KINDER MORGAN INC.

Run for Shareholders, By Shareholders

Steve Kean
Chief Executive Officer

August 30-31, 2016

Forward-Looking Statements / Non-GAAP Financial Measures

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. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. 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. Future actions, conditions or events and future results of operations of Kinder Morgan, Inc. may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond Kinder Morgan's 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 and regulatory conditions and developments; the timing and success of business development efforts; technological developments; capital and credit markets conditions; inflation rates; interest rates; the political and economic stability of oil producing nations; energy markets; weather conditions; environmental conditions; business, regulatory and legal decisions; terrorism, including cyber-attacks; and other uncertainties. 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. Please read "Risk Factors" and "Information Regarding Forward-Looking Statements" in our most recent Annual Report on Form 10-K and our subsequently filed Exchange Act reports, which are available through the SEC's EDGAR system at www.sec.gov and on our website at www.kindermorgan.com.

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 the Appendix to this presentation. These non-GAAP measures should not be considered an alternative to GAAP financial measures.

Unparalleled Asset Footprint

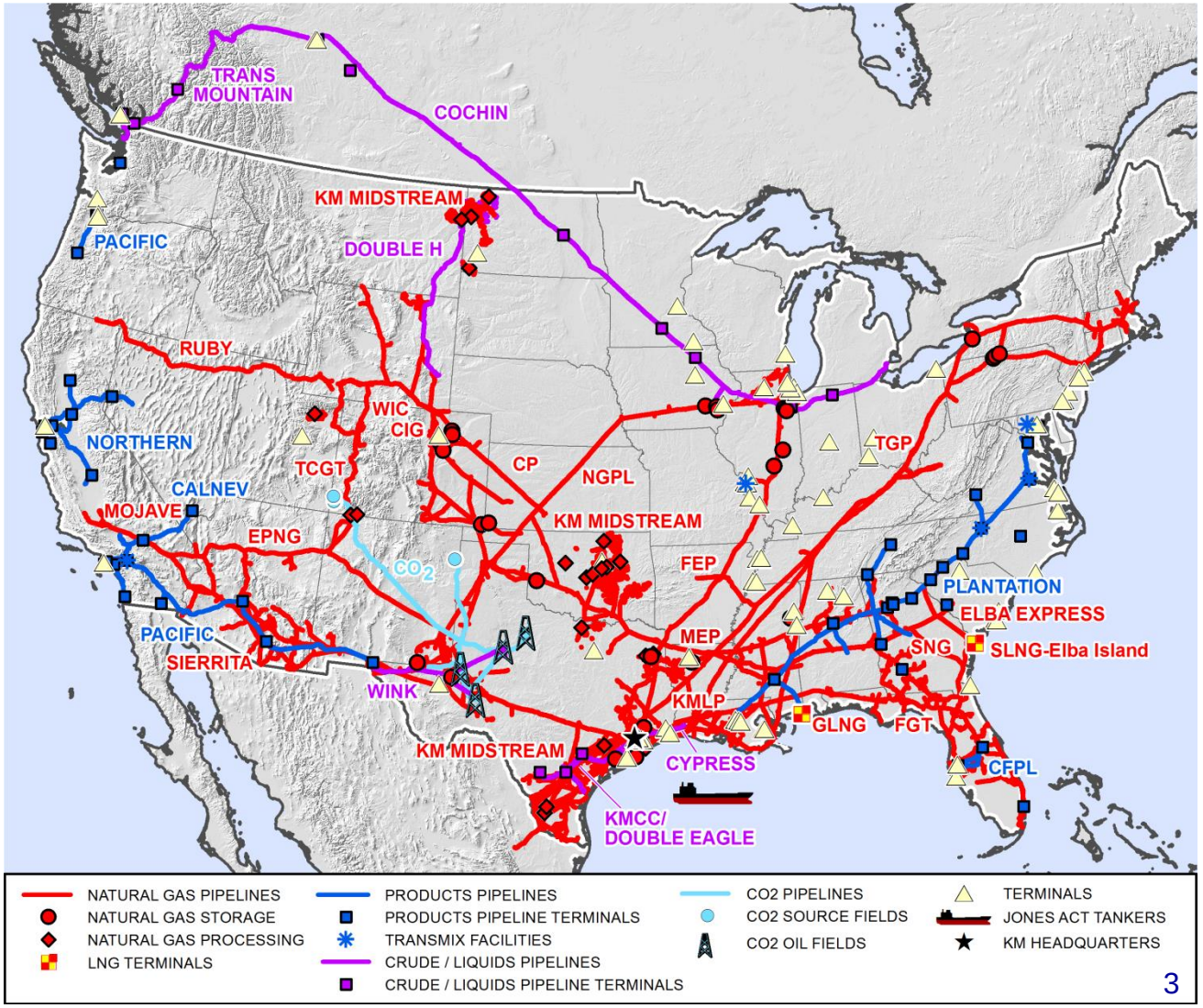
Largest Energy Infrastructure Company in North America

World class asset footprint:

- **Largest natural gas pipeline network in North America**
  - Own an interest in / operate over 69,000 miles of natural gas pipeline
  - Connected to every important U.S. natural gas resource play, including: Eagle Ford, Marcellus, Utica, Permian, Bakken and Haynesville
- **Largest independent transporter of petroleum products in North America**
  - Transport ~2.1 MMBbl/d[(a)]
- **Largest CO_2 transporter in North America**
  - Transport ~1.2 Bcf/d of CO_2[(a)]
- **Largest independent terminal operator in North America**
  - Own an interest in / operate ~180 liquids / dry bulk terminals
  - ~152 MMBbls of liquids capacity
  - Handle ~65 MMtons of dry bulk products[(a)]
  - Strong Jones Act shipping position
- **Only Oilsands pipeline serving West Coast**
  - Transports ~300 MBbl/d to Vancouver / Washington State; proposed expansion takes capacity to 890 MBbl/d

Footprint drives growth project pipeline:

- **$13.5 billion 5-year growth capex program**
  - Secured by long-term contracts
  - Attractive, fee-based returns

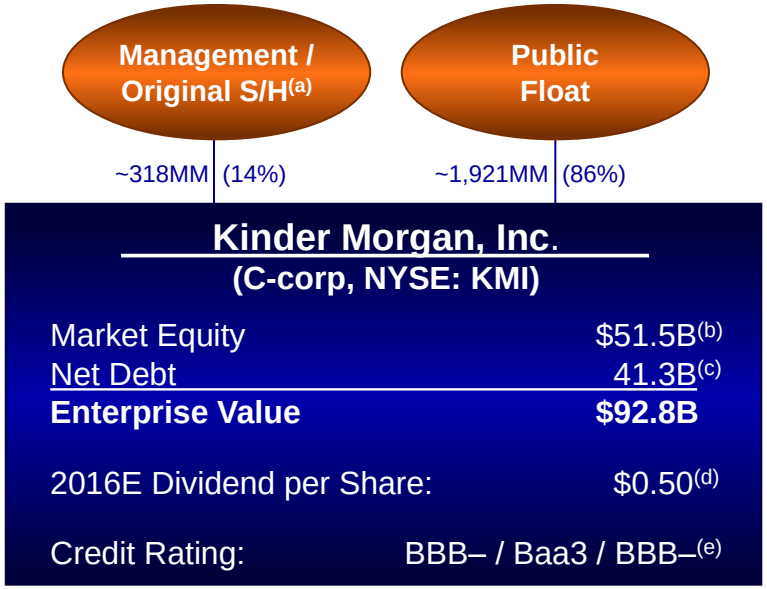


(a) 2016 budget.

KMI Overview

Management Aligned with Investors; 14% Stake in KMI

Simple Public Structure



Simple Structure:

- One equity base
- One dividend policy
- One debt rating
- No structural subordination
- No incentive distribution rights

(a) Includes Form-4 filers and unvested restricted shares.
(b) Market prices as of 8/19/2016; KMI market equity based on ~2,239 million shares outstanding (including unvested restricted stock) at a price of $22.28, ~293 million warrants at a price of $0.03, and 32 million mandatorily convertible depositary shares at a price of $50.30.
(c) Debt of KMI and its consolidated subsidiaries as of 6/30/2016, net of cash, and excluding fair value adjustments and Kinder Morgan G.P., Inc.'s $100 million preferred stock due 2057.
(d) Declared dividend per share per 2016 budget.
(e) KMI corporate credit ratings from S&P (Stable outlook), Moody's (Stable) and Fitch (Stable), respectively.

Our Strategy

- **Focus on stable fee-based assets that are core to North American energy infrastructure**
  - Market leader in each of our business segments
- **Maintaining a strong balance sheet is paramount**
  - Our primary investing entity has been investment grade for our entire 19-year history
  - Reduced dividend demonstrates our commitment to investment grade
- **Control costs**
  - It's investors' money, not management's – treat it that way
- **Leverage asset footprint to seek attractive capital investment opportunities, both expansion and acquisition**
  - Since 1997, Kinder Morgan has completed approximately $29 billion in acquisitions and invested approximately $25 billion in greenfield / expansion projects[(a)]
- **Transparency to investors**
- **Keep it simple**

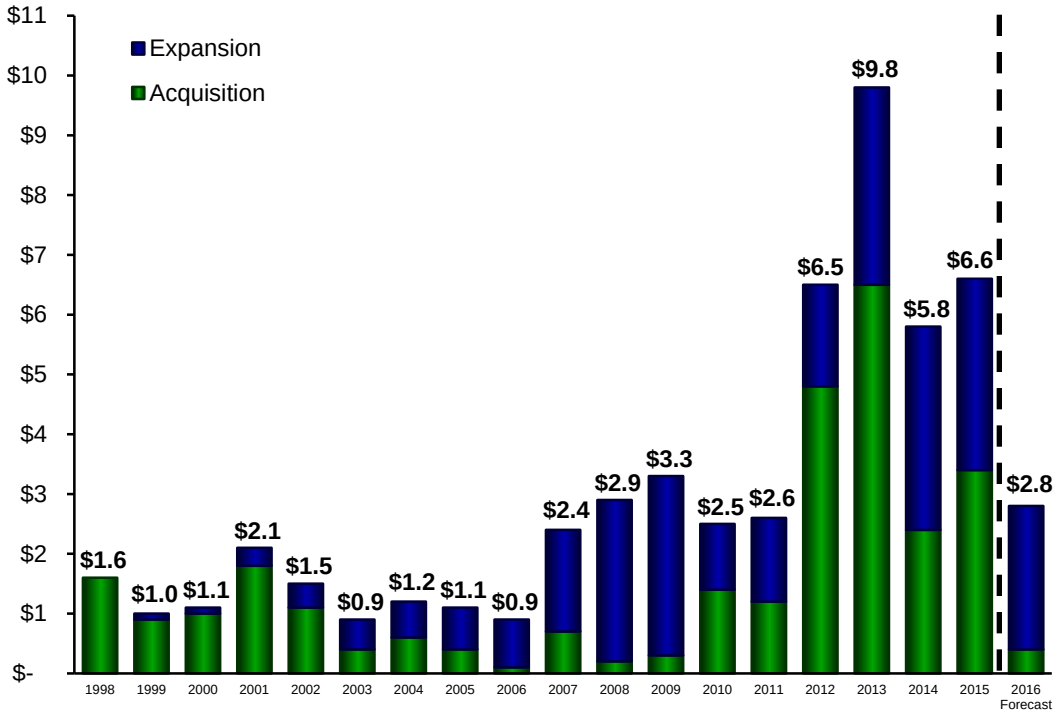
(a) From 1997 inception through 2015; represents combined investment of KMP (1997-2014), EPB (2013-2014), and KMI (2015).

Capital Invested

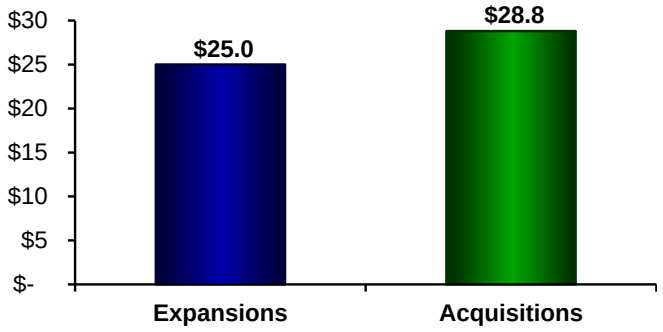
~$54 Billion of Asset Investment & Acquisitions Since Inception[(a,c)]

($ in billions)

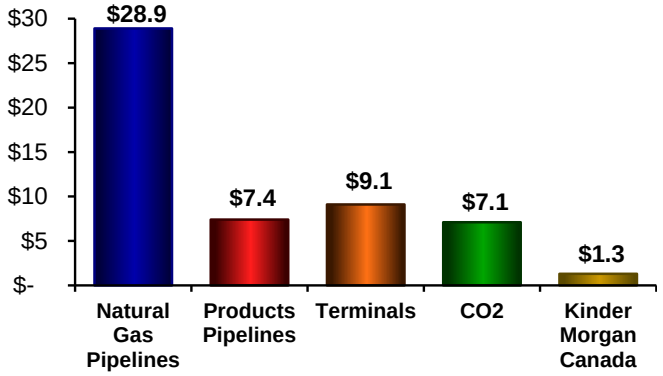
Total Invested by Year[(b,c)]



Total Invested by Type[(a,c)]



Total Invested by Segment[(a,c)]



Note: Includes equity contributions to joint ventures.

(a) 1997-2015; represents investment of KMP (1997-2014), EPB (2013-2014), and KMI (2015).

(b) 1997-2016F; represents investment of KMP (1997-2014), EPB (2013-2014), and KMI (2015-2016F).

(c) Net of proceeds from 2012 FTC Rockies divestiture in Natural Gas Pipelines segment. Excludes ~$11.3 billion in EPB asset acquisitions prior to KMI's acquisition of El Paso, but which is included in our ROI calculation beginning in 2013.
Net of proceeds from 2013 divestiture of Express-Platte pipeline system in Kinder Morgan Canada segment.
Excludes approximately $800 million Products Pipelines segment legal settlement and reserves incurred over the past decade, but which is included in our ROI calculation.

Returns on Invested Capital

Consistent Returns Demonstrate Asset Performance, Management Discipline

Segment ROI[a]:	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Natural Gas Pipes	13.3%	15.5%	12.9%	13.5%	14.0%	15.5%	16.7%	17.5%	16.9%	14.0%	11.9%	11.9%	11.9%	10.9%[b]	10.9%[b]	10.3%[b,c]
Products Pipelines	11.9	11.8	12.8	12.9	12.4	11.6	11.8	13.2	12.5	13.4	13.7	12.9	12.1	12.4	12.3	12.6
Terminals	19.1	18.2	17.7	18.4	17.8	16.9	17.1	15.8	15.5	15.1	14.6	14.3	13.5	12.1	11.2	10.2
CO_2	27.5	24.6	22.0	21.9	23.8	25.7	23.1	21.7	25.4	23.1	25.3	25.9	28.1	25.9	22.8	16.2
KM Canada	--	--	--	--	--	--	--	11.0	12.1	12.8	13.7	14.1	16.3	14.8	11.5	9.7
Return on Investment	12.3%	12.7%	12.6%	13.1%	13.6%	14.3%	14.4%	14.1%	14.8%	13.9%	13.5%	13.5%	13.6%	11.9%	11.4%	10.3%
Return on Equity	17.2%	19.4%	20.9%	21.7%	23.4%	23.9%	22.6%	22.9%	25.2%	25.2%	24.3%	24.0%	24.0%	21.7%	20.2%	14.3%

Notes: Reflects KMP (2000–2012), KMP and EPB (2013–2014) and KMI (2015). A definition of these measures may be found in the Appendix to our Analyst Day presentation, dated 1/27/2016, on our website at www.kindermorgan.com.

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

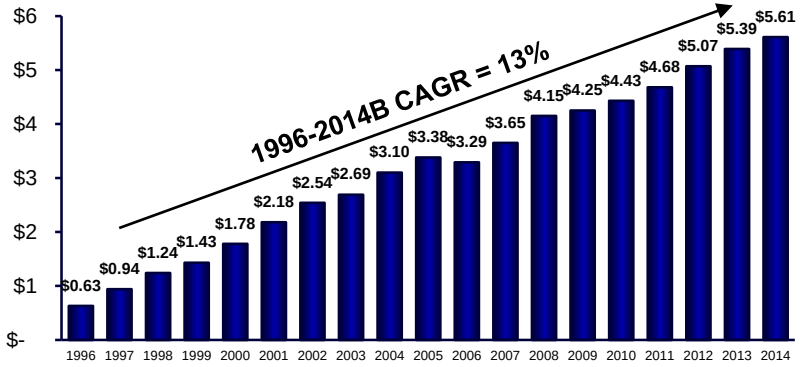
(b) Includes EPB assets. The denominator includes approximately $1.1 billion in REX capital not recovered in Nov-2013 sale price (i.e., leave behind). Excluding the leave behind cost would increase the Natural Gas Pipes-ROI to 11.3%, 11.2% and 10.5% in 2013, 2014 and 2015, respectively.

(c) Includes NGPL and Citrus investments.

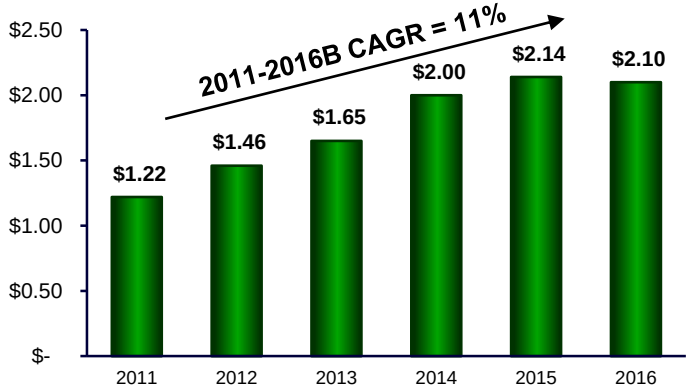
19 Years of Stable Growth

Strategy Has Led to Consistent, Growing Results

KMP Annual LP DCF per Unit[(a)]



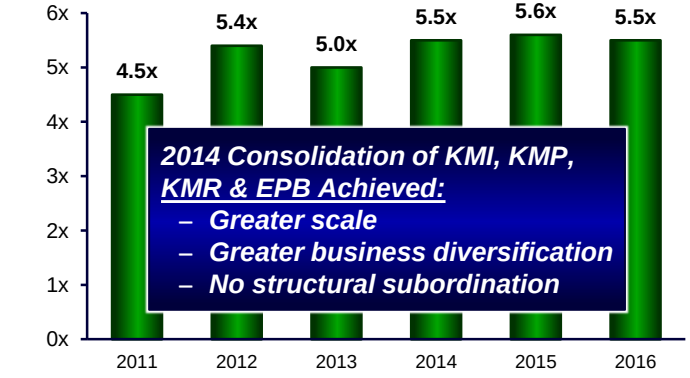
KMI Annual DCF per Common Share



KMP Net Debt[(b)] to Adjusted EBITDA



KMI Net Debt[(b)] to Adjusted EBITDA



Notes: DCF and Adjusted EBITDA are before certain items (non-GAAP measures). 2016 per budget. See Appendix for defined terms and reconciliation to GAAP measures.
KMP was Kinder Morgan's primary investment vehicle and held the majority of operating assets from 1996 to 2014.

(a) KMP annual LP DCF per share. 2014 data per budget as KMP was acquired by KMI prior to close of 4Q 2014. Assumes full distribution of DCF per unit for 1996-1999.

(b) Debt is net of cash and excludes fair value adjustments. KMP 2014 as of 9/30/2014.

2016 Budget Guidance[(a)]

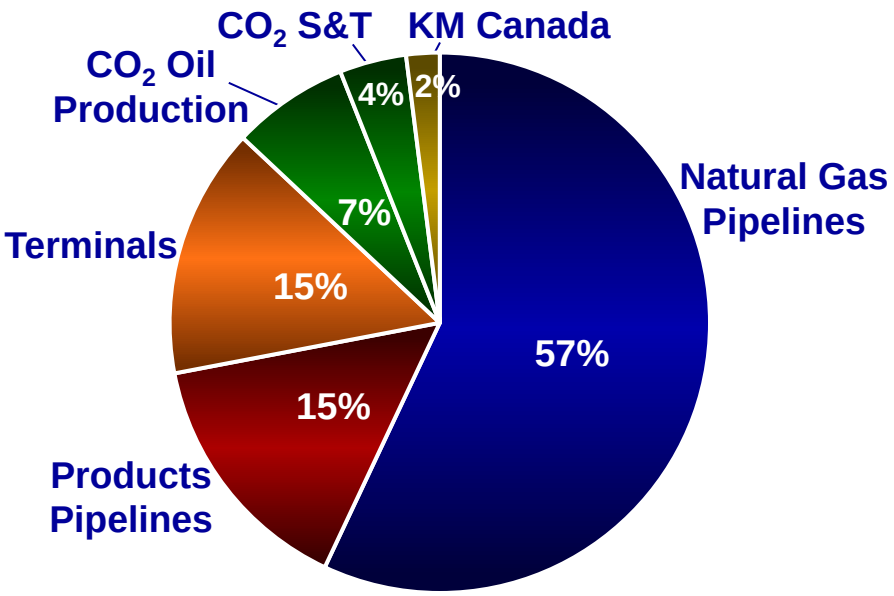
Supported by Diversified, Fee-based Cash Flow

- **2016 Published Budget**
  - DCF of $4.7 billion[(b)]
    - 2016 declared dividend of $0.50 per share
    - ~$3.6 billion of cash in excess of dividend
  - Growth capex of $3.3 billion in expansions, JV contributions, and acquisitions
  - Segment EBDA of $8.0 billion and Adjusted EBITDA of $7.5 billion[(b)]
  - Year-end 2016 net debt to Adjusted EBITDA ratio of 5.5x
  - 2016 budget assumes WTI oil price of $38/Bbl and natural gas price of $2.50/MMBtu[(c)]
    - $1/Bbl change in oil price = ~$6.5 million DCF impact
    - 10¢/MMBtu change in natural gas price = ~$0.6 million DCF impact
    - 1% change in NGL/WTI ratio = ~$2.0 million DCF impact
  - Given current market conditions, we expect KMI's 2016 Adjusted EBITDA and DCF to be approximately 3% and 4% below budget, respectively[(b)]
    - To be consistent with prior guidance, these projections are presented without taking the SNG transaction into account

Note: Before certain items. See Appendix for defined terms and reconciliation to GAAP net income.
(a) All 2016 Budget figures throughout this presentation reflect KMI's budget published 1/27/2016.
(b) DCF, Segment EBDA and Adjusted EBITDA are before certain items and include KM-share of Certain Equity Investee DD&A (non-GAAP measures).
(c) Natural Gas Midstream sensitivity incorporates current hedges, assumes same directional move in oil and gas prices, ethane rejection, no change in ethane frac spread, and assumes other NGL prices maintain same relationship with oil prices.

Segment Overview

2016 Budgeted Segment EBDA = $8.0 billion[(a)]



91% of cash flows fee-based for 2016; 97% fee-based or hedged

Natural Gas Pipelines

- 72% interstate pipelines
- 20% gathering, processing & treating
  - 87% fixed-fee[(b)]
  - 13% other
- 8% intrastate pipelines & storage

Products Pipelines

- 60% refined products
- 40% crude / liquids

Terminals

- 76% liquids
- 24% bulk

CO_2

- 34% CO_2 transport and sales
- 66% oil production-related
  - Production hedged:

	Hedged[(c)]	Avg. Px.
2016	81%	$62
2017	55%	$65
2018	41%	$68
2019	25%	$59
2020	15%	$51

Kinder Morgan Canada

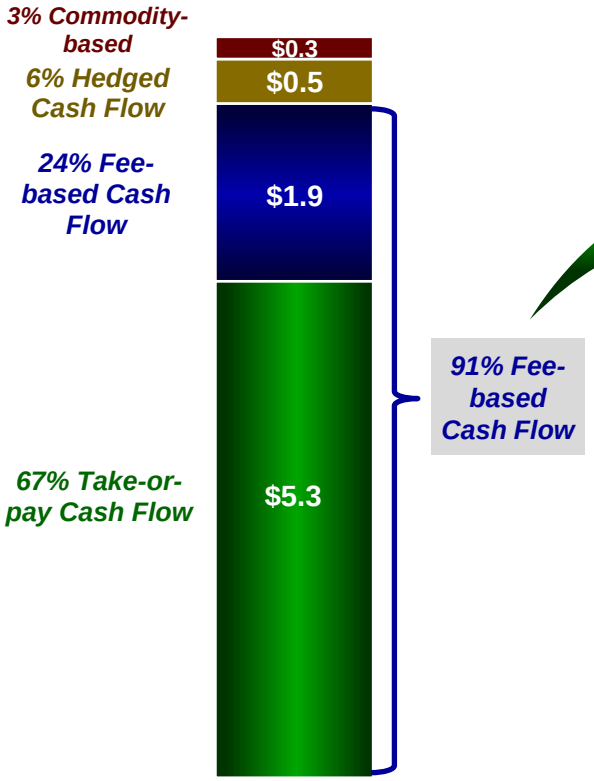
- 100% petroleum pipelines

(a) 2016 budgeted Segment EBDA before certain items and including KM-share of Certain Equity Investee DD&A (non-GAAP measure).
(b) Approximately 87% of gathering, processing and treating business is derived from fixed-fee contracts. Approximately 30% of that is take-or-pay.
(c) Percentages based on currently hedged crude oil and propane volumes as of 6/30/2016 relative to crude oil, propane and heavy NGL (C4+) net equity production projected for Jul-Dec 2016, and the Netherland Sewell reserve report plus management-approved Tall Cotton project barrels for 2017-2020.

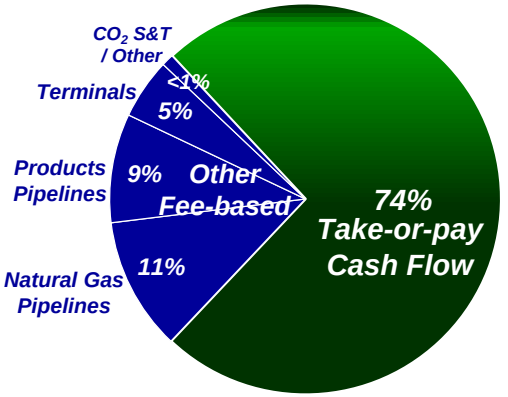
KMI's High Quality Cash Flow

Not all "fee-based" cash flow is created equal

2016 Budgeted Segment EBDA = $8.0 billion[(a)]



Composition of 91% Fee-based Cash Flow



- **74% of fee-based cash flow secured by take-or-pay contracts**
- **Other fee-based cash flow supported by stable volumes / fee-based contracts / critical infrastructure between major supply hubs and stable end-user demand**
  - Natural Gas Pipelines: G&P cash flow protected by dedicated producers and economically viable acreage
  - Products Pipelines: refined product volumes within ~1% of budget over past six years
  - Terminals: ~2/3 of Terminals' Other Fee-based associated with high-utilization liquids assets and requirements contracts for petcoke and steel

(a) Based on 2016 budgeted Segment EBDA before certain items and including KM-share of Certain Equity Investee DD&A (non-GAAP measure).

Natural Gas Transportation & Storage

57% of KMI 2016 Budgeted Segment EBDA[(a)]

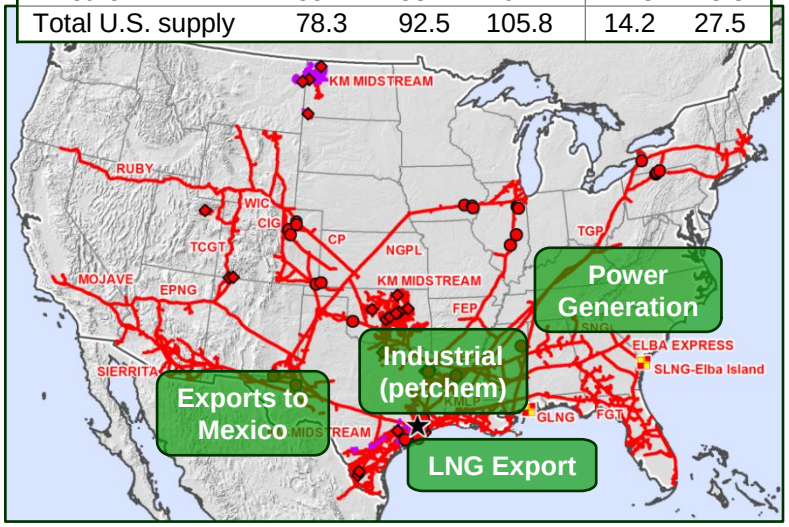
Natural gas transport & storage is KMI's largest business

- **U.S. natural gas demand expected to rise 35% through 2025[(b)]**
- **KM moves about 38% of natural gas consumed in the U.S.**
- **Transportation demand drivers:** power demand, exports (Mexico and LNG) and industrial market
  - 8.2 Bcf/d of new and pending contracts secured over past ~2 years (11% of 2015 total U.S. demand)
- **Storage demand drivers:** power and LNG export demand variability (U.S. as swing LNG provider to world market)
  - KM the largest storage operator in the U.S. with 672 Bcf out of 4.0 Tcf market (17%)
  - Well-positioned to serve the variable-load requirements of LNG exports and power generation
  - Current increased contracting activity at improved rates in the Interstate and Intrastate markets
- **Gathering & processing trends:**
  - New LPG export capacity (docks and fleet) and Gulf Coast petrochemical demand
  - Meaningful upside if market returns to normal levels

	NGL/ WTI Ratio [(c)]	NGL Processing Spreads [(d)]	
Historical:	Weighted Avg.	Ethane	Propane
2007-2012 Average	58%	$0.22	$0.62
2013-2015 Average	41%	($0.10)	$0.41

U.S. Natural Gas Supply & Demand[(a)] (Bcf/d)

				Increase	
Demand	2015	2020	2025	5-yr	10-yr
LNG net exports	-0.1	5.6	10.9	5.7	11.0
Mexican net exports	2.9	4.9	6.3	2.0	3.4
Power	26.5	27.5	30.5	1.0	4.0
Industrial	20.6	23.8	24.7	3.2	4.1
Other	28.4	30.7	33.4	2.3	5.0
Total U.S. demand	78.3	92.5	105.8	14.2	27.5
Supply					
Marcellus / Utica	18.9	34.4	43.1	15.5	24.2
All other	59.4	58.1	62.7	-1.3	3.3
Total U.S. supply	78.3	92.5	105.8	14.2	27.5



(a) Based on KMI 2016 budgeted Segment EBDA before certain items and including KM-share of Certain Equity Investee DD&A (non-GAAP measure).
(b) Source: Wood Mackenzie Spring 2016 Long-Term View.
(c) NGL mix is 37% ethane, 32% propane, 11% normal butane, 6% isobutane, 14% natural gasoline.
(d) Represents $/gal, assumes $0.10/gal T&F fee.

Liquids Transportation, Storage & Handling

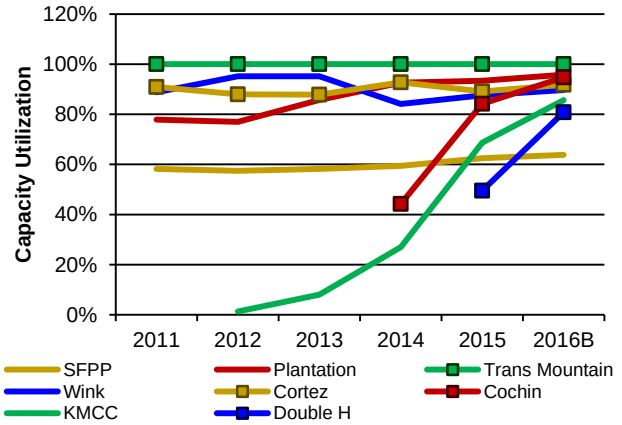
33% of KMI 2016 Budgeted Segment EBDA[(a)]

Strong Fundamentals & Demand Drivers

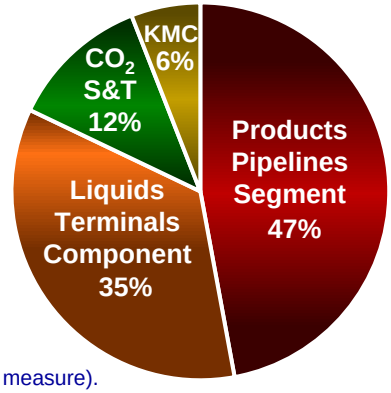
- **Stable refined products demand:** vital pipeline network connecting refinery / port hubs to stable / growing demand markets
  - Refined product volumes within ~1% of budget over past 5 years
- **Petchem demand growth:** abundant, affordable domestic natural gas supply driving U.S. industrial and petrochemical renaissance
  - 261 announced U.S. projects representing cumulative investment of $158 billion from 2010 to 2023[(b)]
  - UTOPIA pipeline provides needed takeaway capacity for Utica NGLs; backstopped by long-term take-or-pay contract (planned in-svc. Jan-2018)
- **Insufficient Oilsands takeaway capacity:** production expected to exceed takeaway capacity in 2017[(c)]
  - KM terminaling and crude-by-rail logistics serve critical role, have significant presence in Edmonton
  - TMEP pipeline provides critical Westcoast tidewater access for crude oil; backstopped by long-term take-or-pay contracts (planned in-svc. 3Q 2019)
- **World-leading Footprint in Houston Ship Channel:** 1) Point of origin for 10 refineries, 2) Close proximity to growing industrial / petchem complex, 3) access to Eagle Ford light crude inputs
  - KM footprint on HSC provides unparalleled market access and connectivity: 43 MMBbls liquids capacity, best-in-class access to dock space, rail, pipeline
- **Permian pipelines are key intra-region supply:** Wink the only crude pipeline to serve El Paso refinery, Cortez the primary source of CO_2 for enhanced oil recovery

Highlighting Asset Utilization

- **Location matters, contracts matter**



Liquids Business Profile[(a)]



(a) Based on KMI 2016 budgeted Segment EBDA before certain items and including KM-share of Certain Equity Investee DD&A (non-GAAP measure).
(b) American Chemistry Council, Year-end 2015 Chemical Industry Situation and Outlook; *American Chemistry Accelerating Growth*, December 2015.
(c) Canadian Association of Petroleum Producers, Crude Oil Forecast, Markets & Transportation, June 2015, and Kinder Morgan analysis.

Market Update

Natural Gas[(a)]

- **U.S. natural gas-fired power generation**
  - In 2016, SNG recorded its five highest power gen days ever
  - Week ending July 29, 2016 the first Summertime withdrawal from natural gas storage since 2006

Power Gen (MMWh/d)	2014	2015	'16 YTD	2016E	2017E
Nat gas-share	27%	33%	33%	34%	33%
Coal-share	39%	33%	27%	30%	31%

- **Natural gas exports to Mexico**
  - Natural gas displacing fuel oil for power gen
  - Mexico's natural gas production is declining

Mexican Exports (Bcf/d)	2014	2015	'16 YTD	2016E	2017E
KM Pipelines	1.6	2.0	2.3		
Non-KM	0.4	0.9	1.1		
Total Mexican Exports	2.0	2.9	3.3	3.8	4.3

- **LNG Exports**

LNG (Imports) / Exports (Bcf/d)	2014	2015	'16 YTD	2016E	2017E
U.S.	-0.04	-0.08	0.21	0.51	1.19
Δ YoY		-0.04	0.29	0.59	0.69

NGLs[(b)]

- **Significant NGL supply growth driving infrastructure development**
  - NGL exports projected to be 1.3 MMBbl/d by 2018, a 32% increase vs. 2015
    - Ethane export capacity expected to grow to ~400 MBbl/d by 2019
  - Petchem NGL demand projected to be 2.1 MMBbl/d by 2018, a 22% increase vs. 2015

NGL Demand (MMBbl/d)	2014	2015	2016E	2017E	2018E	Δ % '15-18E
Petchem	1.6	1.7	1.7	1.9	2.1	22%
Export	0.7	1.0	1.0	1.1	1.3	32%
Other (res/comm & mogas)	1.1	1.1	1.1	1.1	1.1	2%

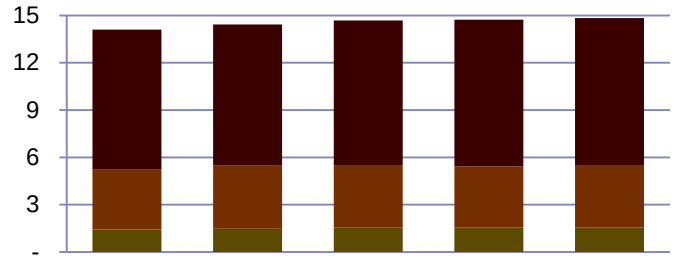
Note: YTD periods are through May 2016.
(a) Sources: Wood Mackenzie Spring 2016 Long-Term View, EIA, KM
(b) Source: Platts Bentek 2Q 2016 NGL Market Update

Market Update *(Cont'd)*

Refined Products[(a)]

- **Continued steady, modest volume growth**
- **Inflation-based tariff adjustment mechanism**

U.S. Refined Product Consumption (MMBbl/d)

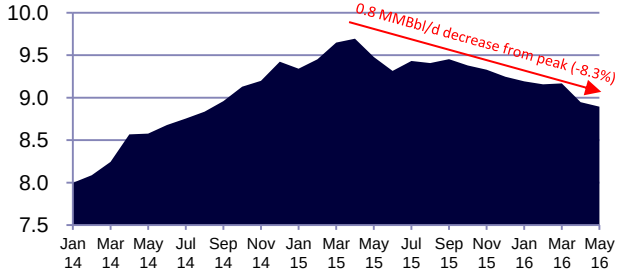


	2013	2014	2015	2016E	2017E
Motor Gasoline	8.84	8.92	9.16	9.29	9.31
Distillate Fuel Oil	3.83	4.04	3.98	3.88	3.96
Jet Fuel	1.43	1.47	1.54	1.56	1.56
Total Products	14.10	14.43	14.68	14.73	14.83
Δ %		2.3%	1.7%	0.3%	0.7%
KM Total Products	1.57	1.63	1.68	1.71	
Δ %		3.5%	3.1%	1.9%	

Crude Oil

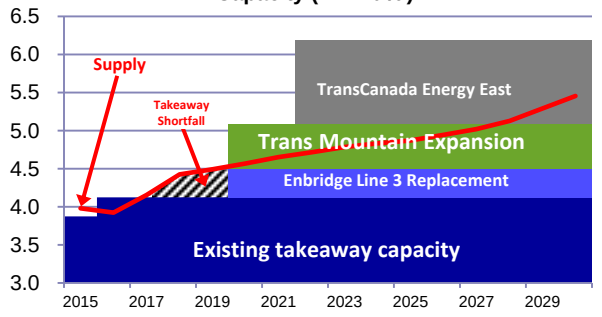
- **Oil price decrease leading to curtailed U.S. production[(b)]**

U.S. Monthly Oil Production (MMBbl/d)



- **As Canadian Oilsands projects currently under development come on line, region will be short takeaway capacity[(c)]**

Western Canada Supply vs. Takeaway Capacity (MMBbl/d)



(a) Sources: EIA July 2016 Short-Term Energy Outlook, Table 4a, KM (2016 per budget)
(b) Source: EIA July Monthly Crude Oil and Natural Gas Production Report
(c) Source: CAPP 2016 Crude Oil Forecast, Markets & Transportation, KM

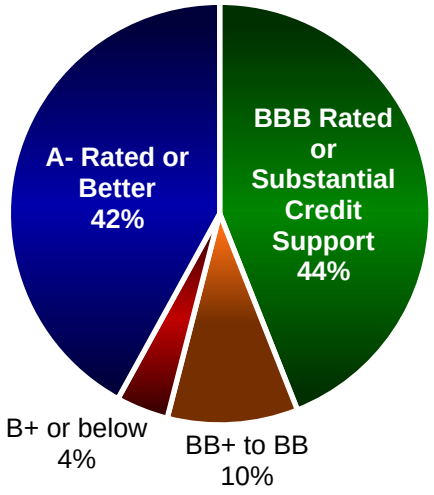
KMI Counterparty Exposure

Strong Customer Credit Profiles Limit KMI's Risk[a]

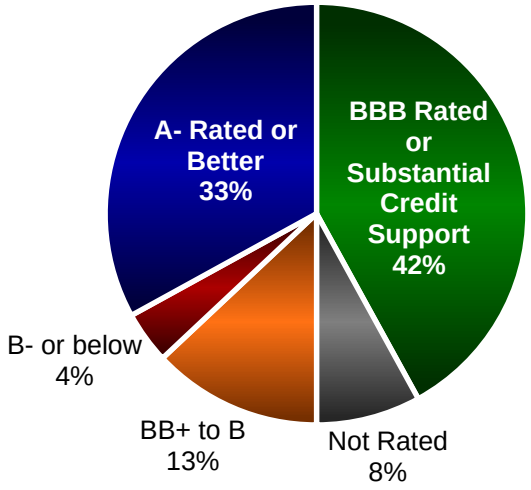
High-Quality, Diversified Customer Base

- **Estimate approximately 2/3 of revenue[b] generated by end-users (utilities, LDCs, refineries, chemical, large integrateds, etc.)**
- **KMI's average customer represents less than 0.10% of annual revenue[b]**
- **Top 25 customers represent ~46% of KMI's revenue[b]**
- **Top 206 customers[c] represent ~83% of KMI's revenue[b]**
  - ~5% of these revenues come from customers with a B- or lower rating, reflecting recent downgrade actions by S&P / Moody's (of which, our expected net exposure is approximately half[d])

Top 25 Customers[b]



Top 206 Customers[b,c]



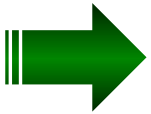
(a) Company credit ratings as of 8/19/2016.
(b) Based on budgeted 2016 net revenues of $11.5 billion, which includes our share of unconsolidated joint ventures, net margin for our Texas Intrastate customers, and net of dock premiums for our Canadian customers. Company credit ratings per S&P and Moody's. The charts above use S&P's equivalent rating symbols utilizing a blended rate for split-rated companies.
(c) Customers who individually represent >$5 million of 2016 budgeted revenue.
(d) Net exposure is revenues less credit support less market value of capacity.

5-year Growth Capex Program[(a)]

~$13.5B of Attractive, Fee-based Projects

- **World class asset footprint has helped secure growth projects with attractive returns, and secured by long-term, fee-based contracts with creditworthy counterparties**
  - ~86% of backlog is for fee-based pipelines, terminals and associated facilities
  - ~$1.8 billion of incremental EBITDA expected to be generated from growth capex program, excluding CO_2[(b)]
  - Target at least 15% unlevered after-tax return to fund CO_2 projects
- **Due to current challenging capital markets, we are focused on further high-grading these investment opportunities**

Segment	Growth Projects[(a)] ($B)
Natural Gas Pipelines	$4.0
Products Pipelines	0.3
Terminals	2.0
CO_2 – S&T[(c)]	0.5
CO_2 – EOR[(c)]	1.3
KM Canada	5.4
Total	$13.5



Incremental EBITDA Generation

- ~$1.8 billion excluding CO_2[(b)]
  - ~6.5x multiple[(d)]
- Target 15% minimum after-tax return for CO_2

(a) 5-year growth project backlog primarily consists of projects in progress for which commercial contracts have been secured. Includes KM's proportionate share of non-wholly owned projects. As of 6/30/2016. Includes estimated capitalized corporate overhead of $0.7 billion. Projects in-service prior to 7/1/2016 excluded.
(b) Estimated first full-year EBITDA generated from fee-based pipelines, terminals and associated facilities. Excludes EBITDA from CO_2 projects. Includes roughly $175 million of EBITDA contribution in 2016 budget.
(c) S&T = CO_2 Source & Transportation. EOR = Enhanced Oil Recovery.
(d) Investment multiple calculated as total project cost divided by first full-year expected EBITDA.

Business Risks

- **Regulatory**
  - Products Pipeline FERC rate cases
  - Natural Gas FERC rate cases
  - Legislative and regulatory changes
- **CO_2 crude oil production volumes**
- **Throughput on our volume-based assets**
- **Counterparty credit**
- **Commodity prices**
  - 2016 budget price assumptions: $38/Bbl for crude, and $2.50/MMBtu for natural gas
  - Price sensitivities (full-year):
    - ~$6.5 million DCF per $1/Bbl change in crude price
    - ~$0.6 million DCF per $0.10/MMBtu change in natural gas price[(a)]
    - ~$2.0 million DCF per 1% change in NGL / crude ratio
- **Foreign exchange rates**
  - 2016 budget rate assumption of 0.72 CAD / USD
  - Price sensitivity (full-year): ~$3 million DCF per 0.01 ratio change
- **Project cost overruns / in-service delays**
- **Economically sensitive businesses (e.g., steel terminals)**
- **Environmental (e.g., pipeline / asset failures)**
- **Terrorism**
- **Interest rates**
  - Full-year impact of 100-bp increase in floating rates equates to a pre-tax ~$115 million increase in interest expense[(b)]

(a) Natural Gas Midstream sensitivity incorporates current hedges, assumes same directional move in oil and gas prices, ethane rejection, no change in ethane frac spread, and assumes other NGL prices maintain same relationship with oil prices.
(b) As of 6/30/2016 approximately $11.5 billion of KMI's net debt was floating rate (approximately 28% floating).

KMI: Attractive Value Proposition

- Unparalleled asset footprint
- Stable, fee-based cash flows
- Strong and improving investment grade balance sheet
- $13.5 billion of capital committed to attractive growth projects
- No need to access capital markets to fund growth projects
- Experienced management team aligned with investors

Appendix

Energy Toll Road

Security of Cash

	Natural Gas Pipelines	Products Pipelines	Terminals	CO_2	Kinder Morgan Canada
Volume Security	– **Interstate & LNG:** take or pay – **Intrastate:** ~73% take or pay[a,b] – **G&P:** ~87% fee-based[b] with minimum volume requirements / acreage dedications	– **Refined products:** primarily volume-based – **Crude / liquids:** primarily take or pay	– **Liquids & Jones Act:** primarily take or pay – **Bulk:** primarily minimum volume guarantee, or requirements	– **S&T:** primarily minimum volume guarantee – **O&G:** volume-based	– Essentially no volume risk
Average Remaining Contract Life	– **Interstate:** 6.3 yrs. – **LNG:** 16.4 yrs. – **Intrastate:** 4.8 yrs.[a] – **G&P:** 5.0 yrs.	– **Refined products:** generally not applicable – **Crude / liquids:** 5.8 yrs.	– **Liquids:** 3.8 yrs. – **Jones Act:** 3.6 yrs.[c] – **Bulk:** 3.7 yrs.	– **S&T:** 9.0 yrs.	– 3.0 yrs.[d]
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 / liquids:** primarily fixed based on contract	– Based on contract; typically fixed or tied to PPI	– **S&T:** 82% protected by minimum volumes and floors[b] – **O&G:** volumes 81% hedged[e]	– Fixed based on toll settlement
Regulatory Security	– **Interstate:** regulated return – **Intrastate:** essentially market-based – **G&P:** market-based	– **Pipelines:** regulated return – **Terminals & transmix:** not price regulated[f]	– Not price regulated	– Primarily unregulated	– Regulated return
Commodity Price Exposure	– **Interstate:** no direct exposure – **Intrastate:** limited exposure – **G&P:** limited exposure	– Minimal, limited to transmix business	– No direct exposure	– Full-yr 2016: $4.8MM in DCF per $1/Bbl change in oil price	– No direct exposure

All figures as of 1/1/2016, except where noted.

(a) Transportation for intrastate pipelines includes term purchase and sale portfolio.

(b) Based on KMI 2016 budgeted Segment EBDA before certain items and including KM-share of Certain Equity Investee DD&A where applicable (non-GAAP measure).

(c) Jones Act vessels: average remaining contract term for operating tankers (8) and tankers under construction (6) is 3.6 years, or 5.8 years including options to extend.

(d) Expected to be extended to coincide with in-service of Trans Mountain expansion.

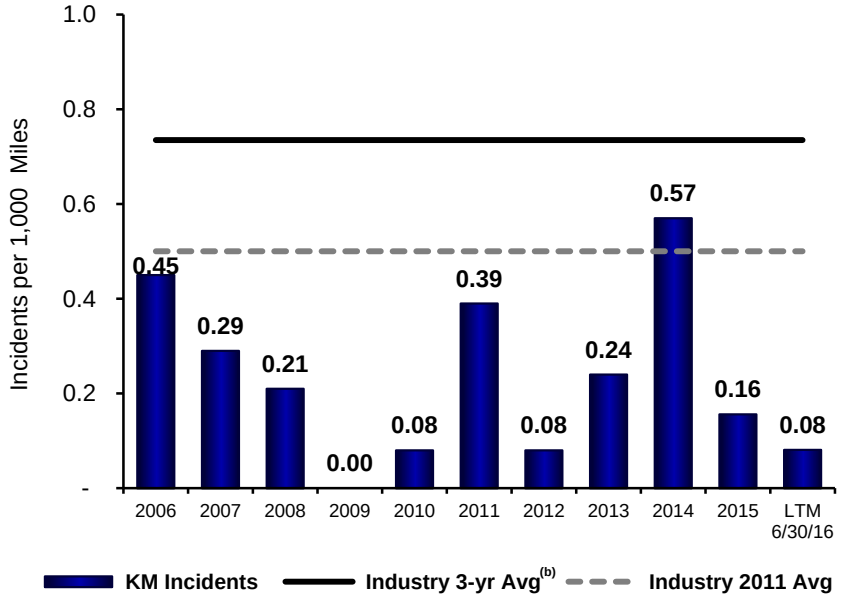
(e) Percent of 2016 forecast net crude oil, propane and heavy NGL (C4+) net equity production projected for Jul-Dec 2016.

(f) Terminals not FERC regulated, except portion of CALNEV.

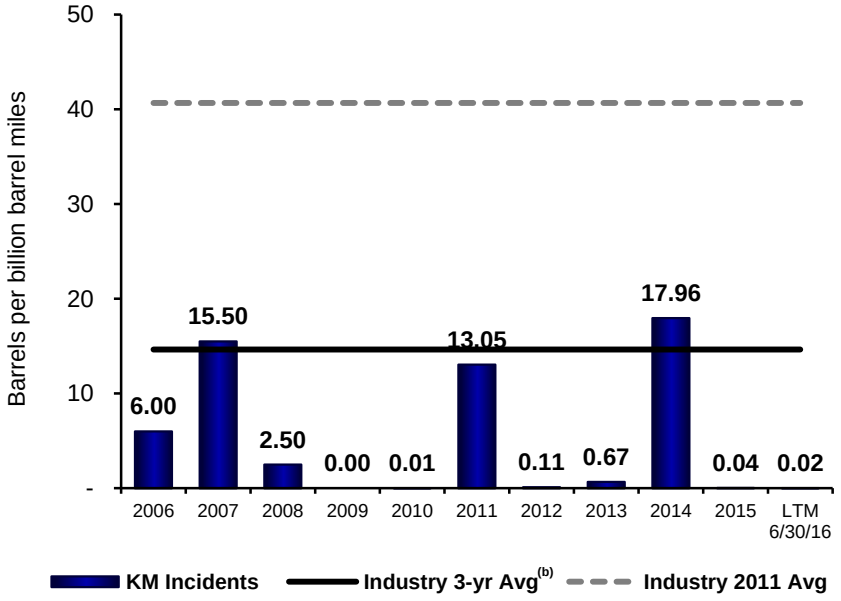
Incidents & Releases

Liquids Pipeline Right-of-way

Liquids Pipelines Incidents per 1,000 Miles[(a)]



Liquids Pipelines Release Rate[(a)]



Note: KM totals exclude natural gas transportation assets, non-DOT jurisdictional CO_2 Gathering and Crude Gathering for compatibility with industry comparisons.

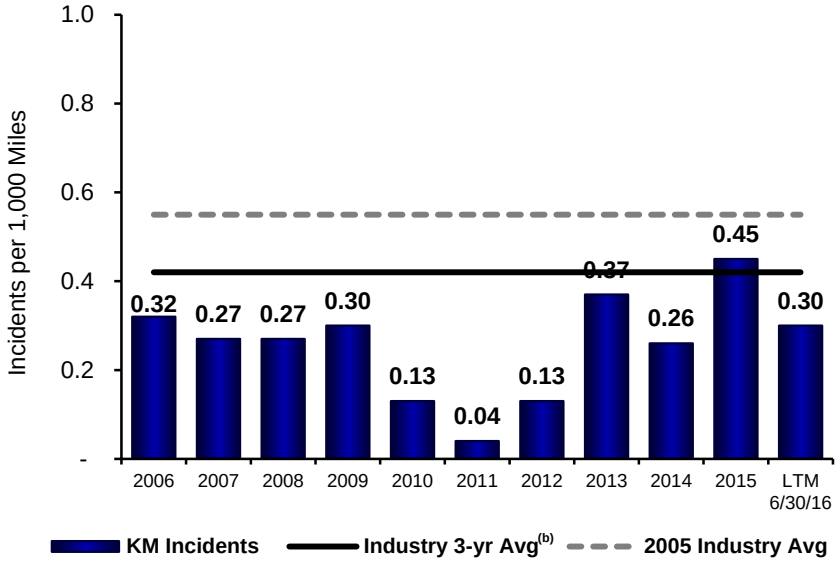
(a) Failures involving onshore pipelines that occurred on the ROW, including valve sites, in which there is a release of the liquid or carbon dioxide transported resulting in any of the following:
- (1) Explosion or fire not intentionally set by the operator.
- (2) Release 5 barrels or greater. (NOTE: PHMSA does not record system location for releases less than 5 barrels)
- (3) Death of any person.
- (4) Personal injury necessitating hospitalization.
- (5) 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) 2013–2015 most recent PHMSA 3-yr average available.

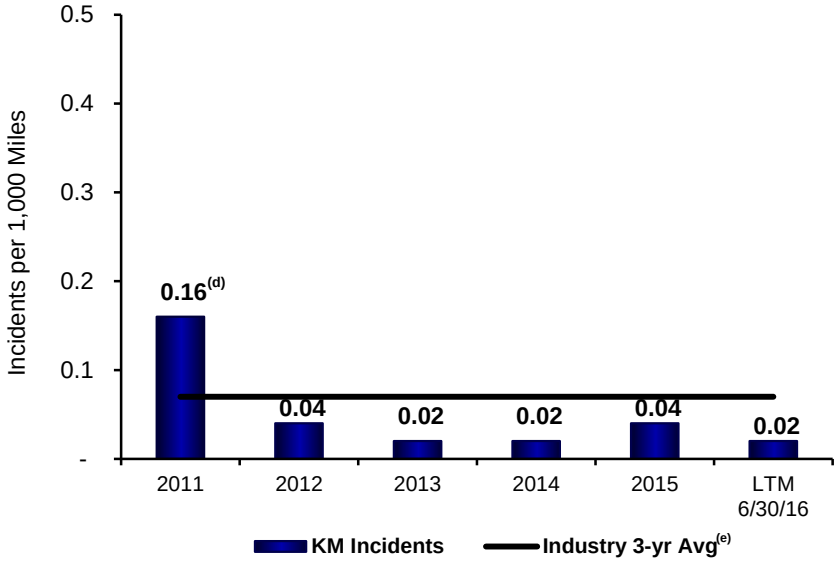
Incidents & Releases

Natural Gas Pipeline Right-of-way

Natural Gas Pipelines
Incidents Rate All Reportable Incidents[a]



Natural Gas Pipelines
Incidents Rate Onshore Ruptures-only[c]



(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:
- (1) 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:
  - i. A death or personal injury necessitating in-patient hospitalization; or
  - ii. 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)
  - iii. Unintentional estimated gas loss of 3 million cubic feet or more.
- (2) An event that results in an emergency shutdown of an LNG facility.
- (3) An event that is significant, in the judgment of the operator, even though it did not meet the criteria of paragraphs (1) or (2) above.

(b) 2013–2015 most recent PHMSA 3-yr average available.

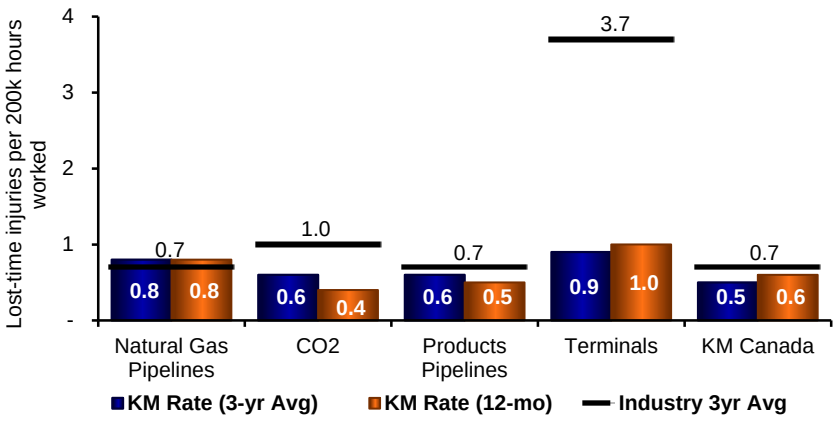
(c) Rupture defined as a break, burst, or failure that exposes a visible pipeline fracture surface.
- (1) Kinder Morgan rupture rates calculated using 2014 pipeline mileage.
- (2) Industry rate excludes Kinder Morgan data.

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

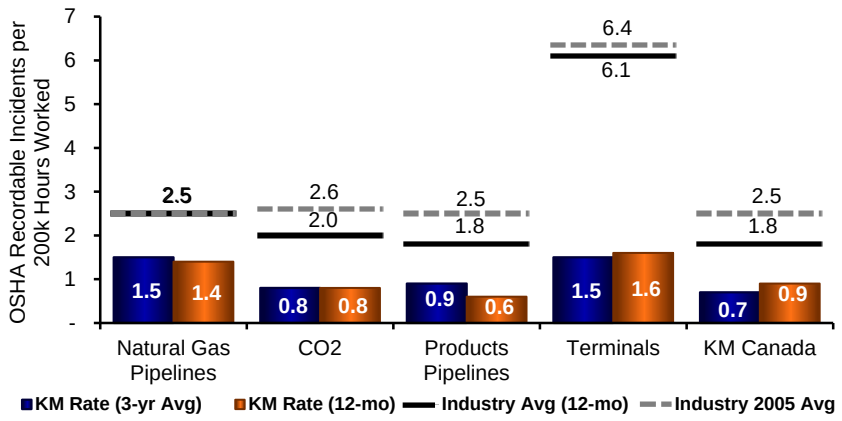
(e) 2013–2015 most recent PHMSA 3-yr average available.

Employee Safety Statistics[a]

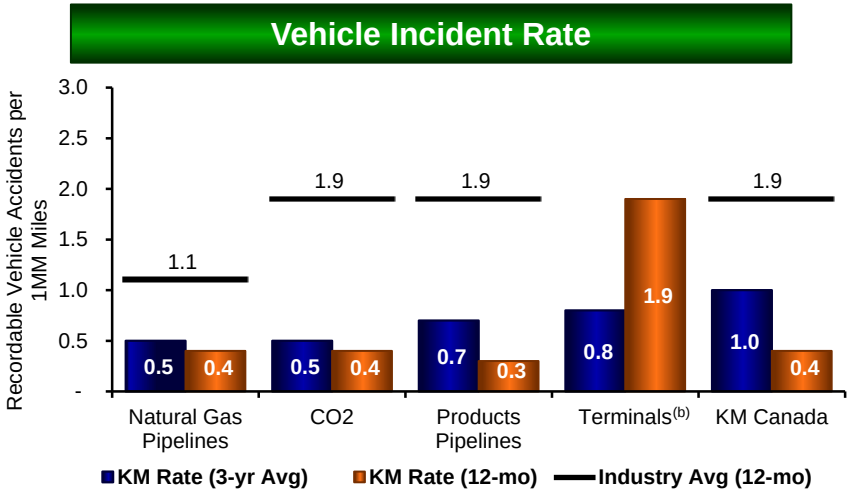
KM Lost-time Incident Rate (DART)



OSHA Recordable Incident Rate



Vehicle Incident Rate



(a) 12-month safety performance summary as of 6/30/2016.
(b) Industry average not available for Terminals.

Natural Gas Pipelines

Segment Outlook

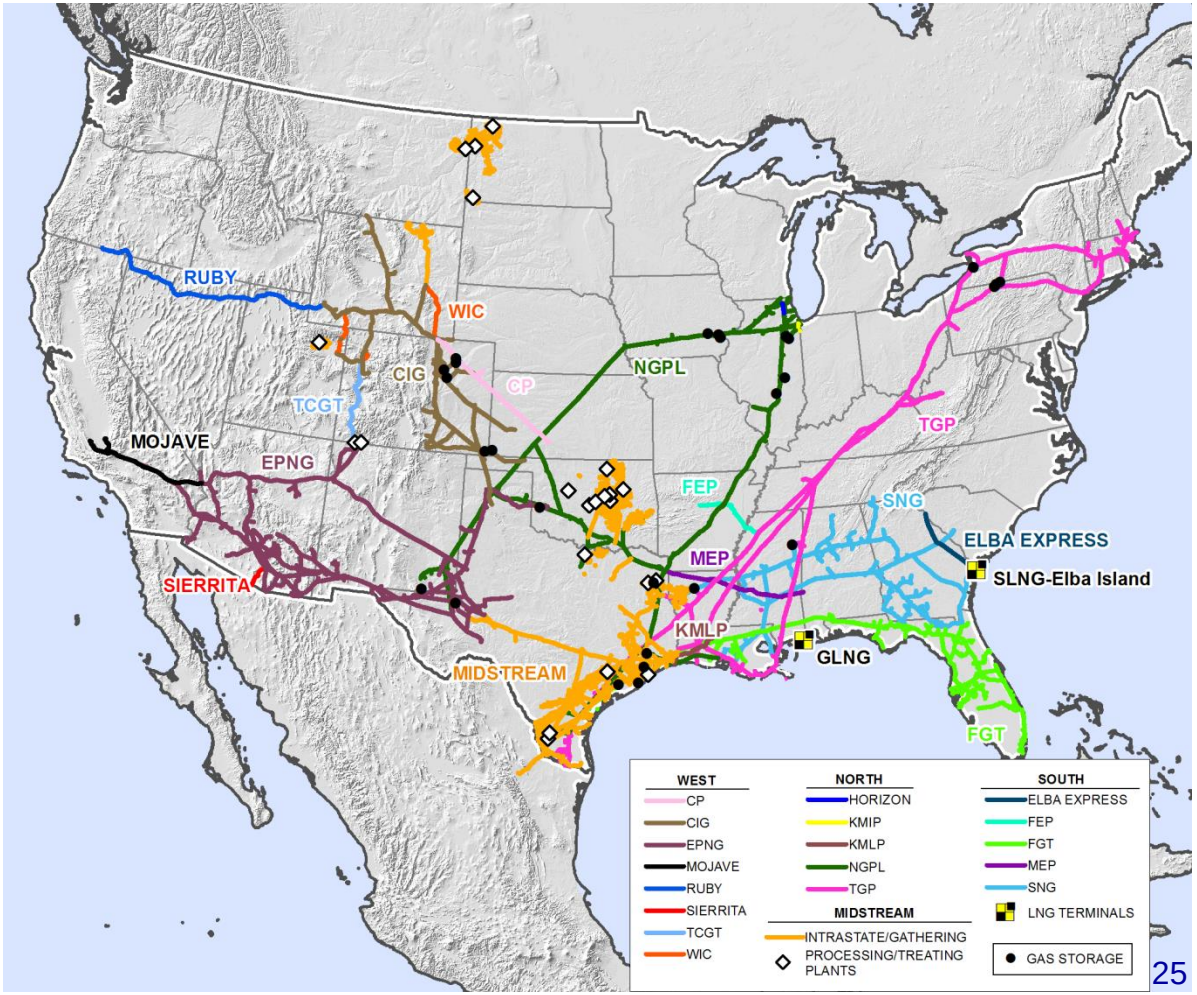
Well-positioned connecting key natural gas resources with major demand centers

Long-term Growth Drivers:

- Shale-driven expansions / extensions
- LNG exports
  - Liquefaction facilities
  - Pipeline infrastructure
- Gas demand for power generation
  - Coal plant retirements
  - Regional gas-fired power demand growth
  - Backstop for wind and solar
- Industrial demand growth
- Exports to Mexico
- Repurposing opportunities
- Acquisitions

Project Backlog:

- $4.0 billion of identified growth projects over next five years (2016-2020)[(a)], including:
  - LNG liquefaction (Elba Island)
  - Transport projects supporting LNG liquefaction
  - TGP north-to-south projects
  - SNG / Elba Express expansions
  - Expansions to Mexico border



(a) Excludes acquisitions, includes KM share of non-wholly owned projects. Includes projects currently under construction.

KINDER MORGAN INC.

Contracted Capacity and Term by Region

Region	Service	Contracted Capacity	Avg. Term Remaining
North	Storage	356 Bcf	3 yrs., 7 mos.
	Transport	19.1 Bcf/d	5 yrs., 7 mos.
South	Storage	52 Bcf	1 yrs., 10 mos.
	Transport	13.0 Bcf/d	7 yrs., 11 mos.
	LNG	18 Bcf	16 yrs., 5 mos.
West	Storage	45 Bcf	6 yrs., 3 mos.
	Transport	17.9 Bcf/d	5 yrs., 11 mos.
Midstream	Purchases	2.6 Bcf/d	2 yrs., 1 mos.
	Sales	3.3 Bcf/d	2 yrs., 6 mos.
	Storage	93 Bcf	4 yrs., 2 mos.
	Transport	3.3 Bcf/d	4 yrs., 4 mos.
	Processing	1.6 Bcf/d	5 yrs., 9 mos.

Interstate Transport Contracts Avg. = 6 yrs., 4 mos.

- **Net annual incremental re-contracting exposure (KM-share)[(a)]:**

Region	% of KMI's $8.0B Segment EBDA[(b)] 2017	2018
North	0.0%	(0.9%)
South	(0.1%)	(0.2%)
West	(0.5%)	(0.1%)
Midstream	(0.1%)	(0.1%)
Total Nat. Gas Segment	(0.7%)	(1.3%)

(a) Negative figures represent unfavorable re-contracting exposure. Includes transportation and storage contracts.
(b) Based on KMI 2016 budgeted Segment EBDA before certain items and including KM-share of Certain Equity Investee DD&A (non-GAAP measure).

Products Pipelines

Segment Outlook

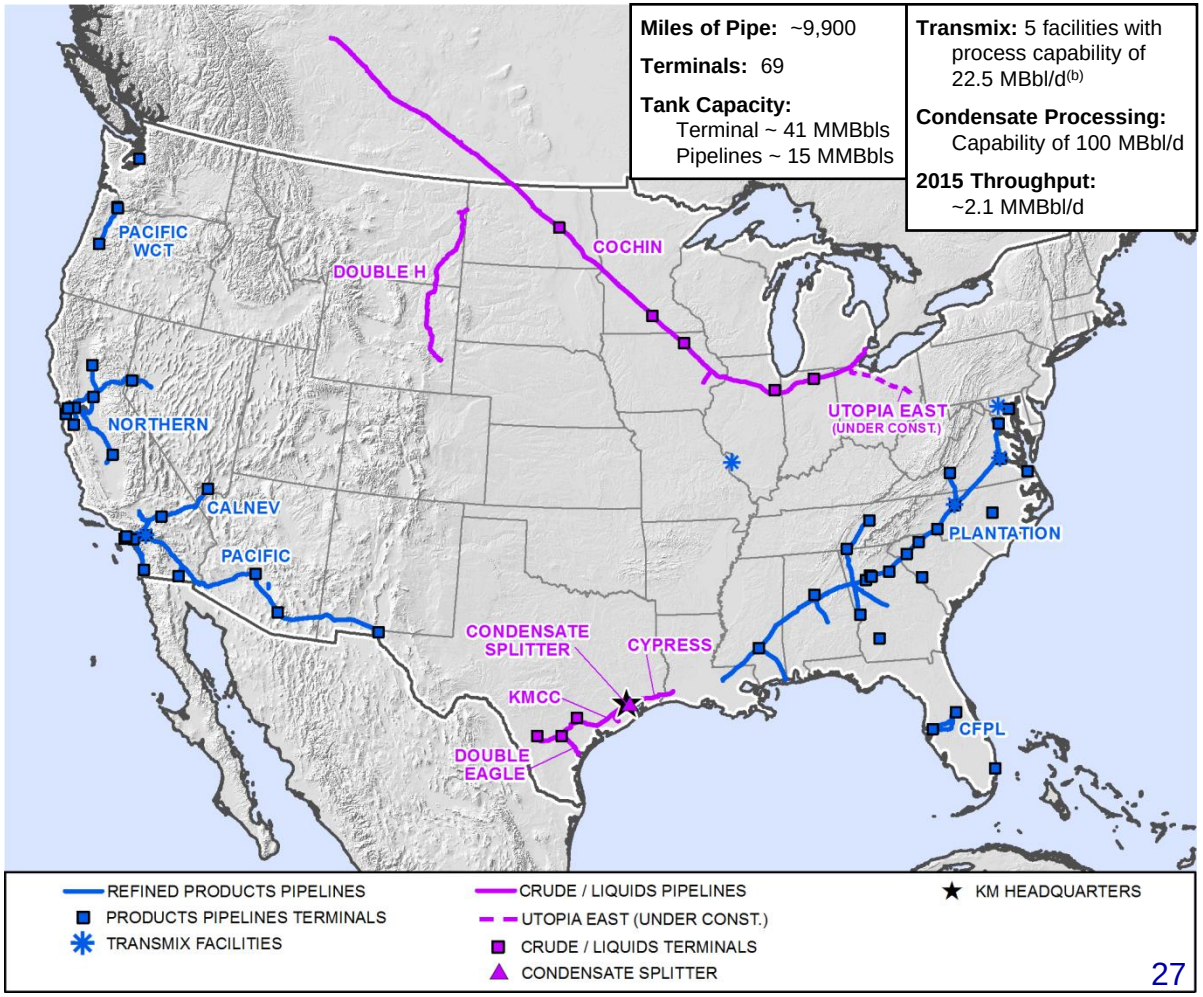
Stable refined product demand; opportunities for growth from increased liquids production

Long-term Growth Drivers:

- Increased demand for refined product volumes
- Development of shale play liquids transportation and processing
- Repurposing portions of existing footprint in different product uses
- Tuck-in acquisitions

Project Backlog:

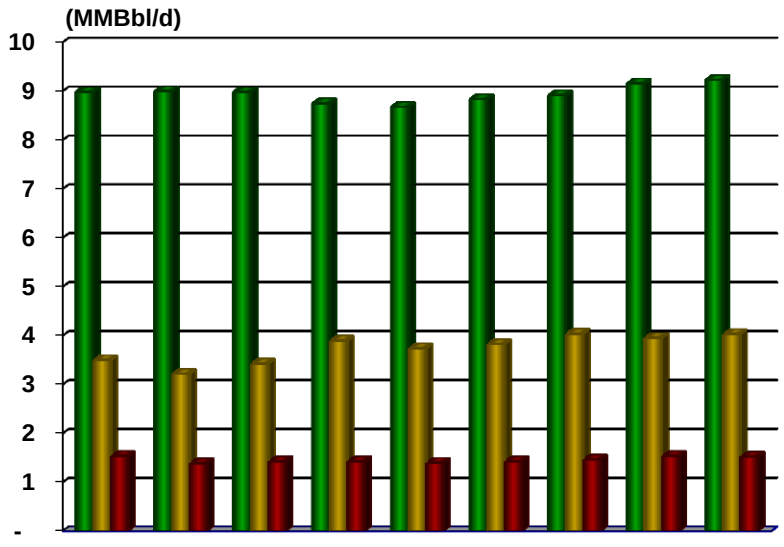
- $0.3 billion of identified growth projects over next three years (2016-2018)[(a)], including:
  - Transport Marcellus-fractionated liquids (ethane / E-P mix) to end-use market (UTOPIA)
  - Terminals projects to support customer needs and increased demand



(a) Excludes acquisitions, includes KM share of non-wholly owned projects. Includes projects currently under construction.
(b) Adjusted for 2Q 2016 sale of a transmix facility.

Historical Demand and 2016 EIA Outlook[(a)]

U.S. Refined Product Consumption



	2008	2009	2010	2011	2012	2013	2014	2015	2016E
Motor Gasoline	8.99	9.00	8.99	8.75	8.68	8.84	8.92	9.16	9.23
Distillate Fuel Oil	3.50	3.22	3.43	3.90	3.74	3.83	4.04	3.96	4.03
Jet Fuel	1.54	1.39	1.43	1.43	1.40	1.43	1.47	1.54	1.53

U.S. Refined Product Demand Outlook

	2014	2015	2016E
Mogas	0.9%	2.6%	1.1%
Distillate	5.5%	-1.9%	2.1%
Jet Fuel	2.5%	4.8%	-0.5%
Total – EIA	2.3%	1.6%	1.2%
KM	3.5%	3.1%	1.9%

FERC Tariff Index

	Jul'14 - Jun'15	Jul'15 - Jun'16	Jul'16 - Jun'17
FERC Rate Increase	3.89%	4.58%	-1.97%[(b)]

(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 – January 2016
(b) Expected rate decrease based on current regulatory information, based on PPI FG +1.23%.

Terminals

Segment Outlook

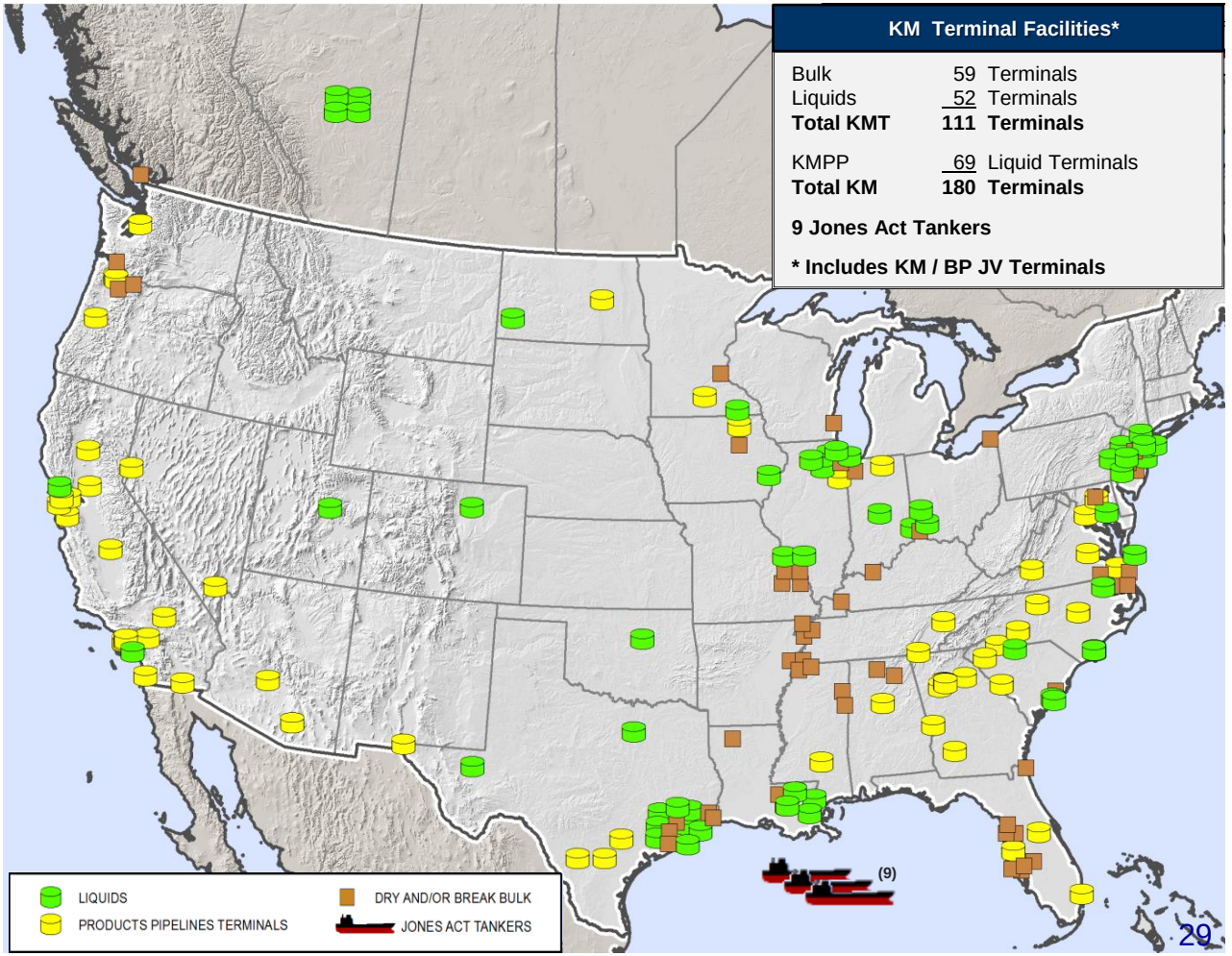
Well-located in refinery / port hubs and inland waterways

Long-term Growth Drivers:

- Refined product supply and demand growth
- Gulf Coast liquids exports
- Chemical infrastructure and base business growth built on production increases
- Tuck-in acquisitions

Project Backlog:

- $2.0 billion of identified growth projects over next three years (2016-2018)[(a)], including:
  - Jones Act tanker builds
  - Edmonton merchant crude terminal
  - Houston Ship Channel network expansion
  - Chemical terminal development

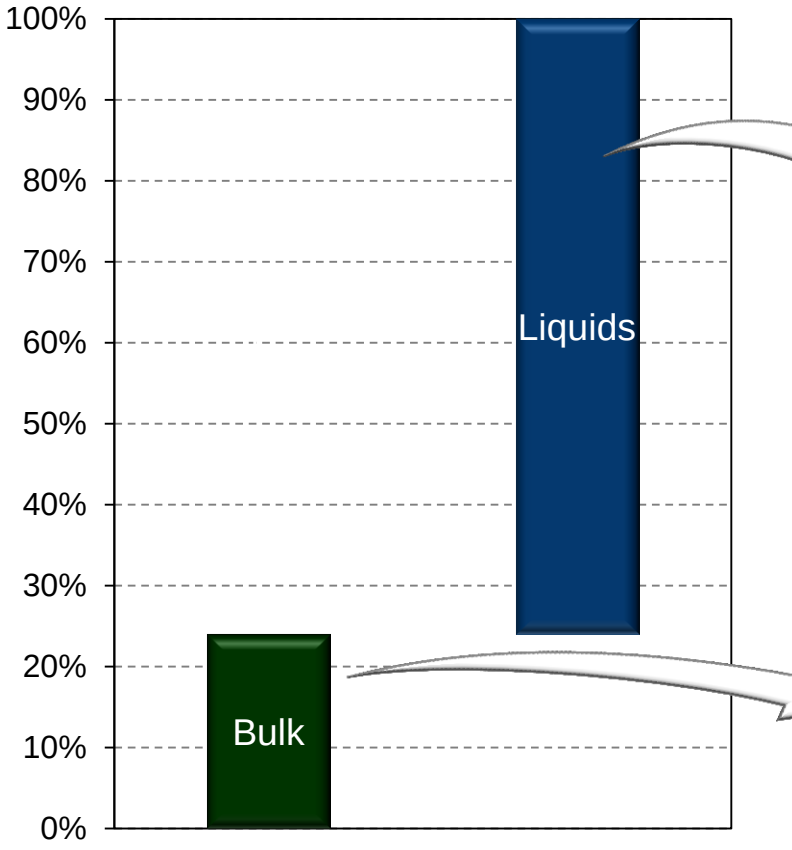


(a) Excludes acquisitions, includes KM share of non-wholly owned projects. Includes projects currently under construction.

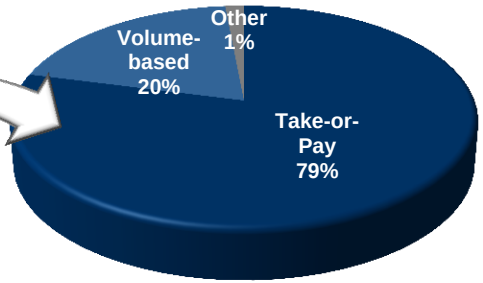
Terminals Segment

76% of Terminals 2016 Budgeted Segment EBDA is Liquids-based[(a)]

Terminals 2016 Budgeted Segment EBDA[(a)]

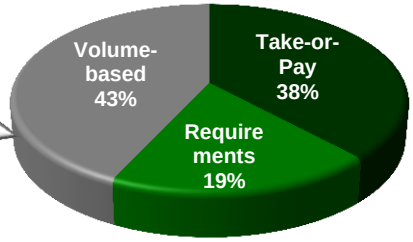


Liquids Revenue[(b)]



- **79% of liquids revenues secured by take-or-pay contracts**
  - Fixed monthly advanced lease payments for use of our assets
  - Monthly Warehousing Charge (MWC) tank capacity leases
  - Minimum throughput-based contracts
  - Marine charters
- **20% fee-based**
  - Ancillary fees: blending, additives and docks
  - Throughput fees: supported by local market demand

Bulk Revenue[(b)]



- **38% of revenues supported by Take-or-Pay contracts**
  - Minimum throughput commitments
- **19% supported by requirements contracts**
  - Tied to either petroleum coke manufacture or steel production
- **43% fee-based**
  - Volumetric per ton fees and ancillary services

(a) Based on KMI 2016 budgeted Segment EBDA before certain items and including KM-share of Certain Equity Investee DD&A (non-GAAP measure).
(b) 2016 Budget

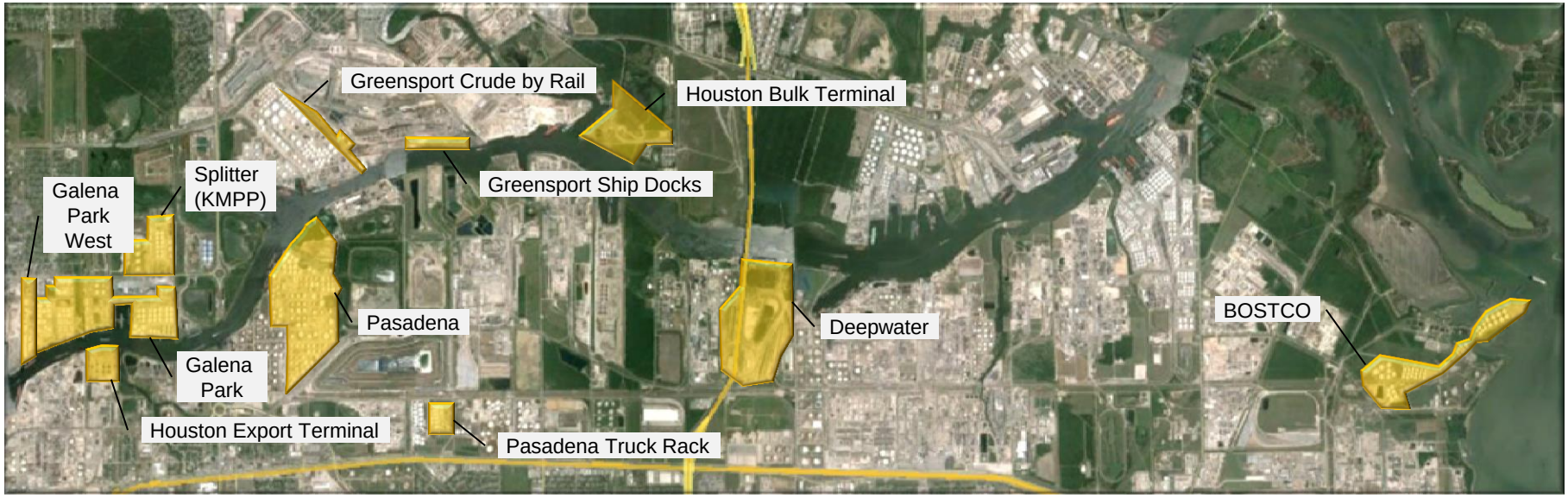
KINDER MORGAN INC.

Houston Ship Channel

Market: World's largest integrated refined product terminaling system

Infrastructure: 43 million barrels of capacity connected to 10 refineries

Customers: Refiners, integrated majors, international traders, chemical producers, wholesale marketers



Fee-based revenues tied to tank leases

- Tank capacity under current lease: 100%
- Average remaining contract lease: 3.5 years[(a)]
- Top 5 customers: 36%[(b)]
- Top 10 customers: 53%[(b)]

Irreplicable integrated assets

- 20 inbound pipelines, 15 outbound pipelines
- 14 cross-channel pipelines
- 12 barge docks
- 11 ship docks
- 9-bay truck rack (90 MBbl/d avg.)
- Unit train facilities (crude, condensate, ethanol)

(a) As of 1/1/2016 for petroleum liquids.
(b) Based on 2016 budgeted revenues.

CO_2
Segment Outlook[(a)]

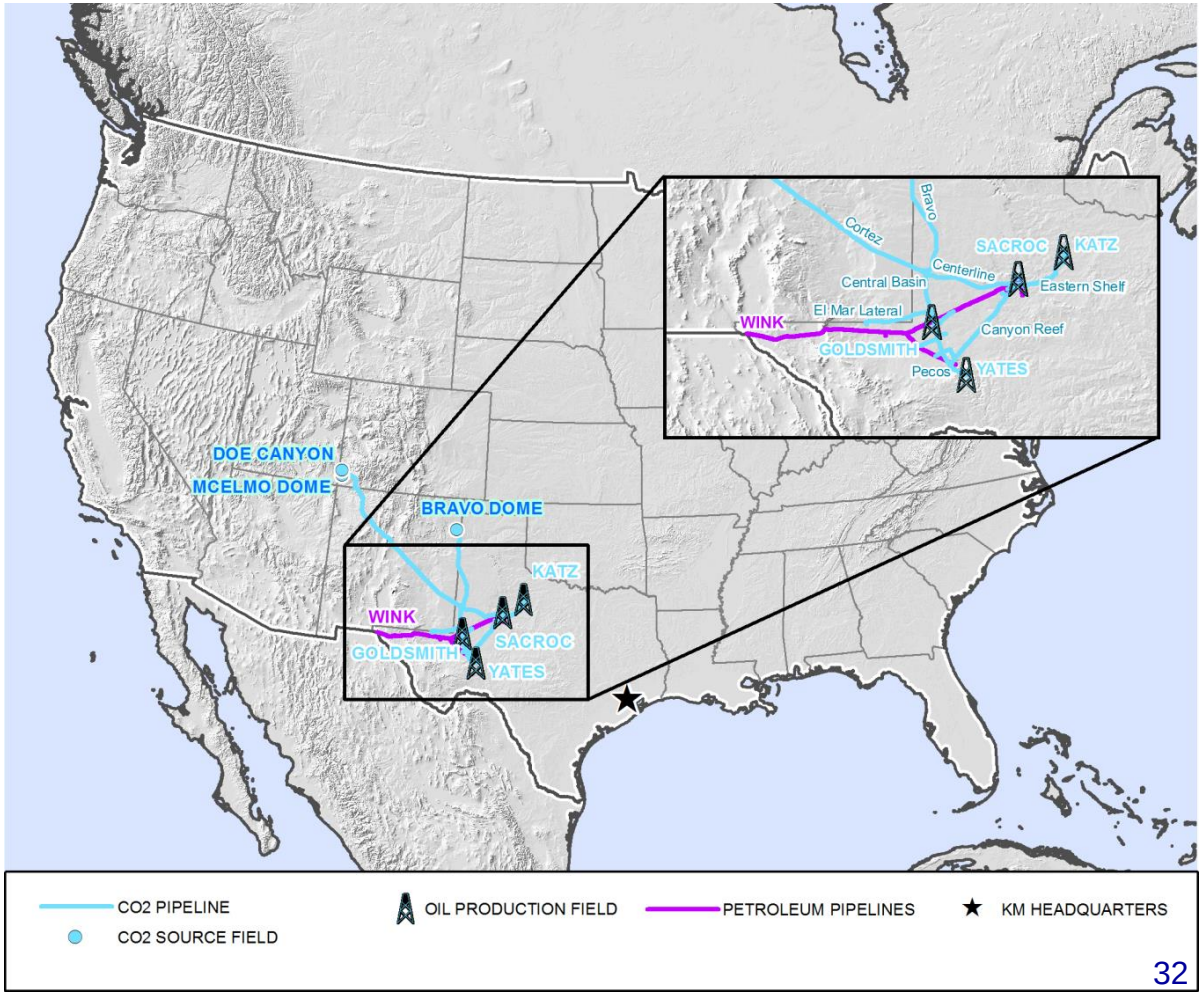
Own and operate best source of CO_2 for EOR

Long-term Growth Drivers:

- Demand for scarce supply of CO_2 drives volume and price
- Expect to maintain current CO_2 production levels with minimal incremental investment
- Billions of barrels of domestic oil still in place to be recovered in the Permian Basin, including KM operated fields

Project Backlog:

- Identified growth projects totaling $0.5 billion and $1.3 billion in S&T and EOR, respectively, over next five years[(b)], including:
  - S&T: Southwest Colorado CO_2 production
  - EOR: SACROC / Yates / Katz / Goldsmith / Tall Cotton



(a) EOR = Enhanced Oil Recovery, S&T = Source & Transportation
(b) Excludes acquisitions, includes KM share of non-wholly owned projects. Includes projects currently under construction.

Kinder Morgan Canada

Segment Outlook

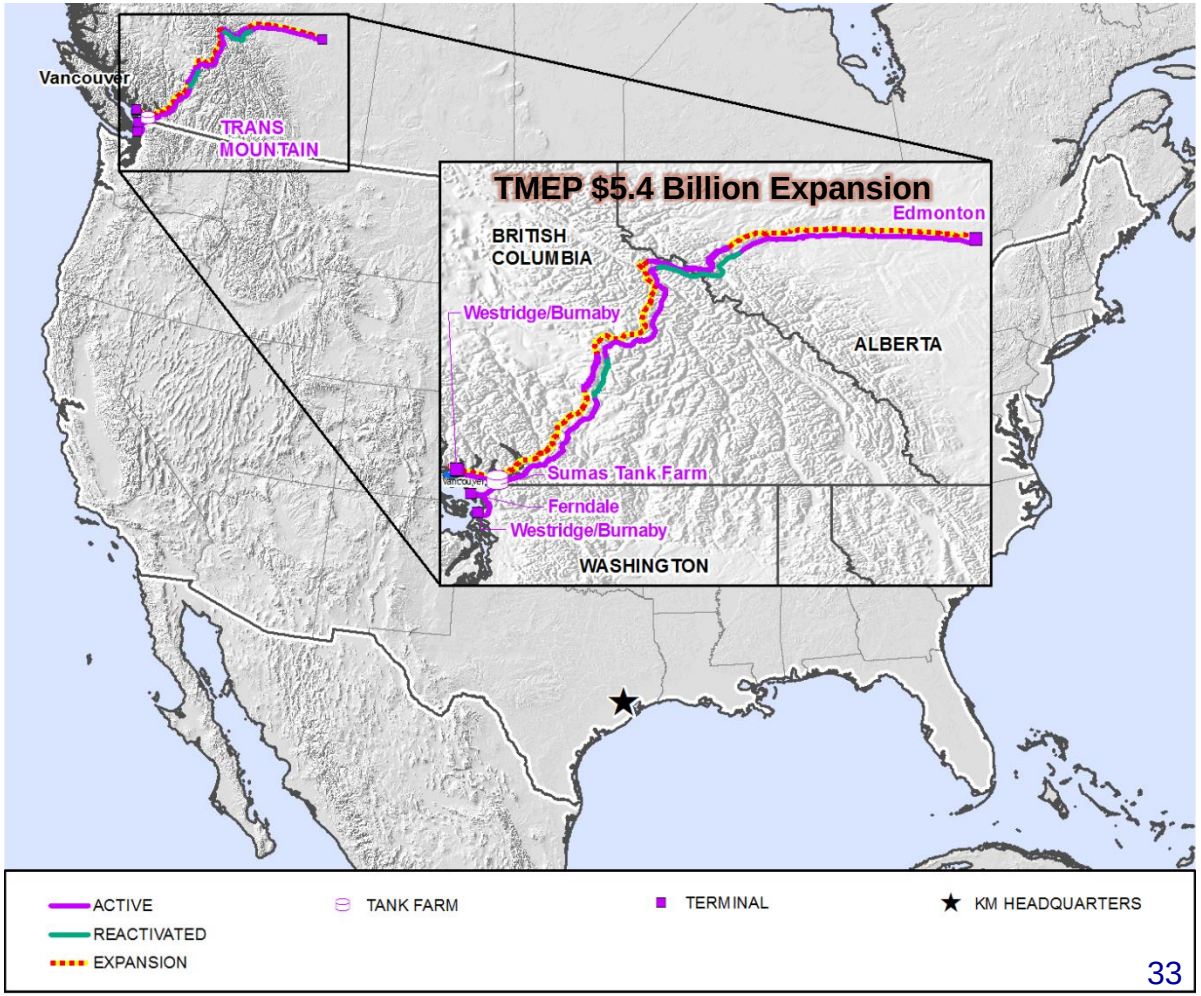
Sole oil pipeline from Oilsands to West Coast / export markets

Long-term Growth Drivers:

- Expand Oilsands export capacity to West Coast and Asia
  - Following successful open season, major expansion plans under way
  - The Trans Mountain Pipeline Expansion Project (TMEP) more than doubles capacity, from 300 MBbl/d currently to approximately 890 MBbl/d
  - Strong commercial support from shippers with binding long-term 15 and 20 year contracts for 708 MBbl/d of firm transport capacity
  - Expected in-service end of 4Q 2019
- Expanded dock capabilities (Vancouver)
  - TMEP will increase dock capacity to over 600 MBbl/d
  - Access to global markets

Project Backlog:

- USD $5.4 billion expansion of TMEP



2016 Budgeted Growth Capital

(millions)

Growth capital[(a)]	2016 Forecast	2015 Actual
Natural Gas Pipelines	$ 1,289	$ 1,528
CO_2 - S&T	1	163
CO_2 - EOR	227	449
Products Pipelines	235	431
Terminals	925	854
Kinder Morgan Canada	122	105
Corporate/Other	-	2
Subtotal - growth capital excl. large acquisitions[(a)]	2,799	3,532
Hiland Midstream	-	3,058
Total growth capital	**$ 2,799**	**$ 6,590**

2016 growth capital fully funded by operating cash flow, no requirement to access capital markets

(a) Includes JV Contributions of $206 and $125 million, acquisitions of $356 and $358 million (net of JV partner contributions for their share of project capex) and inclusion capital of $25MM and $19MM, for 2016 and 2015, respectively.

Credit Ratios and Liquidity[a]

($ in millions)

Leverage metrics	2012	2013	2014	2015	2016 Budget
Net debt[b] to Adjusted EBITDA	**5.4x**	**5.0x**	**5.5x**	**5.6x**	**5.5x**
Adjusted EBITDA to interest	4.0x	3.9x	4.1x	3.5x	3.6x

Revolver capacity[c]	
Committed revolving credit facility	$ 5,000
Less:	
CP / Revolver borrowing	(724)
Letters of credit	(174)
Excess capacity	**$ 4,102**

Long-term debt maturities[d,e]	
2016	$ -
2017	$ 3,059
2018	$ 2,327
2019	$ 3,817
2020	$ 2,932

Note: As of 6/30/2016. Before certain items.
(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.
(c) KMI corporate revolver (maturity in November 2019).
(d) 5-year maturity schedule of annual aggregate long-term debt principal. Excludes corporate revolver.
(e) Remaining 2016 maturities as of 6/30/2016.

Use of Non-GAAP Financial Measures

The non-generally accepted accounting principles (non-GAAP) financial measures of distributable cash flow (DCF), both in the aggregate and per share, segment earnings before depreciation, depletion, amortization and amortization of excess cost of equity investments (DD&A) and certain items (Segment EBDA before certain items), and net income before interest expense, taxes, DD&A and certain items (Adjusted EBITDA) are presented herein. Our non-GAAP measures described above should not be considered alternatives to GAAP net income or other GAAP measures and have important limitations as analytical tools. Our computations of DCF, Segment EBDA before certain items and Adjusted EBITDA 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. 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.

Certain Equity Investees, for the periods during which these are accounted for as equity method investments, include 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, WATCO, and Greens Port.

Certain items 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, hurricane impacts and casualty losses).

DCF is a significant performance measure used by us and by external users of our financial statements to evaluate our performance and to measure and estimate 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 dividends, stock repurchases, retirement of debt, or expansion capital expenditures. Management uses this measure and believes it provides users of our financial statements with a measure that more accurately reflects our business's ability to generate cash earnings than a comparable GAAP measure. We believe the GAAP measure most directly comparable to DCF is net income available to common stockholders. A reconciliation of DCF to net income available to common stockholders is provided herein. DCF per share is DCF divided by average outstanding shares, including restricted stock awards that participate in dividends.

Segment EBDA before certain items is used by management in its analysis of segment performance and management of our business. General and administrative expenses are generally not under the control of our segment operating managers, and therefore, are not included when we measure business segment operating performance. We believe Segment EBDA before certain items is a significant performance metric because it enables us and external users of our financial statements to better understand the ability of our segments to generate segment cash earnings on an ongoing basis. We believe it is useful to investors because it is a measure that management uses to allocate resources to our segments and assess each segment's respective performance. We believe the GAAP measure most directly comparable to Segment EBDA before certain items is segment earnings before DD&A and amortization of excess cost of equity investments (Segment EBDA). Segment EBDA before certain items is calculated by adjusting Segment EBDA for the certain items attributable to a segment, which are specifically identified in the footnotes to the accompanying tables.

Adjusted EBITDA is used by management and external users, in conjunction with our net debt, to evaluate certain leverage metrics. We believe Adjusted EBITDA is useful to investors because it is a measure that management uses to assess the company's leverage metrics. We believe the GAAP measure most directly comparable to Adjusted EBITDA is net income. Adjusted EBITDA is calculated by adjusting net income before interest expense, taxes, and DD&A (EBITDA) for certain items, noncontrolling interests, and KMI's share of certain equity investees' DD&A and book taxes, which are specifically identified in the footnotes to the accompanying tables.

GAAP Reconciliation

($ in millions)

Reconciliation of DCF	2015 Actual
Net income	$ 208
Certain items	1,441
Net income before certain items	1,649
DD&A	2,360
JV DD&A[a]	323
Book taxes [b]	976
Cash taxes	(32)
Noncontrolling interest - 3rd party [c]	(18)
Sustaining capex incl. KM-share of JV sustaining capex [d]	(565)
Other [e]	32
Distributable cash flow (DCF) to KMI	4,725
Preferred stock dividends	(26)
DCF available to Common Stockholders	$ 4,699

Reconciliation of Segment DCF	
Segment EBDA	$ 5,779
Certain items impacting segments	1,783
Segment EBDA before certain items	7,562
JV DD&A[a]	323
Segment EBDA before certain items, including JV DD&A	7,885
Segment sustaining capital expenditures with overhead [d]	(551)
Segment DCF	$ 7,334

Reconciliation of net debt	
Long-term debt excluding fair value adjustments [f]	$ 39,632
Current portion of debt	1,821
Less: cash & equivalents	(229)
Net debt	$ 41,224

Reconciliation of Adjusted EBITDA	2015 Actual
Net income	$ 208
Certain items	1,441
Net income before certain items	1,649
Book taxes [b]	976
Noncontrolling interest - 3rd party [c]	(18)
DD&A	2,360
JV DD&A[c]	323
Interest, net	2,082
Adjusted EBITDA	$ 7,372

Certain items (net of noncontrolling)	
Acquisition expense	$ 19
Pension plan net benefit	(35)
Fair value amortization	(94)
Contract early termination revenue	(200)
Legal and environmental reserves	94
Mark to market and ineffectiveness	(139)
Loss on impairment of goodwill	1,325
Loss on asset disposals/impairments, net of insurance	800
Other [g]	11
Subtotal	1,781
Book taxes on certain items	(340)
Total certain items	$ 1,441

Note: Definitions for defined terms found in the Appendix.

(a) Includes KM-share of Certain Equity Investees DD&A.

(b) Includes KM-share of certain equity method investees book taxes of $72 million and excludes book taxes on certain items of ($340) million.

(c) Represents net income allocated to third-party ownership interests in consolidated subsidiaries. Excludes NCI of $63 million related to impairments included as certain items.

(d) Includes KM-share of certain equity investee sustaining capital expenditures of $70 million.

(e) Consists primarily of book to cash timing differences related to certain defined benefit plans and other items.

(f) Excludes Kinder Morgan G.P. Inc.'s $100 million preferred stock due 2057.

(g) Other certain items include a $10 million carried interest adjustment for CO_2 McElmo Dome carried interest, $7 million legacy marketing contracts, $6 million adjustment for NGPL equity earnings which were in DCF but not in GAAP net income given the investment write-off, ($34) million coal customer bankruptcy write-offs, and $1 million other.


KINDER MORGAN
INC.