The Best is Yet to Come

January 25, 2017
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; condition of capital and credit markets; 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 as alternatives to GAAP financial measures.
Kinder Morgan Investor Conference

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<tr>
<td>8:00 - 8:20</td>
<td>Vision – Rich Kinder</td>
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<tr>
<td>8:20 - 9:30</td>
<td>Operational Excellence – Steve Kean</td>
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<td>9:30 - 9:45</td>
<td>Break</td>
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<td>9:45 - 10:30</td>
<td>Financial Excellence – Kimberly Dang</td>
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<td>10:30 - 11:30</td>
<td>Q&amp;A</td>
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Vision

Rich Kinder

Executive Chairman
The Importance of Fossil Fuels

- **Our way of life would be impossible without fossil fuels**
  - Widespread use of coal, oil and natural gas began during the Industrial Revolution, replacing wood as the primary energy source in the U.S.
  - With fossil fuels, quality of life and productivity has significantly improved
    - Fossil fuels have driven the development of long-distance transportation, access to fresh food year-round, improved medicine and health care, increased productivity via vehicles and equipment, development of plastics and other modern goods, etc.
  - No other energy source is an economically viable and reliable substitute today

- **Fueling America’s growth for over a century**
  - While the mix of fuel has changed, fossil fuels have accounted for over 80% of total U.S. energy consumption for more than 100 years

Fuels Our Daily Essentials

Electricity and Transportation…

- **Electricity**
  - Fossil fuels generated ~67% of U.S. electricity in 2015 (~66% for 1st 9 months of 2016)(\textsuperscript{a})
  - Despite decades of R&D and subsidies, renewables only accounted for ~13% of generation in 2015 (~15% for 1st 9 months of 2016); about half is hydropower which is not expected to grow\textsuperscript{(a)}
  - The power grid needs reliable sources of fuel to meet variable-load demand
  - Solar and wind are intermittent while natural gas can be stored and dispatched as needed
  - Without substantial breakthroughs in battery technology, solar and wind require reliable backup power generation sources
    - It would take ~6 million Tesla Powerwall 2 batteries (about $30 billion) to equal one day of energy supplied by just one of Kinder Morgan’s natural gas storage fields\textsuperscript{(b)}
    - As solar and wind power increases, the need for fast-starting, reliable natural gas-powered generation as a backstop and load smoother increases concurrently

- **Transportation**
  - Over 99% of U.S. light vehicles today run on gasoline or diesel (>250 million cars and trucks)\textsuperscript{(c)}
  - Electric vehicles (EVs) are still relatively expensive, have limited driving ranges and supporting infrastructure is not well-developed
    - Given range anxiety and projections that EVs will remain relatively expensive for the foreseeable future, EVs are expected to account for only ~2% of U.S. vehicles in operation by 2025\textsuperscript{(c)}
    - Also, EVs are a potential source of demand for natural gas; incremental power demand from EVs could equate to almost 2 Bcf/d of natural gas by 2035\textsuperscript{(d)}

\textsuperscript{(a)} EIA, Monthly Energy Review, December 2016.
\textsuperscript{(b)} Tesla website and KMI internal calculations. Assumes 0.7 Bcf/d natural gas storage withdrawal capacity, equivalent to our West Clear Lake facility.
\textsuperscript{(c)} Goldman Sachs, Start Me Up v2.0, November 2016.
\textsuperscript{(d)} Wood Mackenzie, Tesla Model 3: Does it signal an Electric Car Revolution?, May 2016, based on “Increased Adoption – Medium” case.
Fuels Our Daily Essentials
… and Much, Much More

- **Clothing**
  - Approximately 66% of global textile production comes from synthetic fibers derived from fossil fuels\(^{(a)}\)
  - The extensive use of synthetic fibers has improved the affordability and durability of clothes
  - Even the production of cotton (28% of textile production)\(^{(a)}\) depends heavily on fossil fuels for fertilizing, irrigating and harvesting the material as well as manufacturing and distributing the final product

- **Plastics and petrochemicals**
  - Everything “plastic” originates from petroleum or natural gas
  - Petrochemical crackers use natural gas and petroleum feedstocks to produce the basic building blocks for making chemicals and plastics

- **Agriculture**
  - Diesel and natural gas fuels tilling, planting and harvesting
  - Natural gas is the key feedstock for fertilizers and pesticides to enhance soil fertility and to protect against pests and weeds

- **Technology, medicine, chemicals, steel, asphalt, construction materials, etc…**

Natural Gas Critical to Climate Goals

- Natural gas is the cleanest burning fossil fuel with significantly lower emissions than coal or fuel oil.

- Switching from coal to natural gas has driven a reduction in the nation’s power sector CO₂ emissions:
  - 2015 U.S. power sector CO₂ emissions were the lowest since 1993 despite a 28% increase in overall power generation\(^{(a)}\).
  - 2015 U.S. power sector CO₂ emissions were ~21% lower than 2007 emissions\(^{(a)}\).

- U.S. methane emissions decreased 6% from 1990 to 2014\(^{(b)}\) despite a 46% increase in natural gas production\(^{(a)}\) over the same period.

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<tr>
<td>U.S. Population</td>
<td>~260 million</td>
<td>~301 million</td>
<td>~321 million</td>
</tr>
<tr>
<td>Real GDP</td>
<td>~$9.5 trillion</td>
<td>~$14.9 trillion</td>
<td>~$16.3 trillion</td>
</tr>
<tr>
<td>Power sector CO₂ emissions</td>
<td>1.92 GT</td>
<td>2.42 GT</td>
<td>1.91 GT</td>
</tr>
<tr>
<td>Power generation (GWh)</td>
<td>3,197,191</td>
<td>4,156,745</td>
<td>4,077,601</td>
</tr>
<tr>
<td>Coal</td>
<td>53%</td>
<td>49%</td>
<td>33%</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>13%</td>
<td>22%</td>
<td>33%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>19%</td>
<td>19%</td>
<td>20%</td>
</tr>
<tr>
<td>Solar/Wind</td>
<td>&lt;1%</td>
<td>&lt;1%</td>
<td>5%</td>
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\(^{(a)}\) EIA, Monthly Energy Review, December 2016.
Becoming Cheaper and More Abundant
Technology has Reduced Costs and Increased Effectiveness

**U.S. Oil and Gas Proved Reserves**

Since 2000:
- Oil reserves up ~50%
- Natural gas reserves up ~74%

**U.S. Shale Breakeven Cost Curve**

Over the past year:
- Breakeven costs have decreased >$14/Bbl (down ~30% on average)

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(a) EIA, 2015 U.S. Crude Oil and Natural Gas Proved Reserves, December 2016. Crude oil includes lease condensate proved reserves.
(b) Based on JPM research. Assumes 15% IRRs.
The Need for Fossil Fuel

- Fossil fuels are essential to our way of life
- They are affordable, dependable, plentiful and are becoming more affordable, plentiful and environmentally sustainable due to advancements in technology
- Fossil fuels are supported by enormous installed infrastructure that would take decades and substantial cost to replace
- Increased natural gas use has been and will continue to be critical to meeting climate goals
  - Replacing coal-fired power generation as plants are retired
  - Backstopping less reliable solar and wind generation
  - The International Energy Agency forecasts that even under the Paris Climate Accord, natural gas consumption will increase 50% through 2040\(^{(a)}\)
    - And the world will still be using ~103 MMBbl/d of crude oil – even while hundreds of millions will remain without basic energy services\(^{(a)}\)

\(^{(a)}\) IEA, 2016 World Energy Outlook, November 2016.
Fossil Energy Demand is Strong

**Natural Gas**

- Multiple trends driving increased demand for U.S. natural gas

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<tr>
<td>Power Gen&lt;sup&gt;(a)&lt;/sup&gt;</td>
<td></td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>Nat gas-share</td>
<td>28%</td>
<td>33%</td>
<td>34%</td>
<td>32%</td>
<td>33%</td>
</tr>
<tr>
<td>Coal-share</td>
<td>39%</td>
<td>33%</td>
<td>30%</td>
<td>32%</td>
<td>32%</td>
</tr>
<tr>
<td>Exports to Mexico&lt;sup&gt;(b,c)&lt;/sup&gt;</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>KM Pipelines</td>
<td>1.9</td>
<td>2.3</td>
<td>2.8</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Non-KM</td>
<td>0.1</td>
<td>0.5</td>
<td>0.8</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>2.0</td>
<td>2.9</td>
<td>3.6</td>
<td>4.1</td>
<td>4.4</td>
</tr>
<tr>
<td>LNG Exports&lt;sup&gt;(d)&lt;/sup&gt;</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Net LNG Exports from U.S.</td>
<td>0.0</td>
<td>-0.1</td>
<td>0.4</td>
<td>1.5</td>
<td>3.2</td>
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**Natural Gas Liquids (NGL)**

- Petchem NGL demand projected to increase 33% by 2018
- NGL exports projected to increase 32% by 2018

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<tr>
<td>NGL Demand&lt;sup&gt;(d)&lt;/sup&gt;</td>
<td></td>
<td></td>
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<tr>
<td>Petchem</td>
<td>1.5</td>
<td>1.6</td>
<td>1.6</td>
<td>1.8</td>
<td>2.1</td>
<td>33%</td>
</tr>
<tr>
<td>Export</td>
<td>0.7</td>
<td>1.0</td>
<td>1.2</td>
<td>1.2</td>
<td>1.3</td>
<td>32%</td>
</tr>
<tr>
<td>Other</td>
<td>1.4</td>
<td>1.4</td>
<td>1.4</td>
<td>1.4</td>
<td>1.4</td>
<td>0%</td>
</tr>
<tr>
<td>Total</td>
<td>3.6</td>
<td>4.0</td>
<td>4.2</td>
<td>4.4</td>
<td>4.8</td>
<td>23%</td>
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**Refined Products**

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

- U.S. Refined Product Demand (MMBbl/d)<sup>(a)</sup>

**Crude Oil**

- Oil price decrease led to declines in U.S. production
- Market expected to balance in second half of 2017

(a) EIA, Short-term Energy Outlook, January 2017.
(b) Wood Mackenzie, Fall 2016 North America Gas Long-Term Outlook, December 2016.
(c) KM Pipelines calculation of exports to Mexico includes its deliveries into the NET Mexico pipeline. Non-KM deliveries is adjusted by an offsetting amount.
(d) Wells Fargo, Quarterly NGL Supply/Demand Update, November 2016.
Long Term Demand is Strong

- Substantial natural gas and oil growth expected for the foreseeable future

**U.S. Natural Gas Production (Bcf/d)**

**U.S. Crude Oil Production (MMBbl/d)**

U.S. Natural Gas Expected to grow >50%

U.S. Crude Oil Expected to grow ~30%

(a) EIA, Annual Energy Outlook 2016, reference case.
Kinder Morgan’s Role
Well-Positioned to Support Future of Fossil Fuels

- The nation needs fossil fuels and the infrastructure that delivers them
- Pipelines are the safest, most economic and environmentally friendly means of transporting U.S. fuels
  - Damage and injury rates per billion ton-miles: 0.9 for natural gas pipelines, 0.6 for liquids pipelines, 2.1 for rail and 20.0 for road transportation\(^{(a)}\)
- Kinder Morgan is well positioned to take advantage of this growth
  - Kinder Morgan moves ~40% of the natural gas consumed in the U.S.; expects to maintain or expand that share
  - Extensive network of ~84,000 miles of pipelines (~70,000 miles of natural gas pipelines) which leads to opportunities to invest and expand the network
- Increased volumes = increased value of our infrastructure

\(^{(a)}\) Manhattan Institute for Policy Research, Pipelines are Safest for Transportation of Oil and Gas, June 2013.
Operational Excellence

Steve Kean

President and Chief Executive Officer
Unparalleled Asset Footprint
Largest Energy Infrastructure Company in the U.S.

- Largest natural gas network in North America
  - Own or operate ~70,000 miles of natural gas pipeline
  - Connected to every important natural gas resource play in the U.S.
- Largest independent transporter of petroleum products in North America
  - Transport ~2.1 MMBbl/d\(^{(a)}\)
- Largest transporter of CO\(_2\) in North America
  - Transport ~1.3 Bcf/d of CO\(_2\)\(^{(a)}\)
- Largest independent terminal operator in North America
  - Own or operate ~155 terminals\(^{(b)}\)
  - ~152 MMBbls liquids capacity
  - Handle ~53 MMtons of dry bulk products\(^{(a)}\)
  - Own 16 Jones Act vessels (including 4 under construction)
- Only Oilsands pipeline serving the West Coast
  - Transports ~300 MBbl/d to Vancouver/Washington State; planned expansion takes capacity to 890 MBbl/d

\(^{(a)}\) 2017 budget.
\(^{(b)}\) Excludes assets to be divested.
KMI Overview
Management Aligned with Investors; 14% Stake in KMI

Simple Public Structure

- Management & Directors\(^{(a)}\)
  - ~319MM (14%)
- Public Float
  - ~1,920MM (86%)

Kinder Morgan, Inc.
(C-corp, NYSE: KMI)

- Market Equity: $47.9B\(^{(b)}\)
- Net Debt: 38.2B\(^{(c)}\)
- Enterprise Value: $86.1B
- 2017E Dividend per Share: $0.50\(^{(d)}\)
- Credit Rating: BBB– / Baa3 / BBB–\(^{(e)}\)

Simple Structure:
- One equity base and dividend
- One debt rating
- No structural subordination
- No incentive distribution rights

Highly liquid: Nearly 15 million KMI shares traded daily on average during 4Q 2016

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\(^{(a)}\) Includes Form-4 filers and unvested restricted shares.
\(^{(b)}\) Market prices as of 12/30/2016; KMI market equity based on ~2,239 million shares outstanding (including unvested restricted stock) at a price of $20.71, ~293 million warrants at a price of $0.01, and 32 million mandatorily convertible depositary shares at a price of $48.65.
\(^{(c)}\) Debt of KMI and its consolidated subsidiaries as of 12/31/2016, 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 2017 budget.
\(^{(e)}\) KMI corporate credit ratings from S&P (Stable outlook), Moody’s (Stable) and Fitch (Stable), respectively.
Segment Overview

2017 Budgeted Segment EBDA = $7.7 billion\(^{(a)}\)

93% Pipelines & Terminals
- Natural Gas Pipelines
  - 73% interstate pipelines
  - 9% intrastate pipelines & storage
  - 18% gathering, processing & treating
    - 88% fixed-fee (~27% of which is take-or-pay)
- Products Pipelines
  - 62% refined products
  - 38% crude/liquids
- Terminals
  - 81% liquids
  - 19% bulk
- CO₂
  - 34% CO₂ transport and sales
  - 66% oil production-related
    - Production hedged (Bbl/d)\(^{(b)}\):
      | Year | Hedged Vol. | % Hedged | Avg. Px. |
      |------|-------------|----------|---------|
      | 2017 | 35,109      | 75%      | $59     |
      | 2018 | 15,029      | 53%      | $65     |
      | 2019 | 8,100       | 33%      | $57     |
      | 2020 | 4,200       | 20%      | $53     |
      | 2021 | 0           | 0%       | $-      |
- Kinder Morgan Canada
  - 100% petroleum pipelines

\(^{(a)}\) 2017 budgeted Segment EBDA before Certain Items and including KM-share of Certain Equity Investee DD&A (non-GAAP measure).

\(^{(b)}\) Percentages based on currently hedged crude oil and propane volumes as of 12/31/2016 relative to crude oil, propane and heavy NGL (C4+) net equity production projected for 2017, and the Ryder Scott reserve report for 2018-2021.
KMI Overview by Product Served\(^{(a)}\)

**Natural Gas is our Largest Market**

- **Natural gas**: ~80% take-or-pay cash flow
- **Refined products**: competitively advantaged connection between refineries and end markets (includes ~61% of KMT liquids business)
  - Piped volumes within ~1.5% of budget over past 7 years
  - Terminals utilization ~96% since 2001
- **Crude and condensate**: >95% take-or-pay cash flow
  - KMCC, Splitter, Double H, Wink, Trans Mountain, and including ~24% of KMT liquids business
- **Carbon dioxide (CO\(_2\))**: >80% take-or-pay cash flow
- **NGLs**: >95% take-or-pay cash flow

**Stability of Cash Flows**

- **Location matters, contracts matter**

**Refined Product and Liquids Assets**

- **91% of cash flows fee-based for 2017; 97% fee-based or hedged**

\(^{(a)}\) All percentages based on 2017 budgeted Segment EBDA before Certain Items and including KM-share of Certain Equity Investee DD&A (non-GAAP measure).
KMI’s High Quality Cash Flow

Not all “fee-based” cash flow is created equal

2017 Budgeted Segment EBDA = $7.7 billion

- 25% Fee-based Cash Flow
  - $0.2
  - $0.5
  - $1.9

- 6% Hedged Cash Flow
  - $0.2

- 3% Commodity-based

- 66% Take-or-pay Cash Flow
  - $5.1

91% Fee-based Cash Flow

Composition of 91% Fee-based Cash Flow

- 72% Take-or-pay Cash Flow
- Other Fee-based
- Other Fee-based
- Natural Gas Pipelines
- Products Pipelines
- Terminals
- CO₂ S&T /Other

- 72% 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 products volumes within ~1.5% of budget over past 7 years
  - **Terminals**: ~75% of Terminals' Other Fee-based associated with high-utilization liquids assets and requirements contracts for petcoke and steel

(a) Based on 2017 budgeted Segment EBDA before Certain Items and including KM-share of Certain Equity Investee DD&A (non-GAAP measure).
KMI: Compelling Investment Thesis
Attractive Relative Value, Best in Class Coverage

Attractive Relative Value\(^{(a)}\)

Best in Class Coverage\(^{(b)}\)

Insulated from Capital Market Risk\(^{(c)}\)

KMI Positioning

- Best in class dividend coverage
- No reliance on equity or debt markets in 2017 and beyond to fund growth projects
- Secure cash flow; 97% fee-based or hedged for 2017
- Significant growth opportunities

Notes: KMI financial measures before Certain Items. See Appendix for defined terms and reconciliations to GAAP measures.


(a) 12/30/2016 share price divided by 2016 DCF per share. Peer estimates per Bloomberg consensus and actual for KMI.
(b) 2016 DCF per share divided by 2016 dividend per share. Peer estimates per Bloomberg consensus and actuals for KMI.
(c) DCF per share and dividend per share per Bloomberg consensus for peers and actual for KMI. Share count per Bloomberg for peers and actual for KMI.
2016 Achievements

A Year of Progress

- **Improve balance sheet and liquidity**
  - Net debt/Adjusted EBITDA reduced from 5.6x at year-end 2015 to 5.3x at year-end 2016
  - $2.8 billion of cash flow in excess of our dividend used to fund growth capital
  - Increased credit facility capacity by $1.0 billion and raised a $1.0 billion term loan at the beginning of the year; current liquidity is >$5.0 billion

- **Secure strategic partners and divest non-core assets**
  - Strategic 50/50 joint venture with Southern Company on SNG pipeline
  - Secured 50% partner for Utopia pipeline project
  - Non-core asset divestitures: Parkway, bulk terminals, and a transmix facility

- **High-grade backlog**
  - Reduced overall backlog: placed ~$1.8 billion in service, eliminated lower return projects and reduced project costs
  - Capex/EBITDA multiple improved from 7.5x at beginning of 2016 to 6.7x at beginning of 2017

Resulting in Strong Stock Performance

The market appreciated KMI’s achievements in 2016…

… and we believe the best is yet to come
2017 Goals

- Budgeted DCF/share of $1.99
- Year-end 2017 budgeted net debt/Adjusted EBITDA of 5.4x
  - Continue to find ways to accelerate the strengthening of our balance sheet
- Meet or exceed our environmental and safety targets
  - Perform better than industry average
  - Improve operational performance relative to our own past performance
- Execute on our project backlog, place projects in-service on time and on budget
- JV or IPO of Trans Mountain
- Expect to communicate updated dividend guidance in latter part of 2017, with a view toward delivering additional value to shareholders in 2018
Our Strategy

- Focus on stable fee-based assets that are core to North American energy infrastructure
  - Market leader in each of our business segments
  - Fees largely independent of underlying commodity prices and substantially secured by take-or-pay contracts

- Maintain a strong balance sheet
  - Our primary investing entity has been investment grade since inception
  - Reduced dividend demonstrates our commitment to investment grade and our ability to fund growth projects without need to access capital markets

- Operate safely and efficiently
  - Control costs: It’s investors’ money, not management’s – treat it that way
  - Performing better than industry averages; target zero incidents

- Leverage asset footprint to seek attractive capital investment opportunities, both expansion and acquisition
  - Since 1997, Kinder Morgan has completed approximately $31.4 billion in acquisitions and invested approximately $27.3 billion in greenfield/expansion projects\(^{(a)}\)

- Transparency to investors

- Keep it simple

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Asset Integrity and Safety are Top Priorities
Consistent, Better-than-industry Performance Across our Businesses

- Safe operation of our assets is mission critical to our long-term success
- Continuous reduction in risk to the public, employees, contractors, assets and the environment
- We strive for continual improvement in safety and efficiency of existing operations
- Well-executed expansions and effective integration of acquired operations
- Consistently perform better than industry average
  - Track over 36 safety metrics and post monthly updates to our public website
  - Currently better than industry in 35 of 36 metrics

% of Safety Metrics KM Performed Better than or Equal to Industry (a)

(a) Based on year-end Kinder Morgan metrics versus most applicable industry performance.
Business Risks

- Regulatory
  - FERC rate cases (Products pipelines and Natural Gas pipelines)
  - Legislative and regulatory changes

- CO₂ crude oil production volumes

- Throughput on our volume-based assets

- Commodity prices
  - 2017 budget price assumptions: $53/Bbl average strip price for crude, and $3.00/MMBtu average strip price for natural gas
  - Price sensitivities (full-year):
    - $1/Bbl change in oil price = ~$6 million DCF impact
    - 10¢/MMBtu change in natural gas price = ~$1 million DCF impact
    - 1% change in NGL/crude ratio = ~$3 million DCF impact

- Project cost overruns/in-service delays

- Economically sensitive businesses (e.g. steel and coal terminals)

- Foreign exchange rates
  - 2017 budget rate assumption of 0.77 CAD/USD
  - Price sensitivity (full-year): 0.01 ratio change = ~$2.3 million DCF impact

- Environmental (e.g. pipeline/asset failures)

- Terrorism

- Interest rates
  - Full-year impact of 100-bp increase in floating rates equates to a ~$110 million increase in interest expense

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(a) Natural Gas Midstream sensitivity incorporates current hedges, and assumes ethane recovery for majority of year, constant ethane frac spread, and assumes other NGL prices maintain same relationship with oil prices.

(b) As of 12/31/2016 approximately $11.0 billion of KMI’s net debt was floating rate (~28% floating).
The Best is Yet to Come
Positioned to Succeed for the Long-Term

- World class set of midstream assets
- Secure and growing fee-based cash flows
- Disciplined allocator of capital; high bar for new investment opportunities
- Investment grade balance sheet and substantial liquidity
- As future cash flow exceeds investment needs, we have value-enhancing options:
  - Invest in high-return acquisitions and/or expansions
  - Further de-lever balance sheet
  - Return cash to shareholders via increased dividends and/or share buybacks
  - Expect to communicate updated dividend guidance in latter part of 2017, with a view toward delivering additional value to shareholders in 2018

- Experienced management team aligned with investors
- Transparency to investors
Overview of Business Segments
Natural Gas Pipelines

Segment Outlook

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

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

Project Backlog:
- $3.5 billion of identified growth projects over next four years (2017-2020)(a), including:
  - LNG liquefaction (Elba Island)
  - Transport projects supporting LNG liquefaction, including Elba Express
  - Expansions to Mexico border
  - TGP North-South projects

(a) Includes KM share of non-wholly owned projects. Includes projects currently under construction.
Natural Gas Transportation & Storage
55% of 2017 Budgeted Segment EBDA before Certain Items(a)

Natural gas transport & storage is KMI’s largest business

- U.S. natural gas demand(b) expected to rise by 35% through 2026(c)
  - KM moves about 40% of natural gas consumed in the U.S.

- Transportation demand drivers:
  - Power demand, exports (Mexico and LNG) and industrial market

- Storage demand drivers:
  - Power and LNG exports have variable-load characteristics which require storage support
  - KM well-positioned to meet demand as the largest storage operator in the U.S. with 689 Bcf out of 4.3 Tcf market (~16%)
  - Increased contracting activity at improved rates in the Interstate and Intrastate markets

- Gathering & processing trends:
  - Gathering supported by overall volume trends
  - Processing supported by new LPG export capacity (docks and fleet) and Gulf Coast petrochemical demand

(a) Based on KMI 2017 budgeted Segment EBDA before Certain Items and including KM-share of Certain Equity Investee DD&A (non-GAAP measure).
(b) Including net exports of liquefied natural gas (LNG) and net exports to Mexico.
(c) Wood Mackenzie, Fall 2016 North America Natural Gas Long-Term Outlook, December 2016.
Drivers of Future Growth

LNG Exports

- LNG Export Opportunity (a)
  - 18.5 Bcf/d of FERC approved projects
  - 10.3 Bcf/d of projects under construction
  - 9.8 Bcf/d of additional projects pending approval

- Elba Liquefaction – KM facility at Elba Island, GA

- LNG Transport
  - 4.5 MMdth/d of contracted transport capacity
  - Total capital of $981 MM
  - Avg. contract term: 19 years
  - Seven active projects on five KM pipelines

---

<table>
<thead>
<tr>
<th>KM Asset</th>
<th>KM Project/Transportation (Terminal)</th>
<th>Contracted Capacity (MMdth/d)</th>
<th>In-Service Date</th>
<th>KM Capital ($MM)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NGPL</td>
<td>Firm Transport (Sabine Pass)</td>
<td>550</td>
<td>In-Service</td>
<td>N/A</td>
</tr>
<tr>
<td>EEC</td>
<td>EEC for Shell (Elba Island)</td>
<td>436</td>
<td>2/2017-11/2018</td>
<td>$102.2</td>
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<tr>
<td>TGP</td>
<td>SW Louisiana Supply (Cameron)</td>
<td>900</td>
<td>2/2018</td>
<td>$178.5</td>
</tr>
<tr>
<td>NGPL</td>
<td>Gulf Coast Southbound (Corpus Christi)</td>
<td>385</td>
<td>4Q/2018</td>
<td>$106.1</td>
</tr>
<tr>
<td>Intrastate</td>
<td>TX Intrastate Crossover (Corpus Christi/Freeport)</td>
<td>590</td>
<td>1Q-3Q 2019</td>
<td>$182.1</td>
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<tr>
<td>TGP</td>
<td>Lone Star (Corpus Christi)</td>
<td>300</td>
<td>7/2019</td>
<td>$133.8</td>
</tr>
<tr>
<td>KMLP</td>
<td>Sabine Pass Expansion</td>
<td>600</td>
<td>4Q/2019</td>
<td>$151.3</td>
</tr>
<tr>
<td>KMLP</td>
<td>Magnolia LNG Expansion</td>
<td>700</td>
<td>4Q/2020</td>
<td>$127.0</td>
</tr>
</tbody>
</table>

---

(a) FERC as of 1/5/17, industry and KM analysis.
**Liquefaction at Elba Island**

*Elba Liquefaction Company (ELC) / SLNG*

- **Capacity:**
  - LNG output capacity equivalent to 350 MMcf/d

- **Capital (100%):**
  - Elba Liquefaction Company (ELC): $1,436.4 MM
  - SLNG: $433.8 MM

- **Phased In-service:** Mid 2018 through early 2019

- **Project Scope:**
  - Facilities for liquefaction (10 modular units)
  - Ship loading facilities; boil-off gas compression

- **Avg. Contract Term:** 20 years

- **Current Status:**
  - FERC certificate issued June 2016
  - FERC denied requests for rehearing Dec 2016
  - Shell has committed to entire capacity of facility, as well as Elba Express expansion
  - DOE FTA and non-FTA authorizations received
  - Construction underway

- **Major Milestones:**
  - JV negotiations for ELC are ongoing
Drivers of Future Growth

*Kinder Morgan Delivers ~76% of U.S. Exports to Mexico*

- Exports to Mexico are forecasted to increase by 2.0 Bcf/d to 5.6 Bcf/d by 2021\(^{(a)}\)
- KM deliveries to Mexico ~2.8 MMDth/d\(^{(b)}\) through 17 interconnects (12 direct & 5 indirect)
  - KM up 20% from 2015; 76% of 2016 U.S. total
  - Well positioned to serve incremental demand through extensive network connected to multiple prolific supply basins
- KM projects and new long term commitments for export to Mexico entered into since 2013:
  - Capacity: ~2.4 MMDth/d
  - Capital: ~$667 MM

### Mexico Gas Supply (Bcf/d)\(^{(a)}\)

<table>
<thead>
<tr>
<th>KM Asset</th>
<th>KM Project / Transportation (Shipper)</th>
<th>Contracted Capacity (MDth/d)</th>
<th>In-Service Date</th>
<th>KM Capital ($MM)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sierrita</td>
<td>Sierrita Gas PL (CFE)</td>
<td>200</td>
<td>10/2014</td>
<td>$64.1</td>
</tr>
<tr>
<td>EPNG</td>
<td>S. Mainline Exp. (CFE)</td>
<td>471</td>
<td>10/2014 - 7/2020</td>
<td>$134.8</td>
</tr>
<tr>
<td>TX Intra</td>
<td>Mier Monterrey (MexGas/Others)</td>
<td>225</td>
<td>12/2014</td>
<td>$94.0</td>
</tr>
<tr>
<td>EPNG</td>
<td>Transport (CFE)</td>
<td>85</td>
<td>2014 / 2017</td>
<td>NA</td>
</tr>
<tr>
<td>TGP</td>
<td>S. System Flex (MexGas)</td>
<td>500</td>
<td>1/2015 - 12/2015 - 10/2016</td>
<td>$229.6</td>
</tr>
<tr>
<td>TGP</td>
<td>Transport (MexGas)</td>
<td>100</td>
<td>1Q 2016</td>
<td>NA</td>
</tr>
<tr>
<td>TX Intra</td>
<td>Crossover Project (^{(c)})</td>
<td>527</td>
<td>9/2016</td>
<td>$125.0</td>
</tr>
<tr>
<td>EPNG</td>
<td>Transport (GIGO)</td>
<td>20</td>
<td>4Q 2016</td>
<td>NA</td>
</tr>
<tr>
<td>EPNG</td>
<td>Trans. (Mexicana de Cobre)</td>
<td>9</td>
<td>4Q 2016</td>
<td>NA</td>
</tr>
<tr>
<td>Sierrita</td>
<td>Sierrita Gas PL Expansion (CFE)</td>
<td>230</td>
<td>4/2020</td>
<td>$19.8</td>
</tr>
</tbody>
</table>

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\(\text{(a)}\) Wood Mackenzie, Fall 2016 North America Natural Gas Long-Term Outlook, December 2016.

\(\text{(b)}\) 2016 calendar year average.

\(\text{(c)}\) Commitment to part of larger Crossover project designed to support LNG Exports, Gulf Coast Industrial demand and Exports to Mexico.
Drivers of Future Growth

Other

- **Power generation**
  - Continued trend of generators procuring firm transportation and storage services to ensure their performance in ISO capacity reliability programs
  - Increasing need for transportation, storage and ancillary services to backstop variable renewable generation

- **New opportunities in growing export markets**
  - Storage and ancillary services in support of LNG liquefaction and exports to Mexico

- **Industrial growth markets**
  - Well positioned to serve >$170 billion announced U.S. natural-gas related petrochemical expansion projects ($76 billion completed or under construction)\(^{(a)}\)

- **Residential and commercial markets**
  - Small to moderate expansions and extensions off our existing footprint to support LDC growth around the country, especially New England

- **Supply-based expansions//extensions**
  - Expansions and extensions off existing network to support growth as demand balances with existing supply

---

\(^{(a)}\) American Chemistry Council, Trade: A Pro-Growth, Pro-Competitiveness Agenda for Chemical Manufacturing factsheet, December 21, 2016.
Products Pipelines

Segment Outlook

Long-term Growth Drivers:
- Increased demand for refined products volumes
- Development of shale play liquids transportation and processing (e.g. Utopia and KMCC / splitter)
- Tuck-in acquisitions (e.g. KM Phoenix Terminals)
- Expansion of refined products pipeline systems and Terminal Networks
- Repurposing portions of existing footprint in different product uses

Project Backlog:
- $318 million of identified growth projects over next two years (a) (first year total Adjusted EBITDA $22.8 million (b)), including:
  - Utopia
  - Multiple refined products Terminaling and Bio Fuels projects

(a) Includes KM share of non-wholly owned projects. Includes projects currently under construction.
(b) KM Share.
Stability and Growth (a)

**Refined Products (b):**
- **2016:**
  - Refined products volumes 1,651 MBbl/d, up 0.3% vs. 2015
  - Gasoline up 1.2%, diesel down 3.5%, jet fuel up 1.7%
- **2017:**
  - 1,676 MBbl/d budgeted, 1.5% up vs. 2016
  - Budget volume sensitivity: 1% change = $7.5M

**NGLs:**
- **2016:**
  - NGL volumes 108 MBbl/d, up 2.7% vs. 2015
  - Drivers: higher volumes on Cochin Pipeline
- **2017:**
  - Budgeted volume up 5.6% vs. 2016
  - Drivers: Increased demand on Cochin; no forecasted turnaround in 2017 at Cypress Pipeline terminus

**Crude/Condensate:**
- **2016:**
  - Crude/condensate volumes 323 MBbl/d, up 18.3% vs. 2015
  - Drivers: expansion projects on KMCC/Double Eagle and acquisition of Double H pipeline
- **2017:**
  - 312 MBbl/d budgeted, down 3.3% vs. 2016
  - Drivers: Decreased production from the Eagle Ford

---

(a) All volumes reflect KM-share for joint ventures.
(b) Parkway divested July 2016. Parkway volumes and revenue not included.
(c) EIA, Short-term Energy Outlook, January 2017.
(d) Combined throughput of KM crude/condensate pipelines: KMCC, Double Eagle and Double H.
KMCC / Double Eagle
Location, Contracts, Connectivity

Kinder Morgan Crude & Condensate (KMCC)
- Capacity = 300 MBbl/d, expandable to 360 MBbl/d; Approximately 90% of current capacity committed
- Provides Eagle Ford producers access to Houston Ship Channel (Refineries, Export Opportunities), KM Splitter, Phillips 66 Sweeny Refinery

Double Eagle Pipeline
- Capacity 100 MBbl/d; 75% of capacity committed; 50/50 JV w/ Magellan
- Provides Eagle Ford producers access to Magellan Corpus Christi Terminal and KMCC

2016 Milestones
- KMCC / Double Eagle volumes grew 15.3% year over year as the full year impact of expansion projects and new customer commitments were realized
- KMCC volumes grew from 2015 to 2016, despite a 22% decline across the Eagle Ford

2017 Plans
- Maintain volumes
- Focus on superior location, customer base, and connectivity

KM Eagle Ford Crude/Condensate Volumes (a)

(a) Combined throughput of KMCC and Double Eagle.
(b) EIA, Drilling Report, January 2017.
Utopia Pipeline Project

- **Project Scope**
  - 50/50 JV with Riverstone Holdings closed on June 28, 2016
  - 215 mile new build and existing 67 mile 12" pipeline
  - Will transport ethane and ethane-propane mix from points in Harrison County, Ohio to Windsor, Ontario, Canada
  - Supported by long-term, fee-based transportation agreement
  - Initial pipeline capacity of 50 MBbl/d; expandable to 75 MBbl/d
  - Approximate $540 million\(^{(a)}\) investment

- **Market Drivers**
  - Utopia will provide a new feedstock source for petrochemical companies in Ontario, and a new market outlet for Utica NGL producers
  - Common carrier pipeline system is supported by a long-term (>20 years), fee-based transportation services agreement

- **Project Status and Timeline**
  - ROW acquisition ongoing
  - Commencement of construction 1Q 2017
  - Planned in-service date of January 2018

\(^{(a)}\) 100% project cost, excluding AFUDC.
Terminals
Segment Outlook

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
- $1.4 billion of identified growth projects over the next two years\(a\), including:
  - Houston Ship Channel network expansion
  - Edmonton merchant crude terminal
  - Jones Act tanker builds

KM Terminal Facilities

<table>
<thead>
<tr>
<th></th>
<th>Terminals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulk(a)</td>
<td>37</td>
</tr>
<tr>
<td>Liquids</td>
<td>51</td>
</tr>
<tr>
<td>Total KMT</td>
<td>88</td>
</tr>
<tr>
<td>KMPP</td>
<td>67</td>
</tr>
<tr>
<td>Total KM</td>
<td>155</td>
</tr>
</tbody>
</table>

16 Jones Act Tankers\(b\)

\(a\) Excludes terminals held for divestiture.
\(b\) Includes 4 new tankers to be delivered in 2017.
Stable Fee-Based Business

- ~2/3 of KMT’s 2017 budgeted EBDA is supported by take-or-pay contracts

**Liquids**
- 73% Take-or-pay
  - fixed monthly lease payments (MWC)
  - minimum throughput guarantees
  - Jones Act tanker charters
- 27% Other fee-based
  - ancillary fees for blending, additives, dock services, etc.
  - throughput fees

**Bulk**
- 37% Take-or-pay
- minimum throughput guarantees
- 23% Requirements
  - tied to petroleum coke or steel production
- 40% Other fee-based
  - throughput & ancillaries

KMT 2017 Budgeted EBDA = $1,178 million

Note: All data is based on 2017 budget.
Diversified Revenues

- Diversified revenues across liquids and bulk

### 2017 Budget

<table>
<thead>
<tr>
<th>Category</th>
<th>Revenue ($ millions)</th>
<th>Percent</th>
</tr>
</thead>
<tbody>
<tr>
<td>Liquids</td>
<td>$1,426</td>
<td>74%</td>
</tr>
<tr>
<td>Bulk</td>
<td>$500</td>
<td>26%</td>
</tr>
<tr>
<td>Total Revenue</td>
<td>$1,926</td>
<td>100%</td>
</tr>
</tbody>
</table>

### Top-10 Customers

<table>
<thead>
<tr>
<th>Category</th>
<th>Revenue ($ millions)</th>
<th>Percent</th>
</tr>
</thead>
<tbody>
<tr>
<td>Top-10 Customers</td>
<td>$911</td>
<td>47%</td>
</tr>
</tbody>
</table>

### Average Remaining Contract Term

<table>
<thead>
<tr>
<th>Category</th>
<th>Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Liquids</td>
<td>3.7</td>
</tr>
<tr>
<td>Bulk</td>
<td>4.9</td>
</tr>
</tbody>
</table>

(a) 2017 budget includes non-controlling interests in certain terminals.
(b) No single customer is greater than 9.5% of revenues.
(c) Budget weighted average as of Jan 1, 2017.
KMT Presence in Liquids Hubs

Edmonton Alberta
- 90 million Bbls of capacity
- ~1.0 billion Bbls throughput
- 97.5% utilization\(^{(a)}\)
- $1.43 billion revenues
- $957 million EBDA

KMT Liquids
- 90 million Bbls of capacity
- ~1.0 billion Bbls throughput
- 97.5% utilization\(^{(a)}\)
- $1.43 billion revenues
- $957 million EBDA

Liquids Revenues

All data is based on 2017 budget.

(a) Size is relative to revenues.
(b) Terminal utilizations reflect tankage unavailable for lease due to API inspections and routine maintenance.
KMT’s Houston Ship Channel terminal network is the largest integrated refined product terminaling system in the world: ~43 million barrels of capacity

- **Fee-Based Business**
  - Tank leases: term-contracted, take-or-pay commitments
  - Ancillary fees: ship & barge loading & unloading, blending, transfers

- **Customer Value in Physical Connectivity**
  - Multimodal: pipeline, tanker, barge, rail and truck
  - Multisource: local refineries, chemical plants, Mont Belvieu, imports

### Connectivity

- **20 inbound pipelines** – 10 Houston area refineries and local chemical plants
- **15 outbound pipelines** – Texas, mid-continent 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 markets
- **9 bay truck rack** – averaging 90 thousand bpd of products to local Houston markets
- **3 unit train facilities** – crude oil, condensates and ethanol
Tankers – APT Jones Act Fleet

All of APT’s available vessels are sailing under time-charter with limited 2017 exposure

- Average term contract length of 2.8 years across 16-vessels
- 4 new vessels to be delivered in ‘17
  - American Freedom
  - Palmetto State
  - American Liberty
  - American Pride
- Currently-uncontracted vessels:
  - $2.9 million or 0.2% exposure to KMT’s 2017 budgeted EBDA
- Marketing
  - Short-term charters
  - Bundled terminaling services
  - Prompt market voyages
**CO₂ Segment Outlook**(a)

**Long-term Growth Drivers:**
- Demand for scarce supply of CO₂ drives volume and price
- Expect to maintain current CO₂ production levels with minimal incremental investment
- Billions of barrels of domestic oil still in place to be recovered in the Permian Basin
- >9 billion barrels Original Oil In Place in KM operated fields

**Project Backlog:**
- Identified growth projects totaling $0.3 billion and $1.1 billion in S&T and EOR, respectively, over next five years(b), including:
  - S&T: Southwest Colorado CO₂ production
  - EOR: SACROC / Yates / Goldsmith / Tall Cotton oil production

---

(a) EOR = Enhanced Oil Recovery, S&T = Source & Transportation.
(b) Includes KM share of non-wholly owned projects. Includes projects currently under construction.
2017 Projects – Price Sensitivity

AT IRR % vs Oil Price

<table>
<thead>
<tr>
<th></th>
<th>$50 flat</th>
<th>$53 flat</th>
<th>$60 flat</th>
<th>Forward Curve&lt;sup&gt;a&lt;/sup&gt;</th>
</tr>
</thead>
<tbody>
<tr>
<td>SACROC-Bypass (Long Lateral)</td>
<td>27%</td>
<td>32%</td>
<td>44%</td>
<td>37%</td>
</tr>
<tr>
<td>SACROC-Bypass (Sidetrack Lateral)</td>
<td>41%</td>
<td>47%</td>
<td>61%</td>
<td>50%</td>
</tr>
<tr>
<td>SACROC Hawaii</td>
<td>14%</td>
<td>19%</td>
<td>30%</td>
<td>22%</td>
</tr>
<tr>
<td>Yates Horizontal Drain Hole Program</td>
<td>65%</td>
<td>73%</td>
<td>96%</td>
<td>75%</td>
</tr>
<tr>
<td>Tall Cotton Phase 2</td>
<td>32%</td>
<td>36%</td>
<td>43%</td>
<td>38%</td>
</tr>
</tbody>
</table>

- **Budgeted 2017 operating cash costs:**
  - SACROC = $17.91 /Bbl
  - Yates = $13.14 /Bbl

<sup>a</sup> Forward curve as of 1/18/2017.
KM CO₂ Current Outlook
$4.7 Billion Cumulative Free Cash Flow Generated Since Inception\(^{(a)}\)

**Development Plans 2017-2026**

- **SACROC**
  - Continue platform development/redevelopment
  - Expand Bypass Pay/Infill programs
  - Exploit transition zone opportunity

- **Yates**
  - Continue HDH programs and gravity drainage depletion plan
  - Initiate new Westside Waterflood
  - Evaluate HCM pilot

- **Katz**
  - Continue conformance program
  - Optimize flood performance

- **GLSAU**
  - Continue downspacing evaluation
  - Optimize flood performance

- **Tall Cotton**
  - Commence Phase 2 expansion
  - Develop additional project prospects

- **CO₂ S&T**
  - Maintain capacity in existing source fields (McElmo & Doe Canyon)
  - Optimize production and increase efficiency
  - Manage source portfolio to be prepared for increase in demand

**Total Business IRR (2000-2026): 28.2%**

<table>
<thead>
<tr>
<th></th>
<th>2017-2026</th>
<th>KM Share Capex (MM)(^{(c)})</th>
</tr>
</thead>
<tbody>
<tr>
<td>SACROC</td>
<td>58</td>
<td>$697</td>
</tr>
<tr>
<td>Yates</td>
<td>26</td>
<td>143</td>
</tr>
<tr>
<td>Katz</td>
<td>7</td>
<td>61</td>
</tr>
<tr>
<td>GLSAU</td>
<td>12</td>
<td>268</td>
</tr>
<tr>
<td>Tall Cotton</td>
<td>46</td>
<td>1,006</td>
</tr>
<tr>
<td>CO₂ S&amp;T</td>
<td></td>
<td>442</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>150</td>
<td><strong>$2,617</strong></td>
</tr>
</tbody>
</table>

\((e)\) CO₂ profits not eliminated from S&T.

---

\(\text{(a)}\) Net of invested capital.

\(\text{(b)}\) Net BOE = Net Crude plus Net NGLs plus Net Residue Gas sold and thereafter divided by 6.

\(\text{(c)}\) KM Share Capex is inclusive of Capitalized CO₂ and Capitalized OH.

\(\text{(d)}\) 2017 = Budget, 2017 at $53/Bbl, 2018 at $55/Bbl, 2019 at $60/Bbl, 2020+ at $65/Bbl; cost metrics based on 2016 run rate; development plans may change in different price scenarios.

\(\text{(e)}\) CO₂ profits not eliminated from S&T.
Kinder Morgan Canada

Segment Outlook

Long-term Growth Drivers:

- Expand Oilsands export capacity to West Coast and Asia
  - Following successful regulatory process, 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 2019
- Expanded dock capabilities (Vancouver)
  - TMEP will increase dock capacity to over 600 MBbl/d
  - Access to global markets
Trans Mountain Expansion Project (TMEP)

- Expansion to 890 MBbl/d from 300 MBbl/d
  - 615 miles new pipe; 12 new pump stations
  - 630 MBbl/d tanker export capacity; 3 new berths
  - 20 new tanks

- 13 companies contracted for 708 MBbl/d
  - 15 & 20 year take-or-pay contracts
  - Commercial terms approved by NEB May 2013

- Projected Cost
  - Finalizing cost estimates with contractors
  - Demand remains strong; we expect shippers to remain committed or have other shippers subscribe if final costs are above $6.8 billion CAD
  - Each $100mm >$6.8 billion CAD = ~$0.07 tariff increase
  - Additional cost pass through protection during construction
  - Substantial development cost protection

(a) Canadian Association of Petroleum Producers (CAPP), 2016 Crude Oil Forecast, Markets & Transportation, June 2016, and KM analysis.
Trans Mountain Expansion Project Timeline

**2016**
- NEB Recommendation May ‘16
- Federal Approval Dec. ‘16

**2017**
- BC Approval Jan. ‘17
- Cost Review with Shippers Feb. ‘17
- KM FID 1Q / 2Q 2017
- Begin Construction Sept. ‘17

**2018 – 2019**
- Complete Construction, In-Service Dec. ‘19
Financial Excellence

Kimberly Dang

Chief Financial Officer
Cost & Allocation of Capital

Disciplined Capital Allocation

**Current:**
- Live within cash flow, ration and allocate capital to highest risk-adjusted returns
- Require after-tax, unlevered project returns significantly higher than reasonable estimates of KMI’s cost of capital

**Future:**
- Once we have achieved our target leverage of approximately 5.0x net debt/Adjusted EBITDA, we will evaluate several options, including:
  - Investing in high return midstream investment opportunities and/or acquisitions
  - Further paying down debt and/or increasing dividends and/or repurchasing shares
  - Currently, we would expect to increase our dividend, targeting a dividend level that would permit us to cover the equity needs for growth capital with DCF
Self-Reliant Funding
No Need to Access Capital Markets During 2017

(millions)

- Distributable cash flow can fully cover dividends and growth capital needs
  - No need to access equity market in 2017

- Over $5 billion of liquidity at beginning of 2017 adds tremendous flexibility
  - No need to access debt market in 2017

- 2017 budget assumes a 50% partner on Trans Mountain to fund its share of expansion capital
  - Budget does not include any proceeds in excess of the partner’s share of expansion capital
  - KMI expects to receive such proceeds, but did not quantify them for budget purposes

<table>
<thead>
<tr>
<th>Sources</th>
<th>2017 Budget</th>
<th>2017 Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>DCF</td>
<td>$ 4,456</td>
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<tr>
<td>LT Debt Issuance</td>
<td>2,500</td>
<td></td>
</tr>
<tr>
<td>ST Borrowing (net of cash)(a)</td>
<td>(36)</td>
<td></td>
</tr>
<tr>
<td>Total Sources</td>
<td>$ 6,920</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Uses</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Dividends</td>
<td>$ 1,120</td>
<td></td>
</tr>
<tr>
<td>Growth Capital</td>
<td>3,240</td>
<td></td>
</tr>
<tr>
<td>Debt Maturities(b)</td>
<td>2,560</td>
<td></td>
</tr>
<tr>
<td>Total Uses</td>
<td>$ 6,920</td>
<td></td>
</tr>
</tbody>
</table>

Note: See Appendix for defined terms and reconciliations of non-GAAP measures for the historical period.
(a) Excludes changes in working capital including potential rate case refunds.
(b) 2017 Budget assumes EP Trust Preferred Securities, which are convertible into the EP merger consideration, are not converted during 2017. Budget also assumes Cora revenue bonds are not put to KMI during 2017. Both are classified as short term debt under GAAP.
5-year Growth Project Backlog\(^{(a)}\)

\(~\$12\) Billion of Attractive, Fee-based Projects

- World class asset footprint has driven attractive growth opportunities, secured by long-term, fee-based contracts with creditworthy counterparties
  - ~88% of backlog is for fee-based pipelines, terminals and associated facilities
  - ~\$1.6 billion of annual Adjusted EBITDA expected to be generated from growth projects\(^{(b)}\), excluding CO\(_2\), an approximate 6.7x investment multiple\(^{(c)}\)
  - Target at least 15% unlevered after-tax return to fund CO\(_2\) projects

- We anticipate achieving a JV or IPO of our Trans Mountain expansion project; backlog currently includes 100% of the project pending further progress

### Segment Growth Projects\(^{(a)}\) ($B)

<table>
<thead>
<tr>
<th>Segment</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas Pipelines</td>
<td>3.5</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Products Pipelines</td>
<td>0.3</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Terminals</td>
<td>1.4</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>KM Canada</td>
<td>5.4</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Subtotal non-CO(_2)</td>
<td>10.6</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO(_2) – S&amp;T(^{(d)})</td>
<td>0.3</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO(_2) – EOR(^{(d)})</td>
<td>1.1</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>12.0</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

\(^{(a)}\) 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. Includes estimated capitalized corporate overhead of \$0.5 billion. Projects in-service prior to 1/1/2017 excluded.

\(^{(b)}\) Estimated first full-year Adjusted EBITDA generated from fee-based pipelines, terminals and associated facilities. Excludes Adjusted EBITDA from CO\(_2\) projects and includes 100% of TMEP. Includes roughly \$150 million of Adjusted EBITDA contribution in the 2017 budget.

\(^{(c)}\) Investment multiple calculated as total project cost divided by first full-year expected Adjusted EBITDA.

\(^{(d)}\) S&T = CO\(_2\) Source & Transportation. EOR = Enhanced Oil Recovery.
KMI Counterparty Exposure

*Strong Customer Credit, Valuable Services Limit KMI’s Risk*\(^{(a)}\)

---

### High-Quality, Diversified Customer Base

- KMI’s 2016 DCF was impacted by less than $10 million due to oil & gas bankruptcies
- Greater than 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 = ~50% of KMI’s revenue\(^{(b)}\)
- Top 218 customers\(^{(c)}\) = ~88% of KMI’s revenue\(^{(b)}\)
  - <4% of these revenues from customers with B- or lower rating (net exposure is approximately half\(^{(d)}\) of this)

---

\(^{(a)}\) Company credit ratings as of 1/18/2017.

\(^{(b)}\) Based on budgeted 2017 net revenues, which include 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 2017 budgeted revenue.

\(^{(d)}\) Net exposure is revenues less credit support less market value of capacity.
Capital Invested
~$59 Billion of Asset Investment & Acquisitions Since Inception\(^{(a,c)}\)

Note: Includes equity contributions to joint ventures.
(c) Excludes $2.6 billion and $1.8 billion for 2016 50% SNG divestiture and 2012 FTC Rockies divestiture, respectively, in Natural Gas Pipelines segment. 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. Excludes $0.3 billion for 2013 divestiture of Express-Platte pipeline system in Kinder Morgan Canada segment. Excludes $0.8 billion of Products Pipelines legal and other settlements incurred over the past decade. However, we do include these impacts in the denominator of our ROI calculation.
# Returns on Invested Capital

<table>
<thead>
<tr>
<th></th>
<th></th>
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<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas Pipes</td>
<td>13.3%</td>
<td>15.5%</td>
<td>12.9%</td>
<td>13.5%</td>
<td>14.0%</td>
<td>15.5%</td>
<td>16.7%</td>
<td>17.5%</td>
<td>16.9%</td>
<td>14.0%</td>
<td>11.9%</td>
<td>11.9%</td>
<td>11.9%</td>
<td>10.9%(^{(b)})</td>
<td>10.9%(^{(b)})</td>
<td>10.3%(^{(b,c)})</td>
<td>9.9%(^{(b,c)})</td>
</tr>
<tr>
<td>Products Pipelines</td>
<td>11.9</td>
<td>11.8</td>
<td>12.8</td>
<td>12.9</td>
<td>12.4</td>
<td>11.6</td>
<td>11.8</td>
<td>13.2</td>
<td>12.5</td>
<td>13.4</td>
<td>13.7</td>
<td>12.9</td>
<td>12.1</td>
<td>12.4</td>
<td>12.3</td>
<td>12.6</td>
<td>13.1</td>
</tr>
<tr>
<td>Terminals</td>
<td>19.1</td>
<td>18.2</td>
<td>17.7</td>
<td>18.4</td>
<td>17.8</td>
<td>16.9</td>
<td>17.1</td>
<td>15.8</td>
<td>15.5</td>
<td>15.1</td>
<td>14.6</td>
<td>14.3</td>
<td>13.5</td>
<td>12.1</td>
<td>11.2</td>
<td>10.2</td>
<td>10.0</td>
</tr>
<tr>
<td>CO(_2)</td>
<td>27.5</td>
<td>24.6</td>
<td>22.0</td>
<td>21.9</td>
<td>23.8</td>
<td>25.7</td>
<td>23.1</td>
<td>21.7</td>
<td>25.4</td>
<td>23.1</td>
<td>25.3</td>
<td>25.9</td>
<td>28.1</td>
<td>25.9</td>
<td>22.8</td>
<td>16.2</td>
<td>12.3</td>
</tr>
<tr>
<td>KM Canada</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>11.0</td>
<td>12.1</td>
<td>12.8</td>
<td>13.7</td>
<td>14.1</td>
<td>16.3</td>
<td>14.8</td>
<td>11.5</td>
<td>9.7</td>
<td>10.1</td>
</tr>
<tr>
<td>Return on Investment</td>
<td>12.3%</td>
<td>12.7%</td>
<td>12.6%</td>
<td>13.1%</td>
<td>13.6%</td>
<td>14.3%</td>
<td>14.4%</td>
<td>14.1%</td>
<td>14.8%</td>
<td>13.9%</td>
<td>13.5%</td>
<td>13.5%</td>
<td>13.6%</td>
<td>11.9%</td>
<td>11.4%</td>
<td>10.3%</td>
<td>9.7%</td>
</tr>
<tr>
<td>Return on Equity</td>
<td>17.2%</td>
<td>19.4%</td>
<td>20.9%</td>
<td>21.7%</td>
<td>23.4%</td>
<td>23.9%</td>
<td>22.6%</td>
<td>22.9%</td>
<td>25.2%</td>
<td>25.2%</td>
<td>24.3%</td>
<td>24.0%</td>
<td>24.0%</td>
<td>21.7%</td>
<td>20.2%</td>
<td>15.9%</td>
<td>13.9%</td>
</tr>
</tbody>
</table>

Notes: Reflects KMP (2000–2012), KMP and EPB (2013–2014) and KMI (2015-2016). A definition of these measures may be found in the Appendix to this presentation.

(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) 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%, 10.5% and 10.1% in 2013, 2014, 2015 and 2016, respectively.

(c) Includes NGPL and Citrus investments.
2017 Guidance
Supported by Diversified, Fee-based Cash Flow

**2017 Published Budget**

- **DCF of $4.46 billion**
  - 2017 DCF per share of $1.99
  - 2017 declared dividend of $0.50 per share
  - ~$3.3 billion of DCF generated in excess of dividend (before growth capex)

- **Growth capital of $3.2 billion including JV contributions**

- **Adjusted EBITDA of $7.2 billion**

- **Expected year-end 2017 net debt/Adjusted EBITDA ratio of 5.4x**
  - Assumes 50% partner on Trans Mountain to fund its share of expansion capital
  - Budget does not include any proceeds in excess the partner’s share of expansion capital; KMI expects to receive such proceeds, but did not quantify for budget
  - Assumes 50% partner on Elba Liquefaction to fund its share of expansion capital as well as a reasonable promote payment

- **2017 budget assumes WTI average crude strip price of $53/Bbl and average natural gas strip price of $3.00/MMBtu**
  - $1/Bbl change in oil price = ~$6 million DCF impact
  - 10¢/MMBtu change in natural gas price = ~$1 million DCF impact

See Appendix for defined terms and reconciliations of non-GAAP measures for the historical period.
(a) Our non-GAAP measures of DCF and Adjusted EBITDA are before Certain Items and include KM-share of Certain Equity Investee DD&A.
(b) Natural gas sensitivity incorporates current hedges, and assumes ethane recovery for majority of year, constant ethane frac spread, and assumes other NGL prices maintain same relationship with oil prices.
2017 Budgeted Distributable Cash Flow (DCF)

(millions, except per share)

<table>
<thead>
<tr>
<th>Distributable Cash Flow</th>
<th>2017 Budget</th>
<th>2016 Actual</th>
<th>Change</th>
<th>$</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Income before Certain Items available to common stockholders</td>
<td>$1,458</td>
<td>$1,477</td>
<td>$(19)</td>
<td>$</td>
<td>-1%</td>
</tr>
<tr>
<td>DD&amp;A including KMI share of JV DD&amp;A&lt;sup&gt;(a)&lt;/sup&gt;</td>
<td>$2,651</td>
<td>$2,617</td>
<td>34</td>
<td></td>
<td>1%</td>
</tr>
<tr>
<td>Book taxes&lt;sup&gt;(b)&lt;/sup&gt;</td>
<td>$1,043</td>
<td>$993</td>
<td>50</td>
<td></td>
<td>5%</td>
</tr>
<tr>
<td>Cash taxes&lt;sup&gt;(c)&lt;/sup&gt;</td>
<td>$(89)</td>
<td>$(79)</td>
<td>$(10)</td>
<td></td>
<td>13%</td>
</tr>
<tr>
<td>Sustaining capex including KMI share of JV sustaining capex&lt;sup&gt;(d)&lt;/sup&gt;</td>
<td>$(630)</td>
<td>$(540)</td>
<td>$(90)</td>
<td></td>
<td>17%</td>
</tr>
<tr>
<td>Other&lt;sup&gt;(e)&lt;/sup&gt;</td>
<td>23</td>
<td>43</td>
<td>$(20)</td>
<td></td>
<td>-47%</td>
</tr>
<tr>
<td><strong>Distributable Cash Flow available to common stockholders (DCF)</strong></td>
<td><strong>$4,456</strong></td>
<td><strong>$4,511</strong></td>
<td><strong>$(55)</strong></td>
<td><strong>$</strong></td>
<td><strong>-1%</strong></td>
</tr>
</tbody>
</table>

| Average adjusted common shares outstanding<sup>(f)</sup> | 2,240 | 2,238 | 3 | 0% |
| DCF per common share | $1.99 | $2.02 | $(0.03) | | -1% |
| Expected/Declared dividend per share | $0.50 | $0.50 | - | | 0% |
| **Excess coverage** | **$3,335** | **$3,392** | **$(57)** | **$** | **-2%** |

Note: See Appendix for defined terms and reconciliations of non-GAAP measures for the historical period.

(a) Includes KMI share of Certain Equity Investee DD&A, $392 and $349 million in 2017 and 2016, respectively.
(b) Includes KMI’s share of Certain Equity Investee book taxes of $108 and $94 million in 2017 and 2016, respectively.
(c) Includes KMI’s share of Certain Equity Investee cash taxes of $76 and $76 million in 2017 and 2016, respectively.
(d) Includes KMI share of Certain Equity Investee sustaining capital expenditures, $112 and $90 million in 2017 and 2016, respectively.
(e) Primarily non-cash compensation associated with our restricted stock program partially offset by retiree medical and pension contributions.
(f) 2016 includes 8 million average unvested restricted shares that contain rights to dividends. 2017 includes 10 million average unvested restricted shares that contain rights to dividends.
## 2017 Budgeted Segment EBDA before Certain Items

*(millions, except per share)*

<table>
<thead>
<tr>
<th></th>
<th>2017 Budget</th>
<th>2016 Actual</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Natural Gas Pipelines</strong></td>
<td>$3,877</td>
<td>$4,036</td>
<td>$(159)</td>
</tr>
<tr>
<td><strong>CO2</strong></td>
<td>880</td>
<td>919</td>
<td>(39)</td>
</tr>
<tr>
<td><strong>Products Pipelines</strong></td>
<td>1,187</td>
<td>1,180</td>
<td>7</td>
</tr>
<tr>
<td><strong>Terminals</strong></td>
<td>1,217</td>
<td>1,169</td>
<td>48</td>
</tr>
<tr>
<td><strong>Kinder Morgan Canada</strong></td>
<td>191</td>
<td>181</td>
<td>10</td>
</tr>
<tr>
<td><strong>Total Segment EBDA before Certain Items</strong></td>
<td>7,352</td>
<td>7,485</td>
<td>$(133)</td>
</tr>
<tr>
<td><strong>General and administrative and corporate charges</strong>&lt;sup&gt;(a)&lt;/sup&gt;</td>
<td>(642)</td>
<td>(665)</td>
<td>23</td>
</tr>
<tr>
<td><strong>Interest, net</strong>&lt;sup&gt;(a)&lt;/sup&gt;</td>
<td>(1,879)</td>
<td>(1,999)</td>
<td>120</td>
</tr>
<tr>
<td><strong>DD&amp;A</strong></td>
<td>(2,259)</td>
<td>(2,268)</td>
<td>9</td>
</tr>
<tr>
<td><strong>Pre-tax income before Certain Items</strong></td>
<td>2,572</td>
<td>2,553</td>
<td>19</td>
</tr>
<tr>
<td><strong>Book taxes</strong>&lt;sup&gt;(a)&lt;/sup&gt;</td>
<td>(935)</td>
<td>(899)</td>
<td>(36)</td>
</tr>
<tr>
<td><strong>Net Income before Certain Items</strong></td>
<td>1,637</td>
<td>1,654</td>
<td>$(17)</td>
</tr>
<tr>
<td><strong>Noncontrolling interests</strong>&lt;sup&gt;(a)&lt;/sup&gt;</td>
<td>(23)</td>
<td>(21)</td>
<td>(2)</td>
</tr>
<tr>
<td><strong>Preferred stock dividends</strong></td>
<td>(156)</td>
<td>(156)</td>
<td>-</td>
</tr>
<tr>
<td><strong>Net Income before Certain Items available to common stockholders</strong></td>
<td>$1,458</td>
<td>$1,477</td>
<td>$(19)</td>
</tr>
</tbody>
</table>

### Adjusted Earnings per share

<table>
<thead>
<tr>
<th></th>
<th>2017</th>
<th>2016</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Average adjusted common shares outstanding</strong>&lt;sup&gt;(b)&lt;/sup&gt;</td>
<td>2,240</td>
<td>2,238</td>
<td>3</td>
</tr>
<tr>
<td><strong>Adjusted EPS</strong>&lt;sup&gt;(c)&lt;/sup&gt;</td>
<td>$0.65</td>
<td>$0.66</td>
<td>$(0.01)</td>
</tr>
</tbody>
</table>

Note: See Appendix for defined terms and reconciliations of non-GAAP measures for the historical period.

(a) Before Certain Items.
(b) 2016 includes 8 million average unvested restricted shares that contain rights to dividends. 2017 includes 10 million average unvested restricted shares that contain rights to dividends.
(c) Adjusted Earnings per share based on net income attributable to common shareholders before Certain Items divided by average adjusted common shares outstanding.
2017 Budgeted Adjusted EBITDA

(millions)

<table>
<thead>
<tr>
<th>Adjusted EBITDA</th>
<th>2017 Budget</th>
<th>2016 Actual</th>
<th>Change</th>
<th>$</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Segment EBDA before Certain Items</td>
<td>$ 7,352</td>
<td>$ 7,485</td>
<td>(133)</td>
<td></td>
<td>-2%</td>
</tr>
<tr>
<td>Natural Gas Pipelines JV DD&amp;A</td>
<td>379</td>
<td>349</td>
<td>30</td>
<td></td>
<td>9%</td>
</tr>
<tr>
<td>CO2 JV DD&amp;A</td>
<td>7</td>
<td>-</td>
<td>7</td>
<td></td>
<td>n/a</td>
</tr>
<tr>
<td>Products Pipelines JV DD&amp;A</td>
<td>12</td>
<td>4</td>
<td>8</td>
<td></td>
<td>200%</td>
</tr>
<tr>
<td>Terminals JV DD&amp;A</td>
<td>(6)</td>
<td>(4)</td>
<td>(2)</td>
<td></td>
<td>50%</td>
</tr>
<tr>
<td><strong>Subtotal: Segment EBDA before Certain Items plus JV DD&amp;A</strong></td>
<td><strong>7,744</strong></td>
<td><strong>7,834</strong></td>
<td><strong>(90)</strong></td>
<td></td>
<td>-1%</td>
</tr>
<tr>
<td>JV book taxes (a)</td>
<td>108</td>
<td>94</td>
<td>14</td>
<td></td>
<td>15%</td>
</tr>
<tr>
<td>Noncontrolling interests (b)</td>
<td>(23)</td>
<td>(21)</td>
<td>(2)</td>
<td></td>
<td>10%</td>
</tr>
<tr>
<td>General and administrative and corporate charges (b)</td>
<td>(642)</td>
<td>(665)</td>
<td>23</td>
<td></td>
<td>-3%</td>
</tr>
<tr>
<td><strong>Adjusted EBITDA</strong></td>
<td><strong>$ 7,187</strong></td>
<td><strong>$ 7,242</strong></td>
<td><strong>(55)</strong></td>
<td></td>
<td>-1%</td>
</tr>
</tbody>
</table>

Note: See Appendix for defined terms and reconciliations of non-GAAP measures for the historical period.
(a) KM-share of Certain Equity Investee book taxes.
(b) Before Certain Items.
Reconciliation of Financials Presentation, from 4Q ‘16 Earnings Release to Jan ‘17 Analyst Day

(millions)

<table>
<thead>
<tr>
<th></th>
<th>4Q ER As Reported</th>
<th>Book Tax</th>
<th>Interest Income</th>
<th>Other Segment</th>
<th>As Revised</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas Pipelines</td>
<td>$4,029</td>
<td>$7</td>
<td>-</td>
<td>-</td>
<td>$4,036</td>
</tr>
<tr>
<td>CO₂</td>
<td>917</td>
<td>2</td>
<td>-</td>
<td>-</td>
<td>919</td>
</tr>
<tr>
<td>Products Pipelines</td>
<td>1,185</td>
<td>(5)</td>
<td>-</td>
<td>-</td>
<td>1,180</td>
</tr>
<tr>
<td>Terminals</td>
<td>1,133</td>
<td>36</td>
<td>-</td>
<td>-</td>
<td>1,169</td>
</tr>
<tr>
<td>Kinder Morgan Canada</td>
<td>161</td>
<td>20</td>
<td>-</td>
<td>-</td>
<td>181</td>
</tr>
<tr>
<td>Other</td>
<td>(22)</td>
<td>(3)</td>
<td>25</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>Total Segment EBDA before Certain Items</td>
<td>7,403</td>
<td>60</td>
<td>(3)</td>
<td>25</td>
<td>7,485</td>
</tr>
<tr>
<td>General and administrative and corporate charges</td>
<td>(640)</td>
<td>-</td>
<td>-</td>
<td>(25)</td>
<td>(665)</td>
</tr>
<tr>
<td>Interest, net</td>
<td>(2,002)</td>
<td>-</td>
<td>3</td>
<td>-</td>
<td>(1,999)</td>
</tr>
<tr>
<td>Book DD&amp;A</td>
<td>(2,268)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>(2,268)</td>
</tr>
<tr>
<td>Pre-tax income</td>
<td>2,493</td>
<td>60</td>
<td>-</td>
<td>-</td>
<td>2,553</td>
</tr>
<tr>
<td>Book taxes</td>
<td>(839)</td>
<td>(60)</td>
<td>-</td>
<td>-</td>
<td>(899)</td>
</tr>
<tr>
<td>Net Income before certain items</td>
<td>1,654</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>1,654</td>
</tr>
<tr>
<td>Noncontrolling interests</td>
<td>(21)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>(21)</td>
</tr>
<tr>
<td>Preferred stock dividends</td>
<td>(156)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>(156)</td>
</tr>
<tr>
<td>Net Income before Certain Items available to common stockholders</td>
<td>$1,477</td>
<td>$ -</td>
<td>$ -</td>
<td>$ -</td>
<td>$1,477</td>
</tr>
</tbody>
</table>

In our 2017 budget, 2016 10-K and going forward, we have made minor reclassifications to book tax, interest income and the Other segment. The prior periods will be revised for all periods presented going forward. This change was made to reflect these items at the corporate level and to reflect we no longer have an Other reportable segment. We believe this results in a more straightforward presentation.

Note: See Appendix for defined terms and reconciliations of non-GAAP measures for the historical period.
2017 Budgeted Quarterly Profile

(millions, except per share)

<table>
<thead>
<tr>
<th>Segment EBDA before Certain Items plus JV DD&amp;A&lt;sup&gt;(a)&lt;/sup&gt;</th>
<th>Q1</th>
<th>Q2</th>
<th>Q3</th>
<th>Q4</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017 Budget</td>
<td>25%</td>
<td>24%</td>
<td>24%</td>
<td>27%</td>
<td>$ 7,744</td>
</tr>
<tr>
<td>2016 Actual</td>
<td>27%</td>
<td>24%</td>
<td>24%</td>
<td>25%</td>
<td>$ 7,834</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Adjusted EBITDA</th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>2017 Budget</td>
<td>25%</td>
<td>24%</td>
<td>24%</td>
<td>27%</td>
<td>$ 7,187</td>
</tr>
<tr>
<td>2016 Actual</td>
<td>26%</td>
<td>24%</td>
<td>25%</td>
<td>25%</td>
<td>$ 7,242</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Distributable cash flow (DCF)&lt;sup&gt;(b)&lt;/sup&gt;</th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>2017 Budget</td>
<td>26%</td>
<td>23%</td>
<td>23%</td>
<td>28%</td>
<td>$ 4,456</td>
</tr>
<tr>
<td>2016 Actual</td>
<td>27%</td>
<td>24%</td>
<td>24%</td>
<td>25%</td>
<td>$ 4,511</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Adjusted EPS&lt;sup&gt;(c)&lt;/sup&gt;</th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>2017 Budget</td>
<td>26%</td>
<td>22%</td>
<td>23%</td>
<td>29%</td>
<td>$ 0.65</td>
</tr>
<tr>
<td>2016 Actual</td>
<td>27%</td>
<td>23%</td>
<td>23%</td>
<td>27%</td>
<td>$ 0.66</td>
</tr>
</tbody>
</table>

Note: See Appendix for defined terms and reconciliations of non-GAAP measures for the historical period.

(a) Includes KMI share of Certain Equity Investee DD&A.
(b) Includes KMI share of Certain Equity Investee DD&A and reduced by KMI share of Certain Equity Investee sustaining capital expenditures.
(c) 2017 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.
2017 Budget Assumptions/Highlights

Business segments

- **Natural Gas Pipelines (4%)**: Reduction due to full-yr impact of 50% sale of SNG, lower volumes on gathering and processing assets and CIG rate case. Partially offset by expansion projects on TGP, Elba Express and NGPL.

- **CO₂ (4%)**: Decrease driven by price ~$4/Bbl reduction in weighted average oil price. Oil & Gas: oil volumes net essentially flat ~(150) MBar/d; unhedged price = $53/Bbl. S&T: Cortez expansion, CO₂ volumes ~(1%), CO₂ price ~(2%).

- **Products Pipelines +1%**: Refined products volumes = +1.5%. NGL volumes = +5.6%. Crude and condensate volumes = (3.3%). +9% in terminal volumes from expansions, full-year BP acquisition impact + 3rd party business growth.

- **Terminals +4%**: Growth driven by (i) expansions in the Gulf and Jones Act Fleet, (ii) BP JV and (iii) contract escalations. Partially offset by lower rates on expiring Jones Act contracts, sale of 20 bulk terminals and coal contract expiration.

- **Kinder Morgan Canada +6%**: Capitalized financing costs. CAD/USD 2017 average exchange rate = 0.77x.

Interest expense

- **3-mo LIBOR: ~1.15%**: Average rate for the year, based on approximate forward curve at time of budget.

Cash taxes

- Not expected to be a U.S. federal cash tax payer in 2017.

---

(a) Business segment percentage increase/(decrease) is 2016A to 2017B change in Segment EBDA before Certain Items.
2017 Cash Tax Budget Calculation Detail

(millions)

- Not expected to owe material federal income cash taxes until after 2023 (under current tax structure)

<table>
<thead>
<tr>
<th>Item</th>
<th>2017 Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>Segment EBDA before Certain Items</td>
<td>$ 7,352</td>
</tr>
<tr>
<td>Noncontrolling interests(^{(a)})</td>
<td>(23)</td>
</tr>
<tr>
<td>JV earnings from c-corps(^{(a)})</td>
<td>(200)</td>
</tr>
<tr>
<td>JV distributions from c-corps (net of 80% DRD)</td>
<td>38</td>
</tr>
<tr>
<td>JV book DD&amp;A (pass-thru entities)</td>
<td>258</td>
</tr>
<tr>
<td>General and administrative and corporate charges(^{(a)})</td>
<td>(642)</td>
</tr>
<tr>
<td>Interest, net(^{(a)})</td>
<td>(1,879)</td>
</tr>
<tr>
<td>Book capex items expensed for tax purposes(^{(b)})</td>
<td>(493)</td>
</tr>
<tr>
<td>Tax depreciation from YE 2014 Basis</td>
<td>(4,338)</td>
</tr>
<tr>
<td>Tax depreciation for Post-2014 Assets</td>
<td>(1,535)</td>
</tr>
<tr>
<td>Other items</td>
<td>(89)</td>
</tr>
<tr>
<td><strong>Taxable income (loss)</strong></td>
<td><strong>$ (1,551)</strong></td>
</tr>
</tbody>
</table>

**KMI U.S. federal cash taxes** $ -

**Other cash taxes\(^{(c)}\)** 89

**Total cash taxes** $ 89

**Note:** See Appendix for defined terms and reconciliations of non-GAAP measures for the historical period.

\(^{(a)}\) Before Certain Items.

\(^{(b)}\) Includes certain sustaining capex, interest during construction, capitalized CO2, intangible completion costs, and capitalized overhead which can be expensed for tax purposes.

\(^{(c)}\) Includes cash taxes for (i) our share of Plantation, Citrus, and NGPL (ii) our bulk terminals held in corporate subsidiaries, (iii) Texas margin tax and other state income taxes and (iv) foreign taxes.
2017 Budgeted Sustaining Capital

(millions)

<table>
<thead>
<tr>
<th>Sustaining capital expenditures&lt;sup&gt;(a)&lt;/sup&gt;</th>
<th>2017 Budget</th>
<th>2016 Actual</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas Pipelines</td>
<td>$296</td>
<td>$276</td>
<td>$20</td>
</tr>
<tr>
<td>CO₂</td>
<td>14</td>
<td>9</td>
<td>5</td>
</tr>
<tr>
<td>Products Pipelines</td>
<td>72</td>
<td>45</td>
<td>27</td>
</tr>
<tr>
<td>Terminals</td>
<td>201</td>
<td>160</td>
<td>41</td>
</tr>
<tr>
<td>Kinder Morgan Canada</td>
<td>24</td>
<td>26</td>
<td>(1)</td>
</tr>
<tr>
<td>Corporate / Other</td>
<td>23</td>
<td>24</td>
<td>(1)</td>
</tr>
<tr>
<td><strong>Total sustaining capital expenditures</strong></td>
<td><strong>$630</strong></td>
<td><strong>$540</strong></td>
<td><strong>$90</strong></td>
</tr>
</tbody>
</table>

Note: Before Certain Items.

<sup>(a)</sup> Includes KMI share of Certain Equity Investee sustaining capital expenditures, $112 and $90 million in 2017 and 2016, respectively.
2017 Budgeted Growth Capital

(millions)

- 2017 budgeted growth capital fully funded by internally generated cash flow, with no requirement to access capital markets

<table>
<thead>
<tr>
<th>Growth capital</th>
<th>2017 Budget(a)</th>
<th>2016 Actual</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas Pipelines</td>
<td>$ 1,762</td>
<td>$ 1,304</td>
</tr>
<tr>
<td>CO₂ - S&amp;T</td>
<td>31</td>
<td>(2)</td>
</tr>
<tr>
<td>CO₂ - EOR</td>
<td>321</td>
<td>265</td>
</tr>
<tr>
<td>Products Pipelines</td>
<td>199</td>
<td>183</td>
</tr>
<tr>
<td>Terminals</td>
<td>730</td>
<td>947</td>
</tr>
<tr>
<td>Kinder Morgan Canada</td>
<td>197</td>
<td>110</td>
</tr>
<tr>
<td><strong>Total growth capital</strong></td>
<td><strong>$ 3,240</strong></td>
<td><strong>$ 2,807</strong></td>
</tr>
</tbody>
</table>

(a) 2017 includes JV contributions of $1,109 million and JV catch-up contributions (Elba Liquefaction, Trans Mountain) of $575 million.
Credit Ratios and Liquidity\(^{(a)}\)

\($ in millions\)

<table>
<thead>
<tr>
<th>Leverage metrics</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net debt(^{(b)}) to Adjusted EBITDA</td>
<td>5.0x</td>
<td>5.5x</td>
<td>5.6x</td>
<td>5.3x</td>
<td>5.4x</td>
</tr>
<tr>
<td>Adjusted EBITDA to Interest, net</td>
<td>3.9x</td>
<td>4.1x</td>
<td>3.5x</td>
<td>3.6x</td>
<td>3.8x</td>
</tr>
</tbody>
</table>

\(\text{Revolver capacity}^{(c)}\)

\begin{align*}
\text{Committed revolving credit facility} & \quad $5,000 \\
\text{Less:} & \\
\text{CP / Revolver borrowing} & \quad - \\
\text{Letters of credit} & \quad (160) \\
\text{Excess capacity} & \quad $4,840
\end{align*}

\(\text{Long-term debt maturities}^{(d)}\)

\begin{align*}
\text{2017} & \quad $2,560 \\
\text{2018} & \quad 2,329 \\
\text{2019} & \quad 3,820 \\
\text{2020} & \quad 2,204 \\
\text{2021} & \quad 2,422
\end{align*}

Note: As of 12/31/2016. See Appendix for defined terms and reconciliations of non-GAAP measures for the historical period.

(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.
Financial Excellence

- Disciplined capital allocation
- Attractive return on investments
- Hedge direct commodity exposure
- Maintain strong balance sheet
- Transparency to investors
Next Stop: Happy Sunlit Meadow
Appendix
Natural Gas Pipelines

Segment Presentation
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Natural Gas Pipelines
Segment Outlook

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

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

Project Backlog:
- $3.5 billion of identified growth projects over next four years (2017-2020)(a), including:
  - LNG liquefaction (Elba Island)
  - Transport projects supporting LNG liquefaction, including Elba Express
  - Expansions to Mexico border
  - TGP North-South projects

(a) Includes KM share of non-wholly owned projects. Includes projects currently under construction.
Drivers of Future Growth

**LNG Exports**

- **LNG Export Opportunity**
  - 18.5 Bcf/d of FERC approved projects
  - 10.3 Bcf/d of projects under construction
  - 9.8 Bcf/d of additional projects pending approval

- **Elba Liquefaction – KM facility at Elba Island, GA**

- **LNG Transport**
  - 4.5 MMDth/d of contracted transport capacity
  - Total capital of $981 MM
  - Avg. contract term: 19 years
  - Seven active projects on five KM pipelines

---

### KM Asset | KM Project/Transportation (Terminal) | Contracted Capacity (MDth/d) | In-Service Date | KM Capital ($MM)
--- | --- | --- | --- | ---
NGPL | Firm Transport (Sabine Pass) | 550 | In-Service | N/A
EEC | EEC for Shell (Elba Island) | 436 | 2/2017-11/2018 | $102.2
TGP | SW Louisiana Supply (Cameron) | 900 | 2/2018 | $178.5
NGPL | Gulf Coast Southbound (Corpus Christi) | 385 | 4Q/2018 | $106.1
Intrastate | TX Intrastate Crossover (Corpus Christi/Freeport) | 590 | 1Q-3Q 2019 | $182.1
TGP | Lone Star (Corpus Christi) | 300 | 7/2019 | $133.8
KMLP | Sabine Pass Expansion | 600 | 4Q/2019 | $151.3
KMLP | Magnolia LNG Expansion | 700 | 4Q/2020 | $127.0

---

(a) FERC as of 1/5/17, industry and KM analysis.
Liquefaction at Elba Island
Elba Liquefaction Company (ELC) / SLNG

- **Capacity:**
  - LNG output capacity equivalent to 350 MMcf/d

- **Capital (100%):**
  - ELC: $1,436.4 MM
  - SLNG: $433.8 MM

- **Phased In-service:** Mid 2018 through early 2019

- **Project Scope:**
  - Facilities for liquefaction (10 modular units)
  - Ship loading facilities; boil-off gas compression

- **Avg. Contract Term:** 20 years

- **Current Status:**
  - FERC certificate issued June 2016
  - FERC denied requests for rehearing Dec 2016
  - Shell has committed to entire capacity of facility, as well as Elba Express expansion
  - DOE FTA and non-FTA authorizations received
  - Construction underway

- **Major Milestones:**
  - JV negotiations for ELC are ongoing
Drivers of Future Growth

**Kinder Morgan Delivers ~76% of U.S. Exports to Mexico**

- **Exports to Mexico** are forecasted to increase by 2.0 Bcf/d to 5.6 Bcf/d by 2021\(^{(a)}\)
- **KM deliveries to Mexico** ~2.8 MMDth/d\(^{(b)}\) through 17 interconnects (12 direct & 5 indirect)
  - KM up 20% from 2015; 76% of 2016 U.S. total
  - Well positioned to serve incremental demand through extensive network connected to multiple prolific supply basins
- **KM projects and new long term commitments for export to Mexico entered into since 2013:**
  - Capacity: ~2.4 MMDth/d
  - Capital: ~$667 MM

### Mexico Gas Supply (Bcf/d)\(^{(a)}\)

<table>
<thead>
<tr>
<th>KM Asset</th>
<th>KM Project / Transportation (Shipper)</th>
<th>Contracted Capacity (MDth/d)</th>
<th>In-Service Date</th>
<th>KM Capital ($MM)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sierrita</td>
<td>Sierrita Gas PL (CFE)</td>
<td>200</td>
<td>10/2014</td>
<td>$64.1</td>
</tr>
<tr>
<td>EPNG</td>
<td>S. Mainline Exp. (CFE)</td>
<td>471</td>
<td>10/2014 - 7/2020</td>
<td>$134.8</td>
</tr>
<tr>
<td>TX Intra</td>
<td>Mier Monterrey (MexGas/Others)</td>
<td>225</td>
<td>12/2014</td>
<td>$94.0</td>
</tr>
<tr>
<td>EPNG</td>
<td>Transport (CFE)</td>
<td>85</td>
<td>2014 / 2017</td>
<td>NA</td>
</tr>
<tr>
<td>TGP</td>
<td>S. System Flex (MexGas)</td>
<td>500</td>
<td>1/2015 - 12/2015 - 10/2016</td>
<td>$229.6</td>
</tr>
<tr>
<td>TGP</td>
<td>Transport (MexGas)</td>
<td>100</td>
<td>1Q 2016</td>
<td>NA</td>
</tr>
<tr>
<td>TX Intra</td>
<td>Crossover Project (^{(c)})</td>
<td>527</td>
<td>9/2016</td>
<td>$125.0</td>
</tr>
<tr>
<td>EPNG</td>
<td>Transport (GIGO)</td>
<td>20</td>
<td>4Q 2016</td>
<td>NA</td>
</tr>
<tr>
<td>EPNG</td>
<td>Trans. (Mexicana de Cobre)</td>
<td>9</td>
<td>4Q 2016</td>
<td>NA</td>
</tr>
<tr>
<td>Sierrita</td>
<td>Sierrita Gas PL Expansion (CFE)</td>
<td>230</td>
<td>4/2020</td>
<td>$19.8</td>
</tr>
</tbody>
</table>

---

\(^{(a)}\) Wood Mackenzie, Fall 2016 North America Natural Gas Long-Term Outlook, December 2016.
\(^{(b)}\) 2016 calendar year average.
\(^{(c)}\) Commitment to part of larger Crossover project designed to support LNG Exports, Gulf Coast Industrial demand and Exports to Mexico.
Drivers of Future Growth

Other

- **Power generation**
  - Continued trend of generators procuring firm transportation and storage services to ensure their performance in ISO capacity reliability programs
  - Increasing need for transportation, storage and ancillary services to backstop variable renewable generation

- **New opportunities in growing export markets**
  - Storage and ancillary services in support of LNG liquefaction and exports to Mexico

- **Industrial growth markets**
  - Well positioned to serve >$170 billion announced U.S. natural-gas related petrochemical expansion projects ($76 billion completed or under construction)\(^1\)

- **Residential and commercial markets**
  - Small to moderate expansions and extensions off our existing footprint to support LDC growth around the country, especially New England

- **Supply-based expansions/extensions**
  - Expansions and extensions off existing network to support growth as demand balances with existing supply

---

\(^1\) American Chemistry Council, *Trade: A Pro-Growth, Pro-Competitiveness Agenda for Chemical Manufacturing factsheet*, December 21, 2016.
North Region Assets

Growth Drivers:

- **Power Demand**: New infrastructure required for growing gas-fired power generation
  - Gas-fired power demand growth in the Northeast and Midwest
  - Economic/environmental replacement of coal/oil generation

- **LNG Export**: New infrastructure requirements drive opportunity
  - 6 Bcf/d\(^{(a)}\) of additional demand from 4 approved LNG liquefaction projects near TGP, NGPL and KMLP
  - Additional indirect throughput for KM pipes in the region

- **Mexico Exports**: Demand on TGP and NGPL to deliver shale volumes to Mexico

- **Marcellus/Utica**:
  - TGP provides access for Marcellus and Utica shale plays to Gulf Coast and Northeast markets
  - NGPL provides access to premium Midwest LDC and Gulf Coast markets

- **Industrial Demand**: TGP and NGPL positioned to supply new industrial plants

- **Storage Demand**: Significant storage capacity for new power demand, Mexico and LNG variability

- **NE/Canada Demand**: New gas service and conversions in New England and Canada

---

### Asset Summary

<table>
<thead>
<tr>
<th>Asset (KM ownership shown if not 100%)</th>
<th>Miles</th>
<th>Capacity (Bcf/d)</th>
<th>Storage (Bcf)</th>
<th>Avg. Remaining Contract Term (Yrs)</th>
<th>Effective Date of Next Rate Case</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tennessee Gas Pipeline (TGP)</td>
<td>11,800</td>
<td>10.2</td>
<td>104</td>
<td>7.3 / 3.7(^{(b)})</td>
<td>NA</td>
</tr>
<tr>
<td>Natural Gas Pipeline Co. of America (NGPL, 50%)</td>
<td>9,100</td>
<td>6.9</td>
<td>288</td>
<td>4.8 / 2.9 (^{(b)})</td>
<td>Pending</td>
</tr>
<tr>
<td>Kinder Morgan Louisiana Pipeline (KMLP)</td>
<td>135</td>
<td>2.2</td>
<td>-</td>
<td>0(^{(c)})</td>
<td>NA</td>
</tr>
</tbody>
</table>

\(^{(a)}\) KM analysis.
\(^{(b)}\) Transport / Storage.
\(^{(c)}\) Anchor shippers exercised buyout option in 2015.
South Region Assets

Growth Drivers:

- **LNG Export**: KM participating in LNG liquefaction infrastructure
  - Elba Island terminal liquefaction facilities under construction

- **Expansion**: Additional SNG expansion opportunities to support growth in service territory of JV partner-Southern Company

- **Power Demand**: New infrastructure required for growing gas-fired power generation
  - Gas-fired power demand growth in the Southeast
  - Economic/environmental replacement of coal/oil generation

- **Industrial Demand**: SNG positioned to supply new industrial plants

- **Marcellus/Utica**: SNG provides markets for Marcellus and Utica shale plays to Southeast and Gulf Coast markets

- **Storage Demand**: Significant storage capacity for new power demand and LNG variability

---

<table>
<thead>
<tr>
<th>Asset (KM ownership shown if not 100%)</th>
<th>Miles</th>
<th>Capacity (Bcf/d)</th>
<th>Storage (Bcf)</th>
<th>Avg. Remaining Contract Term (Yrs)</th>
<th>Effective Date of Next Rate Case</th>
</tr>
</thead>
<tbody>
<tr>
<td>Southern Natural Gas (SNG, 50%)</td>
<td>6,900</td>
<td>4.1</td>
<td>68</td>
<td>5.4 / 1.7(a)</td>
<td>9/1/2018</td>
</tr>
<tr>
<td>Elba Express (EEC)</td>
<td>200</td>
<td>1.0</td>
<td>-</td>
<td>-</td>
<td>NA</td>
</tr>
<tr>
<td>Midcontinent Express (MEP, 50%)</td>
<td>510</td>
<td>1.8</td>
<td>-</td>
<td>2.3</td>
<td>NA</td>
</tr>
<tr>
<td>Florida Gas Transmission (FGT, 50%)</td>
<td>5,300</td>
<td>3.6</td>
<td>-</td>
<td>9.9</td>
<td>NA</td>
</tr>
<tr>
<td>Fayetteville Express (FEP, 50%)</td>
<td>185</td>
<td>2.0</td>
<td>-</td>
<td>4.2</td>
<td>NA</td>
</tr>
<tr>
<td>Elba Island LNG (SLNG)</td>
<td>-</td>
<td>1.7</td>
<td>11.5</td>
<td>15.8</td>
<td>NA</td>
</tr>
<tr>
<td>Gulf LNG (GLNG, 50%)</td>
<td>5</td>
<td>1.5</td>
<td>6.6</td>
<td>14.8</td>
<td>NA</td>
</tr>
</tbody>
</table>

(a) Transport / Storage.
West Region Assets

Growth Drivers:
- **Mexico Exports**: Leading connectivity for incremental supply to Mexico
  - 5.6 Bcf/d of exports to Mexico forecast by 2021 (a)
  - 2016 YTD deliveries to Mexico:
    - West Region: 1.1 MMDth/d
    - KM Total: 2.8 MMDth/d
- **Power Demand**: Renewable energy growth promotes gas-fired power backstop
  - Economic/environmental replacement of coal & oil plants
- **Storage Demand**: Significant storage capacity with superior connectivity
- **Supply Access**: Access to all Rockies basins with diverse geology and hydrocarbon mix; opportunities for new builds and conversions
- **LNG Exports**: Potential for 1 Bcf/d of demand from West Coast projects near Ruby

---

(a) Wood Mackenzie, Fall 2016 North America Gas Long-Term Outlook, December 2016.
(b) Transport / Storage.
Midstream Assets

Growth Drivers:
- **Mexico Exports**: Leading connectivity for increased deliveries into Mexico (Texas Intrastate)
- **Industrial Demand**: Well positioned to serve >$170 B announced U.S. pet-chem. expansion projects, $76 B completed or under construction (Texas Intrastate)
- **LNG Exports**: Approximately 1 Bcf/d of additional demand from 1 approved LNG project along the Gulf Coast near Texas Intrastates
- **Storage Demand**: Significant storage capacity and connectivity enable premium services, including load balancing to power and end use markets (Texas Intrastate)
- **Acquisitions**: expansions/acquisitions around extensive gathering and processing footprint

Commodity Price Exposure (2017):

<table>
<thead>
<tr>
<th>Asset (KM ownership shown if not 100%)</th>
<th>Processing and Gas Price Exposures (DCF impact in millions)</th>
<th>Miles</th>
<th>Capacity</th>
<th>Storage</th>
<th>Treating Capacity</th>
<th>Processing Capacity</th>
<th>Avg. Remaining Transport Contract Term (Yrs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>KMTP / Tejas</td>
<td></td>
<td>5,650</td>
<td>6.4 Bcf/d</td>
<td>136 Bcf</td>
<td>1,680 GPM</td>
<td>510 MMcf/d</td>
<td>5.5</td>
</tr>
<tr>
<td>North Texas Pipeline</td>
<td></td>
<td>80</td>
<td>330 MMcf/d</td>
<td></td>
<td></td>
<td></td>
<td>16.6</td>
</tr>
<tr>
<td>Mier-Monterrey</td>
<td></td>
<td>90</td>
<td>650 MMcf/d</td>
<td></td>
<td></td>
<td></td>
<td>11.2</td>
</tr>
<tr>
<td>Endeavor (40%)</td>
<td></td>
<td>100</td>
<td>150 MMcf/d</td>
<td></td>
<td></td>
<td></td>
<td>2.8</td>
</tr>
<tr>
<td>KinderHawk Gathering</td>
<td></td>
<td>500</td>
<td>2.0 Bcf/d</td>
<td></td>
<td>2,600 GPM</td>
<td></td>
<td>Life of Lease</td>
</tr>
<tr>
<td>Eagle Hawk Gathering (25%)</td>
<td></td>
<td>410</td>
<td>1.2 Bcf/d – gas</td>
<td></td>
<td>750</td>
<td>60 MMBl/d – condensate</td>
<td>4,600 GPM</td>
</tr>
<tr>
<td>Red Cedar Gathering (49%)</td>
<td></td>
<td>70</td>
<td>150 MMcf/d – gas</td>
<td></td>
<td>110 MMBl/d – oil</td>
<td>20 MBB</td>
<td>5.8</td>
</tr>
<tr>
<td>Camino Real Gathering</td>
<td></td>
<td>1,350</td>
<td>80 MMcf/d</td>
<td></td>
<td>80 MMBl/d – oil</td>
<td>20 MBB</td>
<td>3.8</td>
</tr>
<tr>
<td>Altamont Gathering</td>
<td></td>
<td>6,780</td>
<td>4.3 Bcf/d – gas</td>
<td></td>
<td>115 MMBl/d – liquid</td>
<td>4,100 GPM</td>
<td>1.3 Bcf/d</td>
</tr>
<tr>
<td>Copano</td>
<td></td>
<td>430</td>
<td>140 MMcf/d – liquid</td>
<td></td>
<td>305 MMBl/d – gas</td>
<td>80 GPM</td>
<td>13.4</td>
</tr>
<tr>
<td>Hiland (Williston Basin)</td>
<td></td>
<td>2,000</td>
<td>305 MMBl/d – gas</td>
<td></td>
<td>240 MMBl/d – oil</td>
<td>80 GPM</td>
<td>13.4</td>
</tr>
</tbody>
</table>

(a) Excluding ethane.
(b) 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.

*Treating - Leased Units: 54 plants in service – Amine; 82 plants in service – MRU; 11 plants in service – Dew Point*
## Contracted Capacity and Term by Region

<table>
<thead>
<tr>
<th>Region</th>
<th>Contracted Capacity</th>
<th>Average Term Remaining</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Storage 355 Bcf</td>
<td>3 yr, 1 mo</td>
</tr>
<tr>
<td>North</td>
<td>Transport 19.7 Bcf/d</td>
<td>6 yr, 2 mo</td>
</tr>
<tr>
<td>South</td>
<td>Storage 52 Bcf</td>
<td>1 yr, 8 mo</td>
</tr>
<tr>
<td></td>
<td>Transport 13.5 Bcf/d</td>
<td>7 yr, 8 mo</td>
</tr>
<tr>
<td></td>
<td>LNG 18 Bcf</td>
<td>15 yr, 5 mo</td>
</tr>
<tr>
<td>West</td>
<td>Storage 45 Bcf</td>
<td>5 yr, 4 mo</td>
</tr>
<tr>
<td></td>
<td>Transport 17.4 Bcf/d</td>
<td>5 yr, 2 mo</td>
</tr>
<tr>
<td>Midstream</td>
<td>Purchases 2.5 Bcf/d</td>
<td>2 yr, 0 mo</td>
</tr>
<tr>
<td></td>
<td>Sales 3.0 Bcf/d</td>
<td>2 yr, 6 mo</td>
</tr>
<tr>
<td></td>
<td>Storage 101.8 Bcf</td>
<td>2 yr, 5 mo</td>
</tr>
<tr>
<td></td>
<td>Transport (a) 5.1 Bcf/d</td>
<td>6 yr, 10 mo</td>
</tr>
<tr>
<td></td>
<td>Processing 1.8 Bcf/d</td>
<td>6 yr, 1 mo</td>
</tr>
</tbody>
</table>

- Interstate Transport Contracts Avg. = 6 yr, 3 mo

### Net annual incremental re-contracting exposure (KM share)(b): (% of $7.7 billion Total KMI Segment EBDA)

<table>
<thead>
<tr>
<th>Region</th>
<th>2018</th>
<th>2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>North</td>
<td>(1.1%)</td>
<td>(0.1%)</td>
</tr>
<tr>
<td>South</td>
<td>(0.2%)</td>
<td>(0.7%)</td>
</tr>
<tr>
<td>West</td>
<td>(0.1%)</td>
<td>(0.1%)</td>
</tr>
<tr>
<td>Midstream</td>
<td>(0.3%)</td>
<td>(0.1%)</td>
</tr>
<tr>
<td>Total GPG</td>
<td>(1.7%)</td>
<td>(1.0%)</td>
</tr>
</tbody>
</table>

(a) Gathering contracts not included.
(b) Negative figures represent unfavorable re-contracting exposure. Includes transportation and storage contracts.
## Natural Gas Segment

### Projects Placed Into Service - 2016

<table>
<thead>
<tr>
<th>Region</th>
<th>Asset</th>
<th>Project</th>
<th>In-service Date</th>
<th>Capacity</th>
<th>Capital, KM Share ($MM)</th>
<th>EBITDA ($MM)</th>
</tr>
</thead>
<tbody>
<tr>
<td>North</td>
<td>TGP</td>
<td>South System Flexibility (MexGas)</td>
<td>Oct 2016</td>
<td>150 MDth/d</td>
<td>178.8</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Exelon (Venango)</td>
<td>Dec 2016</td>
<td>60 MDth/d</td>
<td>5.6</td>
<td></td>
</tr>
<tr>
<td></td>
<td>NGPL</td>
<td>Chicago Market Expansion</td>
<td>Nov 2016</td>
<td>238 MDth/d</td>
<td>34.6</td>
<td></td>
</tr>
<tr>
<td>South</td>
<td>SNG/EEC</td>
<td>MGAG Expansion</td>
<td>Dec 2016</td>
<td>1.7 MDth/d</td>
<td>1.8</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>SNG Expansion</td>
<td>Dec 2016</td>
<td>242 MDth/d</td>
<td>89.0</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>EEC Expansion (non-Shell)</td>
<td>Dec 2016</td>
<td>175 MDth/d</td>
<td>94.0</td>
<td></td>
</tr>
<tr>
<td>West</td>
<td>EPNG</td>
<td>Ramsey North expansion (Anadarko)</td>
<td>Apr-Oct 2016</td>
<td>450 MDth/d</td>
<td>3.5</td>
<td></td>
</tr>
<tr>
<td>Midstream</td>
<td>Texas Intrastate</td>
<td>Well / Market Connects</td>
<td>Throughout 2016</td>
<td>Various</td>
<td>7.6</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>TX Intrastate Crossover Project</td>
<td>3Q 2016</td>
<td>1,000 MDth/d</td>
<td>125.0</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Roosevelt Cryo plant</td>
<td>1Q 2016</td>
<td>45 MMcf/d</td>
<td>74.3</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>NGL stabilization exp. / Lavaca slug catcher mods</td>
<td>1Q 2016</td>
<td>1.5 Mbbbl/d</td>
<td>10.6</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Other System Expansions / Well Connects</td>
<td>Throughout 2016</td>
<td>Various</td>
<td>89.4</td>
<td></td>
</tr>
</tbody>
</table>

| Total Gas Pipeline Group | 714.2 | 158.6 |
# Natural Gas Segment

## Project Backlog – North Region

<table>
<thead>
<tr>
<th>Asset</th>
<th>Board Approval</th>
<th>Customer Execution</th>
<th>Project</th>
<th>Capital, KM Share ($MM)</th>
<th>Capacity</th>
<th>In-service Date</th>
<th>Project Status</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Susquehanna West</td>
<td>156.5</td>
<td>145 MDth/d</td>
<td>11/2017</td>
<td>Complete FERC Notice to Proceed received 1/4/17. Construction to begin 1Q 2017.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Lone Star (Cheniere Corpus Christi LNG)</td>
<td>133.8</td>
<td>300 MDth/d</td>
<td>7/2019</td>
<td>TGP FERC application filed 8/2016. LNG terminal construction underway.</td>
</tr>
<tr>
<td>KMLP</td>
<td>Completed</td>
<td>Completed</td>
<td>Sabine Pass Expansion</td>
<td>151.3</td>
<td>600 MDth/d</td>
<td>4Q 2019</td>
<td>KMLP FERC application filed 12/2016. LNG terminal construction underway.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Magnolia LNG Expansion</td>
<td>127.0</td>
<td>700 MDth/d</td>
<td>4Q 2020</td>
<td>Magnolia received DOE Non-FTA export authorization, 12/2016.</td>
</tr>
<tr>
<td>NGPL</td>
<td>Pending</td>
<td>Pending</td>
<td>Power Plant Interconnect Project</td>
<td>4.3</td>
<td>120 MDth/d</td>
<td>12/2017</td>
<td>Final contract execution and NGPL Board approval pending.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>LDC Interconnect Project</td>
<td>5.9</td>
<td>75 MDth/d</td>
<td>11/2018</td>
<td>Final contract execution and NGPL Board approval pending.</td>
</tr>
</tbody>
</table>

**Total North Region** | **1,618.6** | **EBITDA = $271.8 MM**
# Natural Gas Segment

## Project Backlog (Cont’d) – South, West & Midstream

<table>
<thead>
<tr>
<th>Asset</th>
<th>Board Approval</th>
<th>Customer Execution</th>
<th>Project</th>
<th>Capital, KM Share ($MM)</th>
<th>Capacity</th>
<th>In-service Date</th>
<th>Project Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>SNG</td>
<td>Completed</td>
<td>Completed</td>
<td>Fairburn Expansion Project</td>
<td>120.6</td>
<td>329-341 MDth/d</td>
<td>10/2018</td>
<td>Open season completed. FERC filing Feb 2017.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>SLNG Terminal for Elba Liquefaction</td>
<td>433.8</td>
<td></td>
<td>7/2018</td>
<td></td>
</tr>
<tr>
<td>Total South Region</td>
<td></td>
<td></td>
<td></td>
<td>1,389.2</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EBITDA = $195.6 MM</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EPNG</td>
<td>Completed</td>
<td>Completed</td>
<td>EPNG - Enviro Water Interconnect and Lateral Expansion</td>
<td>2.7</td>
<td>5 MDth/d</td>
<td>1/2017</td>
<td>Construction nearing completion.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>EPNG - South Mainline Expansion (formerly Upstream Sierrita)</td>
<td>132.4</td>
<td>271 MDth/d</td>
<td>4/2017, 7/2020</td>
<td>Open season closed, FTSA executed.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>EPNG - Wink Station Expansion</td>
<td>3.4</td>
<td>71 MDth/d</td>
<td>11/2017</td>
<td>Finalizing interconnect agreement.</td>
</tr>
<tr>
<td>Total West Region</td>
<td></td>
<td></td>
<td></td>
<td>158.3</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EBITDA = $36.2 MM</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Texas Intrastate</td>
<td>Completed</td>
<td>Completed</td>
<td>TX Intrastate Combined Crossover Project</td>
<td>182.1</td>
<td>1,000 MDth/d</td>
<td>3Q 2019</td>
<td>Phase I placed in service 3Q ’16.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Partial</td>
<td>Market / Supply connects</td>
<td>17.8</td>
<td>Varies</td>
<td>2017</td>
<td>Expansion capex for market / supply connects.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Williston Basin Oil (Hiland)</td>
<td>49.2</td>
<td>Varies</td>
<td>2017 - 2018</td>
<td>Crude oil well connections and system expansions.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Williston Basin Gas (Hiland)</td>
<td>35.6</td>
<td>Varies</td>
<td>2017 - 2018</td>
<td>Gas well connections and system expansions.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Other System Expansions and Well connects</td>
<td>56.2</td>
<td>Varies</td>
<td>2017</td>
<td>Expansions / extensions of existing gathering systems.</td>
</tr>
<tr>
<td>Total Midstream</td>
<td></td>
<td></td>
<td></td>
<td>340.9</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EBITDA = $40.7 MM</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Total Natural Gas Pipelines segment | 3,507.0 | EBITDA = $544.3 MM |
# New Firm Transport Capacity

## Firm Transport Capacity Commitments by Capacity Type

<table>
<thead>
<tr>
<th>Dec. 1, 2013 to Present</th>
<th>Existing Capacity (MDth/d)</th>
<th>Repurposed Capacity (MDth/d)</th>
<th>New Committed Capacity (MDth/d)</th>
<th>Total Capacity (MDth/d)</th>
<th>Capital, KM Share ($MM)</th>
<th>Wtd Avg. Contract Term (Yrs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>North</td>
<td>797</td>
<td>180</td>
<td>4,691</td>
<td>5,668</td>
<td>2,212</td>
<td>17.2</td>
</tr>
<tr>
<td>South</td>
<td>4</td>
<td>0</td>
<td>417</td>
<td>421</td>
<td>129</td>
<td>14.5</td>
</tr>
<tr>
<td>West</td>
<td>1,051</td>
<td>0</td>
<td>751</td>
<td>1,802</td>
<td>163</td>
<td>13.5</td>
</tr>
<tr>
<td>Midstream</td>
<td>70</td>
<td>0</td>
<td>750</td>
<td>820</td>
<td>284</td>
<td>17.2</td>
</tr>
<tr>
<td>Total Gas Pipeline Group</td>
<td>1,922</td>
<td>180</td>
<td>6,609</td>
<td>8,711</td>
<td>2,787</td>
<td>16.3</td>
</tr>
<tr>
<td>2016-only</td>
<td>343</td>
<td>180</td>
<td>327</td>
<td>850</td>
<td>125</td>
<td>15.2</td>
</tr>
</tbody>
</table>

## Firm Transport Capacity Commitments by Customer Type / End-use Market

<table>
<thead>
<tr>
<th>Dec. 1, 2013 to Present</th>
<th>LDC / End-user (MDth/d)</th>
<th>Producer (MDth/d)</th>
<th>Mexico (MDth/d)</th>
<th>LNG (MDth/d)</th>
<th>Total Capacity (MDth/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>North</td>
<td>910</td>
<td>2,173</td>
<td>600</td>
<td>1,985</td>
<td>5,668</td>
</tr>
<tr>
<td>South</td>
<td>421</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>421</td>
</tr>
<tr>
<td>West</td>
<td>126</td>
<td>861</td>
<td>815</td>
<td>0</td>
<td>1,802</td>
</tr>
<tr>
<td>Midstream</td>
<td>70</td>
<td>160</td>
<td>0</td>
<td>590</td>
<td>820</td>
</tr>
<tr>
<td>Total Gas Pipeline Group</td>
<td>1,527</td>
<td>3,194</td>
<td>1,415</td>
<td>2,575</td>
<td>8,711</td>
</tr>
<tr>
<td>2016-only</td>
<td>660</td>
<td>61</td>
<td>129</td>
<td>0</td>
<td>850</td>
</tr>
</tbody>
</table>
Products Pipelines

Segment Presentation
Products Pipelines
Segment Outlook

**Long-term Growth Drivers:**
- Increased demand for refined products volumes
- Development of shale play liquids transportation and processing (e.g. Utopia and KMCC / splitter)
- Tuck-in acquisitions (e.g. KM Phoenix Terminals)
- Expansion of refined products pipeline systems and Terminal Networks
- Repurposing portions of existing footprint in different product uses

**Project Backlog:**
- $318 million of identified growth projects over next two years\(^{(a)}\) (first year total Adjusted EBITDA $22.8 million\(^{(b)}\)), including:
  - Utopia
  - Multiple refined products Terminaling and Bio Fuels projects

---

(a) Includes KM share of non-wholly owned projects. Includes projects currently under construction.  
(b) KM Share.
Volumes / Revenues

2016 Actual Volumes (a)
- Refined Products (3): 79%
- Crude & Condensate (2): 16%
- NGL (1): 5%

2017 Plan Volumes (a)
- Refined Products (3): 80%
- Crude & Condensate (2): 15%
- NGL (1): 5%

2016 Actual Revenues (b)
- Refined Products (3): 64%
- Crude & Condensate (2): 25%
- NGL (1): 11%

2017 Plan Revenues (b)
- Refined Products (3): 65%
- Crude & Condensate (2): 24%
- NGL (1): 11%

(a) Pipeline throughput volumes only (not including terminal volumes).
(b) Includes terminal revenues:
1. NGL: Cochin, Cypress, Utopia.
3. Refined Product: SFPP, Calnev, Central Florida, Plantation, Parkway, KMAP, SE terminal, Transmix(Terminal), West coast Terminal.
Volumes / Markets

Refined Products:

- **2016**: Refined products volumes 1,651 MBbl/d, up 0.3% vs. 2015
  - Gasoline up 1.2%, diesel down 3.5%, jet fuel up 1.7%
- **2017**: 1,676 MBbl/d budgeted, 1.5% up vs. 2016
  - Budget volume sensitivity: 1% change = $7.5M

NGLs:

- **2016**: NGL volumes 108 MBbl/d, up 2.7% vs. 2015
  - Drivers: higher volumes on Cochin Pipeline
- **2017**: Budgeted volume to be up 5.6% vs. 2016
  - Drivers: Increased demand on Cochin; no forecasted turnaround in 2017 at Cypress Pipeline terminus

Crude / Condensate:

- **2016**: Crude / condensate vol. 323 MBbl/d, up 18.3% vs. 2015
  - Drivers: expansion projects on KMCC/ Double Eagle and acquisition of Double H pipeline
- **2017**: 312 MBbl/d budgeted, down 3.3% vs. 2016
  - Drivers: Decreased production from the Eagle Ford

---

(a) All volumes reflect KM-share for joint ventures.
(b) Parkway divested July 2016. Parkway volumes and revenue not included in 2016 and 2017.
(c) Combined throughput of KM crude/ condensate pipelines: KMCC, Double Eagle and Double H.
**Historical Demand and 2017 EIA Outlook**

### U.S. Refined Products Consumption (MMBbl/d)

<table>
<thead>
<tr>
<th>Year</th>
<th>Motor Gasoline</th>
<th>Distillate Fuel Oil</th>
<th>Jet Fuel</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td>10</td>
<td>7</td>
<td>3</td>
<td>20</td>
</tr>
<tr>
<td>2010</td>
<td>9</td>
<td>6</td>
<td>2</td>
<td>17</td>
</tr>
<tr>
<td>2011</td>
<td>8</td>
<td>5</td>
<td>1</td>
<td>14</td>
</tr>
<tr>
<td>2012</td>
<td>7</td>
<td>4</td>
<td>0</td>
<td>11</td>
</tr>
<tr>
<td>2013</td>
<td>6</td>
<td>3</td>
<td>-1</td>
<td>10</td>
</tr>
<tr>
<td>2014</td>
<td>5</td>
<td>2</td>
<td>-2</td>
<td>9</td>
</tr>
<tr>
<td>2015</td>
<td>4</td>
<td>1</td>
<td>-3</td>
<td>8</td>
</tr>
<tr>
<td>2016</td>
<td>3</td>
<td>0</td>
<td>-4</td>
<td>7</td>
</tr>
<tr>
<td>2017E</td>
<td>2</td>
<td>-1</td>
<td>-5</td>
<td>6</td>
</tr>
</tbody>
</table>

### U.S. Refined Products Demand Outlook

<table>
<thead>
<tr>
<th></th>
<th>2015</th>
<th>2016</th>
<th>2017E</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mogas</td>
<td>1.1%</td>
<td>0.7%</td>
<td>0.7%</td>
</tr>
<tr>
<td>Distillate</td>
<td>-3.5%</td>
<td>3.2%</td>
<td>1.6%</td>
</tr>
<tr>
<td>Jet Fuel</td>
<td>3.6%</td>
<td>0.5%</td>
<td>0.1%</td>
</tr>
<tr>
<td>Total</td>
<td>0.1%</td>
<td>1.4%</td>
<td>0.8%</td>
</tr>
</tbody>
</table>

### FERC Tariff Index

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>FERC Rate Increase</td>
<td>4.58%</td>
<td>-2.01%</td>
<td>0.20%</td>
</tr>
</tbody>
</table>

---

(a) EIA, Table 4a. U.S. Crude Oil and Liquid Fuel Supply, Consumption, and Inventories and Figure 15 U.S. Liquids Fuel Consumption Growth, January 2017.

(b) BLS, January 2017 release; expected rate increase based on current regulatory information, based on PPI FG +1.23%.
KMCC / Double Eagle
Location, Contracts, Connectivity

Kinder Morgan Crude & Condensate (KMCC)
- Capacity = 300 MBbl/d, expandable to 360 MBbl/d; Approximately 90% of current capacity committed
- Provides Eagle Ford producers access to Houston Ship Channel (Refineries, Export Opportunities), KM Splitter, Phillips 66 Sweeny Refinery

Double Eagle Pipeline
- Capacity 100 MBbl/d; 75% of capacity committed; 50/50 JV w/ Magellan
- Provides Eagle Ford producers access to Magellan Corpus Christi Terminal and KMCC

2016 Milestones
- KMCC / Double Eagle volumes grew 15.3% year over year as the full year impact of expansion projects and new customer commitments were realized
- KMCC volumes grew from 2015 to 2016, despite a 22% decline across the Eagle Ford (b)

2017 Plans
- Maintain volumes
- Focus on superior location, customer base, and connectivity

KM Eagle Ford Crude/ Condensate Volumes (a)

(a) Combined throughput of KMCC and Double Eagle.
(b) EIA, Drilling Report, January 2017.
Utopia Pipeline Project

- **Project Scope**
  - 50/50 JV with Riverstone Holdings closed on June 28, 2016
  - 215 mile new build and existing 67 mile 12" pipeline
  - Will transport ethane and ethane-propane mix from points in Harrison County, Ohio to Windsor, Ontario, Canada
  - Supported by long-term, fee-based transportation agreement
  - Initial pipeline capacity of 50 MBbl/d; expandable to 75 MBbl/d
  - Approximate $540 million\(^{(a)}\) investment

- **Market Drivers**
  - Utopia will provide a new feedstock source for petrochemical companies in Ontario, and a new market outlet for Utica NGL producers
  - Common carrier pipeline system is supported by a long-term (>20 years), fee-based transportation services agreement

- **Project Status and Timeline**
  - ROW acquisition ongoing
  - Commencement of construction 1Q 2017
  - Planned in-service date of January 2018

\(^{(a)}\) 100% project cost, excluding AFUDC.
West Coast Region Assets

Pacific Operation: Kinder Morgan operates ~3,440 miles of refined products pipelines that serve Arizona, California, Nevada, New Mexico, Oregon, Washington and Texas

- **SFPP pipeline System:**
  - **North Line:** transports products from San Francisco Bay area refineries to delivery points in northern California and Nevada
  - **San Diego Line:** pipeline serving major population areas in Orange County and San Diego
  - **Oregon Line:** pipeline transports products from marine terminals in Portland to Eugene, Oregon
  - **West Line:** pipeline transports products from the Los Angeles Basin to Arizona
  - **East Line:** pipeline originating in El Paso, TX transports products to Arizona

- **13 truck-loading terminals**

- **CALNEV pipeline system:**
  - Transports refined products from Los Angeles refineries and marine terminals to terminals in Barstow, CA, and Las Vegas, NV

- **West Coast Liquid Terminals:**
  - Fee-based liquid terminals along the West Coast of the U.S. with a combined total capacity of approximately 10.1 million barrels of storage for both petroleum products and chemicals

- **2017 Plan includes 1.4 % volume increase, 0.7% margin increase vs. 2016 and 100% fee-based margin**
Central Region Assets

NGL Pipelines
- Cochin pipeline: 1,810-mile multi-product pipeline between Metamora, OH and Fort Saskatchewan, Alberta currently shipping light condensate westbound from Kankakee County Illinois to Fort Saskatchewan
- Utopia pipeline (under construction): 215-mile new build, 12-inch diameter pipeline from Harrison County, OH to Kinder Morgan’s existing pipeline and facilities in Fulton County, OH which extend an additional 67 miles to Windsor, Ontario
- Cypress pipeline: 100-mile natural gas liquids pipeline originating at storage facilities in Mont Belvieu, TX and extending east to Sulphur, LA

Crude & Condensate Operations
- Kinder Morgan Crude & Condensate pipeline (KMCC): 250-mile pipeline that originates in the Eagle Ford Shale and delivers crude/condensate to multiple terminals with access to refineries, petrochemical plants and docks on the Texas Gulf Coast
- Double Eagle: 190-mile pipeline that is a 50/50 joint venture between Kinder Morgan and Magellan Midstream Partners, delivers Eagle Ford shale condensate to customers in Corpus Christi, TX and KMCC
- Double H: 510-mile pipeline which transports crude Oil from the Bakken oil production areas near Dore, ND to terminal near Guernsey, WY with connection points including Pony Express Pipeline to Cushing, OK and the Phillips 66 refinery near Ponca City, OK
- Condensate Splitter: consists of two 50MBbl/d units which split condensate into its various components supported by long-term, fee-based agreement with BP North America

2017 Plan includes 100% fee-based, 99% committed margin
East Coast Region Assets

Southeast Operations:

- **Plantation Pipe Line Company**: 3,180-mile refined petroleum products pipeline, which originates in Louisiana and ends in the Washington, D.C. area.
- **Central Florida Pipeline (CFPL)**: 210-mile petroleum pipeline that transports gasoline, batched denatured ethanol, diesel fuel and jet fuel from Tampa to Orlando.
- **Southeast Terminals**: 32 terminals throughout the Southeast United States located along the Plantation and Colonial Pipeline systems which handle gasoline, diesel, jet fuel and ethanol with a total storage capacity of more than 10.8 million barrels.
- **Kinder Morgan Transmix**: facilities which process Transmix into marketable refined products in Colton CA, St Louis, MO, Greensboro, NC, Woodbine, MD and Richmond, VA.

2017 Plan includes 7.9% volume increase, 5.7% margin increase and 87% fee-based margin.
Terminals

Segment Presentation
Terminals
Segment Outlook

**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**
- $1.4 billion of identified growth projects over the next two years\( ^{(a)} \), including:
  - Houston Ship Channel network expansion
  - Edmonton merchant crude terminal
  - Jones Act tanker builds

---

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

---

**KM Terminal Facilities**

<table>
<thead>
<tr>
<th>Type</th>
<th>Terminals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulk( ^{(a)} )</td>
<td>37</td>
</tr>
<tr>
<td>Liquids</td>
<td>51</td>
</tr>
<tr>
<td>Total KMT</td>
<td>88</td>
</tr>
<tr>
<td>KMPP</td>
<td>67 Liquid Terminals</td>
</tr>
<tr>
<td>Total KM</td>
<td>155 Terminals</td>
</tr>
</tbody>
</table>

16 Jones Act Tankers\( ^{(b)} \)

\( ^{(a)} \) Excludes terminals held for divestiture.

\( ^{(b)} \) Includes 4 new tankers to be delivered in 2017.
Stable Fee-Based Business

- ~2/3 of KMT’s 2017 budgeted EBDA is supported by take-or-pay contracts

**Liquids**
- 73% Take-or-pay
  - fixed monthly lease payments (MWC)
  - minimum throughput guarantees
  - Jones Act tanker charters
- 27% Other fee-based
  - ancillary fees for blending, additives, dock services, etc.
  - throughput fees

**Bulk**
- 37% Take-or-pay
  - minimum throughput guarantees
- 23% Requirements
  - tied to petroleum coke or steel production
- 40% Other fee-based
  - throughput & ancillaries

KMT 2017 Budgeted EBDA = $1,178 million

Note: All data is based on 2017 budget.
Diversified Revenues

- Diversified revenues across liquids and bulk

### 2017 Budget

<table>
<thead>
<tr>
<th>Revenue Category</th>
<th>2017 Budget ($ millions)</th>
<th>(percent)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Liquids</td>
<td>$1,426</td>
<td>74%</td>
</tr>
<tr>
<td>Bulk</td>
<td>$500</td>
<td>26%</td>
</tr>
<tr>
<td>Total Revenue</td>
<td>$1,926</td>
<td>100%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Top-10 Customers</th>
<th>Average remaining contract term (years)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>$911</td>
<td>47%</td>
</tr>
</tbody>
</table>

- **Liquids**: 3.7 years
- **Bulk**: 4.9 years

---

(a) 2017 budget includes non-controlling interests in certain terminals.
(b) No single customer is greater than 9.5% of revenues.
(c) Budget weighted average as of Jan 1, 2017.
Focused on U.S. Refining

KM Terminals’ logistics infrastructure serves the world’s most advantaged upstream / downstream industries

- Supply of crude oil and feedstocks
- Product storage and blending
- Advantaged market access

Note: Relative sizes are based on 2017 liquids budgeted revenues.
KMT Presence in Liquids Hubs

KMT Liquids
- 90 million Bbls of capacity
- ~1.0 billion Bbls throughput
- 97.5% utilization\(^{(a)}\)
- $1.43 billion revenues
- $957 million EBDA

All data is based on 2017 budget.
\(^{(a)}\) Size is relative to revenues.
\(^{(b)}\) Terminal utilizations reflect tankage unavailable for lease due to API inspections and routine maintenance.
**High Demand Liquids Hubs**

Critical infrastructure to industry and our customers, 100% contracted

- **Houston Ship Channel** – largest integrated refined product terminaling system in the world
- **New York Harbor** – global refined product clearing hub with liquid, transparent markets
- **Edmonton** – largest independent Canadian merchant crude terminaling system

<table>
<thead>
<tr>
<th>Terminal</th>
<th>EBDA ($ millions)</th>
<th>Total Terminal Capacity (million Bbls)</th>
<th>Capacity added since 2010 (million Bbls)</th>
<th>Average Remaining Contract (years)</th>
<th>Average Utilization (2010-2017B)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Houston Ship Channel</td>
<td>$336</td>
<td>43</td>
<td>16.7</td>
<td>5.5</td>
<td>96.8%</td>
</tr>
<tr>
<td>New York Harbor</td>
<td>$121</td>
<td>16</td>
<td>2.9</td>
<td>2.4</td>
<td>95.8%</td>
</tr>
<tr>
<td>Edmonton</td>
<td>$100</td>
<td>7</td>
<td>5.1</td>
<td>5.0&lt;sup&gt;(d)&lt;/sup&gt;</td>
<td>100%</td>
</tr>
</tbody>
</table>

---

Terminal utilizations reflect tankage unavailable for lease due to API inspections and routine maintenance

---

(a) Based on 2017 budget.
(b) Includes tankage currently under construction and to be completed in 2017.
(c) As of Jan 1, 2017.
(d) Excludes Base Line Terminal which will be in service beginning in the 1st quarter 2018 – 7.5 year average contract life.
KMT’s Houston Ship Channel terminal network is the largest integrated refined product terminaling system in the world: ~43 million barrels of capacity

- **Fee-Based Business**
  - Tank leases: term-contracted, take-or-pay commitments
  - Ancillary fees: ship & barge loading & unloading, blending, transfers

- **Customer Value in Physical Connectivity**
  - Multimodal: pipeline, tanker, barge, rail and truck
  - Multisource: local refineries, chemical plants, Mont Belvieu, imports

### Connectivity

- 20 **inbound pipelines** – 10 Houston area refineries and local chemical plants
- 15 **outbound pipelines** – Texas, mid-continent 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 markets
- 9 **bay truck rack** – averaging 90 thousand bpd of products to local Houston markets
- 3 **unit train facilities** – crude oil, condensates and ethanol
Houston – Market Connectivity

A market-making hub serving our customers’ businesses

- **Inbound:** products and blendstocks from refineries, chemical plants, renewables, and NGLs
  - staging, storage, blending services, buy/sell transfers
- **Outbound:** pipeline, truck, rail, ship and barge to domestic and international markets

Supply

- Renewables
- Chemicals

Value-added terminaling and blending services matching Houston’s petroleum and petrochemical complex with global markets

KMT throughputs: 459 million Bbls

Demand

- Local
- Jones Act

KMT Customers:
- refiners
- traders
- international majors
- chemical companies
- biofuels companies

Note: Commodity and market supply and demand scaling is indicative.

- Supply representative of KMT’s Houston Ship Channel business.
- Demand based on Texas Gulf Coast gasoline and distillate markets, source EIA.
Texas refining base becoming the world’s advantaged supplier of refined products

- Houston-Galveston Port District (a):
  - ~ 40% of PADD 3 distillate exports
  - ~ 55% of PADD 3 gasoline exports

Houston-Galveston Primary Export Markets

Department of Census and EIA, 2016 LTM thru Oct-16, Gasoline includes blendstocks.
(a) District includes the Port of Corpus Christi.
Houston – Expansion

Adding dock capacity with KMET, Pit 11 / North Docks projects, and other debottlenecking

- Expanding ship loading capacity to meet long-term export demand growth

**Pit 11 / North Docks**
($258 million KM capital)
- Adds ~2.0 million Bbls of tankage
- 3 cross-channel refined product pipelines
- 2 new ship docks located at WATCO’s Greensport site
- 4Q 2017 in-service

**KMET**
($245 million KM capital)
- Adds ~1.5 million Bbls of tankage
- Pipeline connectivity with Pasadena and Galena Park
- 1 new ship dock
- 1 new barge dock with 2 berths
- 1Q 2017 in-service
New York Harbor (NYH) – Physical Connectivity

A global refined product clearing hub with liquid, transparent markets: KMT with ~16 million barrels of capacity

- Fee-Based Business
  - Monthly tank leases: term-contracted, take-or-pay commitments
  - Ancillary fees: ship & barge loading & unloading, blending, transfers

- Customer Value in Physical Connectivity
  - Multimodal: pipeline, tanker, barge, rail and truck
  - Multisource: local refineries, PADD 3 pipeline receipts, imports, Jones Act vessels

Connectivity

- 5 ship docks & 11 barge berths
  - imports, exports and Jones Act movements
- 11 pipeline connections
  - inbound and outbound connections including Colonial, Buckeye and Sunoco systems
- 2 truck racks
  - KM:BP JV facilities in Carteret, NJ and Brooklyn, NY
- 1 unit train facility
  - Ethanol receipts with pipeline connections to Carteret
NYH – Market Connectivity

A global refined product clearinghouse

**Inbound:** products and blendstocks
- Imports from Canada, Europe and worldwide
- East Coast refineries
- Colonial Pipeline
- Staging, storage, blending services, buy/sell transfers

**Outbound:** pipeline, truck rack, and barge
- Local metropolitan markets
- Regional pipelines
- Inter-harbor transfers
- Jones Act voyages to New England
- CME delivery point for RBOB
- Customer value in market connectivity

**KMT throughput:**
- **Imports:**
  - Pipeline
  - Ethanol
  - Local Refineries

**Demand:**
- Jones Act
- Jet Demand
- Distillate Demand
- Gasoline Demand
- Exports

**Value-added terminaling and blending services matching worldwide supply with local customers and markets**

**KMT Customers:**
- refiners
- traders
- international majors
- biofuels companies
- chemical companies

---

Note: Commodity and market supply and demand scaling is indicative.
- Representative of U.S. Mid-Atlantic refined product markets, source EIA.
Edmonton – Physical Connectivity

KMT has the largest independent Canadian merchant crude terminaling system with ~7 million barrels of capacity\(^{(a)}\)

- **Fee-Based Business**
  - Monthly tank leases: term-contracted, take-or-pay commitments
  - Ancillary fees: blending services
- **Customer Value in Physical Connectivity**
  - Multimodal: pipeline and rail
  - Multisource: SAGD, mining, syncrude & conventional

**Edmonton Crude Takeaway Capacity\(^{(a)}\)**

- **12 inbound crude pipelines**\(^{(c)}\)
- **6 outbound connections including Trans Mountain and Trans Mountain Expansion**\(^{(b)}\)
- Blending and staging services
- Local refinery demand
- Crude-by-rail origination
- Key JV Partners in Imperial & Keyera

---

(a) Increasing to ~12 million Bbls with the addition of Base Line Terminal. Excludes KM Canada Trans Mountain Pipeline regulated tankage.

(b) Source: CAPP.

(c) Total pipeline connections vary by individual facility.
Edmonton – Market Connectivity

A Market-making Crude Hub for Western Canada

- **Inbound**: connected to a majority of Alberta production
  - Staging, storage, blending services, buy/sell transfers
- **Outbound**: pipeline and rail connections to markets
  - Trans Mountain expansion to tidewater opens foreign markets

U.S. & Canada Refinery Runs by Crude Source (MBbl/d)(a)

Note: Commodity and market supply and demand scaling is indicative.
- Representative of Western Canada’s crude production and markets, source CAPP.

(a) Source: CAPP.
Edmonton – Expansion

**Base Line Crude Terminal**
($341 million\(^{(a)}\) KM capital)

- Joint Venture with Keyera
- 4.8 million Bbls crude terminal
  - 12 x 400,000 Bbl tanks
  - expansion options to 6.6 million Bbls
  - connections with KMT terminals and rail facilities, Trans Mountain and other pipelines
- 2018 phased in-service completion
  - 100% contracted
  - 7.5-year average contract length

\(^{(a)}\) Includes some capital invested by KM outside of the 50/50 JV. Certain adjustments have been made for estimated realized CAD/USD FX rates.
Tankers – Jones Act Markets

KM’s Jones Act fleet to reach 16 tankers in 2017

- Demand has fallen alongside Eagle Ford production declines
  - Vessels have shifted to U.S. Gulf and West Coast product trade
  - New vessel deliveries adding to near-term market length
  - Short-term expected shift of ATB charters toward Tankers
  - Long-term development of extended Jones Act markets

**Jones Act Deployment**

- **ATBs**
  - U.S. Gulf Product
  - Chemicals
  - West Coast
  - U.S. Gulf Crude

- **Tankers**
  - Gulf Coast Crude
  - Gulf Coast Product
  - West Coast
  - Military Sealift Command

**U.S. Jones Act Fleet**

- 53 ATBs - 10.4 million Bbls
- 48 tankers - 15.8 million Bbls

**American Endurance**

---

(a) Includes vessels currently under construction, excludes tankers currently in ANS crude service, and does not reflect any retirements / rationalization.
(b) Service relative to capacity. Source data: Navigistics Consulting’s Wilson Gillette Report, December 2016.
Tankers – APT Jones Act Fleet

All of APT’s available vessels are sailing under time-charter with limited 2017 exposure

- Average term contract length of 2.8 years across 16-vessels
- 4 new vessels to be delivered in ‘17
  - American Freedom
  - Palmetto State
  - American Liberty
  - American Pride
- Currently-uncontracted vessels:
  - $2.9 million or 0.2% exposure to KMT’s 2017 budgeted EBDA
- Marketing
  - Short-term charters
  - Bundled terminaling services
  - Prompt market voyages

### KM Fleet Charter Status

<table>
<thead>
<tr>
<th>Vessel</th>
<th>Charter Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Palmetto State</td>
<td>1x2-yr</td>
</tr>
<tr>
<td>American Freedom</td>
<td>1x2-yr</td>
</tr>
<tr>
<td>American Endurance</td>
<td>3x1-yr</td>
</tr>
<tr>
<td>Bay State</td>
<td>3x1-yr</td>
</tr>
<tr>
<td>Garden State</td>
<td>3x1-yr</td>
</tr>
<tr>
<td>Magnolia State</td>
<td>3x1-yr</td>
</tr>
<tr>
<td>Lone Star State</td>
<td>1x1-yo</td>
</tr>
<tr>
<td>Empire State</td>
<td>2x2-yr</td>
</tr>
<tr>
<td>Evergreen State</td>
<td>3x1-yr</td>
</tr>
<tr>
<td>American Liberty</td>
<td>1x1-yr</td>
</tr>
<tr>
<td>Florida</td>
<td></td>
</tr>
<tr>
<td>Pelican State</td>
<td>1x1-yr</td>
</tr>
<tr>
<td>American Pride</td>
<td></td>
</tr>
<tr>
<td>Pennsylvania</td>
<td></td>
</tr>
<tr>
<td>Sunshine State</td>
<td></td>
</tr>
<tr>
<td>Golden State</td>
<td>3 mo</td>
</tr>
</tbody>
</table>

- under construction
- term charter
- charter option(s)
- uncontracted
KMT’s diversified, multimodal ethanol service offerings capture ~31% of U.S. demand

- Increasing midstream solutions needed to meet RFS
  - Ethanol mandates require higher level ethanol blends (E15 and E85 market penetration)
  - Advanced biofuel mandates require increasing imports of biodiesel, qualifying feedstocks, and Brazilian ethanol
Bulk Industry Hubs

Pacific Northwest
- Pacific Northwest: 20%
- Gulf & Lower River: 28%
- Mid Atlantic: 18%
- Nucor Services: 13%
- Other: 21%

KMT Bulk
- 54 million tons handled
- $500 million revenues

All data based on 2017 budget. Excludes terminals to be contributed to WATCO. Size relative to revenues.
Petroleum Coke – Value Chain

KMT is the largest U.S. petcoke handler

Top U.S. Petcoke Export Markets

Kinder Morgan petcoke tonnage (~38% of production)

KMT Petcoke Revenues

Requirements 49%
Take-or-Pay 38%
Fee-Based 13%

Source: EIA.
Vancouver Wharves

A diversified Canadian multi-commodity export hub

- Strategically located in the Port of Vancouver for trans-Pacific trade growth
- 6 million tons of export capacity
- 4 separate berths handling multiple commodities
  - Copper exports and zinc concentrate imports
  - Diesel exports and biodiesel imports
  - 3.0 million tons sulfur export capacity
  - 1.5 million tons wheat and canola export capacity
- $190 million in KMT investment since acquisition
  - connecting key Canadian industries to global markets
  - import / export expansion available
## Terminals Segment Historical Growth

<table>
<thead>
<tr>
<th>Year</th>
<th>2013 Actual</th>
<th>2014 Actual</th>
<th>2015 Actual</th>
<th>2016 Actual</th>
<th>2017 Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>Revenue (net)</td>
<td>$1,388,319</td>
<td>$1,689,930</td>
<td>$1,843,578</td>
<td>$1,878,836</td>
<td>$1,926,469</td>
</tr>
<tr>
<td>Opex</td>
<td>576,822</td>
<td>681,381</td>
<td>760,094</td>
<td>710,138</td>
<td>708,976</td>
</tr>
<tr>
<td>Adjusted EBITDA</td>
<td>$811,497</td>
<td>$1,008,549</td>
<td>$1,083,484</td>
<td>$1,168,698</td>
<td>$1,217,493</td>
</tr>
<tr>
<td><strong>EBDA before Certain Items</strong></td>
<td><strong>$797,875</strong></td>
<td><strong>$978,854</strong></td>
<td><strong>$1,054,771</strong></td>
<td><strong>$1,132,871</strong></td>
<td><strong>$1,178,134</strong></td>
</tr>
<tr>
<td>Sustaining Capital</td>
<td>104,654</td>
<td>140,721</td>
<td>141,940</td>
<td>141,691</td>
<td>167,596</td>
</tr>
<tr>
<td>DCF</td>
<td>$693,221</td>
<td>$838,133</td>
<td>$912,831</td>
<td>$991,180</td>
<td>$1,010,538</td>
</tr>
<tr>
<td>Expansion Capital</td>
<td>$817,137</td>
<td>$728,273</td>
<td>$570,899</td>
<td>$699,333</td>
<td>$688,049</td>
</tr>
<tr>
<td>Operating Margin</td>
<td>58.45%</td>
<td>59.68%</td>
<td>58.77%</td>
<td>62.20%</td>
<td>63.20%</td>
</tr>
<tr>
<td>Growth from prior year (earnings before DD&amp;A)</td>
<td>6.06%</td>
<td>22.68%</td>
<td>7.76%</td>
<td>7.40%</td>
<td>4.00%</td>
</tr>
<tr>
<td>Internal</td>
<td>5.52%</td>
<td>16.20%</td>
<td>3.23%</td>
<td>4.98%</td>
<td>3.72%</td>
</tr>
<tr>
<td>Acquisition</td>
<td>0.53%</td>
<td>6.48%</td>
<td>4.53%</td>
<td>2.42%</td>
<td>0.28%</td>
</tr>
</tbody>
</table>

**EBDA CAGR**

12.22% (c)

(a) Includes terminals contributed to WATCO through closing.
(b) Excludes JV sustaining capital.
(c) 15-year cumulative average growth (2002-2017).
## Terminals Projects Placed in Service during 2016

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Product</th>
<th>Capacity</th>
<th>Capital (MM) (a)</th>
<th>First Full Year EBITDA</th>
<th>In Service</th>
<th>Avg. Contract Length (b)</th>
</tr>
</thead>
<tbody>
<tr>
<td>North Docks 1 &amp; 2 (Greens Port)</td>
<td>Refined Products</td>
<td>200K bpd</td>
<td>$72.4</td>
<td>Q1/16 - Q4/16</td>
<td>7.5</td>
<td></td>
</tr>
<tr>
<td>South Hill Tankage (Wilmington, NC)</td>
<td>Methanol</td>
<td>0.1MM Bbls</td>
<td>$6.6</td>
<td>Q1/16</td>
<td>7</td>
<td></td>
</tr>
<tr>
<td>Galena Park Infrastructure Improvements</td>
<td>Gasoline Blendstock</td>
<td>n/a</td>
<td>$40.0</td>
<td>Q2/16</td>
<td>7</td>
<td></td>
</tr>
<tr>
<td>Jones Act Tankers (4) (c)</td>
<td>Crude/Products</td>
<td>1.3MM Bbls</td>
<td>$621.2</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Magnolia State</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Garden State</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bay State</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>American Endurance</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Carteret Product Tanks</td>
<td>Gasoline</td>
<td>0.3MM Bbls</td>
<td>$32.1</td>
<td>Q3/16</td>
<td>5</td>
<td></td>
</tr>
<tr>
<td>Rubicon GLT Expansion</td>
<td>MDI/Aniline</td>
<td>0.1MM Bbls</td>
<td>$14.4</td>
<td>Q3/16</td>
<td>14</td>
<td></td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td></td>
<td></td>
<td>$786.8</td>
<td>$86.4</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

(a) Net to KM, includes capitalized overhead.
(b) Initial term.
(c) Capital for State Class tankers include a portion of allocated purchase price.
## Terminals Project Backlog

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Product</th>
<th>Capacity</th>
<th>Capital (MM)</th>
<th>First Full Year EBITDA</th>
<th>Expected In Service</th>
<th>Avg. Contract Length</th>
</tr>
</thead>
<tbody>
<tr>
<td>Houston Export Terminal</td>
<td>Blendstock</td>
<td>1.5MM Bbls</td>
<td>$244.7</td>
<td></td>
<td>Q1/17</td>
<td>11</td>
</tr>
<tr>
<td>Jones Act Tankers (4)</td>
<td>Crude/Products</td>
<td>1.3MM Bbls</td>
<td>$604.6</td>
<td></td>
<td>Q2/17</td>
<td>5</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Palmetto State</td>
<td>Q2/17</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>American Endurance</td>
<td>Q2/17</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>American Freedom</td>
<td>Q3/17</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>American Liberty</td>
<td>Q4/17</td>
</tr>
<tr>
<td>Pit 9 Pasadena Tank Project</td>
<td>Refined Products</td>
<td>0.3MM Bbls</td>
<td>$25.7</td>
<td></td>
<td>Q2/17</td>
<td>7</td>
</tr>
<tr>
<td>Galena Park Ship Dock 3 Expansion</td>
<td>Lube Oil</td>
<td>25K bpd</td>
<td>$7.3</td>
<td></td>
<td>Q3/17</td>
<td>15</td>
</tr>
<tr>
<td>Jefferson Street Truck Rack VRU</td>
<td>Gasoline</td>
<td>37K bpd</td>
<td>$5.7</td>
<td></td>
<td>Q3/17</td>
<td>n/a</td>
</tr>
<tr>
<td>Pit 11 Development</td>
<td>Refined Products</td>
<td>2.0MM Bbls</td>
<td>$185.1</td>
<td></td>
<td>Q4/17</td>
<td>7</td>
</tr>
<tr>
<td>Edmonton Base Line Terminal (d)</td>
<td>Crude</td>
<td>4.8MM Bbls</td>
<td>$341.4</td>
<td></td>
<td>Q4/18</td>
<td>7.5</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td></td>
<td></td>
<td><strong>$1,414.4</strong></td>
<td><strong>$138.9</strong></td>
<td></td>
<td>7</td>
</tr>
</tbody>
</table>

(a) Net to KM, includes capitalized overhead.
(b) Certain adjustments have been made for estimated realized CAD:USD FX rates.
(c) Initial term.
(d) Includes some capital invested by KM outside of the 50/50 JV.
## Terminals Liquids Throughput

<table>
<thead>
<tr>
<th></th>
<th>Actual 2016(^{(a)})</th>
<th>Budget 2017(^{(a)})</th>
<th>Amt</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chemical</td>
<td>44,147,450</td>
<td>47,495,296</td>
<td>3,347,847</td>
<td>7.0%</td>
</tr>
<tr>
<td>Distillate</td>
<td>139,270,328</td>
<td>158,940,986</td>
<td>19,670,658</td>
<td>12.4%</td>
</tr>
<tr>
<td>Gasoline</td>
<td>422,735,919</td>
<td>480,222,777</td>
<td>57,486,858</td>
<td>12.0%</td>
</tr>
<tr>
<td>Fuel Grade Ethanol / Bio-diesel</td>
<td>66,697,344</td>
<td>68,895,473</td>
<td>2,198,129</td>
<td>3.2%</td>
</tr>
<tr>
<td>Petroleum(^{(b)})</td>
<td>219,870,740</td>
<td>222,672,613</td>
<td>2,801,872</td>
<td>1.3%</td>
</tr>
<tr>
<td>Other</td>
<td>3,497,996</td>
<td>4,440,026</td>
<td>942,030</td>
<td>21.2%</td>
</tr>
<tr>
<td>Vegetable Oils</td>
<td>5,148,847</td>
<td>5,277,896</td>
<td>129,049</td>
<td>2.4%</td>
</tr>
<tr>
<td>Animal Fats</td>
<td>3,426</td>
<td>-</td>
<td>(3,426)</td>
<td>0.0%</td>
</tr>
<tr>
<td>Oil Fields</td>
<td>222,540</td>
<td>371,100</td>
<td>148,560</td>
<td>40.0%</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
<td><strong>901,594,591</strong></td>
<td><strong>988,316,168</strong></td>
<td><strong>86,721,577</strong></td>
<td><strong>8.8%</strong></td>
</tr>
</tbody>
</table>

**KMLT Throughput (bbls)**

<table>
<thead>
<tr>
<th></th>
<th>Actual 2016(^{(a)})</th>
<th>Budget 2017(^{(a)})</th>
<th>Amt</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity Utilization Rate(^{(c)})</td>
<td>94.8%</td>
<td>97.5%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Capacity (MM bbls)</td>
<td>87.8</td>
<td>90.5</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Key Take-aways:**

- Gasoline and distillate volume growth led by liquids hub expansions and export volume growth
- Chemicals growth reflects continued industry growth and terminaling demand
- Biofuels volumes commensurate with RFS mandates
- Petroleum crude throughput growth at Edmonton reflecting marginal increases to Alberta production

\(^{(a)}\) Excludes terminals divested or held for divestiture.
\(^{(b)}\) Primarily crude oil and black oils.
\(^{(c)}\) Terminal utilizations reflect tankage unavailable for lease due to API inspections and routine maintenance.
Terminals Bulk Tonnage

<table>
<thead>
<tr>
<th>Material</th>
<th>Actual 2016 (a)</th>
<th>Budget 2017 (a)</th>
<th>Amt</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>7,857,117</td>
<td>6,823,538</td>
<td>(1,033,579)</td>
<td>-15.1%</td>
</tr>
<tr>
<td>Petcoke</td>
<td>13,523,672</td>
<td>14,155,518</td>
<td>631,846</td>
<td>4.5%</td>
</tr>
<tr>
<td>Cement (Including Clinker)</td>
<td>966,392</td>
<td>972,383</td>
<td>5,991</td>
<td>0.6%</td>
</tr>
<tr>
<td>Fertilizers</td>
<td>2,382,631</td>
<td>2,470,764</td>
<td>88,132</td>
<td>3.6%</td>
</tr>
<tr>
<td>Salt</td>
<td>2,051,992</td>
<td>2,412,738</td>
<td>360,745</td>
<td>15.0%</td>
</tr>
<tr>
<td>Ores/Metals (Bulk &amp; Break-Bulk)</td>
<td>14,855,106</td>
<td>15,290,381</td>
<td>435,275</td>
<td>2.8%</td>
</tr>
<tr>
<td>Soda Ash</td>
<td>4,694,914</td>
<td>4,461,777</td>
<td>(233,137)</td>
<td>-5.2%</td>
</tr>
<tr>
<td>Aggregate</td>
<td>3,594,798</td>
<td>3,948,466</td>
<td>353,669</td>
<td>9.0%</td>
</tr>
<tr>
<td>Other Bulk</td>
<td>2,735,955</td>
<td>2,813,106</td>
<td>77,151</td>
<td>2.7%</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
<td><strong>52,662,576</strong></td>
<td><strong>53,348,670</strong></td>
<td><strong>686,095</strong></td>
<td><strong>1.3%</strong></td>
</tr>
</tbody>
</table>

### Key Take-aways:
- Declining coal volumes as a result of depressed export markets
- Increased petcoke tonnage reflects increased export handling at Pier IX and IMT and high refinery utilizations
- Base business budgeted growth of 1.3%

(a) Excludes terminals divested or held for divestiture.
CO$_2$

Segment Presentation
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CO₂
Segment Outlook\(^{(a)}\)

Long-term Growth Drivers:
- Demand for scarce supply of CO₂ drives volume and price
- Expect to maintain current CO₂ production levels with minimal incremental investment
- Billions of barrels of domestic oil still in place to be recovered in the Permian Basin
- >9 billion barrels Original Oil In Place in KM operated fields

Project Backlog:
- Identified growth projects totaling $0.3 billion and $1.1 billion in S&T and EOR, respectively, over next five years\(^{(b)}\), including:
  - S&T: Southwest Colorado CO₂ production
  - EOR: SACROC / Yates / Goldsmith / Tall Cotton oil production

---

\(^{(a)}\) EOR = Enhanced Oil Recovery, S&T = Source & Transportation.
\(^{(b)}\) Includes KM share of non-wholly owned projects. Includes projects currently under construction.
## 2017 Projects – Price Sensitivity

### AT IRR % vs Oil Price

<table>
<thead>
<tr>
<th>$/Bbl</th>
<th>$50 flat</th>
<th>$53 flat</th>
<th>$60 flat</th>
<th>Forward Curve&lt;sup&gt;(a)&lt;/sup&gt;</th>
</tr>
</thead>
<tbody>
<tr>
<td>SACROC-Bypass (Long Lateral)</td>
<td>27%</td>
<td>32%</td>
<td>44%</td>
<td>37%</td>
</tr>
<tr>
<td>SACROC-Bypass (Sidetrack Lateral)</td>
<td>41%</td>
<td>47%</td>
<td>61%</td>
<td>50%</td>
</tr>
<tr>
<td>SACROC Hawaii</td>
<td>14%</td>
<td>19%</td>
<td>30%</td>
<td>22%</td>
</tr>
<tr>
<td>Yates Horizontal Drain Hole Program</td>
<td>65%</td>
<td>73%</td>
<td>96%</td>
<td>75%</td>
</tr>
<tr>
<td>Tall Cotton Phase 2</td>
<td>32%</td>
<td>36%</td>
<td>43%</td>
<td>38%</td>
</tr>
</tbody>
</table>

- Budgeted 2017 operating cash costs:
  - SACROC = $17.91 /Bbl
  - Yates = $13.14 /Bbl

<sup>(a)</sup> Forward curve as of 1/18/2017.
KM CO₂ Current Outlook

$4.7 Billion Cumulative Free Cash Flow Generated Since Inception\(^{(a)}\)

### Development Plans 2017-2026

- **SACROC**
  - Continue platform development/redevelopment
  - Expand Bypass Pay/Infill programs
  - Exploit transition zone opportunity

- **Yates**
  - Continue HDH programs and gravity drainage depletion plan
  - Initiate new Westside Waterflood
  - Evaluate HCM pilot

- **Katz**
  - Continue conformance program
  - Optimize flood performance

- **GLSAU**
  - Continue downspacing evaluation
  - Optimize flood performance

- **Tall Cotton**
  - Commence Phase 2 expansion
  - Develop additional project prospects

- **CO₂ S&T**
  - Maintain capacity in existing source fields (McElmo & Doe Canyon)
  - Optimize production and increase efficiency
  - Manage source portfolio to be prepared for increase in demand

### Total Business IRR (2000-2026): 28.2%

<table>
<thead>
<tr>
<th></th>
<th>Net BOE(^{(b)}) (MMBOE)</th>
<th>KM Share Capex (MM(^{(c)}))</th>
</tr>
</thead>
<tbody>
<tr>
<td>SACROC</td>
<td>58</td>
<td>$697</td>
</tr>
<tr>
<td>Yates</td>
<td>26</td>
<td>143</td>
</tr>
<tr>
<td>Katz</td>
<td>7</td>
<td>61</td>
</tr>
<tr>
<td>GLSAU</td>
<td>12</td>
<td>268</td>
</tr>
<tr>
<td>Tall Cotton</td>
<td>46</td>
<td>1,006</td>
</tr>
<tr>
<td>CO₂ S&amp;T</td>
<td></td>
<td>442</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>150</td>
<td>$2,617</td>
</tr>
</tbody>
</table>

### DCF ($MM)\(^{(e)}\)

- Net BOE = Net Crude plus Net NGLs plus Net Residue Gas sold and thereafter divided by 6.
- KM Share Capex is inclusive of Capitalized CO₂ and Capitalized OH.
- 2017 = Budget, 2017 at $53/Bbl, 2018 at $55/Bbl, 2019 at $60/Bbl, 2020+ at $65/Bbl; cost metrics based on 2016 run rate; development plans may change in different price scenarios.
- CO₂ profits not eliminated from S&T.

\(^{(a)}\) Net of invested capital.

\(^{(b)}\) Net BOE = Net Crude plus Net NGLs plus Net Residue Gas sold and thereafter divided by 6.

\(^{(c)}\) KM Share Capex is inclusive of Capitalized CO₂ and Capitalized OH.

\(^{(d)}\) 2017 = Budget, 2017 at $53/Bbl, 2018 at $55/Bbl, 2019 at $60/Bbl, 2020+ at $65/Bbl; cost metrics based on 2016 run rate; development plans may change in different price scenarios.

\(^{(e)}\) CO₂ profits not eliminated from S&T.
History of CO₂ Group and Looking Forward

Track Record – Consistently very close to budget despite inherent volatility

- Shell CO₂ formed in 1998, KM share 20%
- Acquired remaining 80% in April 2000
- Acquired SACROC interests June 2000
- Acquired Yates interests in 2001 and 2003
  - Feb 24, 2016 - 1.5 billionth barrel of oil produced
- Ramped up developments at SACROC 2003+
  - Constructed Centerline pipeline in 2003
  - Constructed power plant in 2005
  - Increased oil production 3X+
- Acquired Wink pipeline in 2004
- Acquired Katz field 2006
- Increased SW Colorado CO₂ capacity 30% 2008
- Katz CO₂ project: CO₂ injection commenced Dec-2010
- 2013-Acquired Goldsmith Landreth San Andres (GLSAU)
- Tall Cotton (ROZ) CO₂ project: CO₂ injection commenced Nov-2014
- Increased SW Colorado CO₂ capacity 13% in 2015
  - 200 MMcf/d
- Increased Cortez Capacity to 1.5Bcf/d in 2016
- Initiated Tall Cotton Phase II in 2016

Our assets, resources and technologies provide us with growth opportunities

- Stable CO₂ demand
- Continued developments at SACROC, Yates, Tall Cotton/ROZ, and GLSAU

(a) CO₂ Source and Transportation includes Yates Oil Gathering System (YOGS), CO₂ sales profit on KM’s use has not been eliminated.
2017 DCF and Capex by Asset Group\(^{(a)}\)

2017 DCF = $866 MM

2017 Budget – $352 MM Expansion Capital

Note: CO\(_2\) purchases and staff overhead are allocated to assets.

\(^{(a)}\) Segments shown without elimination, includes allocated hedges based on net barrels.
Impact of Oil Price / Volume Variance on 2017 DCF

($ in millions)

2017 Budget:  $866MM

Volume +/- 1,000 Bbl/d

- SACROC / Katz / GLSAU / Tall Cotton: $15.0MM
- Yates: $8.1MM

CO₂ Volume +/- 50 MMcf/d: $7.2MM

Oil Price +/- $1/Bbl WTI

- NGL: $1.6MM
- CO₂: $0.3MM
- Crude: $2.5MM

TOTAL: $4.4MM

NGL/Crude Ratio +/- 1%: $2.3MM

Mid/Cush Diff +/- $1/Bbl: $8.3MM

Notes: Unhedged WTI price assumed to average $53/Bbl; WTI-WTS spread = ($1.20)/Bbl / Midland-Cushing spread = ($0.65)/Bbl. NGL price assumed to be $21.74 (41% WTI).
**CO₂ Asset Summary**

<table>
<thead>
<tr>
<th>CO₂ Reserves</th>
<th>KMI Interest</th>
<th>Location</th>
<th>Remaining Deliverability</th>
<th>Operator</th>
</tr>
</thead>
<tbody>
<tr>
<td>McElmo Dome</td>
<td>45%</td>
<td>SW Colorado</td>
<td>20+ years</td>
<td>KMI</td>
</tr>
<tr>
<td>Doe Canyon</td>
<td>87%</td>
<td>SW Colorado</td>
<td>10+ years</td>
<td>KMI</td>
</tr>
<tr>
<td>Bravo Dome</td>
<td>11%</td>
<td>NE New Mexico</td>
<td>10+ years</td>
<td>Oxy</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Pipelines</th>
<th>KMI Interest</th>
<th>Location</th>
<th>Capacity (MMcf/d)</th>
<th>Operator</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cortez</td>
<td>50%</td>
<td>McElmo Dome to Denver City</td>
<td>1,500</td>
<td>KMI</td>
</tr>
<tr>
<td>Bravo</td>
<td>13%</td>
<td>Bravo Dome to Denver City</td>
<td>375</td>
<td>Oxy</td>
</tr>
<tr>
<td>Central Basin (CB)</td>
<td>100%</td>
<td>Denver City to McCamey</td>
<td>700</td>
<td>KMI</td>
</tr>
<tr>
<td>Canyon Reef</td>
<td>98%</td>
<td>McCamey to Snyder</td>
<td>290</td>
<td>KMI</td>
</tr>
<tr>
<td>Centerline</td>
<td>100%</td>
<td>Denver City to Snyder</td>
<td>300</td>
<td>KMI</td>
</tr>
<tr>
<td>Pecos</td>
<td>95%</td>
<td>McCamey to Iraan</td>
<td>125</td>
<td>KMI</td>
</tr>
<tr>
<td>Eastern Shelf</td>
<td>100%</td>
<td>Snyder to Katz</td>
<td>110</td>
<td>KMI</td>
</tr>
<tr>
<td>Wink (crude)</td>
<td>100%</td>
<td>McCamey &amp; Snyder to El Paso</td>
<td>145 MBbl/d</td>
<td>KMI</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Crude Reserves (a)</th>
<th>KMI Interest / (Net of royalty)</th>
<th>Location</th>
<th>Operator</th>
</tr>
</thead>
<tbody>
<tr>
<td>SACROC</td>
<td>97% (83%)</td>
<td>W Texas</td>
<td>KMI</td>
</tr>
<tr>
<td>Yates</td>
<td>50% (44%)</td>
<td>W Texas</td>
<td>KMI</td>
</tr>
<tr>
<td>Katz</td>
<td>99% (83%)</td>
<td>W Texas</td>
<td>KMI</td>
</tr>
<tr>
<td>Goldsmith</td>
<td>100% (88%)</td>
<td>W Texas</td>
<td>KMI</td>
</tr>
<tr>
<td>Tall Cotton</td>
<td>100% (88%)</td>
<td>W Texas</td>
<td>KMI</td>
</tr>
</tbody>
</table>

**Original gas in place (TCF)**

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>McElmo Dome</td>
<td>22</td>
</tr>
<tr>
<td>Doe Canyon</td>
<td>3</td>
</tr>
<tr>
<td>Bravo Dome</td>
<td>12</td>
</tr>
</tbody>
</table>

Note: In addition to KMI’s interests above, KMI has a 22%, 51%, and 100% working interest in the Synder gasoline plant, Diamond M gas plant and North Synder plant, respectively. (a) Reserve life ~4 years based on current independent consultant reserve report.
2017 Expansion Program Summary

Capex Program $352MM\(^{(a)}\)

<table>
<thead>
<tr>
<th>Project</th>
<th>Capex Program ($MM)</th>
<th>% of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>S&amp;T – $31MM Capex (incl. $4MM Cap OH)</td>
<td>$31MM</td>
<td>9%</td>
</tr>
<tr>
<td>SACROC – $190MM Capex(^{(b,c)}) (incl. $52MM Cap OH &amp; Cap CO(_2))</td>
<td>$190MM</td>
<td>54%</td>
</tr>
<tr>
<td>Yates – $29MM Capex(^{(c)}) (incl. $9MM Cap OH &amp; Cap CO(_2))</td>
<td>$30MM</td>
<td>8%</td>
</tr>
<tr>
<td>Katz – $17MM Capex (incl. $16MM Cap OH &amp; Cap CO(_2))</td>
<td>$17MM</td>
<td>5%</td>
</tr>
<tr>
<td>GLSAU - $15MM Capex (incl. $10MM Cap OH &amp; Cap CO(_2))</td>
<td>$15MM</td>
<td>4%</td>
</tr>
<tr>
<td>Tall Cotton - $69MM Capex (incl. $18MM Cap OH &amp; Cap CO(_2))</td>
<td>$69MM</td>
<td>20%</td>
</tr>
<tr>
<td><strong>Total Capex(^{(a)})</strong></td>
<td><strong>$352MM</strong></td>
<td><strong>100%</strong></td>
</tr>
</tbody>
</table>

---

\(^{(a)}\) Included in $352 million total capex program are overhead and CO\(_2\) purchases, in the aggregate, of approximately $109 million.

\(^{(b)}\) Includes minor properties, unallocated costs.

\(^{(c)}\) Includes secondary objectives.
CO₂ Entitlement Volumes
Produced and Sold to our Customers

Significant growth since 2008:
- CAGR: volumes +2.22%
- 2017 vs 2016: volumes -1.49%

As a reminder:
- Sales revenues are based on our working interest entitlement and not deliveries
- KM share of EOR demand consumes ~31% of our entitled production in 2017
- Elimination: consolidation results in eliminating profit on sales to ourselves, however we view our S&T and O&G businesses independently, and price sales to ourselves at market prices
Demand Growth and Regeneration

5-year Contracted CO₂ Volumes

- Weighted average contract life with 3rd parties is 9.49 years
Oil and Gas Segment
Production and DCF

Net Hydrocarbon Production (MBOE/d)

Original oil in place (Billion Bbls)

<table>
<thead>
<tr>
<th>Segment</th>
<th>Actual</th>
<th>Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>SACROC</td>
<td>2.8</td>
<td></td>
</tr>
<tr>
<td>Yates</td>
<td>5.0</td>
<td></td>
</tr>
<tr>
<td>Katz</td>
<td>0.23</td>
<td></td>
</tr>
<tr>
<td>GLSAU</td>
<td>0.48</td>
<td></td>
</tr>
<tr>
<td>Tall Cotton</td>
<td>0.70</td>
<td></td>
</tr>
</tbody>
</table>

Gross production (Bbl/d)(a)

<table>
<thead>
<tr>
<th>Segment</th>
<th>Actual</th>
<th>Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>SACROC oil</td>
<td>29,323</td>
<td>27,478</td>
</tr>
<tr>
<td>SGP NGLs</td>
<td>20,925</td>
<td>20,900</td>
</tr>
<tr>
<td>Yates</td>
<td>18,368</td>
<td>18,090</td>
</tr>
<tr>
<td>Katz</td>
<td>4,054</td>
<td>4,215</td>
</tr>
<tr>
<td>GLSAU</td>
<td>1,874</td>
<td>2,310</td>
</tr>
<tr>
<td>Tall Cotton</td>
<td>1,078</td>
<td>2,200</td>
</tr>
</tbody>
</table>

DCF ($MM)

DCF(a) ($MM, w/o Elim, w/ Alloc Hedges)

<table>
<thead>
<tr>
<th>Segment</th>
<th>Actual</th>
<th>Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>SACROC(a,b)</td>
<td>413</td>
<td>378</td>
</tr>
<tr>
<td>Yates(a)</td>
<td>131</td>
<td>117</td>
</tr>
<tr>
<td>Katz</td>
<td>40</td>
<td>37</td>
</tr>
<tr>
<td>GLSAU</td>
<td>13</td>
<td>19</td>
</tr>
<tr>
<td>Tall Cotton</td>
<td>12</td>
<td>22</td>
</tr>
</tbody>
</table>

Notes:
BOE: Oil and NGL = 1:1, Residue gas sales = 6:1.
Gas Processing includes net BOE attributable to our plant interests and processing agreements but excluded from reserve report.
(a) Includes Secondary Objectives.
(b) Includes other minor oil and gas properties near SACROC.
CO₂ Oil Production Hedge Profile

- Hedge our BOE production
  - Targeted minimum hedge amounts:
    - Current Year: 70%
    - Year 2: 50%
    - Year 3: 30%
    - Year 4: 10%

Net Oil Production (Mboe/d)\(^{(a)}\)

Hedged
Unhedged
% Hedged

<table>
<thead>
<tr>
<th>Year</th>
<th>Hedged</th>
<th>Unhedged</th>
<th>% Hedged</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017</td>
<td>75%</td>
<td>25%</td>
<td>75%</td>
</tr>
<tr>
<td>2018</td>
<td>53%</td>
<td>47%</td>
<td>53%</td>
</tr>
<tr>
<td>2019</td>
<td>33%</td>
<td>67%</td>
<td>33%</td>
</tr>
<tr>
<td>2020</td>
<td>20%</td>
<td>80%</td>
<td>20%</td>
</tr>
<tr>
<td>2021</td>
<td>0%</td>
<td>100%</td>
<td>0%</td>
</tr>
</tbody>
</table>

Average hedge price
WTI & WTS ($/Bbl)\(^{(b)}\)

<table>
<thead>
<tr>
<th>Year</th>
<th>Average Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017</td>
<td>$59.02</td>
</tr>
<tr>
<td>2018</td>
<td>$65.30</td>
</tr>
<tr>
<td>2019</td>
<td>$57.38</td>
</tr>
<tr>
<td>2020</td>
<td>$53.43</td>
</tr>
<tr>
<td>2021</td>
<td>$-</td>
</tr>
</tbody>
</table>

Total volume hedged (Mboe/d)

<table>
<thead>
<tr>
<th>Year</th>
<th>Crude oil swaps</th>
<th>Crude oil puts</th>
<th>Propane</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017</td>
<td>29.1</td>
<td>4.0</td>
<td>2.0</td>
</tr>
<tr>
<td>2018</td>
<td>14.7</td>
<td>0.3</td>
<td>-</td>
</tr>
<tr>
<td>2019</td>
<td>8.1</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>2020</td>
<td>4.2</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>2021</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

(a) Net equity production: 2017 Based on 2017 Budget, 2018 - 2022 based on Ryder Scott reserve report. Includes heavier NGL components (C4+).
(b) Where collars are used, pricing incorporated into average hedge price is the collar floor; for swaps and puts, strike price net of premium is used.
**Oil & Gas**

**Margins and Cost Structure**

---

**Oil & Gas Cash Cost Structure**

**(a) ($/Net BOE)**

---

**O&G cost structure has strong correlation to energy prices**

- Power is tied to gas prices
- Purchased CO$_2$ and TOTI(b) are strongly correlated to oil prices
- Market conditions have decreased material and service costs
- Achieved aggregate operating cost savings of ~35% 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](http://www.eia.gov).
Oil and Gas Segment

*Over past 9 years capex 0.5% below plan, oil production 0.8% below plan*

---

**Capex ($MM)**

<table>
<thead>
<tr>
<th>Year</th>
<th>Budget</th>
<th>Actual</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>$400</td>
<td></td>
</tr>
<tr>
<td>2009</td>
<td>$450</td>
<td></td>
</tr>
<tr>
<td>2010</td>
<td>$300</td>
<td></td>
</tr>
<tr>
<td>2011</td>
<td>$350</td>
<td></td>
</tr>
<tr>
<td>2012</td>
<td>$400</td>
<td></td>
</tr>
<tr>
<td>2013</td>
<td>$450</td>
<td></td>
</tr>
<tr>
<td>2014</td>
<td>$500</td>
<td></td>
</tr>
<tr>
<td>2015</td>
<td>$550</td>
<td></td>
</tr>
<tr>
<td>2016</td>
<td>$600</td>
<td></td>
</tr>
</tbody>
</table>

**Net Oil Production (MBbl/d)**

<table>
<thead>
<tr>
<th>Year</th>
<th>Budget</th>
<th>Actual</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>30</td>
<td></td>
</tr>
<tr>
<td>2009</td>
<td>35</td>
<td></td>
</tr>
<tr>
<td>2010</td>
<td>40</td>
<td></td>
</tr>
<tr>
<td>2011</td>
<td>45</td>
<td></td>
</tr>
<tr>
<td>2012</td>
<td>50</td>
<td></td>
</tr>
<tr>
<td>2013</td>
<td>55</td>
<td></td>
</tr>
<tr>
<td>2014</td>
<td>60</td>
<td></td>
</tr>
<tr>
<td>2015</td>
<td>65</td>
<td></td>
</tr>
<tr>
<td>2016</td>
<td>70</td>
<td></td>
</tr>
</tbody>
</table>

*Note: Capex includes CO₂ purchases and capitalized overhead.*
Oil and Gas Segment Production Forecasts

*Production expectations tend to grow over time*

- We expect production to exceed our reserve report over the long-term
  - Higher recoveries and additional targets added to inventory
  - New Technologies

---

**Evolution of Forecasted 2017 Production\(^{(a)}\) over Time (MBbl/d, 8/8ths)**

![Graph showing production by year and location](image)

**Proved Reserves Production Forecast (MBbl/d, 8/8ths)**

![Graph showing production forecasts by year and location](image)

---

\(^{(a)}\) Forecasts based on independent consultant reserve report. Excludes minor properties.
SACROC Unit – Long Range Plan

- **Changes from 2016 plan**
  - Addition of Hawaii Project
  - Addition of BE PH I Project
  - Infill Timing with CTI’s
  - BPP response/timing

- **Examining Transition Zone upside**
Oil & Gas, and Business Unit IRR

All-in O&G IRR (2000-2026): 21.7%
- Proved reserves cash flows: 17.0%
- Adding in Gas Processing excluded from disclosures increases IRR to 19.4%
- Adding in reserves discounted to P2 and using planned development costs increases return to 21.7%

Total business IRR (2000-2026): 28.2%
- Includes S&T assuming volumes increase with higher capacity, valued at market prices

As of 12/31/16, CO₂ Segment cumulative free cash flow is $4.7B+ (net of cumulative invested capital)
Kinder Morgan Canada

Segment Presentation
Kinder Morgan Canada
Segment Outlook

Long-term Growth Drivers:
- Expand Oilsands export capacity to West Coast and Asia
  - Following successful regulatory process, 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 2019
- Expanded dock capabilities (Vancouver)
  - TMEP will increase dock capacity to over 600 MBbl/d
  - Access to global markets

Trans Mountain Expansion Project
Trans Mountain Pipeline

Current Capacity:
- 300 MBbl/d ex-Edmonton
- 241 MBbl/d to Puget Sound

Markets:
- British Columbia
  - Crude and Refined Products
- Washington State Refineries
- Westridge Marine Terminal
  - Offshore Markets

Regulation:
- National Energy Board Regulated
- 2016–2018 toll settlement

TMPL 2016 Throughput by Destination (MBbl/d)

- 61% 191 MBbl/d
- 29% 91 MBbl/d
- 7% 23 MBbl/d
- 3% 11 MBbl/d
Market Access Drivers

Western Canada Supply vs. Takeaway Capacity (MMBbl/d)\(^{(a)}\)

- Pipeline Shortfall
- Supply\(^{(b)}\)

Keystone XL & Energy East
Enbridge Line 3 Replacement
Trans Mountain Expansion
Existing Pipeline Capacity

Brent - WCS Spread ($/Bbl)\(^{(c)}\)

Markets For Canadian Crude (MMBbl/d)\(^{(d)}\)

- China net imports
- U.S net imports

---

\(a\) Canadian Association of Petroleum Producers (CAPP), 2016 Crude Oil Forecast, Markets & Transportation, June 2016, and KM analysis.

\(b\) Western Canada supply plus U.S. Bakken movements.

\(c\) Index Mundi, NGX.

\(d\) EIA, Short-term Energy Outlook, January 2017.
Trans Mountain Expansion Project (TMEP)

- **Expansion to 890 MBbl/d from 300 MBbl/d**
  - 615 miles new pipe; 12 new pump stations
  - 630 MBbl/d tanker export capacity; 3 new berths
  - 20 new tanks

- **13 companies contracted for 708 MBbl/d**
  - 15 & 20 year take-or-pay contracts
  - Commercial terms approved by NEB May 2013

- **Projected Cost**
  - Finalizing cost estimates with contractors
  - Demand remains strong; we expect shippers to remain committed or have other shippers subscribe if final costs are above $6.8 billion CAD
  - Each $100mm >$6.8 billion CAD = ~$0.07 tariff increase
  - Additional cost pass through protection during construction
  - Substantial development cost protection

---

(a) Canadian Association of Petroleum Producers (CAPP), 2016 Crude Oil Forecast, Markets & Transportation, June 2016, and KM analysis.
Trans Mountain Expansion Project Timeline

2016
- NEB Recommendation May ‘16
- Federal Approval Dec. ‘16

2017
- BC Approval Jan. ‘17
- Cost Review with Shippers Feb. ‘17
- KM FID 1Q / 2Q 2017
- Begin Construction Sept. ‘17

2018 – 2019
- Complete Construction, In-Service Dec. ‘19
Other

Support Slides
## Energy Toll Road

### Security of Cash

<table>
<thead>
<tr>
<th>Volume Security</th>
<th>Products Pipelines</th>
<th>Terminals</th>
<th>CO₂</th>
<th>Kinder Morgan Canada</th>
</tr>
</thead>
<tbody>
<tr>
<td>- Interstate &amp; LNG: take-or-pay</td>
<td>- Refined products: primarily volume-based</td>
<td>- Liquids &amp; Jones Act: primarily take-or-pay</td>
<td>- S&amp;T: primarily minimum volume guarantee</td>
<td>- Essentially no volume risk</td>
</tr>
<tr>
<td>- Intrastate: ~77% take-or-pay&lt;sup&gt;a,b&lt;/sup&gt;</td>
<td>- Crude / liquids: primarily take-or-pay</td>
<td>- Bulk: primarily minimum volume guarantee, or requirements</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- G&amp;P: ~88% fee-based&lt;sup&gt;b&lt;/sup&gt; with minimum volume requirements / acreage dedications</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

| Average Remaining Contract Life | | | | |
| - Interstate: 6.2 yrs. | - Refined products: generally not applicable | - Liquids: 3.7 yrs. | - S&T: 8.2 yrs. | - 2.0 yrs.<sup>d</sup> |
| - LNG: 15.4 yrs. | - Crude / liquids: 5.2 yrs. | - Jones Act: 2.8 yrs.<sup>c</sup> | | |
| - Intrastate: 5.3 yrs.<sup>a</sup> | | - Bulk: 4.9 yrs. | | |
| - G&P: 4.2 yrs. | | | | |

| Pricing Security | | | | |
| - Interstate: primarily fixed based on contract | - Refined products: annual FERC tariff escalator (PPI-FG + 1.23%) | - Based on contract; typically fixed or tied to PPI | - S&T: 83% protected by minimum volumes and floors<sup>b</sup> | - Fixed based on toll settlement |
| - Intrastate: primarily fixed margin | - Crude / liquids: primarily fixed based on contract | | - O&G: volumes 75% hedged<sup>6</sup> | |
| - G&P: primarily fixed price | | | | |

| Regulatory Security | | | | |
| - Interstate: regulated return | - Pipelines: regulated return | - Not price regulated | - Primarily unregulated | - Regulated return |
| - Intrastate: essentially market-based | - Terminals & transmix: not price regulated<sup>f</sup> | | | |
| - G&P: market-based | | | | |

| Commodity Price Exposure | | | | |
| - Interstate: no direct exposure | - Minimal, limited to transmix business | - No direct exposure | - Full-y 2017: $4.4MM in DCF per $1/Bbl change in oil price | - No direct exposure |
| - Intrastate: limited exposure | | | | |
| - G&P: limited exposure | | | | |

---

**All figures as of 1/1/2017, unless otherwise noted.**

(a) Includes term sale portfolio.
(b) Based on KMI 2017 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 (12) and tankers under construction (4) is 2.8 years, or 4.1 years including options to extend.
(d) Jones Act vessels: average remaining contract term for operating tankers (12) and tankers under construction (4) is 2.8 years, or 4.1 years including options to extend.
(e) Percentage of 2017 budgeted net crude oil, propane and heavy NGL (C4+) net equity production.
(f) Terminals not FERC regulated, except portion of CALNEV.
Two Decades of Stable Growth
Strategy Has Led to Consistent, Growing Results

Notes:
- DCF and Adjusted EBITDA are before Certain Items (non-GAAP measures). 2017 per budget. See Appendix for defined terms and reconciliations to GAAP measures.
- KMP was Kinder Morgan’s primary investment vehicle and held the majority of operating assets from 1996 to 2014.
- 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.
- Debt is net of cash and excludes fair value adjustments. KMP 2014 as of 9/30/2014.

2014 Consolidation of KMI, KMP, KMR & EPB Achieved:
- Greater scale
- Greater business diversification
- No structural subordination
Incidents & Releases
Liquids Pipeline Right-of-way

Liquids Pipelines
Incidents per 1,000 Miles\(^{(a)}\)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Incidents per 1,000 Miles</td>
<td>0.25</td>
<td>0.29</td>
<td>0.21</td>
<td>0.00</td>
<td>0.08</td>
<td>0.08</td>
<td>0.24</td>
<td>0.57</td>
<td>0.16</td>
<td>0.08</td>
<td></td>
</tr>
</tbody>
</table>

Liquids Pipelines
Release Rate\(^{(a)}\)

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Barrels per billion barrel miles</td>
<td>6.00</td>
<td>15.50</td>
<td>2.50</td>
<td>0.00</td>
<td>0.01</td>
<td>0.01</td>
<td>0.11</td>
<td>0.67</td>
<td>0.04</td>
<td>0.01</td>
<td></td>
</tr>
</tbody>
</table>

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) 2013–2015 most recent PHMSA 3-yr average available.
Incidents & Releases
Natural Gas Pipeline Right-of-way

(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:
  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.
- 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 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.
- 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(a)

KM Lost-time Incident Rate (DART)

- Natural Gas Pipelines: KM Rate (3-yr Avg) = 0.8, KM Rate (12-mo) = 0.7, Industry 3yr Avg = 2.5
- CO2: KM Rate (3-yr Avg) = 0.6, KM Rate (12-mo) = 0.5, Industry 3yr Avg = 2.6
- Products Pipelines: KM Rate (3-yr Avg) = 0.7, KM Rate (12-mo) = 0.3, Industry 3yr Avg = 2.5
- Terminals: KM Rate (3-yr Avg) = 0.9, KM Rate (12-mo) = 1.0, Industry 3yr Avg = 1.8
- KM Canada: KM Rate (3-yr Avg) = 0.5, KM Rate (12-mo) = 0.6, Industry 3yr Avg = 6.1

OSHA Recordable Incident Rate

- Natural Gas Pipelines: KM Rate (3-yr Avg) = 1.5, KM Rate (12-mo) = 1.2, Industry 3yr Avg = 2.5
- CO2: KM Rate (3-yr Avg) = 0.8, KM Rate (12-mo) = 1.0, Industry 3yr Avg = 2.6
- Products Pipelines: KM Rate (3-yr Avg) = 0.9, KM Rate (12-mo) = 0.3, Industry 3yr Avg = 2.5
- Terminals: KM Rate (3-yr Avg) = 1.5, KM Rate (12-mo) = 1.6, Industry 3yr Avg = 6.4
- KM Canada: KM Rate (3-yr Avg) = 0.7, KM Rate (12-mo) = 0.6, Industry 3yr Avg = 6.1

Vehicle Incident Rate

- Natural Gas Pipelines: KM Rate (3-yr Avg) = 0.5, KM Rate (12-mo) = 0.5, Industry Avg (12-mo) = 1.1
- CO2: KM Rate (3-yr Avg) = 0.5, KM Rate (12-mo) = 0.7, Industry Avg (12-mo) = 1.9
- Products Pipelines: KM Rate (3-yr Avg) = 0.7, KM Rate (12-mo) = 0.6, Industry Avg (12-mo) = 1.9
- Terminals: KM Rate (3-yr Avg) = 0.8, KM Rate (12-mo) = 1.6, Industry Avg (12-mo) = 1.0
- KM Canada: KM Rate (3-yr Avg) = 0.4, KM Rate (12-mo) = 1.0, Industry Avg (12-mo) = 0.4

(a) 12-month safety performance summary as of 12/31/2016.
(b) Industry average not available for Terminals.
Definitions and GAAP Reconciliations
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), net income before interest expense, taxes, DD&A and Certain Items (Adjusted EBITDA), and adjusted earnings (Adjusted Earnings), both in the aggregate and per share, 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, Adjusted EBITDA and Adjusted Earnings 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. Reconciliations of DCF, Segment EBDA before Certain Items, Adjusted EBITDA and Adjusted Earnings to their most directly comparable GAAP financial measures are included herein.

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 common stock dividends, stock repurchases, retirement of debt, or expansion capital expenditures. Management uses this measure and believes it provides users of our financial statements a useful measure reflective of our business’s ability to generate cash earnings to supplement the comparable GAAP measure. We believe the GAAP measure most directly comparable to DCF is net income available to common stockholders. DCF per share is DCF divided by average outstanding common shares and restricted stock awards that participate in dividends.
Use of Non-GAAP Financial Measures (Cont’d)

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 provides us and external users of our financial statements additional insight into 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 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 when reported.

Adjusted EBITDA is used by management and external users, in conjunction with our net debt, to evaluate certain leverage metrics. Therefore, we believe Adjusted EBITDA is useful to investors. 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 before Certain Items, and KMI’s share of Certain Equity Investees’ DD&A and book taxes, which are specifically identified in the footnotes to the accompanying tables when reported.

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. Adjusted Earnings per share is Adjusted Earnings divided by Average Adjusted Common Shares which include KMI’s weighted average common shares outstanding, unvested restricted shares that contain rights to dividends (which may not be dilutive under GAAP) and any shares resulting from dilutive impact of warrants under treasury stock method.

Budgeted Net Income is not provided (the GAAP financial measure most directly comparable to DCF and Adjusted EBITDA) 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.

Certain Equity Investees, 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. DD&A and sustaining capex for Plantation and Cortez were made beginning in 2017. For joint ventures consolidated by KMI, JV DD&A and sustaining capex are net of our partners’ share of these items.
GAAP Reconciliation

($ in millions)

<table>
<thead>
<tr>
<th>Reconciliation of DCF</th>
<th>12/31/16</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Income</td>
<td>$ 721</td>
</tr>
<tr>
<td>Certain Items</td>
<td>933</td>
</tr>
<tr>
<td>Net Income before Certain Items (Adjusted Earnings)</td>
<td>1,654</td>
</tr>
<tr>
<td>DD&amp;A</td>
<td>2,268</td>
</tr>
<tr>
<td>JV DD&amp;A (a)</td>
<td>349</td>
</tr>
<tr>
<td>Book taxes (b)</td>
<td>993</td>
</tr>
<tr>
<td>Cash taxes</td>
<td>(79)</td>
</tr>
<tr>
<td>Noncontrolling interests (c)</td>
<td>(21)</td>
</tr>
<tr>
<td>Sustaining capex including KMI share of JV sustaining capex</td>
<td>(540)</td>
</tr>
<tr>
<td>Other (e)</td>
<td>43</td>
</tr>
<tr>
<td>Distributable Cash Flow (DCF) attributable to Kinder Morgan, Inc.</td>
<td>4,667</td>
</tr>
<tr>
<td>Preferred stock dividends</td>
<td>(156)</td>
</tr>
<tr>
<td>DCF attributable to Common Stockholders</td>
<td>$ 4,511</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Reconciliation of Adjusted EBITDA</th>
<th>12/31/16</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Income</td>
<td>$ 721</td>
</tr>
<tr>
<td>Certain Items</td>
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<td>Net Income before Certain Items (Adjusted Earnings)</td>
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<td>DD&amp;A</td>
<td>2,268</td>
</tr>
<tr>
<td>JV DD&amp;A (a)</td>
<td>349</td>
</tr>
<tr>
<td>Interest, net before Certain Items</td>
<td>1,999</td>
</tr>
<tr>
<td>Adjusted EBITDA</td>
<td>$ 7,242</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Certain Items</th>
<th>Yr. Ended</th>
</tr>
</thead>
<tbody>
<tr>
<td>Acquisition related costs</td>
<td>$ 13</td>
</tr>
<tr>
<td>Fair value amortization</td>
<td>(143)</td>
</tr>
<tr>
<td>Contract early termination revenue</td>
<td>(57)</td>
</tr>
<tr>
<td>Legal and environmental reserves</td>
<td>(16)</td>
</tr>
<tr>
<td>Mark to market and ineffectiveness</td>
<td>75</td>
</tr>
<tr>
<td>Loss on impairments and divestitures, net</td>
<td>848</td>
</tr>
<tr>
<td>Project write-offs</td>
<td>171</td>
</tr>
<tr>
<td>Other (g)</td>
<td>24</td>
</tr>
<tr>
<td>Subtotal</td>
<td>915</td>
</tr>
<tr>
<td>Book taxes on Certain Items</td>
<td>18</td>
</tr>
<tr>
<td>Total Certain Items</td>
<td>$ 933</td>
</tr>
</tbody>
</table>

Note: Definitions for defined terms found in the Appendix.

(a) Includes KMI share of Certain Equity Investees DD&A.
(b) Includes KMI share of Certain Equity Investee book taxes of $94 million, and excludes book taxes on Certain Items of $13 million.
(c) Before Certain Items. Represents net income allocated to third-party ownership interests in consolidated subsidiaries.
(d) Includes KMI share of Certain Equity Investee sustaining capital expenditures $90 million.
(e) Consists primarily of book to cash timing differences related to certain defined benefit plans partially offset by retiree medical contributions.
(f) Excludes Kinder Morgan G.P. Inc.'s $100 million preferred stock due 2057 and ($43) million non-cash foreign exchange impact on KMI's Euro-denominated debt.
(g) 2016 Other Certain Items include $14 million employee right-sizing, $5 Nassau crane incident, $4 Berry bankruptcy, $4 CBS closure, ($4) mark to market power contract adjustment and $1 other.
# Explanation of Return Calculations

<table>
<thead>
<tr>
<th>Formula</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Segment Return on Investment</td>
<td>Segment EBDA before Certain Items less sustaining capex (a)</td>
</tr>
<tr>
<td>Return on Investment</td>
<td>Average Total Investment (b)</td>
</tr>
<tr>
<td>Return on Equity</td>
<td>DCF before interest (c)</td>
</tr>
<tr>
<td></td>
<td>Average Total Investment (b)</td>
</tr>
<tr>
<td></td>
<td>DCF (after interest) (d)</td>
</tr>
<tr>
<td></td>
<td>Average equity (e)</td>
</tr>
</tbody>
</table>

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

(a) Adjustments are made to Segment EBDA to more closely tie to cash: (1) our share of JV DD&A for Certain Equity Investees 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 (2015-2016).

(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 and KMI’s share of c-corp equity investee’s book taxes.

(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 sustaining capital expenditures for Certain Equity Investees, less equity earnings plus cash distributions received for Express and Endeavor (1H 2014 and prior), additional other equity investees, plus the general partner’s incentive and the general partner non-controlling interest, as applicable. Thereafter, DCF is defined as net income available to common stockholders 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 sustaining capital expenditures for Certain Equity Investees, plus/minus other items (primarily an add-back for non-cash compensation, less retirement benefits). Book and cash taxes include KMI’s share of its C-corp equity investees.

(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 also includes DCF spent to fund growth capital.

(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 Products 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 deduct 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 KMI’s 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.
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