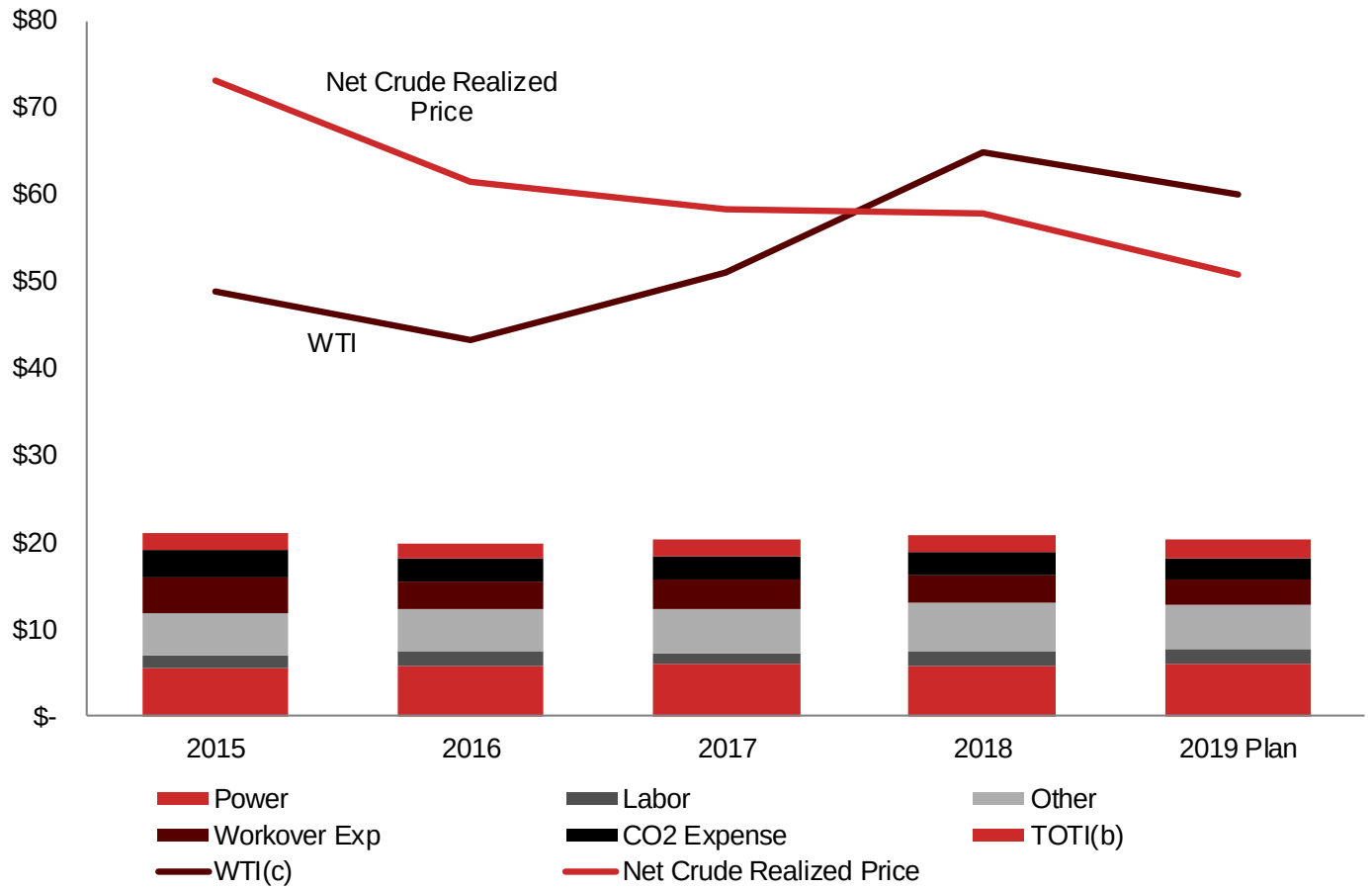
a) Net equity oil production: 2019 based on 2019 Budget, 2020 – 2022 based on independent reservoir engineer reserve report, which is historically below management expectations. Includes heavier NGL components (C4+).

Oil & Gas Production Group: Margins and Costs

CO_2 Segment: Success maintaining cost structure in rising commodity price market

OIL & GAS CASH COST STRUCTURE[(a)]

$ / net BOE



Commentary

- Disciplined approach to managing cost structure
- Maintained aggregate operating cost savings of ~25% since 2014

a) Costs and Revenue per net BOE, including hedges where applicable.
b) Taxes other than income taxes.
c) WTI Cushing Price, Source: www.eia.gov.

Big Fields Get Bigger

Successful track record of extending productive life of mature fields

Significant amounts of recoverable oil in place

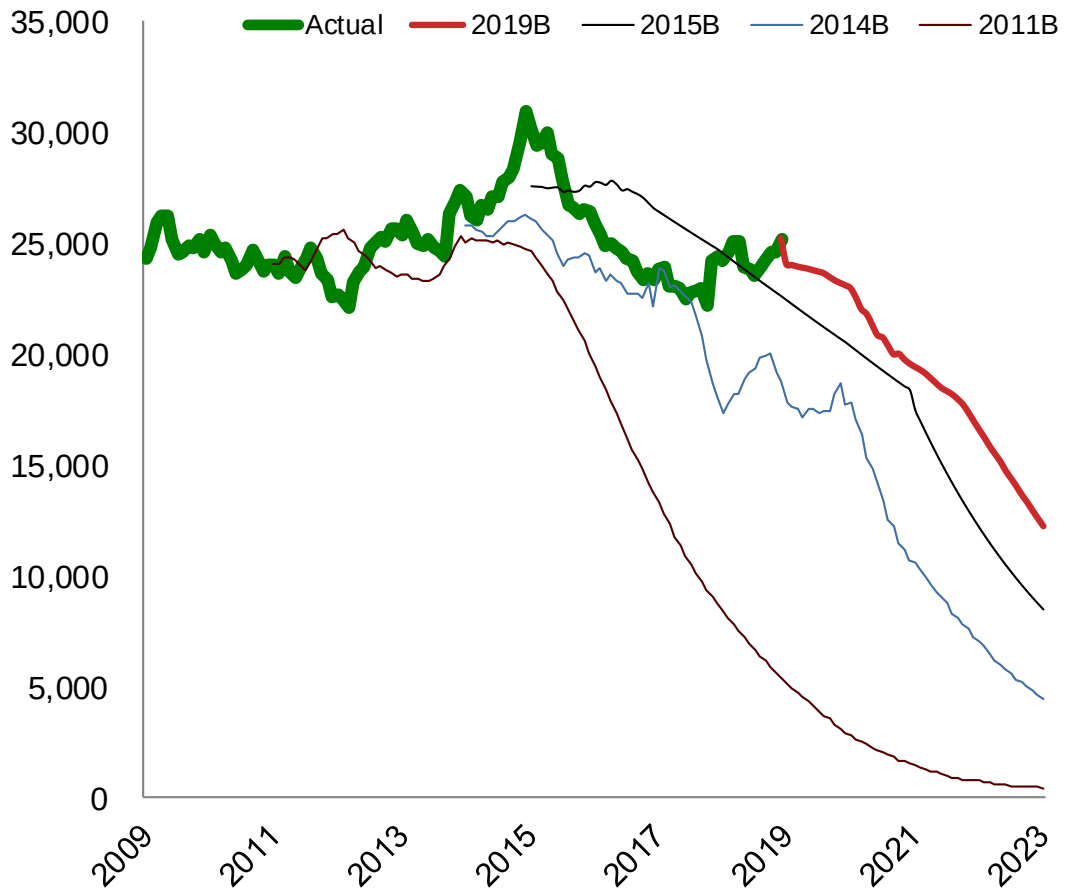
- SACROC – 2.8 billion barrels of original oil in place
  - Exploiting Transition Zone
  - Estimated incremental 700 mmbbls OOIP target
  - Delineation efforts ongoing
  - Executing two projects in 2019, East Flank and West Shore
- Yates – 5.0 billion barrels of original oil in place

Technical expertise will drive future success

- Long track record of expanding the field through advanced technology and new exploitation techniques
  - Advanced seismic reprocessing used to identify:
    - Future development projects
    - Zonal horizontal producers
    - Transition zone
  - Horizontal drilling technology
  - Conformance technologies and techniques:
    - Polymers
    - Mechanical

SACROC NET OIL PRODUCTION FORECASTS

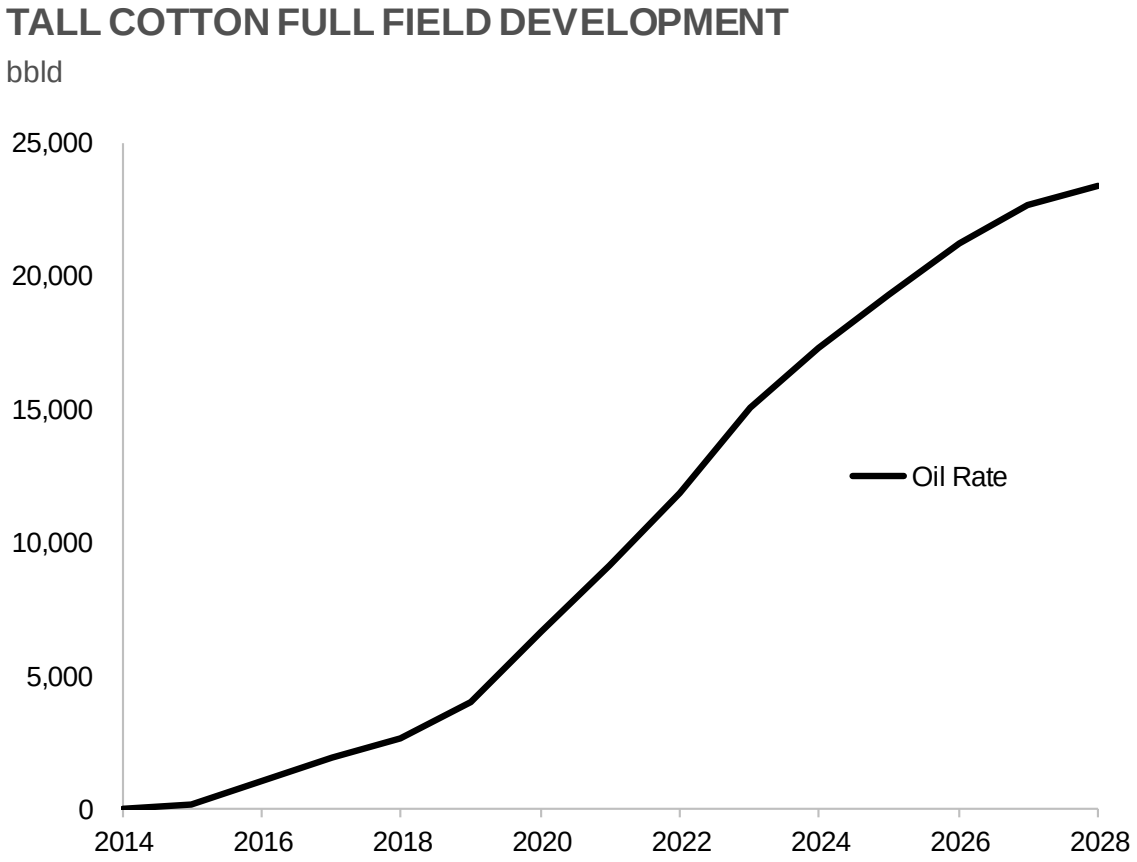
bopd



CO_2 Outlook: Tall Cotton

Long-term development plans

- San Andres Residual Oil Zone (ROZ) oil saturation similar to water-flooded main pay San Andres
- Several significant San Andres ROZ projects underway in the Permian Basin
- Tall Cotton full field development
  - Peak oil rate: 24,418 gross bopd (2031)
  - ~8 section development
  - 294 patterns
  - ~114.7MM BO reserves
  - ~14% recovery factor



Appendix

Energy Toll Road

Cash flow security with ~90% from take-or-pay and other fee-based contracts

	Natural Gas Pipelines	Products Pipelines	Terminals	CO_2
2019B EBDA %[a]	**61%**	**15%**	**14%**	**10%**
Asset Mix (% of Segment EBDA)	72% interstate pipelines 9% intrastate pipelines and storage 19% gathering, processing and treating (G&P)	60% refined products 40% crude	78% liquids 61% terminals 17% Jones Act tankers 22% bulk	62% oil production related 38% CO_2 & transport
Volume Security	**Interstate & LNG:** ~94% take-or-pay[a] **Intrastate:** ~76% take-or-pay[a,b] **G&P:** ~82% fee-based with minimum volume requirements and/or acreage dedications[a]	**Refined products:** primarily volume-based **Crude:** ~61% take-or-pay[a]	**Liquids & Jones Act:** ~80% take-or-pay[a] **Bulk:** primarily minimum volume guarantee or requirements	**CO_2 & Transport:** ~83% minimum volume committed **O&G:** volume-based
Average Remaining Contract Life	**Interstate / LNG:** 6.3 / 13.4 years **Intrastate:** 4.6 years[b] **Gathering:** 3.1 years **NGL Gathering and Transport:** 6.3 years	**Refined products:** generally not applicable **Crude:** 2.4 years	**Liquids:** 3.6 years **Jones Act:** 1.8 years[c] **Bulk:** 5.0 years	**CO_2 & Transport:** 7.2 years
Pricing Security	**Interstate:** primarily fixed based on contract **Intrastate:** primarily fixed margin **G&P:** primarily fixed price	**Refined products:** annual FERC tariff escalator (PPI-FG + 1.23%) **Crude / NGLs:** primarily fixed based on contract	Based on contract; typically fixed or tied to PPI	**CO_2 & Transport:** ~80% protected by contractual price floors[a] **O&G:** volumes ~67% hedged[d]
Regulatory Security	**Interstate:** regulated return **Intrastate:** essentially market-based **G&P:** market-based	**Pipelines:** regulated return **Terminals & transmix:** not price regulated[e]	Not price regulated	Primarily unregulated
Commodity Price Exposure	**Interstate:** no direct exposure **Intrastate:** limited exposure **G&P:** limited exposure	Minimal, limited to transmix business	No direct exposure	Full-year 2019: ~$6mm in DCF per $1/Bbl change in oil price

Note: All figures as of 1/1/2019, unless otherwise noted.
a) Based on 2019 budgeted Segment EBDA before Certain Items plus JV DD&A. See Non-GAAP Financial Measures and Reconciliations.
b) Includes term sale portfolio.
c) Jones Act vessels: average remaining contract term is 1.8 years, or 3.9 years including options to extend.
d) Percentage of FY2019 budgeted net crude oil, propane and heavy NGL (C4+) net equity production.
e) Terminals not FERC regulated, except portion of CALNEV.

Joint Venture Treatment in Key Metrics

	KM controls and fully consolidates (third party portion referred to as noncontrolling interests in financial statements)	KM does not control or consolidate (KM portion referred to as equity investments in financial statements)
Example JVs	KML (~70%), Elba Liquefaction (51%), BOSTCO (55%)	NGPL (50%), SNG (50%), FGT (50%), MEP (50%), FEP (50%), Gulf LNG (50%)
Net Income	**Includes 100% of JV Net Income** (consolidated throughout income statement line items)	**Includes KM owned % of JV Net Income** (included in Earnings from Equity Investments)
Net Income Available to Common Stockholders	**Includes KM owned % of JV Net Income** (excludes Net Income Attributable to Noncontrolling Interests)	**Includes KM owned % of JV Net Income** (included in Earnings from Equity Investments)
Adjusted EBITDA	**Includes 100% of KML** (KML debt consolidated at KMI) **Otherwise, includes KM owned % of JV's Net Income + DD&A + Book Taxes + Interest Expense** (excludes Net Income Attributable to Noncontrolling Interests except KML's)	**Includes KM owned % of JV's Net Income + DD&A + Book Taxes** (i.e., after interest expense)
Distributable Cash Flow (DCF)	**Includes KM owned % of JV's Net Income + DD&A + Book Taxes – Cash Taxes – Sustaining CapEx** (excludes all Net Income Attributable to Noncontrolling Interests)	**Includes KM owned % of JV's Net Income + DD&A + Book Taxes – Cash Taxes – Sustaining CapEx**
Debt	**100% of JV debt included, if any** (fully consolidated on balance sheet) **Includes 50% of KML preferred equity in Adjusted Net Debt**	**No JV debt included** (JV's Adjusted EBITDA contribution is after interest expense)
Sustaining Capex	**Includes KM owned % of JV sustaining capital**	
Growth Capex and Contributions to JVs	**Includes KM contributions to JVs based on %owned, including for projects and debt repayment**	

Note: See Non-GAAP Financial Measures and Reconciliations.

Asset Integrity and Safety are Top Priorities

Kinder Morgan's EHS metrics consistently outperform the industry

Safe operation of our assets is mission critical to our long-term success

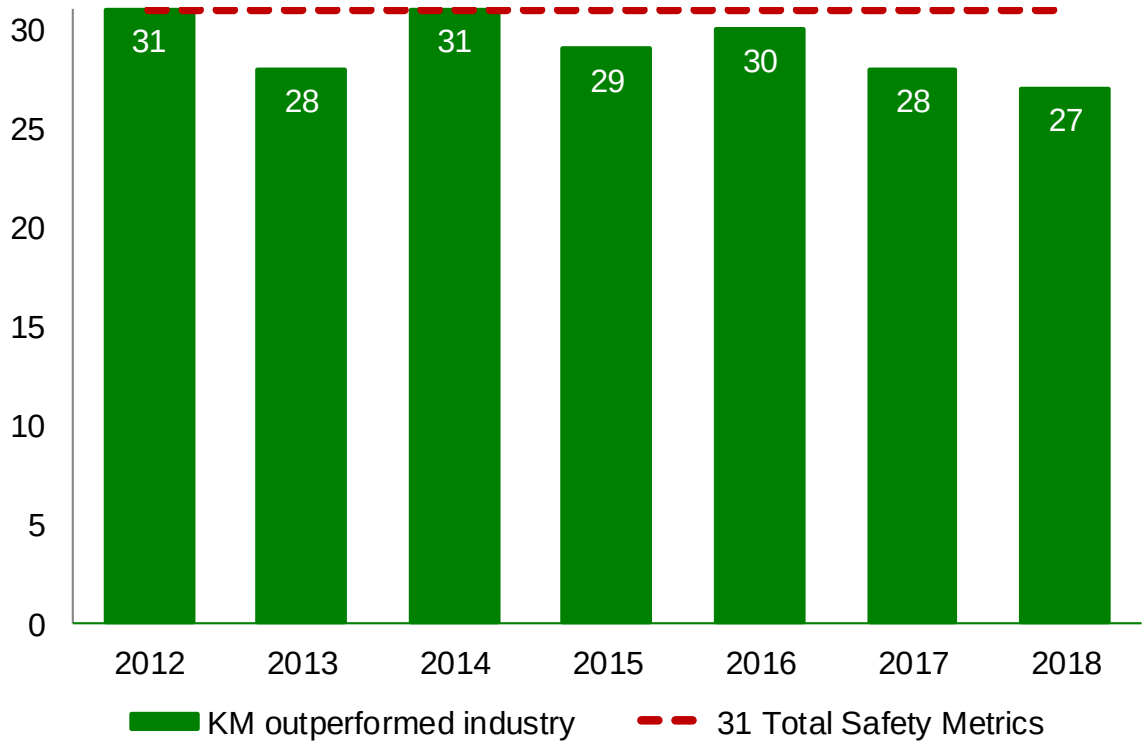
- We continue to reduce operational risks, which in turn benefits our employees, contractors, assets, the public, and the environment
- We strive for improvement in safety and efficiency of existing operations
- Additionally, we properly execute expansions and effectively integrate acquired operations

Kinder Morgan's EHS statistics consistently outperform the industry average

- We track 31 safety metrics and post monthly updates to our public website
- Currently we are outperforming the industry in 27 of the 31 metrics that we track[(a)]

OUR SAFETY PERFORMANCE VS. INDUSTRY[(a)]

of safety metrics

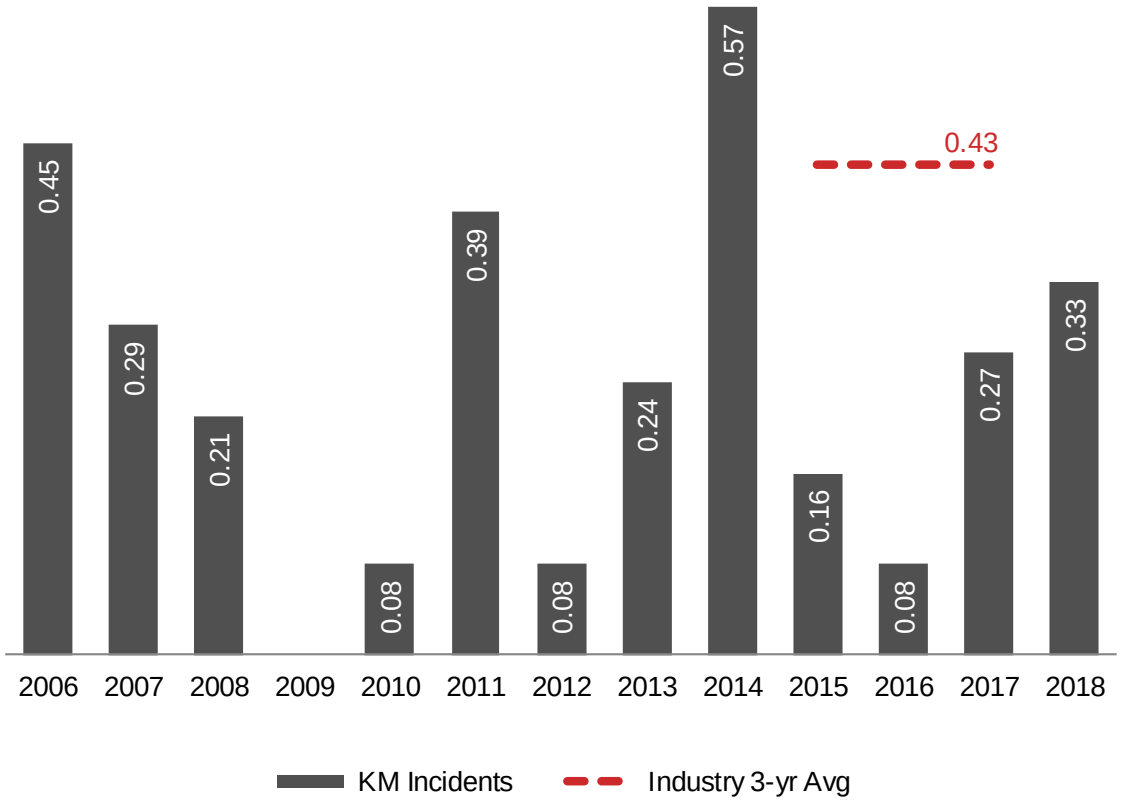


a) Based on period-end Kinder Morgan metrics versus most applicable industry performance.

Incidents & Releases: Liquids Pipelines

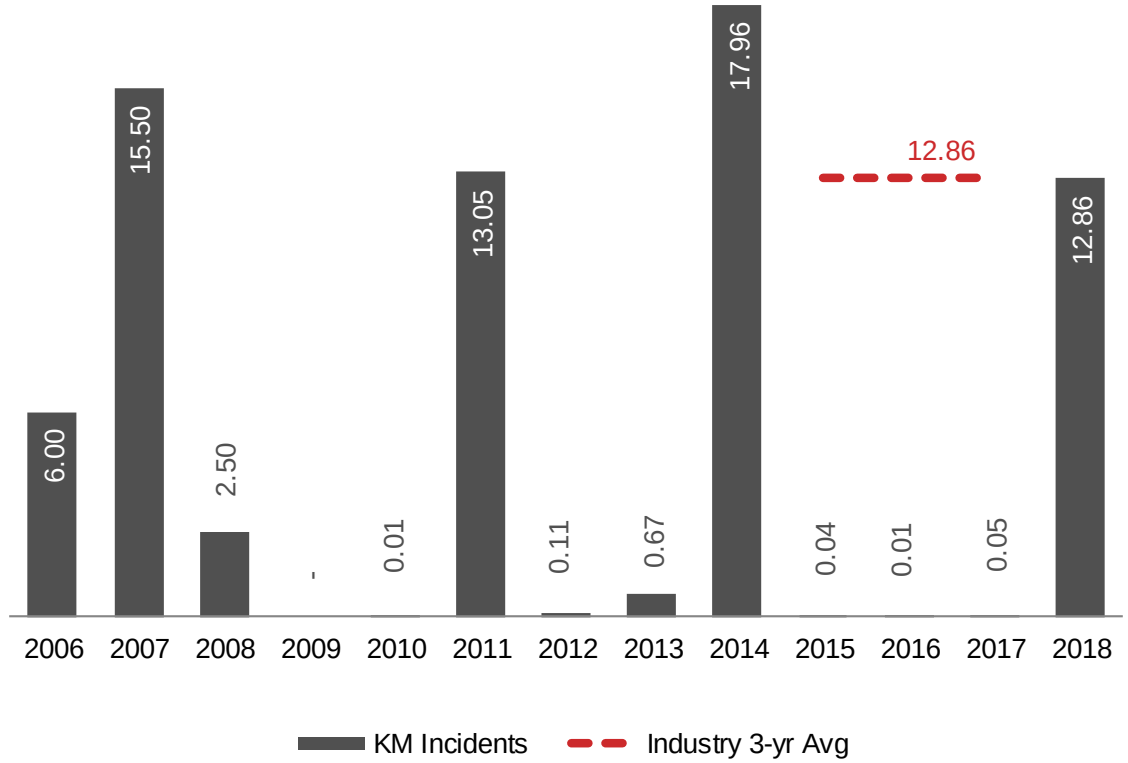
Liquids pipeline right-of-way

INCIDENTS PER 1,000 MILES[a,b]



RELEASE RATE[a,b]

Barrels per billion barrel miles



Note: KM totals exclude non-DOT jurisdictional CO_2 Gathering and Crude Gathering for compatibility with industry comparisons.

a) Failures involving onshore pipelines that occurred on the ROW, including valve sites, in which there is a release of the liquid or carbon dioxide transported resulting in any of the following:
   - Explosion or fire not intentionally set by the operator
   - Release 5 barrels or greater. (NOTE: PHMSA does not record system location for releases less than 5 barrels)
   - Death of any person
   - Personal injury necessitating hospitalization
   - Estimated property damage, including cost of clean-up and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000; not included: natural gas transportation assets

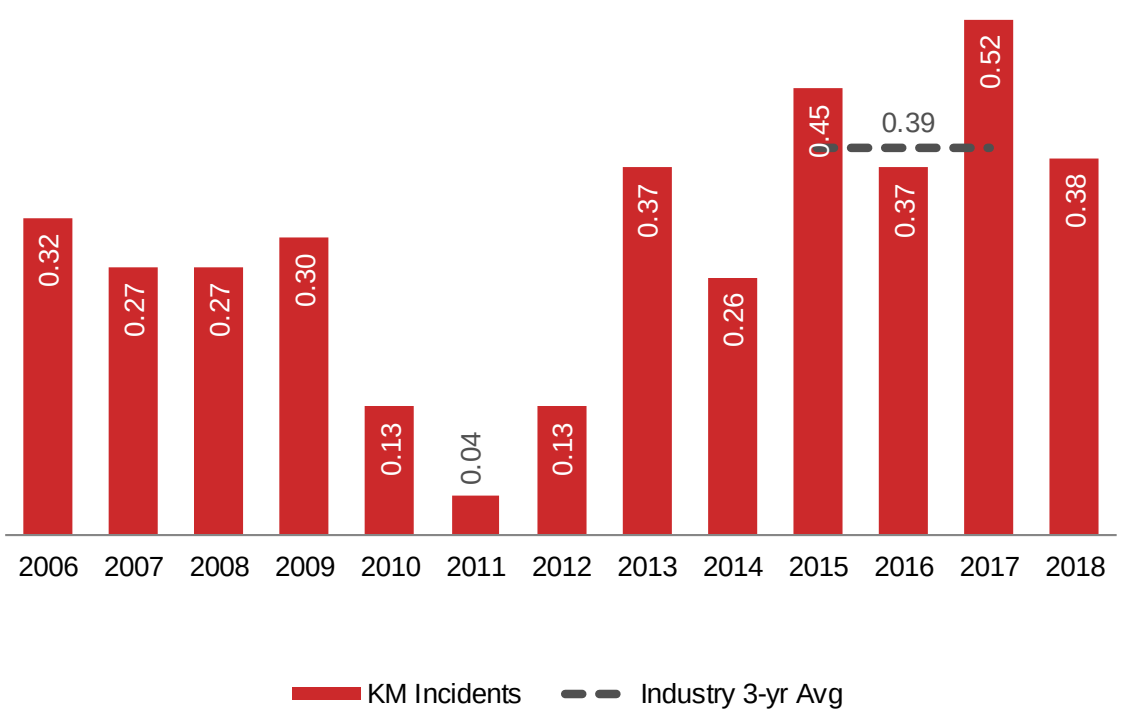
b) 2015-2017 most recent PHMSA 3-year average available.

Incidents & Releases: Natural Gas Pipelines

Natural gas pipeline right-of-way

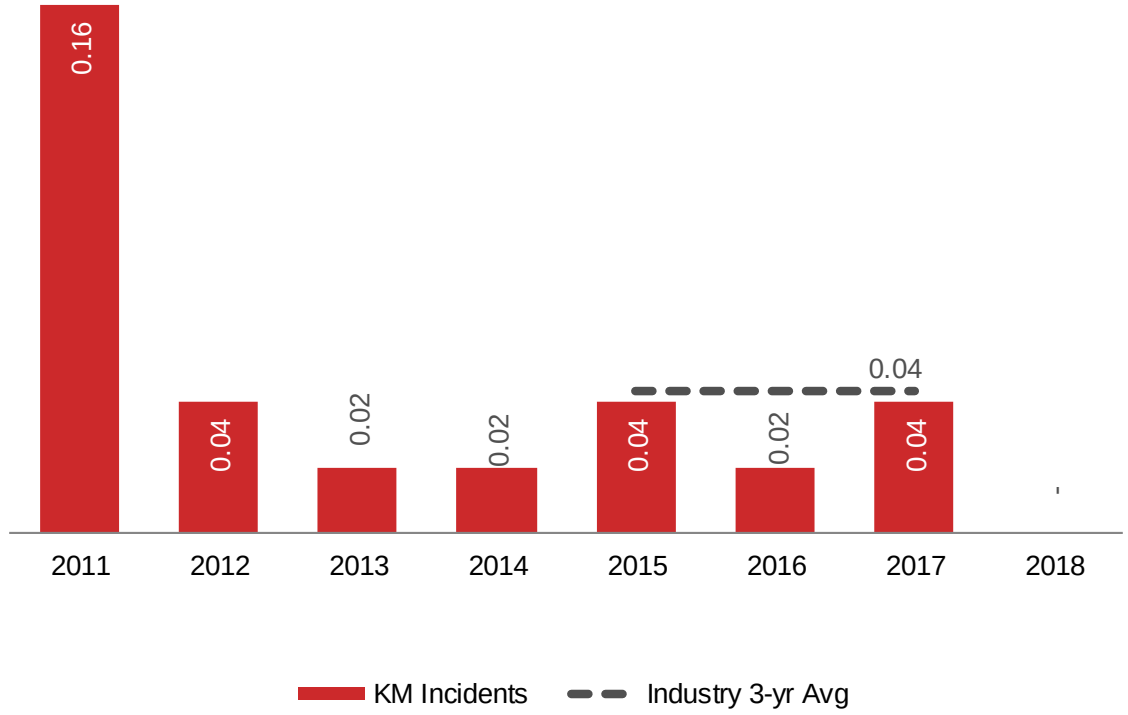
INCIDENTS RATE ALL REPORTABLE INCIDENTS[a,b]

Incidents per 1,000 miles



INCIDENTS RATE ONSHORE RUPTURES ONLY[b,c,d]

Incidents per 1,000 miles



a) Excludes El Paso and Copano assets in periods prior to acquisition (El Paso 5/25/2012, Copano 5/1/2013). An Incident means any of the following events:
   - An event that involves a release of gas from a pipeline, or of liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:
     - A death or personal injury necessitating in-patient hospitalization; or
     - Estimated property damage of $50,000 or more, including loss to the operator and others, but excluding cost of gas lost (2010 and earlier rates include cost of gas lost)
     - Unintentional estimated gas loss of 3 million cubic feet or more
   - An event that results in an emergency shutdown of an LNG facility
   - An event that is significant, in the judgment of the operator, even though it did not meet the criteria above

b) 2015-2017 most recent PHMSA 3-year average available.

c) Rupture defined as a break, burst, or failure that exposes a visible pipeline fracture surface. Kinder Morgan rupture rates calculated using most current pipeline mileage. Industry rate excludes Kinder Morgan data.

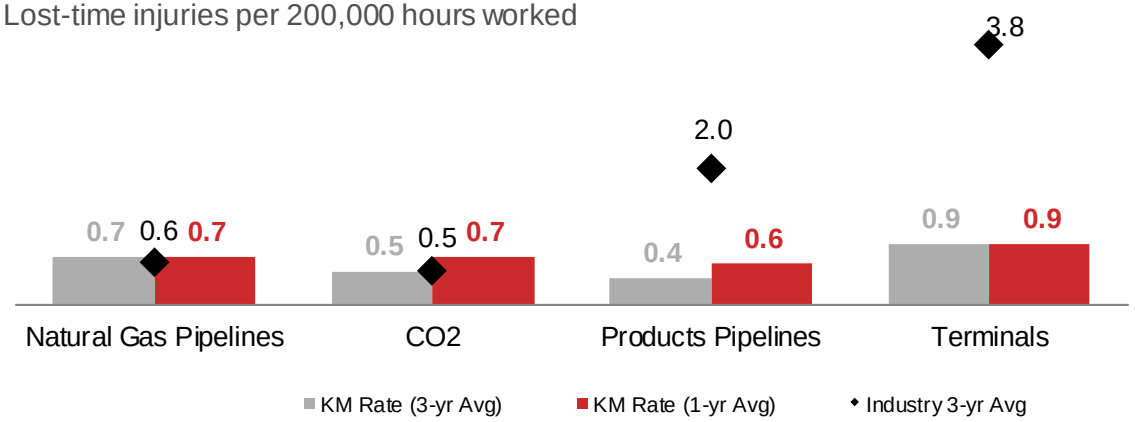
d) All Kinder Morgan ruptures occurred on legacy El Paso facilities prior to the Kinder Morgan acquisition.

Employee Safety Statistics

12-month performance summary as of 12/31/2018

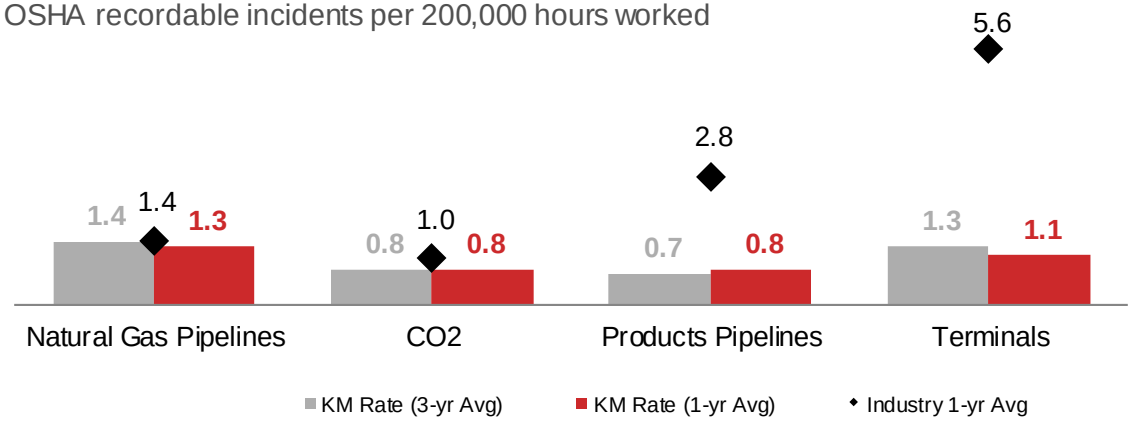
KM LOST-TIME INCIDENT RATE (DART)

Lost-time injuries per 200,000 hours worked



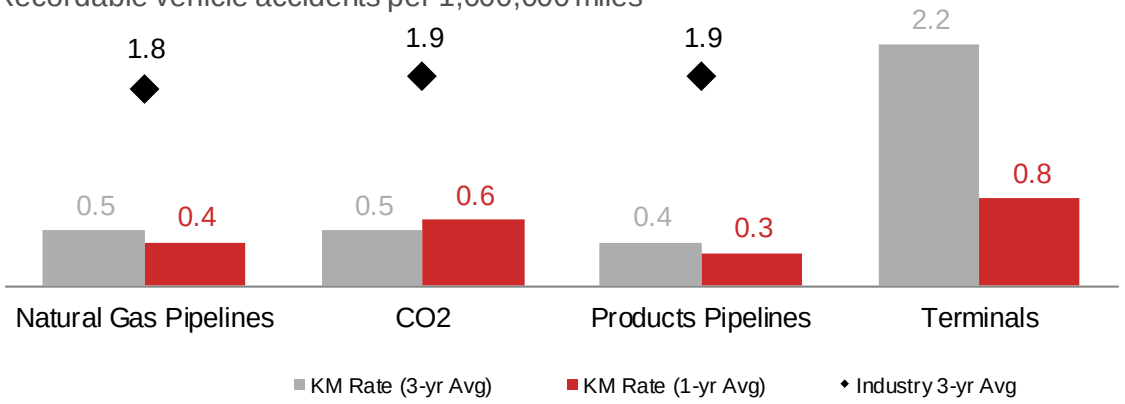
OSHA RECORDABLE INCIDENT RATE

OSHA recordable incidents per 200,000 hours worked



VEHICLE INCIDENT RATE[(a)]

Recordable vehicle accidents per 1,000,000 miles



a) Industry average not available for Terminals.

KMI Business Risks

Summary

- Regulatory
  - FERC rate cases (Products Pipelines and Natural Gas Pipelines)
  - Provincial, state, and local permitting issues
- CO_2 crude oil production volumes
- Throughput on our volume-based assets
- Commodity prices
  - 2019 budget average strip price assumptions: $60.00/bbl for crude and $3.15/mmbtu for natural gas
  - Price sensitivities (full-year):

Price Δ	Commodity	DCF Impact
$1/bbl	Oil	~$8mm
$0.10/mmbtu[a]	Natural Gas	~$1mm
1%	NGL / Crude Ratio	~$3mm

- Project cost overruns / in-service delays
- Interest rates
  - Sensitivity (full-year): 100-bp change in floating rates = ~$110 million interest expense impact[b]
- Foreign exchange rates
  - 2019 budget rate assumption of 0.76 USD per 1.00 CAD
  - Sensitivity (full-year): 0.01 ratio change = ~$0.4 million DCF impact
- Environmental (e.g. pipeline / asset failures)
- Economically sensitive business
- Cyber security

a) Natural Gas Midstream sensitivity incorporates current hedges, and assumes ethane recovery for majority of year, constant ethane frac spread vs. natural gas prices.
b) As of 12/31/2018, approximately $11.0 billion of KMI's long-term debt was floating rate (~30% floating).

KML Business Risks and Key Assumptions

Summary

- Industry demand / supply trends
- Throughput on our volume-based assets
  - If uncontracted volume throughput were higher or lower than forecasted by 10%, the estimated impact on 2019B Adjusted EBITDA would be an increase or decrease of ~5% on a full-year basis
- Project cost overruns and in-service delays
- Regulatory
  - Legislative and regulatory changes
  - Federal, provincial, state and local
  - Regulatory cost and indexing approvals
- Foreign exchange rates
  - 2019 budget rate assumption of 0.76 USD per 1.00 CAD
  - Sensitivity (full-year): 0.01 ratio change = ~C$0.6 million DCF impact
- Interest rates
- Environmental (e.g. pipeline / asset failures)
- Our base business is expected to be relatively stable, though it is subject to re-contracting and other risks

Non-GAAP Financial Measures and Reconciliations

Defined Terms

Reconciliations for the historical period

Use of Non-GAAP Financial Measures

The non-GAAP financial measures of distributable cash flow (DCF), both in the aggregate and per share, Segment EBDA before Certain Items (in the case of KMI only), Adjusted EBITDA, Adjusted Earnings, both in the aggregate and per share, and Net Debt and Adjusted Net Debt are presented herein.

Our non-GAAP measures described above have important limitations as analytical tools and should not be considered alternatives to GAAP net income or other GAAP measures. Our non-GAAP measures may differ from similarly titled measures used by others. You should not consider these non-GAAP measures in isolation or as substitutes for an analysis of our results as reported under GAAP. DCF should not be used as an alternative to net cash provided by operating activities computed under GAAP. Management compensates for the limitations of these non-GAAP measures by reviewing our comparable GAAP measures, understanding the differences between the measures and taking this information into account in its analysis and its decision making processes. Reconciliations of the Non-GAAP financial measures of DCF, Segment EBDA before Certain Items, Adjusted EBITDA and Adjusted Earnings to their most directly comparable GAAP financial measures for 2018 are included herein. 2018 GAAP and Non-GAAP amounts included in this presentation and in the following tables are preliminary and subject to completion of KMI's 2018 audited consolidated financial statements.

Certain Items, as used to calculate our non-GAAP measures, are items that are required by GAAP to be reflected in net income, but typically either (1) do not have a cash impact (for example, asset impairments), or (2) by their nature are separately identifiable from our normal business operations and in our view are likely to occur only sporadically (for example, certain legal settlements, enactment of new tax legislation and casualty losses).

DCF – For KMI, DCF is calculated by adjusting net income available to common stockholders before Certain Items for depreciation, depletion and amortization, or "DD&A," total book and cash taxes, sustaining capital expenditures and other items. For KML, DCF is calculated by adjusting net income before Certain Items for DD&A, total book and cash taxes, preferred share dividends and sustaining capital expenditures. DCF is a significant performance measure useful to management and external users of our financial statements in evaluating our performance and measuring and estimating the ability of our assets to generate cash earnings after servicing our debt and preferred stock dividends, paying cash taxes and expending sustaining capital, that could be used for discretionary purposes such as common stock dividends, stock repurchases, retirement of debt, or expansion capital expenditures. We believe the GAAP measure most directly comparable to DCF is net income available to common stockholders for KMI and net income for KML. For KMI, DCF per share is DCF divided by average outstanding shares, including restricted stock awards that participate in dividends. For KML, DCF to restricted voting shareholders per restricted voting share is DCF attributable to restricted voting shareholders divided by average outstanding restricted voting shares, including restricted share unit awards that participate in dividends.

Segment EBDA before Certain Items is calculated by adjusting segment earnings before DD&A for Certain Items attributable to a segment. General and administrative expenses are generally not under the control of our segment operating managers, and therefore, are excluded when we measure business segment operating performance. Segment EBDA before Certain Items is a significant performance measure useful to management and external users to evaluate segment performance and to provide additional insights into the ability of our segments to generate segment cash earnings on an ongoing basis. Additionally, management uses this measure, among others, to allocate resources to our segments. We believe the GAAP measure most directly comparable to Segment EBDA before Certain Items is segment earnings before DD&A (Segment EBDA).

Adjusted EBITDA is calculated by adjusting net income before interest expense, taxes, and DD&A (EBITDA) for Certain Items, and for KMI, by also adjusting net income before Certain Items for noncontrolling interests before Certain Items, and our share, if any, of unconsolidated JV's DD&A and book taxes. Adjusted EBITDA is useful to management and external users to evaluate, in conjunction with our net debt, certain leverage metrics. We believe the GAAP measure most directly comparable to Adjusted EBITDA is net income available to common stockholders for KMI and net income for KML.

Use of Non-GAAP Financial Measures (Cont'd)

Project EBITDA is calculated for an individual capital project as earnings before interest expense, taxes, and DD&A attributable to such project. Management uses project EBITDA to evaluate our return on investment for capital projects. We believe the GAAP measure most directly comparable to project EBITDA is Project Net Income.

Adjusted Earnings – For KMI, Adjusted Earnings are calculated by adjusting net income available to common stockholders for Certain Items, and Adjusted Earnings per share is Adjusted Earnings divided by average adjusted common shares which include KMI's weighted average common shares outstanding, including restricted stock awards that participate in dividends. For KML, Adjusted Earnings are calculated by adjusting net income available to restricted voting stockholders for Certain Items, and Adjusted Earnings per restricted voting share is net income available to restricted voting shareholders divided by average outstanding restricted voting shares, including restricted share unit stock awards that participate in dividends. Adjusted Earnings is used by certain external users of our financial statements to assess the earnings of our business excluding Certain Items as another reflection of our business's ability to generate earnings. We believe the GAAP measure most directly comparable to Adjusted Earnings is net income available to common stockholders for KMI and net income available to restricted voting stockholders for KML.

Net Debt and Adjusted Net Debt - Net Debt is calculated by subtracting from debt (i) cash and cash equivalents, (ii) the preferred interest in the general partner of Kinder Morgan Energy Partners L.P., (iii) debt fair value adjustments, and (iv) the foreign exchange impact on Euro-denominated bonds for which we have entered into currency swaps. Adjusted Net Debt is Net Debt increased by (i) 50% of the outstanding KML preferred equity and (ii) the amount of cash distributed to KML restricted voting shareholders as a return of capital on January 3, 2018, net of the gain realized on settlement of net investment hedges of our foreign currency risk with respect to our share of the KML return of capital on January 3, 2018. Management believes these measures are useful to investors and other users of our financial information in evaluating our leverage. We believe the most comparable measure to Net Debt and Adjusted Net Debt is debt net of cash and cash equivalents.

Budgeted Net Income (the GAAP financial measure most directly comparable to DCF, Adjusted EBITDA and Adjusted Earnings) and budgeted Project Net Income (the GAAP financial measure most directly comparable to Project EBITDA) are not provided due to the inherent difficulty and impracticability of predicting certain amounts required by GAAP, such as ineffectiveness on commodity, interest rate and foreign currency hedges, unrealized gains and losses on derivatives marked to market, and potential changes in estimates for certain contingent liabilities.

Net Revenue - We do not provide budgeted revenues (the GAAP financial measure closest to net revenue) due to impracticality of predicting certain items required by GAAP including projected commodity prices at the multiple purchase and sale points across certain intrastate pipeline systems. Instead, we are able to project the net revenue received for transportation services based on contractual agreements and historical operational experience.

JV DD&A is calculated as (i) KMI's share of DD&A from unconsolidated JVs, reduced by (ii) our partners' share of DD&A from JVs consolidated by KMI.

JV Sustaining Capex is calculated as KMI's share of sustaining capex made by joint ventures (both unconsolidated JVs and JVs consolidated by KMI).

For KMI, unconsolidated joint ventures for the periods during which these are accounted for as equity method investments, include Plantation, Cortez, SNG, ELC, MEP, FEP, EagleHawk, Red Cedar, Bear Creek, Cypress, Parkway, Sierrita, Bighorn, Fort Union, Webb / Duvall, Liberty, Double Eagle, Endeavor, WYCO, GLNG, Ruby, Young Gas, Citrus, NGPL and others. KMI's share of DD&A and sustaining capex are included for Plantation and Cortez for the periods presented after 2016. KML proportionately consolidates its ownership interests in its equity investees.

KMI GAAP Reconciliation

$ in millions

Reconciliation of DCF	Yr. Ended 12/31/18
Net Income	$ 1,919
Noncontrolling interests' portion of Certain Items	(240)
Noncontrolling interests[a]	(70)
Preferred stock dividends	(128)
Net Income available to common stockholders	1,481
Total Certain Items	501
Adjusted Earnings[b]	1,982
DD&A	2,392
JV DD&A[c]	360
Total book taxes[d]	710
Cash taxes[e]	(77)
Other[f]	15
Sustaining capex[g]	(652)
Distributable Cash Flow (DCF)	$ 4,730

Reconciliation of Segment EBDA before Certain Items	
Segment EBDA	$ 7,403
Certain Items impacting segments	269
Segment EBDA before Certain Items	7,672

Reconciliation of net debt	
Outstanding long-term debt[h]	$ 33,105
Current portion of debt	3,388
Foreign exchange impact on hedges for Euro debt outstanding	(76)
Less: cash & cash equivalents	(3,280)
Net Debt	33,137
50% KML preferred equity	215
KML distribution to restricted voting shareholders	890
Foreign exchange gain on hedge for our share of TMPL sale proceeds	(91)
Adjusted Net Debt	$ 34,151

Reconciliation of Adjusted EBITDA	Yr. Ended 12/31/18
Net Income	$ 1,919
Total Certain Items	501
Noncontrolling interests' portion of Certain Items	(240)
Noncontrolling interests[i]	(12)
DD&A	2,392
JV DD&A[j]	390
Book taxes[d,k]	727
Interest, net before Certain Items	1,891
Adjusted EBITDA	$ 7,568

Certain Items	
Fair value amortization	$ (34)
Legal and environmental reserves	63
Change in fair market value of derivative contracts	80
Losses on impairments and divestitures, net	317
Hurricane damage	(24)
Refund and reserve adjustment of taxes, other than income taxes	(51)
Noncontrolling interests' portion of Certain Items	240
Other	4
Subtotal	595
Book tax Certain Items	(58)
Impact of 2017 Tax Cuts and Jobs Act	(36)
Total Certain Items	$ 501

a) Before Certain Items. Represents net income allocated to third-party ownership interests in consolidated subsidiaries.
b) Adjusted Earnings is net income available to common stockholders before Certain Items.
c) Reduced by the noncontrolling interests' portion of KML DD&A of ($30) million.
d) Includes KMI share of unconsolidated C corp JVs' book taxes, net of the noncontrolling interests' portion of KML book taxes of $65 million, and excludes book tax certain items of $58 million.
e) Includes cash taxes for our share of unconsolidated C corp JVs (Citrus, Plantation, NGPL), Texas margin tax and other state income taxes.
f) Primarily non-cash compensation associated with our restricted stock program, partially offset by pension and retiree medical contributions.
g) Includes JV Sustaining Capex of $105 million. Excludes the noncontrolling interests' portion of KML sustaining capital expenditures.
h) Excludes Kinder Morgan G.P. Inc.'s $100 million preferred stock due 2057 and debt fair value adjustments.
i) Before Certain Items. Represents 3rd party share of consolidated JVs excluding KML noncontrolling interests of ($58) million.
j) JV DD&A is not reduced by the noncontrolling interests' portion of KML DD&A of ($30) million.
k) Total book taxes plus noncontrolling interests' portion of KML book taxes of $17 million.

KML GAAP Reconciliation for Continuing Operations

C$ in millions

Reconciliation of DCF	Yr. Ended 12/31/18
Net Income	$ 1,418
Income from Discontinued Operations, net of tax[(a)]	(1,318)
Income from continuing operations	100
Certain Items	(2)
Adjusted earnings from continuing operations	98
DD&A	83
Total book tax	37
Cash taxes	(8)
Preferred dividends	(29)
Sustaining capital expenditures	(19)
Distributable Cash Flow (DCF) from continuing operations	162
DCF from continuing operations attributable to KMI interest	(114)
DCF from continuing operations for restricted voting stockholders	$ 48

Reconciliation of net debt	
Long-term debt	$ -
Current portion of debt	-
50% of KML preferred equity balance	275
Less: cash & equivalents[(b)]	(361)
Net Debt including 50% of KML preferred equity balance	$ (86)

Reconciliation of Adjusted EBITDA	Yr. Ended 12/31/18
Net Income	$ 1,418
Income from Discontinued Operations, net of tax[(a)]	(1,318)
Income from continuing operations	100
Certain Items	(2)
Adusted earnings from continuing operations	98
DD&A	83
Total book tax	37
Interest, net	(29)
Adjusted EBITDA from continuing operations	$ 189

Certain Items	
Gain on divestitures, net	$ (3)
Book taxes on Certain Items	1
Total Certain Items	$ (2)

(a) Represents income from TMPL, TMEP and related assets prior to the closing of the Trans Mountain transaction on August 31, 2018, including a gain of $1,278 million, net of tax.

(b) Reduced by KML's January 3, 2019 return of capital distribution of $3,977 million to KMI and restricted voting shareholders.

Explanation of Return Calculations

	Formula	Notes
Segment Return on Investment	Segment EBDA before Certain Items less sustaining capex	(a)
	Average Total Investment	(b)
Return on Investment	DCF before interest	(c)
	Average Total Investment	(b)
Return on Equity	DCF (after interest)	(d)
	Average equity	(e)

	Formula	Notes
Calculation of Total Investment:	Gross PP&E	
	Equity Investments (JVs)	(f)
	Goodwill	
	Gross intangibles (excluding amortization)	
	Plus:	
	Asset write-offs / retirements	
	Cumulative environmental reserves	
	Legal reserves / expenditures	(g)
	Cumulative cash spent on asset retirement	(h)
	Minus:	
	Cumulative sustaining capex	
	Assumed liabilities	
	Common control adjustment	(i)
	Cumulative asset retirement costs	(h)
	Proceeds from sold assets / investments	
	Equals:	
	Total Investment	(j)

a) Adjustments are made to Segment EBDA to more closely tie to cash: (1) our share of JV DD&A is added back and our share of JV sustaining capex is deducted, (2) Express and Endeavor (1H 2014 and prior) pre-tax earnings are subtracted and cash received is added back. Reflects KMP segments (2000-2012), KMP and EPB segments (2013 and 2014) and KMI segments (2015 and after).
b) Annual average of the quarterly Total Investment.
c) For all years prior to 2015 (prior to the KMI acquisition of KMP, KMR and EPB), this item is defined as the sum of the individual Segment EBDA before Certain Items less sustaining capex and G&A. Thereafter, this item is defined as the sum of the individual Segment EBDA before Certain Items less sustaining capex, less G&A and cash taxes, plus book taxes deducted at the segment level. Book and cash taxes include KMI's share of unconsolidated C-corp JVs. KML contributions are shown at 100% interest.
d) For all years prior to 2015 (prior to the KMI acquisition of KMP, KMR and EPB), DCF is defined as limited partners' pretax income before Certain Items and DD&A, less cash taxes paid and sustaining capital expenditures for KMP and EPB, plus KMP's and EPB's share of JV DD&A less KMP's and EPB's share of JV sustaining capital expenditures, less equity earnings plus cash distributions received for Express and Endeavor (1H 2014 and prior), plus the general partner's incentive and the general partner non-controlling interest, as applicable. For 2015 and after, DCF is shown and reconciled in the Appendix: GAAP Reconciliation in this or prior year presentations.
e) Prior to 2016, equity is based on cumulative equity raised inception to date as of each quarter end and then averaged for the year. 2016 and after also include DCF spent to fund growth capital (excluding KML growth capital after its IPO).
f) Investments are generally calculated based on cumulative contributions and are not increased for earnings or decreased for distributions.
g) Litigation and environmental reserves deducted as Certain Items are added to investment, except for SFPP and CALNEV litigation reserves. For those pipelines, actual legal payments are added to the investment when they are made.
h) For GAAP purposes, the present value of accumulated asset retirement costs are included in gross PP&E; for purposes of this calculation, we decrease our Total Investment / subtract out the accumulated asset retirement costs, and increase our Total Investment / add back any cash actually spent on asset retirement.
i) For assets acquired from Kinder Morgan, Inc. (for example Express, Trans Mountain, TGP and EPNG) or El Paso, Inc. by either KMP or EPB (the MLPs) which represent a transfer of assets between entities under common control and were recorded for financial statement purposes at KMI's carrying value, an adjustment has been made to reflect these assets at the MLPs' purchase price.
j) For Canadian assets / investments, Total Investment is based on acquisition price plus cumulative expansion capital including overhead. The purpose of calculating Total Investment in this manner is to exclude the foreign exchange impact reflected in our GAAP financials as GAAP financials revalue the entire asset balance based on the end of period exchange rate. Proceeds from KML IPO are not deducted.