KINDER MORGAN
ENERGY PARTNERS, L.P.

Barclays 2009 Fixed Income Energy and Pipeline Conference

March 24, 2009

Forward Looking Statements

This presentation contains forward looking statements. 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 make distributions 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 Energy Partners, L.P. and Kinder Morgan Management, LLC 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 ability to achieve synergies and revenue growth; national, international, regional and local economic, competitive and regulatory conditions and developments; technological developments; capital and credit markets conditions; inflation rates; interest rates; the political and economic stability of oil producing nations; energy markets; weather conditions; environmental conditions; business and regulatory or legal decisions; the pace of deregulation of retail natural gas and electricity and certain agricultural products; the timing and success of business development efforts; terrorism; 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.

Use of Non-GAAP Financial Measures

The non-generally accepted accounting principles ("non-GAAP") financial measures of distributable cash flow before certain items, segment distributable cash flow before certain items, and earnings before interest, taxes and DD&A ("EBITDA") before certain items are included in this presentation. Our non-GAAP financial measures should not be considered as alternatives to GAAP measures such as net income or any other GAAP measure of liquidity or financial performance.

Distributable cash flow before certain items and EBITDA before certain items are significant metrics used by us and by external users of our financial statements, such as investors, research analysts, commercial banks and others, to compare basic cash flows generated by us to the cash distributions we expect to pay our unitholders on an ongoing basis. Management uses these metrics to evaluate our overall performance. Distributable cash flow before certain items also allows management to simply calculate the coverage ratio of estimated ongoing cash flows to expected cash distributions. Distributable cash flow before certain items and EBITDA before certain items are also important non-GAAP financial measures for our unitholders because they serve as indicators of our success in providing a cash return on investment. These financial measures indicate to investors whether or not we typically are generating cash flow at a level that can sustain or support an increase in the quarterly distributions we are paying pursuant to our partnership agreement. Our partnership agreement requires us to distribute all available cash. Distributable cash flow before certain items, EBITDA before certain items and similar measures used by other publicly traded partnerships are also quantitative measures used in the investment community because the value of a unit of such an entity is generally determined by the unit's yield (which in turn is based on the amount of cash distributions the entity pays to a unitholder). The economic substance behind our use of distributable cash flow before certain items and EBITDA before certain items is to measure and estimate the ability of our assets to generate cash flows sufficient to make distributions to our investors.

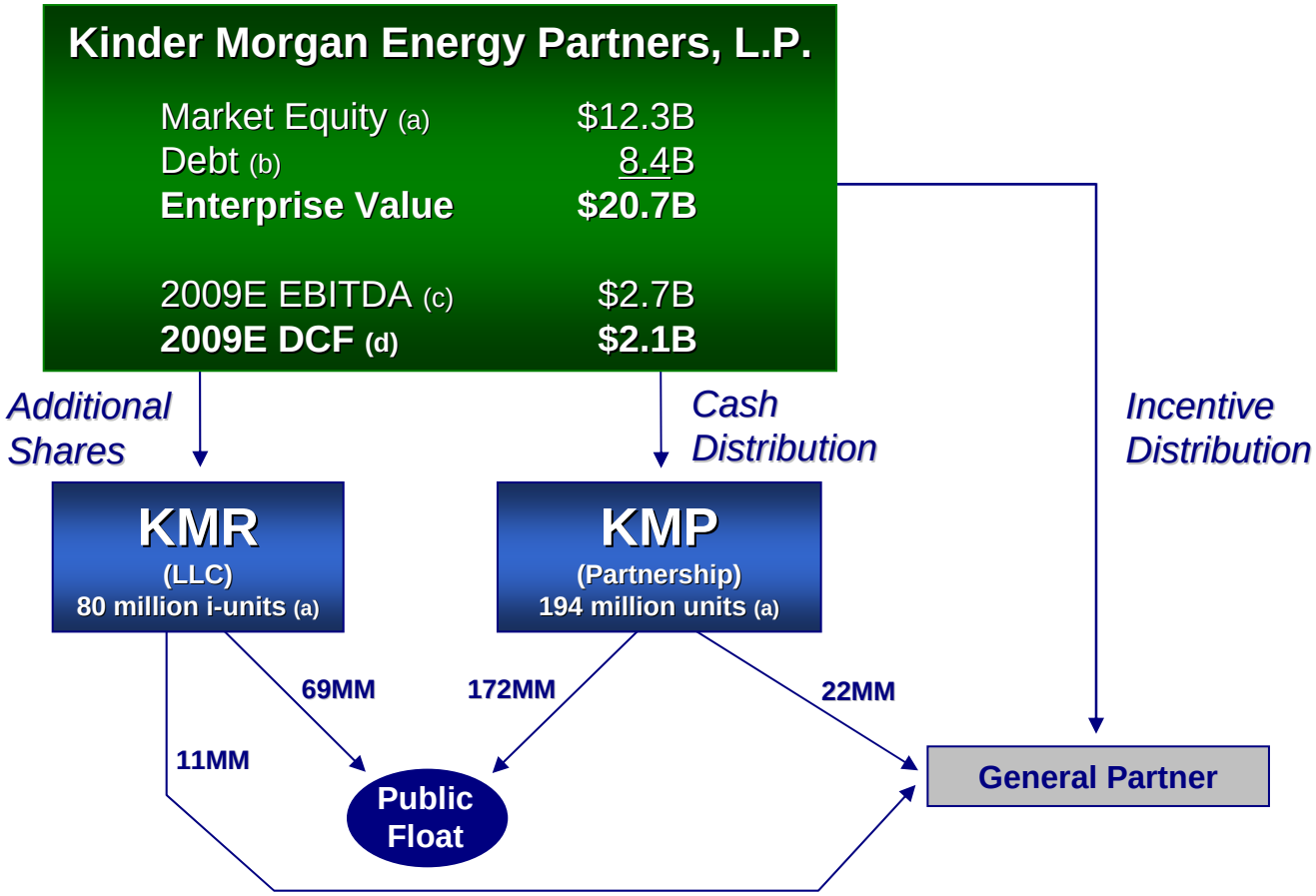
We define distributable cash flow before certain items to be limited partners' pretax income before certain items and DD&A, less cash taxes paid and sustaining capital expenditures for KMP, plus DD&A less sustaining capital expenditures for Rockies Express and Midcontinent Express, our equity method investees. Distributable cash flow before certain items per unit is distributable cash flow before certain items divided by average outstanding units. Segment distributable cash flow before certain items is segment earnings before DD&A less sustaining capital expenditures plus DD&A less sustaining capital expenditures for Rockies Express and Midcontinent Express, our equity method investees. We define EBITDA before certain items as pretax income before certain items, plus interest expense and DD&A. "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, goodwill impairments, allocated compensation for which we will never be responsible, and results from assets prior to our ownership that are required to be reflected in our results due to accounting rules regarding entities under common control, 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 legal settlements, hurricane impacts and casualty losses. Management uses this measure and believes it is important to users of our financial statements because it believes the measure more effectively reflects our business' ongoing cash generation capacity than a similar measure with the certain items included. For similar reasons, management uses segment earnings before DD&A and certain items and segment distributable cash flow before certain items in its analysis of segment performance and managing our business. We believe segment distributable cash flow before certain items is a significant performance metrics because it enables us and external users of our financial statements to better understand the ability of our segments to generate cash on an ongoing basis. We believe it is a useful metric to investors because it is a measure that management believes is important and our chief operating decision makers use for purposes of making decisions about allocating resources to our segments and assessing the segments' respective performance.

We believe the GAAP measure most directly comparable to distributable cash flow before certain items and to EBITDA before certain items is net income. Segment earnings before DD&A is the GAAP measure most directly comparable to segment distributable cash flow before certain items.

Our non-GAAP measures described above should not be considered as an alternative to GAAP net income, segment earnings before DD&A or any other GAAP measure. Distributable cash flow before certain items, segment distributable cash flow before certain items and EBITDA before certain items are not financial measures in accordance with GAAP and have important limitations as analytical tools. You should not consider any of these non-GAAP measures in isolation or as a substitute for an analysis of our results as reported under GAAP. Because distributable cash flow before certain items and EBITDA before certain items exclude some but not all items that affect net income and because these measures are defined differently by different companies in our industry, our distributable cash flow before certain items and EBITDA before certain items may not be comparable to similarly titled measures of other companies. Segment distributable cash flow has similar limitations. 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.

A reconciliation of these measures to the most comparable GAAP measures is provided on our website at: http://www.kindermorgan.com/investor/presentations/.

Capital Structure



(a) KMP market equity based on 194 million common units (includes 5.3 million Class B units owned by Knight Inc.; Class B units are unlisted KMP common units) at a price of $46.43 and 80 million KMR shares at a price of $41.33, as of 18-Mar-2009. Adjusted for Feb-2009 KMR share dividend, Jan-Feb 2009 KMP at-the-market unit issuance and Mar-2009 KMP secondary offering. See footnote "(c)" on slide 23 for additional information regarding the KMP unit issuances.
(b) Debt balance as of 31-Dec-2008, excludes the fair value of interest rate swaps, net of cash. Adjusted for Jan-2009 interest rate swap unwind.
(c) A definition of this measure is outlined on the Non-GAAP Financial Measures slide.
(d) KMP Distributable Cash Flow. A definition of this measure is outlined on the Non-GAAP Financial Measures slide.

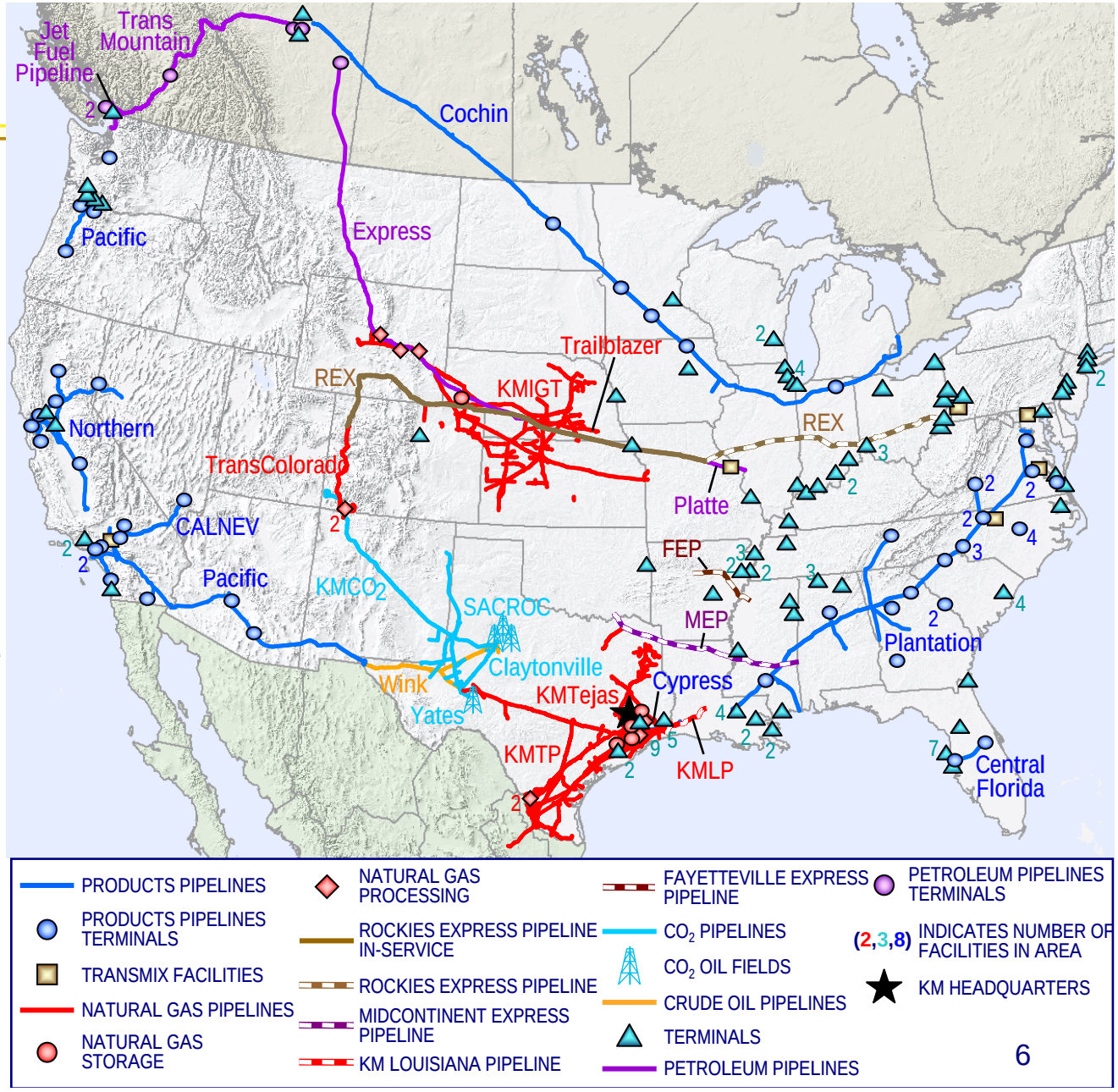
The Kinder Morgan Strategy

Same Strategy Since Inception

- **Focus on stable, fee-based assets which are core to the energy infrastructure of growing markets**
- **Increase utilization of assets while controlling costs**
  - Classic fixed cost businesses with little variable costs
  - Improve productivity to drop all top-line growth to bottom line
- **Leverage economies of scale from incremental acquisitions and expansions**
  - Reduce needless overhead
  - Apply best practices to core operations
- **Maximize benefit of a unique financial structure which fits with strategy**
  - MLP avoids double taxation, increasing distributions from high cash flow businesses
  - Strong balance sheet allows flexibility when raising capital for acquisitions / expansions

Unmatched Footprint

- **Largest independent transporter of petroleum products in the U.S.**
  - Transport nearly 2 million barrels per day (Bbl/d)
- **2nd largest transporter of natural gas in U.S. (a)**
  - Approximately 21,000 miles of interstate / intrastate pipeline
- **Largest transporter of CO_2 in U.S.**
  - Transport ~1.3 Bcf/d of CO_2
- **2nd largest oil producer in Texas**
  - Produce ~55,000 Bbl/d of crude
- **Largest independent terminal operator in the U.S.**
  - 104 million barrels of domestic liquids capacity
  - Handled nearly 100 million tons of dry bulk products in 2008
    - Largest handler of petcoke in U.S.



(a) Includes NGPL

Well-diversified Asset Base

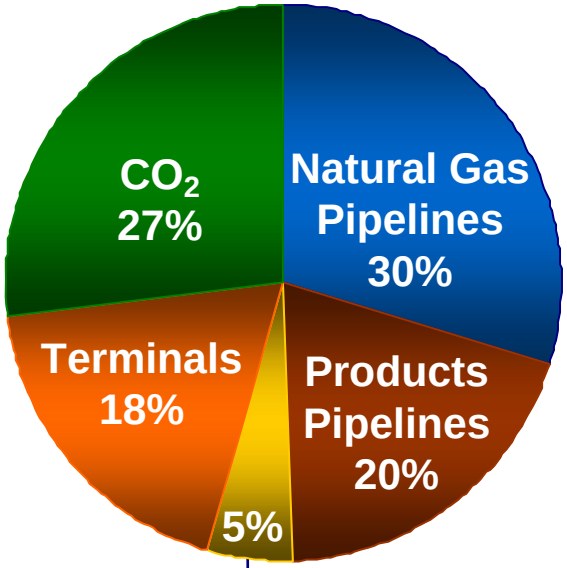
CO_2

- 32% CO_2 transport and sales
- 68% oil production related
- Production hedged (a):
  - 2009=73% ($49/Bbl)
  - 2010=63% ($56)
  - 2011=57% ($63)
  - 2012=35% ($83)
  - 2013=5% ($107)

Terminals

- 52% Bulk
- 48% Liquids
- Geographic and product diversity

KMP 2009 DCF Profile (b)



Natural Gas Pipelines

- 58% Interstate (c)
- 42% Texas Intrastate

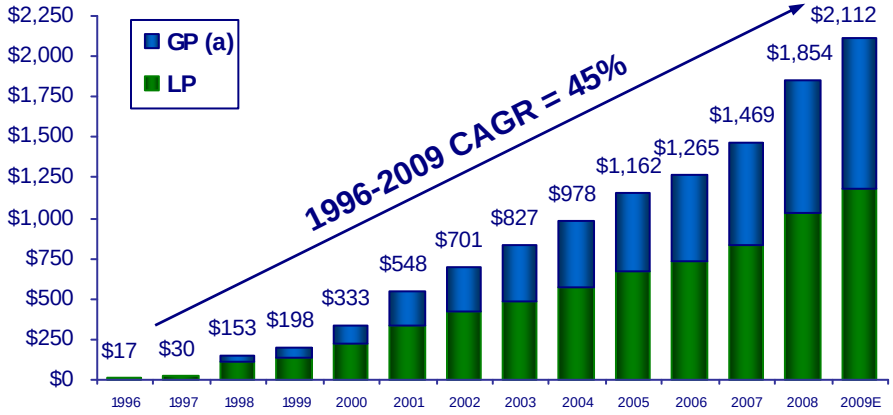
Products Pipelines

- 63% Pipelines
- 32% Associated Terminals (d)
- 5% Transmix

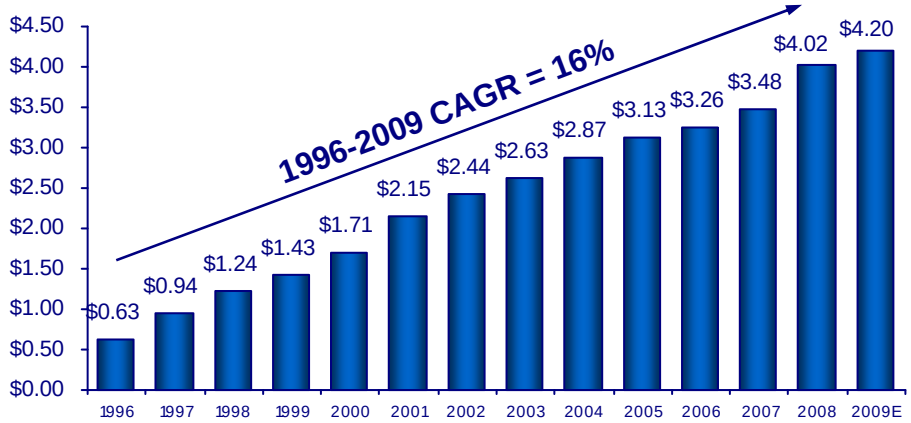
(a) 2009 production based on Kinder Morgan budget; 2010-2013 based on Netherland, Sewell reserve report. Includes heavier NGL components (C4+).
(b) Budgeted 2009 segment distributable cash flow, as defined on the Non-GAAP Financial Measures slide.
(c) Includes upstream segment; ~4% of total natural gas pipeline segment.
(d) Terminals are not FERC regulated except portion of CALNEV.

Twelve Years of Consistent Growth

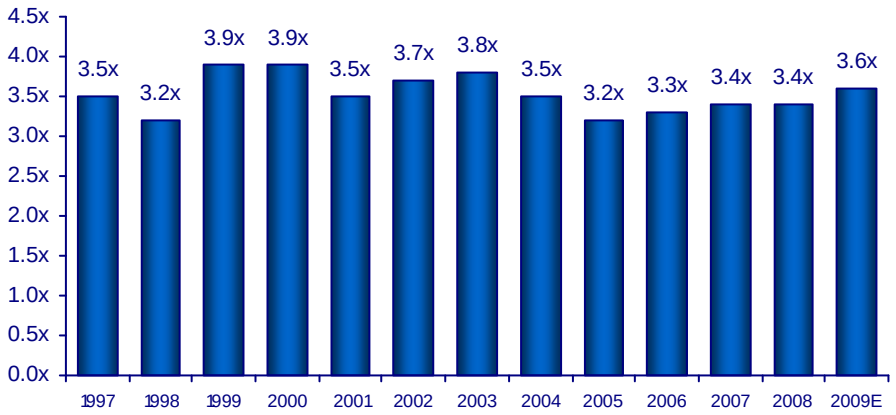
Total Distributions (GP + LP) ($MM)



Annual LP Distribution Per Unit (b)



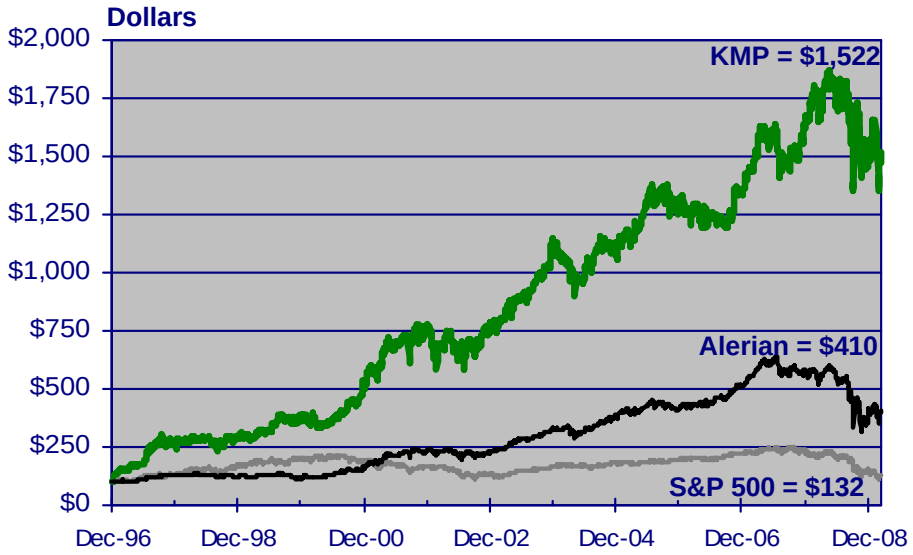
Net Debt to EBITDA (c)



(a) Includes 2% GP interest.
(b) Annual LP distribution, rounded to 2 decimals where applicable.
(c) Debt is net of cash and excludes fair value of interest rate swaps.

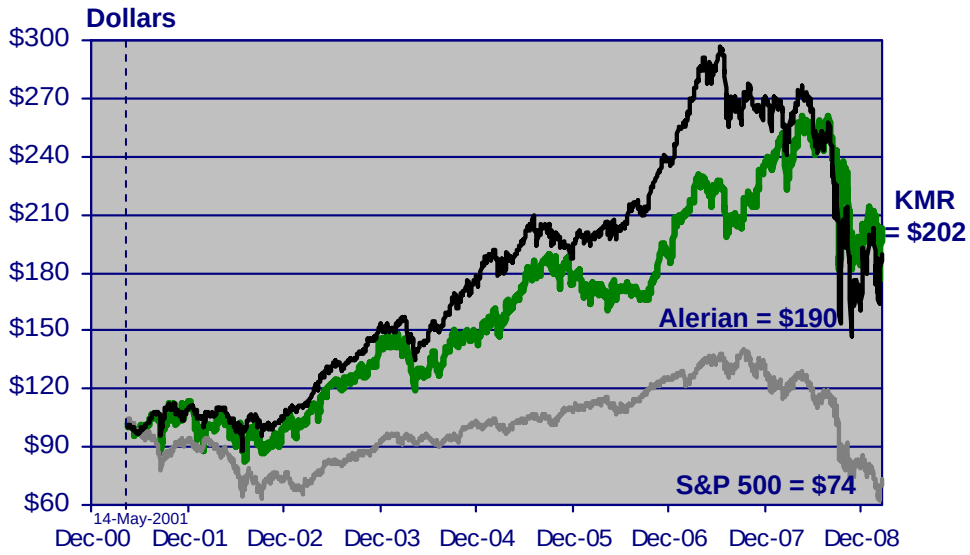
Significant Historical Returns (a)

KMP: 25% CAGR (b)



KMP 2009 YTD Total Return = 4%

KMR: 9% CAGR (c)



KMR 2009 YTD Total Return = 6%

Source: Bloomberg

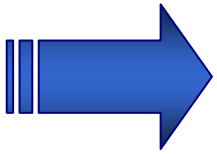
(a) Total returns calculated on a daily basis through 18-Mar-2009 assuming dividends/distributions reinvested in index/stock/unit.

(b) Start date 31-Dec-1996

(c) Start date 14-May-2001; KMR Initial public offering

Promises Made, Promises Kept

Promises Made	Promises Kept
Budgeted	**Actual**
Distribution per unit:	**Distribution per unit:**
2000: $1.60	2000: $1.71
2001: $1.95	2001: $2.15
2002: $2.40	2002: $2.435
2003: $2.63	2003: $2.63
2004: $2.84	2004: $2.87
2005: $3.13	2005: $3.13
2006: $3.28	2006: $3.26
2007: $3.44	2007: $3.48
2008: $4.02	2008: $4.02



2009 Partnership Goals

- **2009 Distribution Target**
  - $4.20 per unit (4.5% growth)
  - Excess coverage of ~$14 million
- **Maintain Solid Balance Sheet**
  - Expansions / acquisitions financed 50% equity, 50% debt
- **Deliver Projects on Current Schedule and Cost Forecast**

Recent Trends

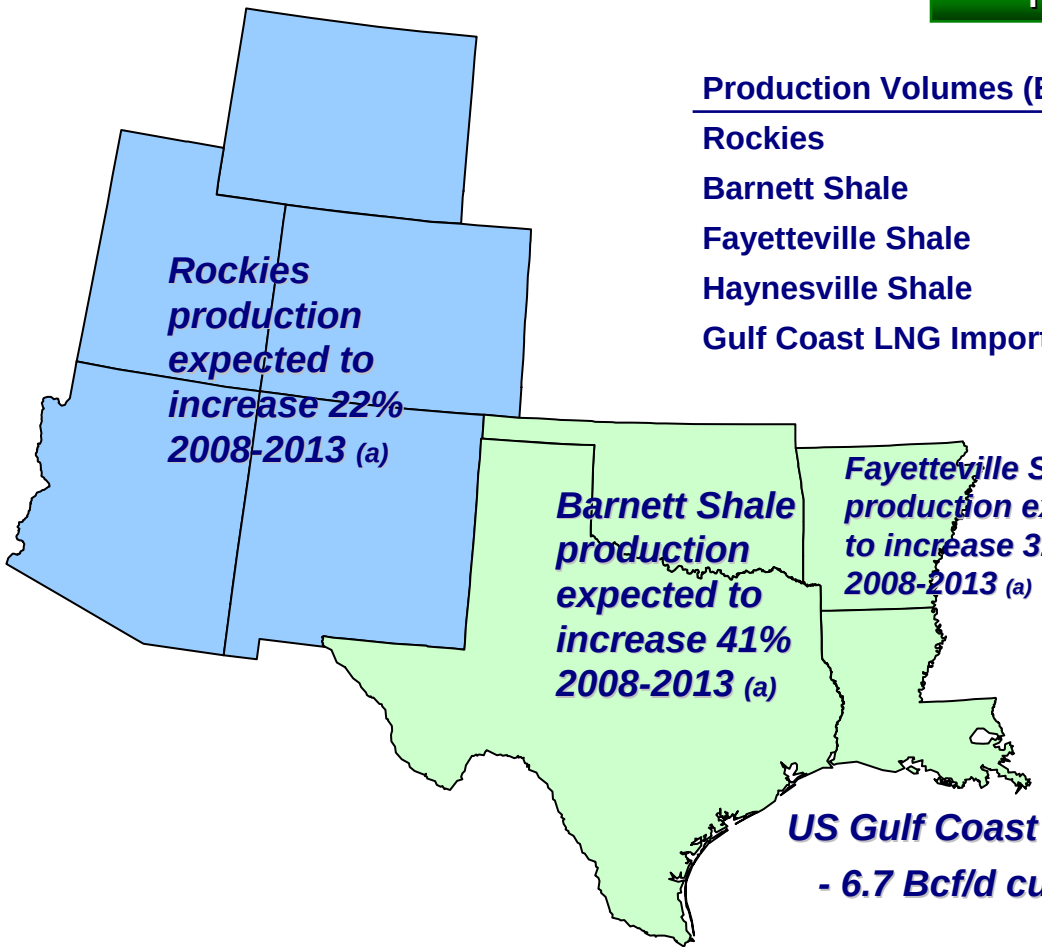
	Impact	Offset / Response
Decline in product demand	– Impacts volumes on product pipelines	– Annual PPI adjustment – Ethanol
Lower oil prices	– Impacts unhedged crude oil and NGL volumes in CO_2 segment	– Lower cost environment; e.g. drilling, equipment, capitalized CO_2, royalties, severance taxes, fuel/operating costs – May help refined product demand
	– Slowing growth in Canadian Oilsands production	– No impact on existing assets – May slow need for additional expansion
Lower short-term interest rates	– Positively impacts floating rate debt	– Impact of 100 bp change = $38MM (a)
Lower raw material costs	– Impacts capital projects	– Less possibility of additional cost overruns – New projects = better economics
Lower natural gas prices	– Slower growth in production	– Insignificant impact on gross margin – Lower power costs – May slow demand for new projects
Contango crude oil/refined products markets	– Crude/products sold forward, drives demand for existing tankage	– Incremental storage opportunities
Increased focus on lower CO_2 emissions	– Should drive demand for natural gas as preferred fossil fuel – Potential legislation regulating CO_2 emissions	– Natural gas expansion/ newbuild opportunities – CO_2 S&T opportunities
Volatility in capital markets	– Lower entity and asset valuations – Fewer entities with access to capital	– Potential for asset acquisitions/mergers

(a) Impact of a 100-basis point change in rates over a full year. Currently, ~43% of total debt exposed to floating rates (long-term fix/float target = 50/50%); reflects Jan-2009 swap unwind and $1 billion of new fix/floating rate swaps entered into Feb-2009.

Continued Growth Opportunities

	Current Projects (2009-2011)	Additional Opportunities
Shifting Natural Gas Supply Sources		
— **Rockies**	– Rockies Express pipeline	– Expansions, extensions and added service on current projects and existing assets
— **Shale Plays**	– Midcontinent Express pipeline – Fayetteville Express pipeline	– Storage
— **LNG**	– KM Louisiana pipeline	
Increased Use of Renewable Fuels		
— **Biodiesel** — **Ethanol**	– Store and blend at terminals – Tampa, Southeast Terminals, Northwest, West Coast, Houston, Argo, Philadelphia – Transport on pipelines – CFPL	– Additional ethanol/biodiesel storage and blending at terminal facilities – Batched and dedicated ethanol/ biodiesel pipelines – Plantation/ Oregon line
Increased Use of Heavy Crude		
— **Petcoke Handling**	– Increased volume at petcoke terminals	– Increased handling of petcoke
— **Sulfur Handling**	– New petcoke locations: • BP Whiting • New Gulf Coast Facility • Deer Park	– Need for sulfur terminaling/storage – Application of sulfur prilling technology at terminal facilities

Shifting Natural Gas Supply Sources



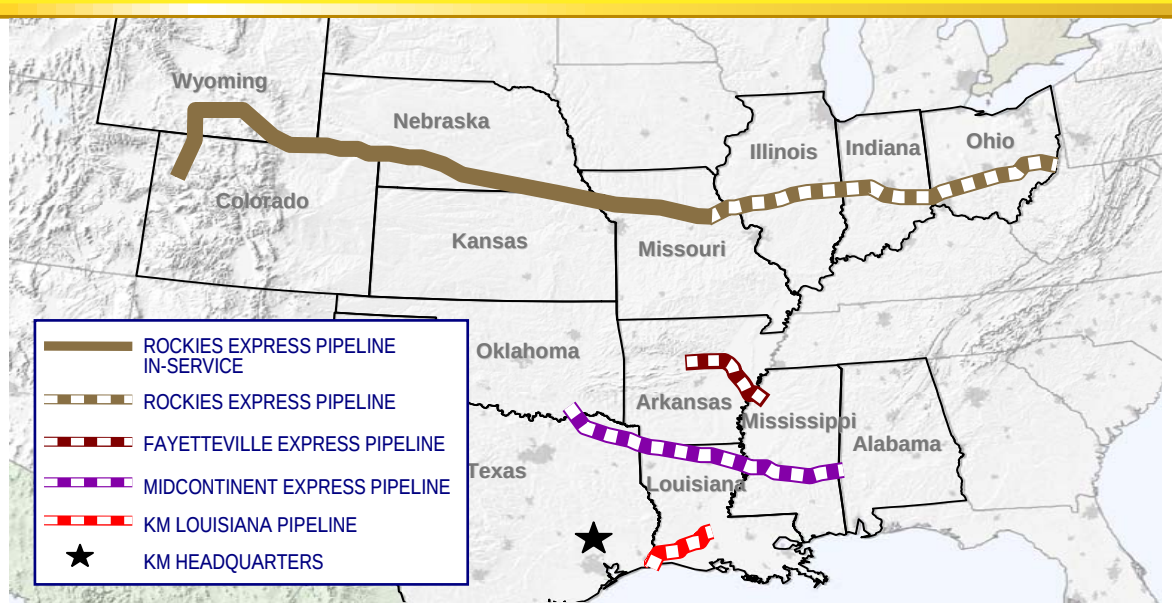
Natural Gas Supply (a)

Production Volumes (Bcf/d)	2008E	2013	Change	% Change
Rockies	8.9	10.9	2.0	22%
Barnett Shale	3.9	5.5	1.6	41%
Fayetteville Shale	0.7	2.9	2.2	314%
Haynesville Shale	0.1	3.7	3.6	n/m
Gulf Coast LNG Imports	0.1	1.8	1.7	n/m

US Gulf Coast LNG import capacity:
- 6.7 Bcf/d currently in place (b)

(a) Sources: Fayetteville Shale, 2013 - Deutsche Bank forecast for 1/1/2012 (Jul-2008). All other natural gas supply - Wood Mackenzie (Dec-2008)
(b) Source: FERC

Newbuild Natural Gas Pipelines

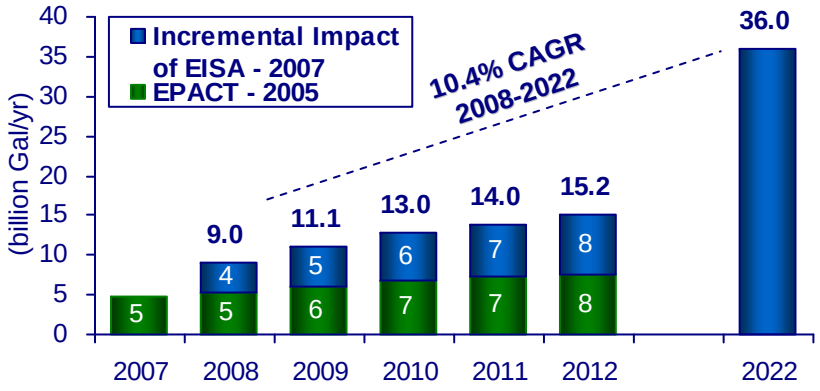


	Rockies Express Pipeline	Midcontinent Express Pipeline	Fayetteville Express Pipeline	KM Louisiana Pipeline		Total
KM Share of Cost ($MM)	$3,153 (a)	$1,114 (b)	$604	$949	=	$5,820
Capacity (Bcf/d)	1.8	1.8 (c)	2.0	2.1	=	7.7
In-service	2007-2009 (d)	2009-2010 (e)	2011	2009		
Term of Contracts	11.5 yrs (f)	10 yrs	10 yrs	20 yrs		
Ownership	KMP 50% (g) SRE 25% COP 25% (g)	KMP 50% ETP 50%	KMP 50% ETP 50%	KMP 100%		

(a) Includes ~$39 million (our share) for the REX-West EnCana expansion.
(b) Includes ~$93 million (our share) for the MEP Zone-1 expansion.
(c) Zone-1 capacity after expansion.
(d) 2009 in-service for base 1.8 Bcf/d project, 2010 in-service for REX-West EnCana expansion.
(e) 2009 in-service for base 1.4 Bcf/d project, 2010 in-service for Zone-1 expansion.
(f) Ten years from in-service of REX East.
(g) Upon completion of construction.

Increased Use of Renewable Fuels

Renewable Fuels Standard (RFS) (a)



- **EPA guidelines for the 2009 RFS requires "Obligated Parties" to blend ethanol at an expected overall 10% level in gasoline (b)**

EPA guidelines require significant ethanol/biodiesel blending in 2009 and beyond

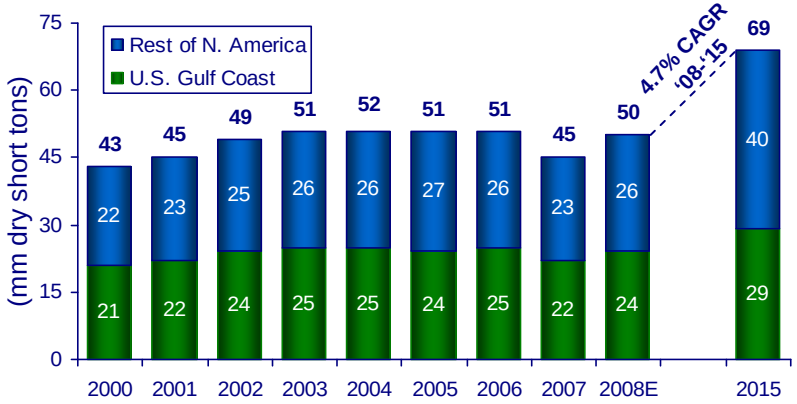
Leverage Existing Assets to be Most Efficient, Add Capacity as Opportunity Arises

- **Invested a total of $161 million through 2008 to expand biofuel handling capabilities across our Products Pipelines and Terminals segments**
  - Handled ~50 million barrels of ethanol in 2008
- **Converted Central Florida Pipeline – first U.S.-based pipeline to transport ethanol**
- **Ran successful test batch of B5 blend (5% biodiesel/95% ULSD) on Plantation Pipe Line System**
  - Pursuing commercial commitments
- **Planning biodiesel movements on Portland-Eugene pipeline**

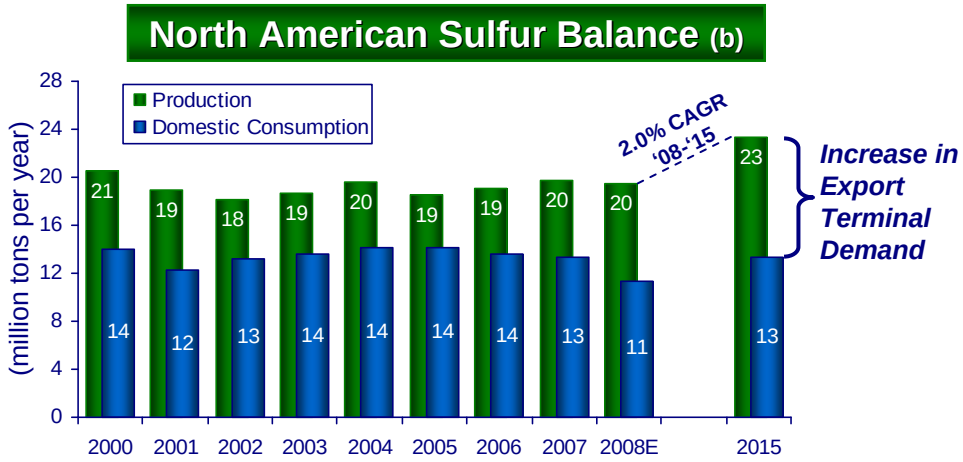
(a) Source: Renewable Fuels Association
RFS: Renewable Fuels Standard; EISA: Energy Independence and Security Act of 2007 (H.R.), EPACT: Energy Policy Act of 2005
(b) Source: EPA. Obligated Parties – all but small refiners and non-refiner/importers of gasoline.

Increased Production and Use of Heavy Crude

North American Petcoke Production (a)



North American Sulfur Balance (b)



(a) Source: Jacobs Consultancy
(b) Source: The Sulfur Institute, PentaSul and Con-Sul Inc.
(c) Source: Turner, Mason and Company (Jan-2009)

Despite drop in crude price, oil slate still getting heavier – 1.4MMbbl/d of incremental heavy refining capacity forecast to be added by 2015 (c)

Leverage strong Gulf Coast position into the Midwest and Canada

- **Heavier, sour crude produces more residue**
  - Petcoke
  - Sulfur
- **Need for more petcoke and sulfur handling**
- **More sulfur to be exported**
  - Need for terminaling/storage
  - Application of proprietary prilling technology
- **Well positioned…**
  - Handled 14.8 million tons of petcoke in 2008, ~34% of total U.S. production
- **Customers are signing deals**
  - BP Whiting
  - Deer Park
  - New Gulf Coast facility
  - Renewed 2 petcoke contracts with Exxon at Baton Rouge and Chalmette
  - Signed a new petcoke contract with Exxon at Baytown

Current Major Projects

$6 Billion In Current Projects 2009-2011 (a)

Project	Estimated Project Cost KM-Share ($MM)	Est. Remaining Project Cost KM-Share ($MM) (b)	Expected Completion
Rockies Express East	$1,825 (a,c)	$845 (a,c)	2009 (d)
Midcontinent Express	1,114 (a,e)	695 (a,e)	2009-2010 (f)
Fayetteville Express	604 (a)	596 (a)	2011
KM Louisiana Pipeline	949	184	2009
CALNEV expansion	426	410	2011
CO_2 – SACROC and Yates	419	419	2009
Other identified projects	638 (a,g)	376 (a,g)	2009-2011
Total	**$5,975 (a)**	**$3,525 (a)**	

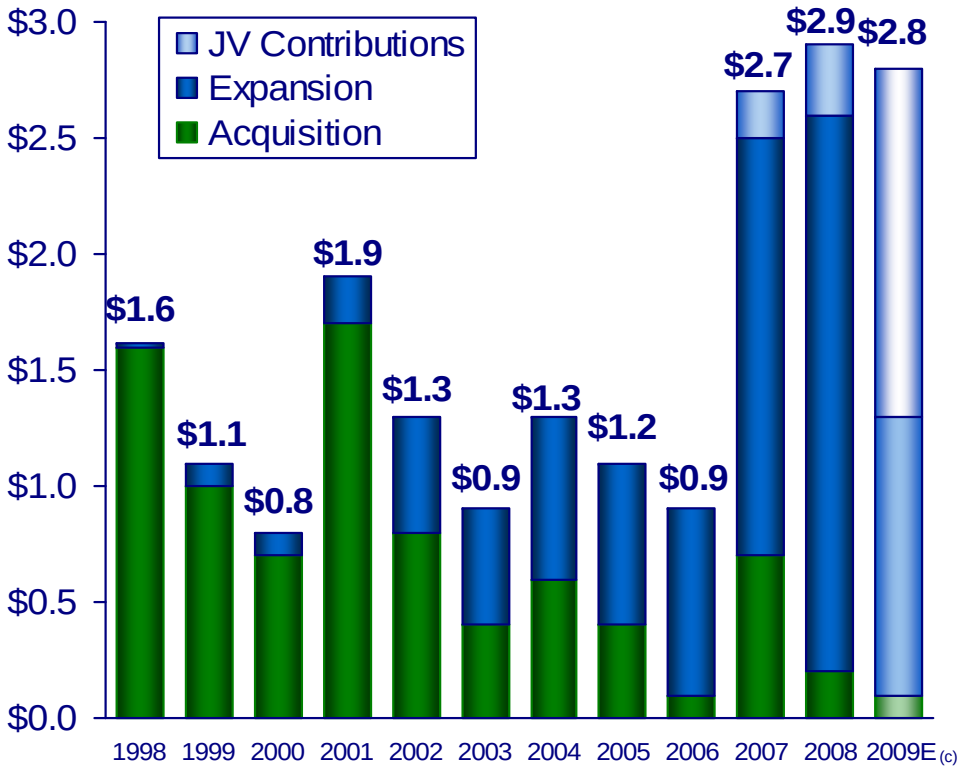
Completed projects totaling $4.3 billion in last ~2 years (h)

(a) Pro rata expenditures for KMP's ownership interest.
(b) As of 1-Jan-2009.
(c) Includes REX-West EnCana expansion.
(d) 2009 in-service for base 1.8 Bcf/d project, 2010 in-service for REX-West EnCana expansion.
(e) Includes MEP Zone-1 expansion.
(f) 2009 in-service for base 1.4 Bcf/d project, 2010 in-service for Zone-1 expansion.
(g) Dayton, Markham, KMTP hill country, Travis AFB, Colton, Carson, Tampa ethanol, CFPL ethanol conversion, Southeast terminals ethanol, Pasadena/Galena Park Phase IV, Deer Park, BP Whiting petcoke, Cora, Van Wharves and other.
(h) KMP's proportionate share of expenditures for projects completed and brought in-service in last ~2 years. Total cost of completed projects = $5.7 billion (8/8ths).

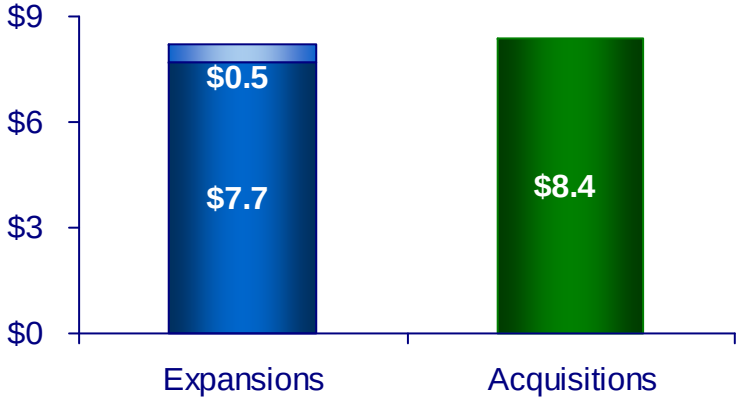
~$17 Billion in Capital Invested To Date (a,b)

(billions)

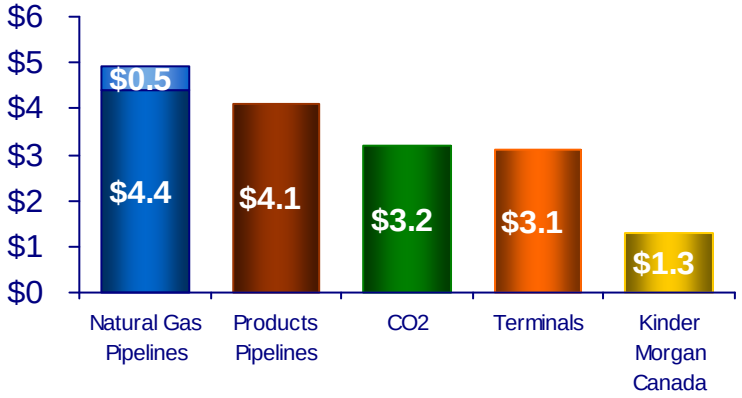
Total Invested by Year (a)



Total Invested by Type (a,b)



Total Invested by Segment (a,b)



(a) For joint-ventures, reflects our equity contributions.
(b) 1998 – 2008, does not include 2009 budget.
(c) 2009 budget.

Returns on Capital

	2000	2001	2002	2003	2004	2005	2006	2007	2008
Segment ROI (a):									
Products Pipelines	11.9%	11.8%	12.8%	12.9%	12.4%	11.6%	11.8%	13.2%	12.5%
Natural Gas Pipelines	13.3	15.5	12.9	13.5	14.0	15.5	16.7	17.6	16.9
CO_2	27.5	24.6	22.0	21.9	23.8	25.7	23.1	21.8	25.9
Terminals	19.1	18.2	17.7	18.4	17.8	16.9	17.1	15.8	15.5
Kinder Morgan Canada	--	--	--	--	--	--	--	11.0	11.9
KMP ROI	12.3%	12.7%	12.6%	13.1%	13.6%	14.3%	14.4%	14.1%	14.8%
KMP Return on Equity	17.4%	19.0%	21.9%	23.2%	25.2%	26.6%	26.8%	27.4%	30.3%

Note: A definition of this measure may be found in the appendix to the KMEP Jan-2009 Investor Conference presentation.

(a) G&A is deducted in calculating the return on investment for KMP, but is not allocated to the segments and therefore not deducted in calculating the segment information.

Balance Sheet Has Remained Solid

(millions)

Credit Summary

	Current (a)	Budgeted Yr-end 2009
L-T Debt Rating	Baa2/BBB (b)	
Credit Metrics		
Debt / EBITDA (c,d)	3.4x	3.6x
EBITDA / Interest (d)	6.1x	5.9x

Revolver Liquidity (a,e)

Total Bank Credit	$1,787
Less:	
Borrowings	---
Letters of Credit	(313)
Plus Jan'09 Swap Unwind	144 (f)
Liquidity	***$1,618***

Long-term Debt Maturities (a,g)

2009	$7 (h)
2010	$262
2011	$706
2012	$956 (i)
2013	$505

(a) As of 31-Dec-2008.
(b) On 13-Oct-2008, S&P revised its outlook on KMEP to 'Negative' from 'Stable'. At the same time, S&P affirmed KMEP's long-term credit rating of 'BBB' but lowered the short-term rating to 'A-3' from 'A-2'.
(c) Debt balance excludes fair value of interest rate swaps and is net of cash.
(d) EBITDA and interest are trailing 12 months.
(e) Adjusted to exclude Lehman commitment.
(f) Cash proceeds of approximately $144 million from Jan-2009 interest rate swap unwind.
(g) Long-term debt, excludes borrowing under revolving credit facility.
(h) Currently remaining in 2009.
(i) Excludes 10-yr bond with 3-yr put (final maturity 2019).

Will We Distribute $4.20 in 2009?

- **Vast majority of $2.1 billion 2009 budgeted DCF is very secure**
- **Impact of oil price at $50/Bbl (vs. $68 in budget) = ~$100 million**
  - 4.7% of total DCF
  - Sensitivity is ~$6 million per $1/Bbl change in crude price
- **Potential offsetting factors**
  - Lower CO_2 operating and capital costs
  - Better performance by other business segments
  - Lower interest rates
  - Lower G&A
  - Acquisitions
  - Cumulative coverage
  - GP contribution

Do Not Require Access to Capital Markets in 2009

(millions)

Uses – Budget		
Growth Expenditures:		
Expansion Capex	$1,188	
Contributions to JVs	1,472	(a)
Acquisitions	130	
Total Growth Capital	$2,790	
Debt Maturities	257	
Total Capital Uses	**$3,047**	

Sources		
Sources:		
Dec'08 Debt Issue	$500	
Dec'08/Jan'09 Swap Unwinds	339	(b)
Year-to-date KMP		
Equity Issuance	295	(c)
KMR Dividend	350	
Additional Secondary Equity	705	
Debt Issuance	750	
Revolving Credit Facility	108	(d)
Total Sources	**$3,047**	

Sources – Alternative		
Already Secured:		
Cash on Hand @ 12/31/08	$63	
Borrow under Revolver	1,457	(e)
Jan'09 Swap Unwind	144	
Year-to-date KMP		
Equity Issuance	295	(c)
KMR Dividend	350	
Knight Purch KMP Units	750	(f)
Total Secured Funding	**$3,059**	
Secured Funding in Excess		
Of Total Uses:	**$12**	

(a) Equity contributions to Rockies Express Pipeline and Midcontinent Express Pipeline.
(b) Two interest rate swaps unwound in Dec-2008 for cash proceeds of $194.3 million. One swap unwound in Jan-2009 for total cash proceeds of $144.4 million.
(c) In January and February 2009, we cumulatively issued approximately 0.6 million KMP units through our at-the-market sales program for gross proceeds before fees of approximately $30.5 million. On 3-Mar-2009, we issued 5.5 million KMP units in an underwritten secondary offering for gross proceeds before discounts and expenses of approximately $264.3 million.
(d) Remaining KMEP revolver borrowing capacity at 31-Dec-2009, adjusted to exclude Lehman commitment, estimated to be approximately $600 million.
(e) Remaining KMEP revolver borrowing capacity was $1,457 million as of 31-Dec-2008.
(f) Knight can fund all but ~$100 million of its $750 million KMP commitment with 2009 expected cash flow. Available capacity on Knight's credit facility at 31-Dec-2008, adjusting for cash on hand and Knight's January tax payment, is ~$800 million.

Risks

- **Regulatory**
  - Pacific Products Pipeline FERC/CPUC case
  - Periodic rate reviews
  - Unexpected policy changes
- **Crude Oil Production Volumes**
- **Crude Oil Prices**
  - Budget assumes $68/Bbl realized price on unhedged barrels
  - 2009 Sensitivity is ~$6 million DCF per $1/Bbl change in crude oil prices
- **Construction Cost Overruns**
- **Environmental**
- **Terrorism**
- **Interest Rates**
  - Currently ~43% floating rate debt (a); long-term target is 50/50% fix/floating
  - Budget assumes rates at a level above the forward curve
  - The full-year impact of a 100-bp increase in rates equates to an approximate $38 million increase in interest expense (a)

(a) Reflects Jan-2009 swap unwind and $1 billion of new fix/floating rate swaps entered into Feb-2009.

Summary

KMP's model works

- **Stable Cash Flow**
  - Own assets core to energy infrastructure
- **Fixed Cost Business**
  - Drop growth to bottom line
- **Available Internal/External Growth Opportunities**
  - Critical mass
  - Well-located assets/favorable demographics
  - At attractive returns
  - With Less competition
- **Demonstrated Access to Capital**
- **Unique Structure**
  - Tax efficient
  - Incentive fee
- **Management Philosophy**
  - Low-cost operator
  - Focused on cash
  - Disciplined investing

KMP/KMR:
8-9% Yield
and
8%
Long-Term
Growth


KINDER MORGAN
ENERGY PARTNERS, L.P.