Enterprise Products Partners L.P.

Analyst Meeting

May 26, 2004

Forward Looking Statements

This presentation contains forward-looking statements and information that are based on Enterprise's beliefs and those of its general partner, as well as assumptions made by and information currently available to them. When used in this presentation, words such as "anticipate," "project," "expect," "plan," "goal," "forecast," "intend," "could," "believe," "may," and similar expressions and statements regarding the contemplated transaction and the plans and objectives of Enterprise for future operations, are intended to identify forward-looking statements.

Although Enterprise and its general partner believes that such expectations reflected in such forward looking statements are reasonable, neither it nor its general partner can give assurances that such expectations will prove to be correct.

Forward Looking Statements (cont.)

Such statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, actual results may vary materially from those Enterprise anticipated, estimated, projected or expected. Among the key risk factors that may have a direct bearing on Enterprise's results of operations and financial condition are:

- Fluctuations in oil, natural gas and NGL prices and production due to weather and other natural and economic forces;
- A reduction in demand for its products by the petrochemical, refining or heating industries;
- A decline in the volumes of NGLs delivered by its facilities;

Forward Looking Statements (cont.)

- The failure of its credit risk management efforts to adequately protect it against customer non-payment;
- Terrorist attacks aimed at its facilities;
- The failure to complete the proposed merger;
- The failure to successfully integrate the respective business operations upon completion of the merger or its failure to successfully integrate any future acquisitions; and
- The failure to realize the anticipated cost savings, synergies and other benefits of the proposed merger.

Enterprise has no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

This presentation also includes Non-GAAP financial measures. Please refer to the reconciliations of GAAP financial statements to Non-GAAP financial measures included in the back of this handout.

Overview of Enterprise

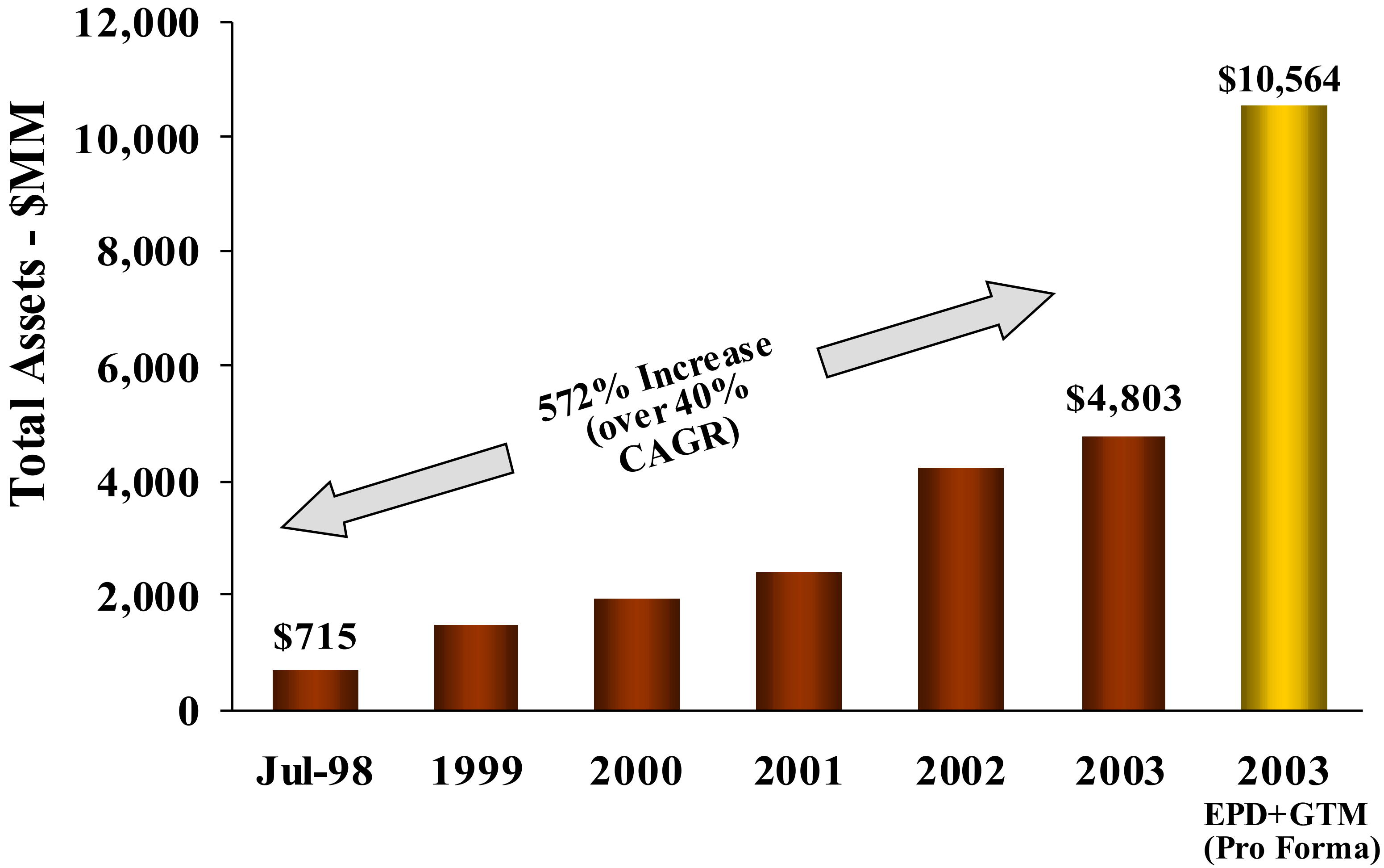
- 2nd largest publicly traded energy partnership serving producers and consumers of natural gas and natural gas liquids (NGLs)
  - IPO in July 1998
  - Currently ranked 336th on Fortune 500 and 7th on Forbes list of America's 25 Fastest-Growing Big Companies
- Large platform of assets across the midstream energy value chain
  - Only integrated natural gas and NGL transportation, fractionation, processing, storage and import/export network in North America
  - Pending merger with GulfTerra Energy Partners adds complementary scale, scope and diversity to existing operations
- Management owns the general partner and limited partner units for total of 58% ownership – highly aligned with our public partners

Business Strategy

- Build an integrated midstream energy business – not just collecting assets
- Capitalize on organic growth opportunities to serve natural gas and NGL production in the Rocky Mountain region and deepwater and continental shelf areas of the GOM
- Partner with customers in joint venture projects to gain access to feedstock and market for products
- Expand asset base through accretive acquisitions of complementary midstream assets
- Increase the amount of cash earned from fee-based businesses and de-emphasize commodity-based activities

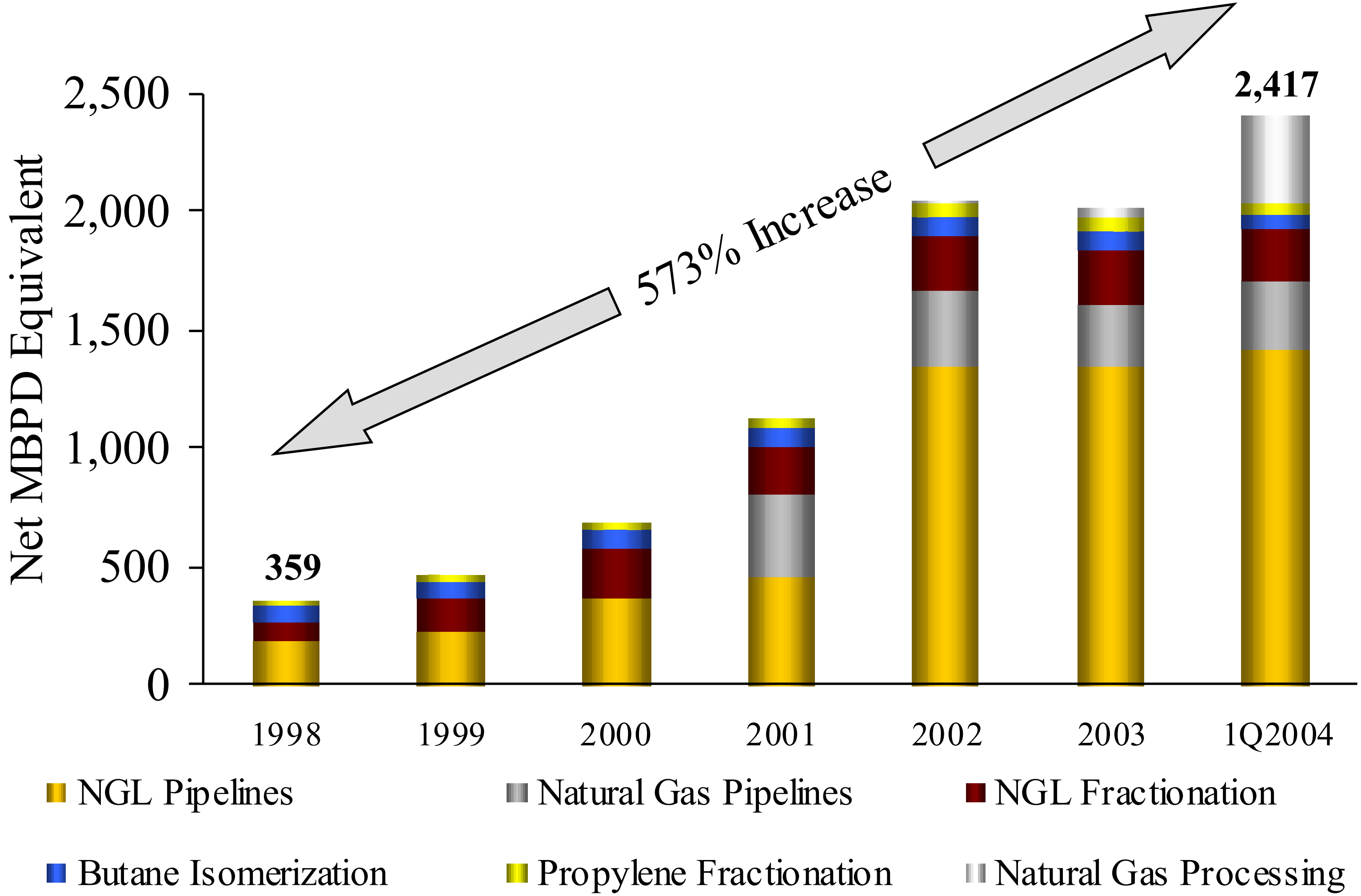
Focus on Growing the Partnership

$4.1 Billion Invested in Hard Assets since IPO

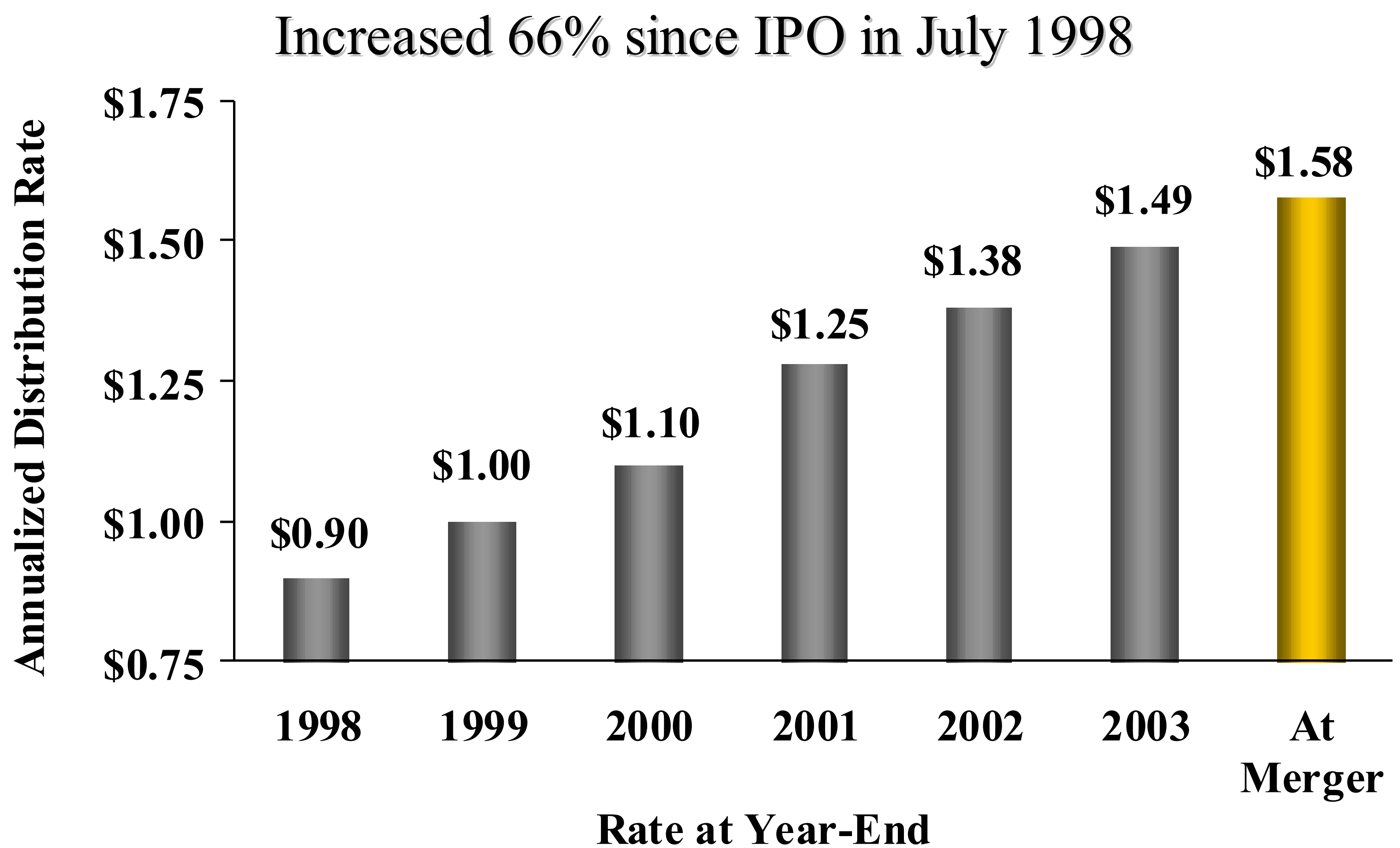


Growing Fee-Based Volumes

Recently converted most of processing to fee-based



Increasing Cash Distributions



Enterprise's Operating and Business Environment

Special Emphasis on the U.S. Ethylene Industry

Peter Fasullo
*En*Vantage, Inc*
May 26, 2004

Topics to be Covered

envantage

Study Scope – Study set out to answer:

1. How sensitive is EPD's profitability to:
   - the business cycles of the US Ethylene Industry; and,
   - to different price decks for crude oil and natural gas?

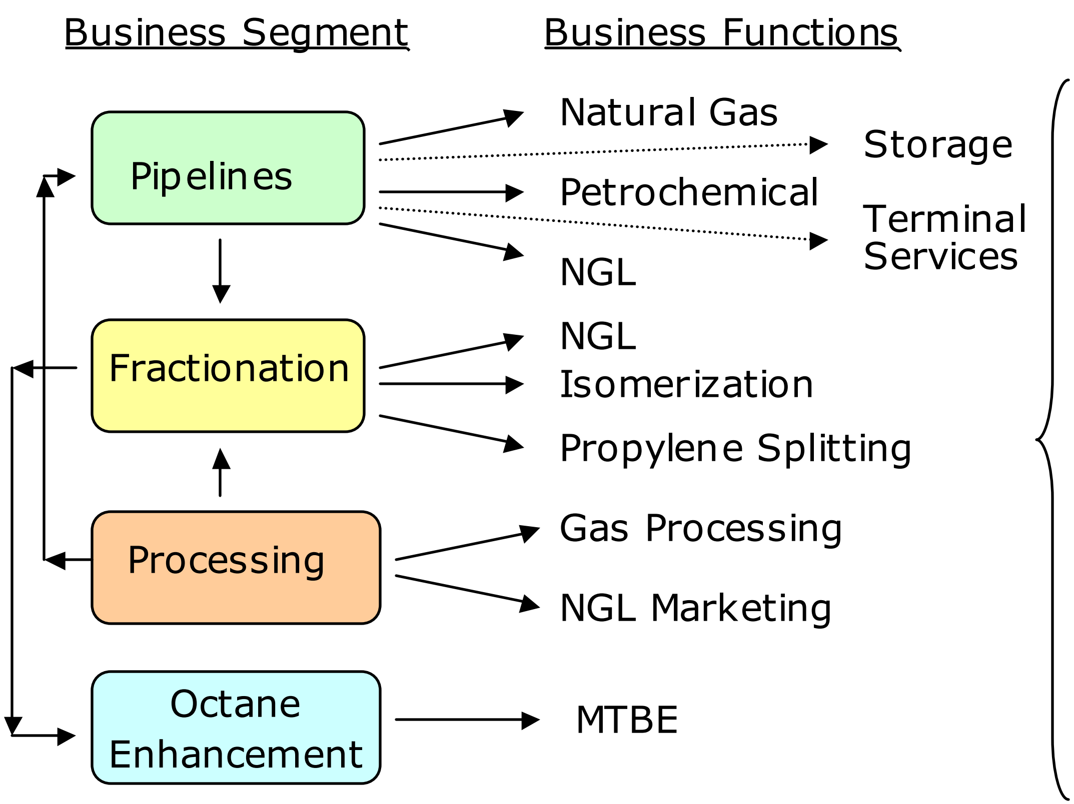
2. Has EPD seen the Ethylene cycle trough and what is the outlook for the Industry?

3. Will the merger with GulfTerra change EPD's sensitivity to Ethylene cycles?

4. Do long term market fundamentals favor EPD?

Basic Approach & Focus Areas (1)

1. Examined EPD's business segments and interrelationships to assess EPD's sensitivity to the US Ethylene Industry.



Profiled each segment:

- ❖ Earnings Contribution
- ❖ Products Handled & Markets
- ❖ Primary Business Drivers

Basic Approach & Focus Areas (2)

2. Specifically focused on:

   - *The Effect of High Natural Gas Prices on:*
     - *The U.S. Ethylene Industry*
     - *The U.S. Gas Processing Industry*
   - *The Economy and its influence on the U.S. Ethylene Industry*

3. Developed short and long term industry outlooks, specifically for ethane.

4. Evaluated EPD's operating income sensitivity (with and without GTM) to changes in Ethylene Operating Environment and Commodity Prices.

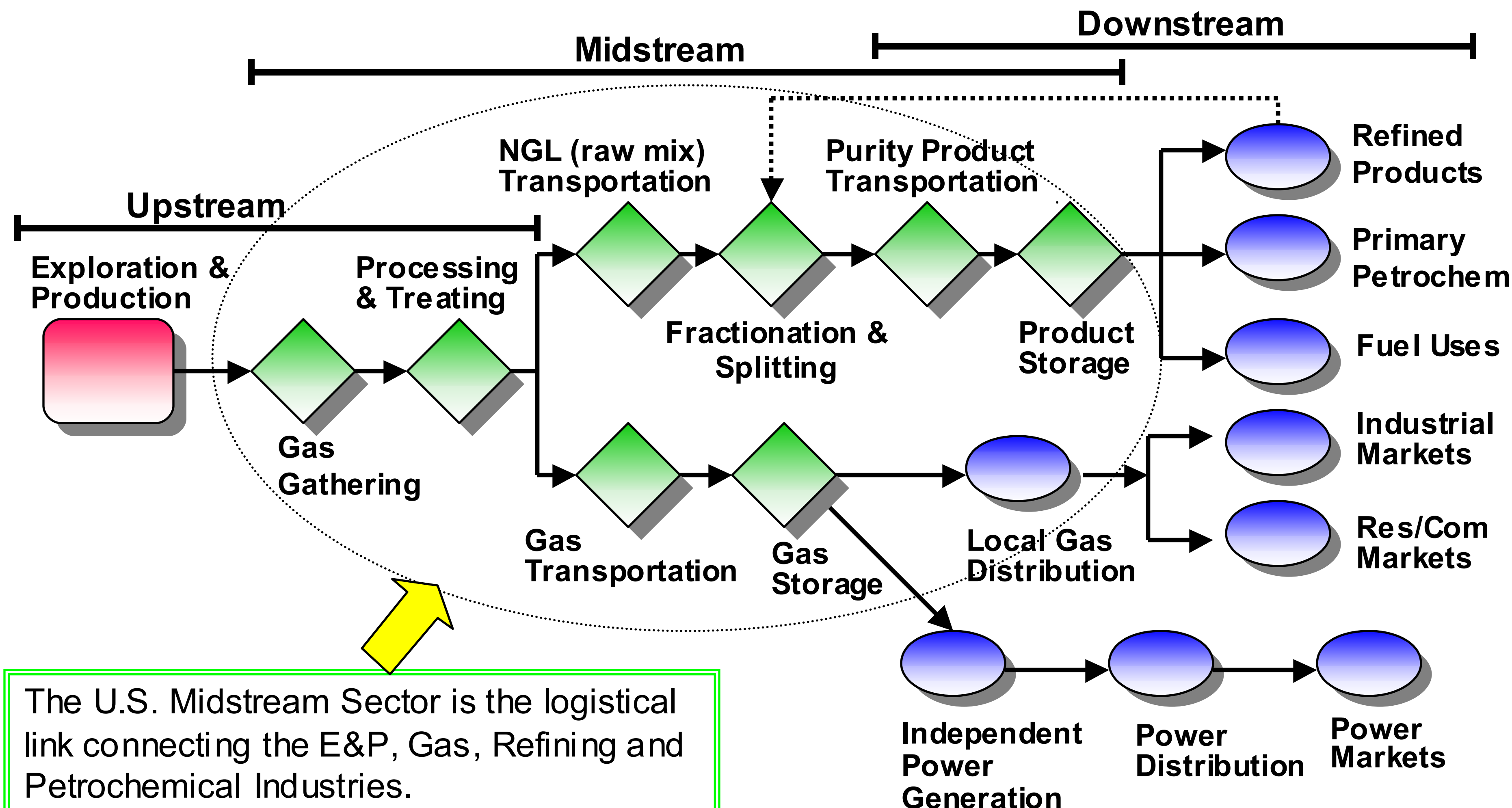
Terminology

- **Y-Grade or Raw NGL Mix** - are the raw NGLs (ethane, propane, butanes and natural gasoline) extracted from natural gas by a gas processing plant.
- **Refinery Gas Liquids (RGLs)** - are light hydrocarbons such as ethane, propane, normal and iso-butanes that are produced as the result of refining crude oil.
- **Fractionation** - the process by which individual NGL components are separated from raw NGL, LPG or RGL mixes.
- **"Frac Spread"** – is the term commonly used to express the price differential between the market value of the individual NGL component and its heating value if left in the natural gas stream. "Frac Spreads" are commonly expressed in cents per gallon (cpg) or dollars per million British Thermal Units ($/MM BTU).
- **Propylene Splitting** - the process of purifying propylene to polymer grade by fractionating out propane and other hydrocarbons from the propane/propylene mix.
- **Isomerization** – the process of changing normal butane to iso-butane..
- **Primary Petrochemicals** - mainly the production of ethylene and other olefin co-products (propylene, butylenes) from the "cracking" of NGLs and refinery intermediate products, such as naphtha and gas oil commonly referred to as heavy liquids. The "cracking" of hydrocarbon feedstocks is the thermal process by which Ethylene plants produce primary petrochemicals.

Business Profiles

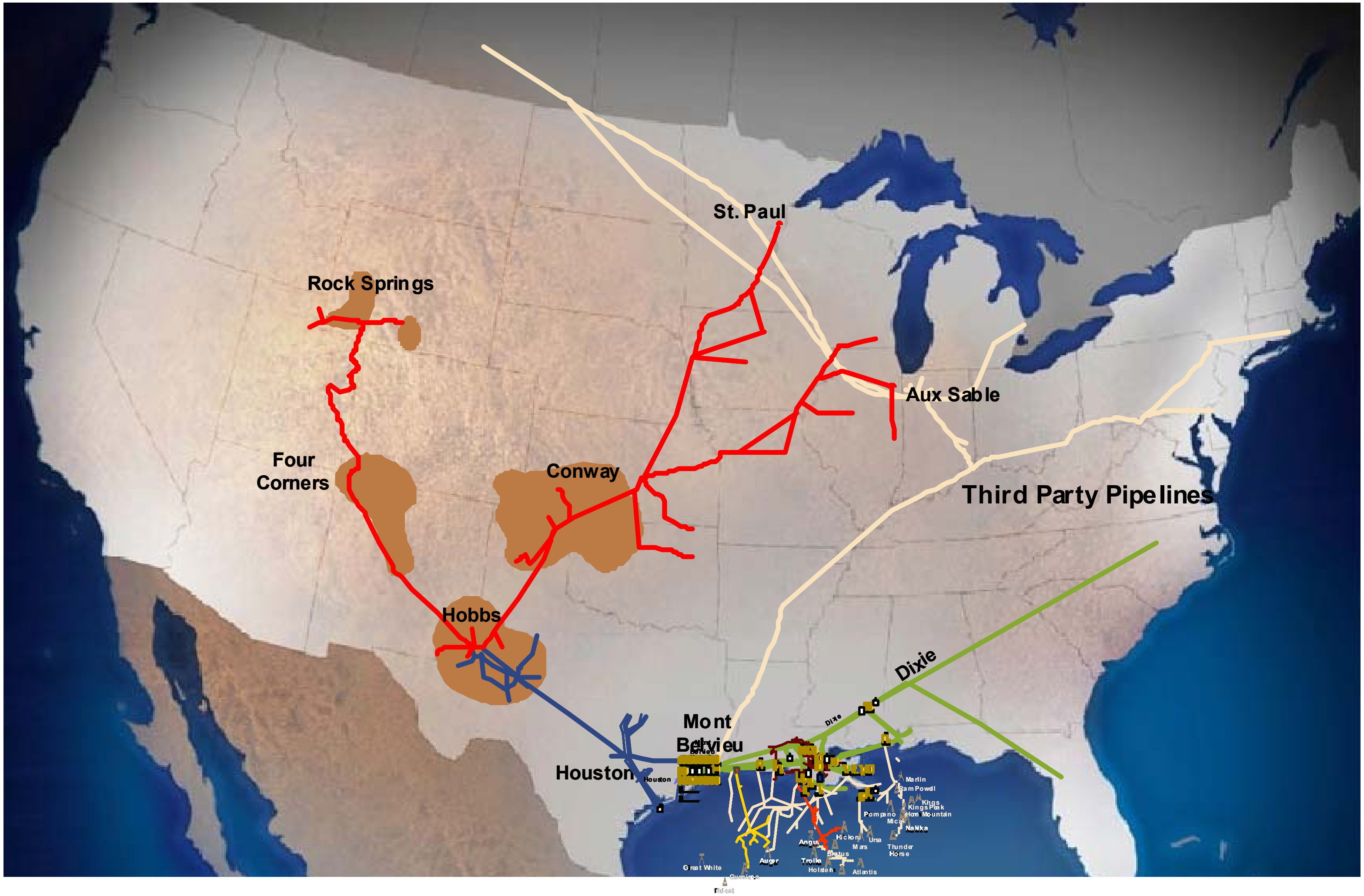
Enterprise & GulfTerra

EPD's primary operating sector is along the NGL value chain. GulfTerra's is weighted more to natural gas midstream services.



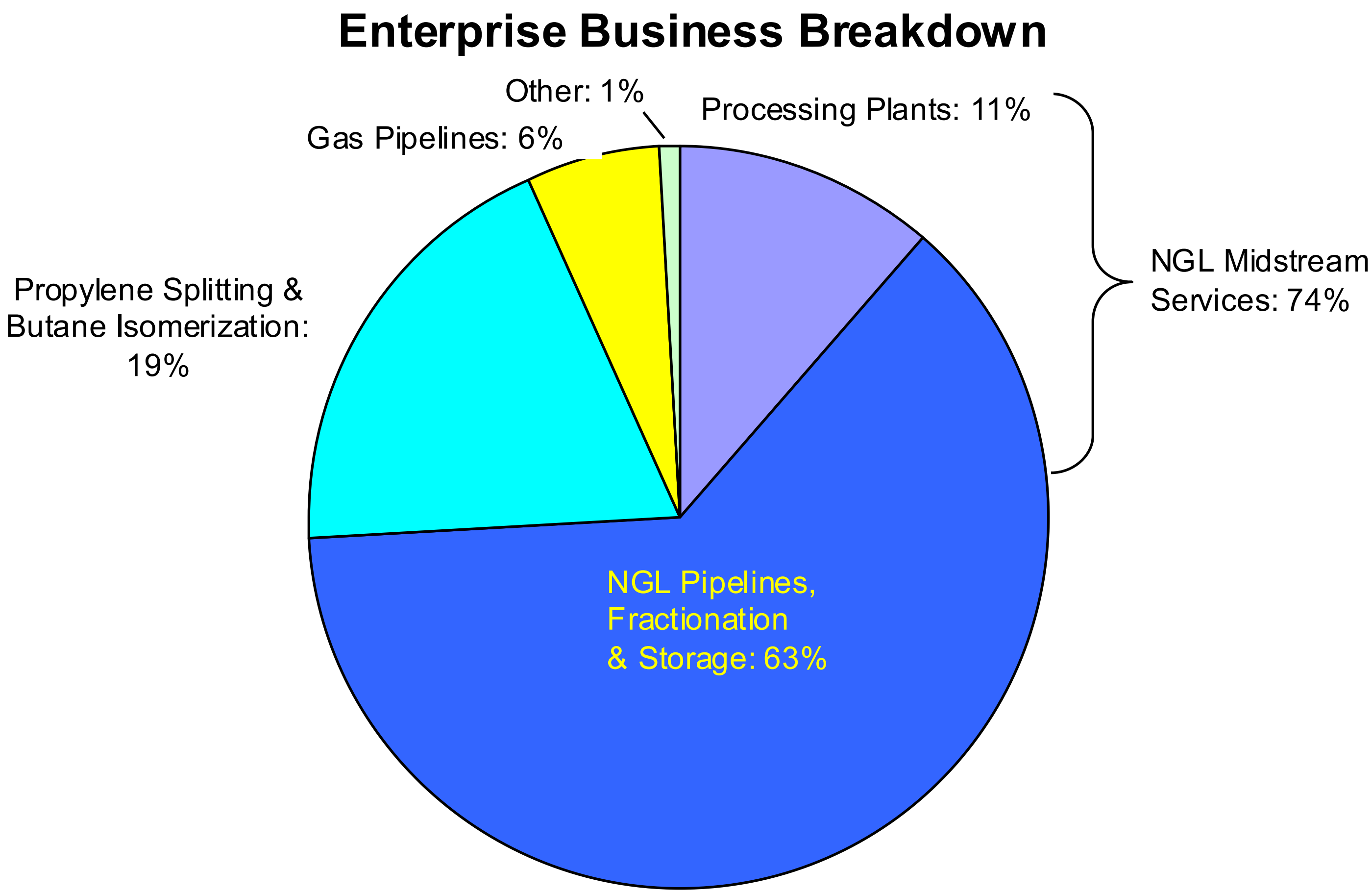
The U.S. Midstream Sector is the logistical link connecting the E&P, Gas, Refining and Petrochemical Industries.

EPD asset base concentrated on Gulf Coast with linkage to the Western and Mid-Cont. producing regions via MAPL/Seminole.

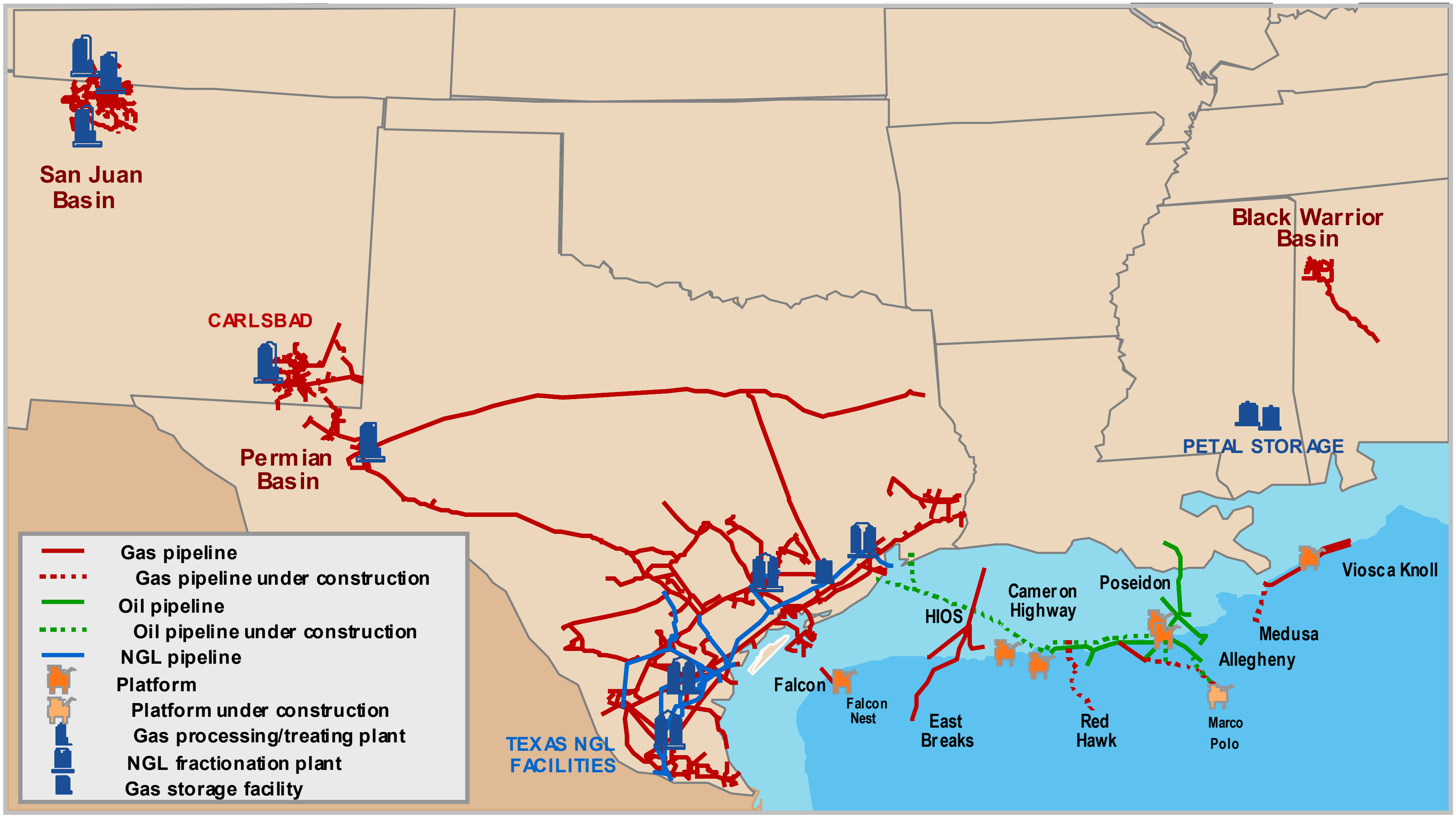


envantage

Over 90% of EPD's Business is expected to be generated from NGL and Petrochemical Midstream Services during 2004.

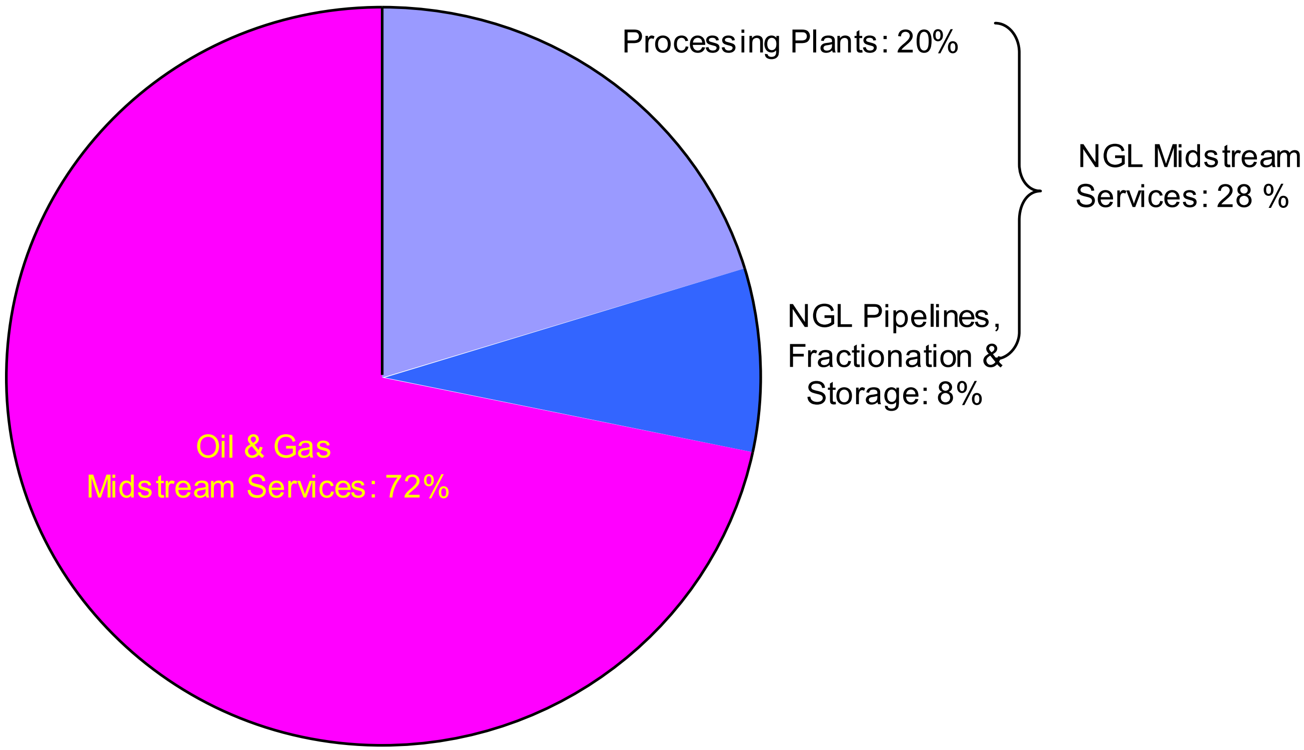


GTM asset base highly concentrated in Texas and San Juan Basin with positions in the GOM.



During 2004, over 70% of GTM's Business is expected to be Oil & Gas Midstream Services - only 28% generated from NGL Midstream Services.

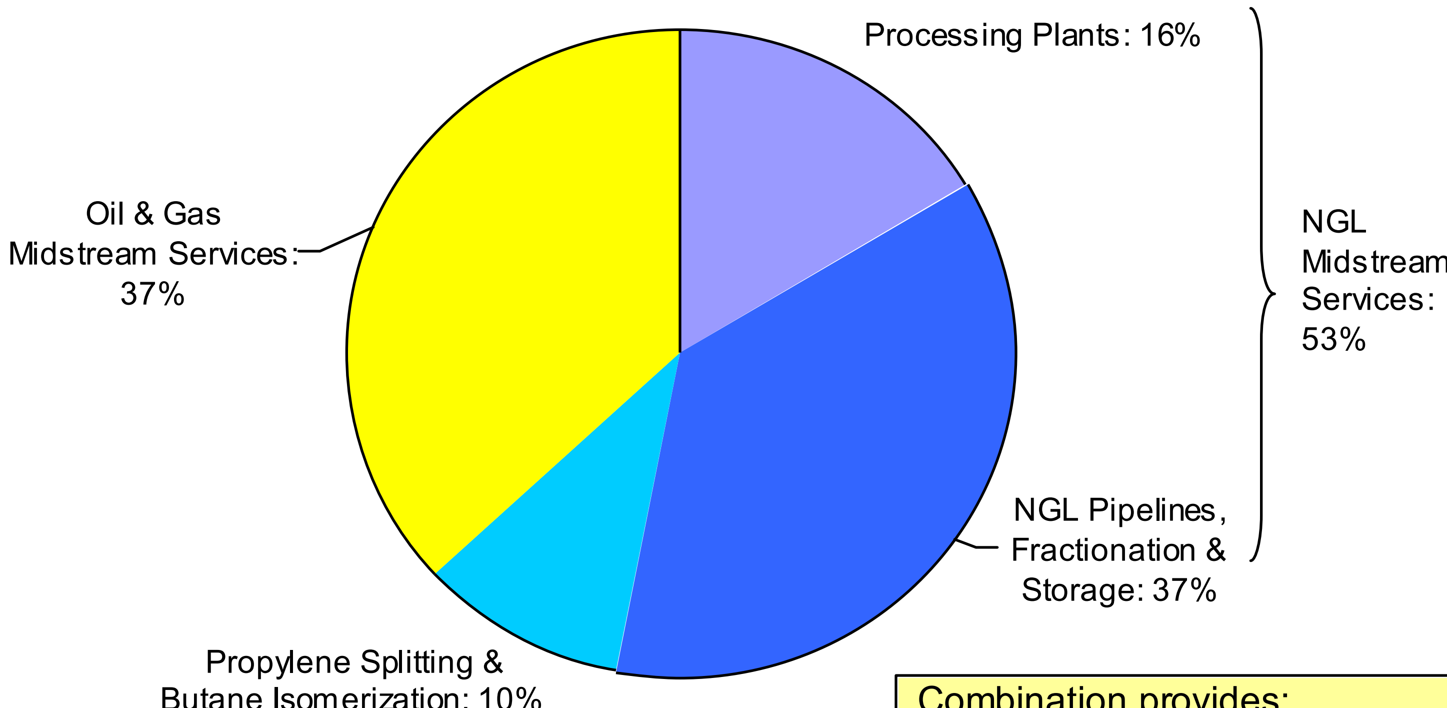
GulfTerra Business Breakdown*



* Includes GulfTerra and 9 Gas Processing Plants to be Acquired from El Paso Corp.

The Merger will diversify EPD's business and provide more balance in Midstream Services for Both Companies.

Expected Enterprise + GulfTerra Business Breakdown For 2004



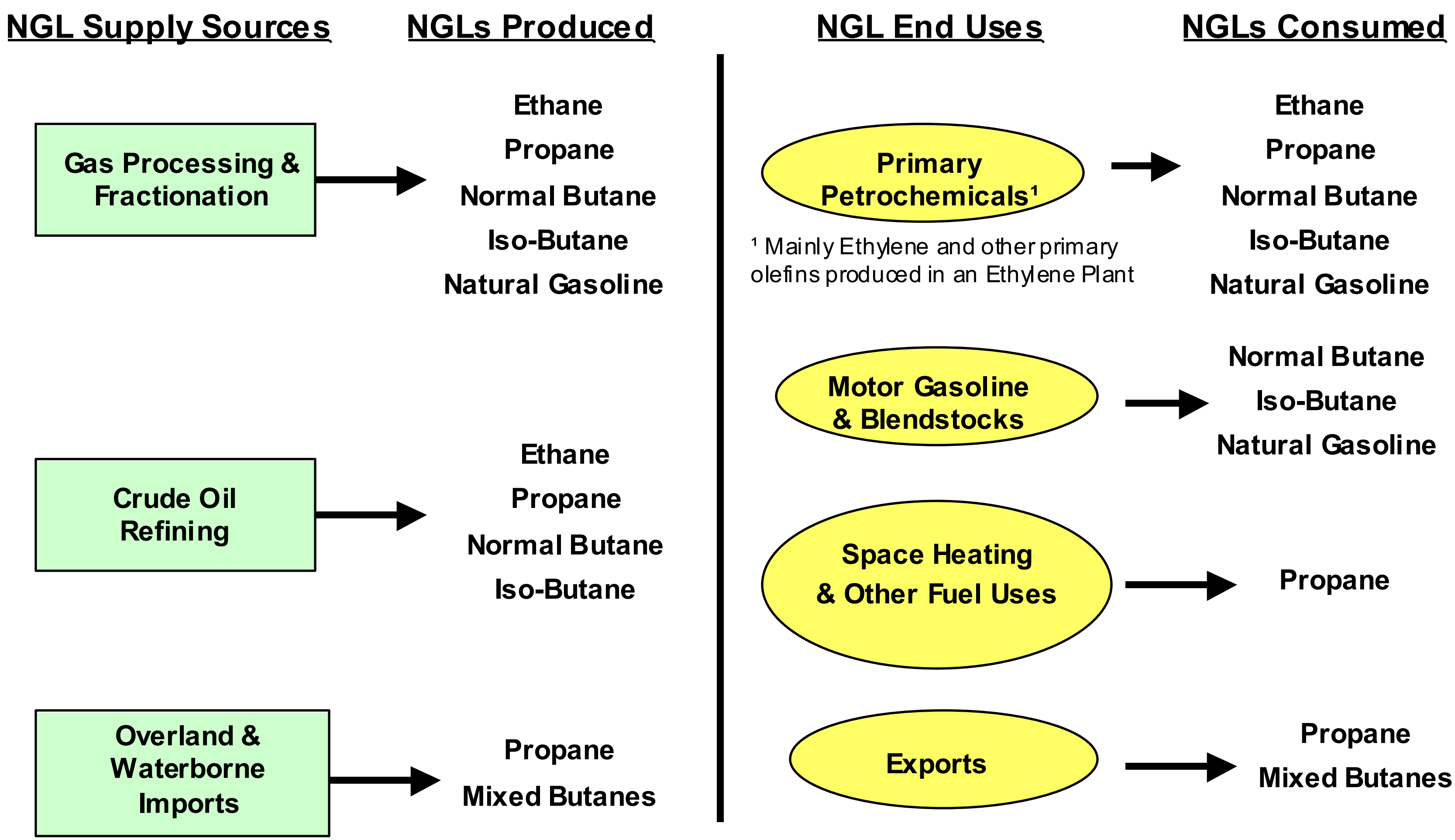
Combination provides:
- Better balance between NGLs, Oil, and Gas Services
- Integration of Facilities
- Business Risk Mitigation

*Does Not Include the $30 MM Cost Saving Synergies or Commercial Synergies yet to be Quantified.

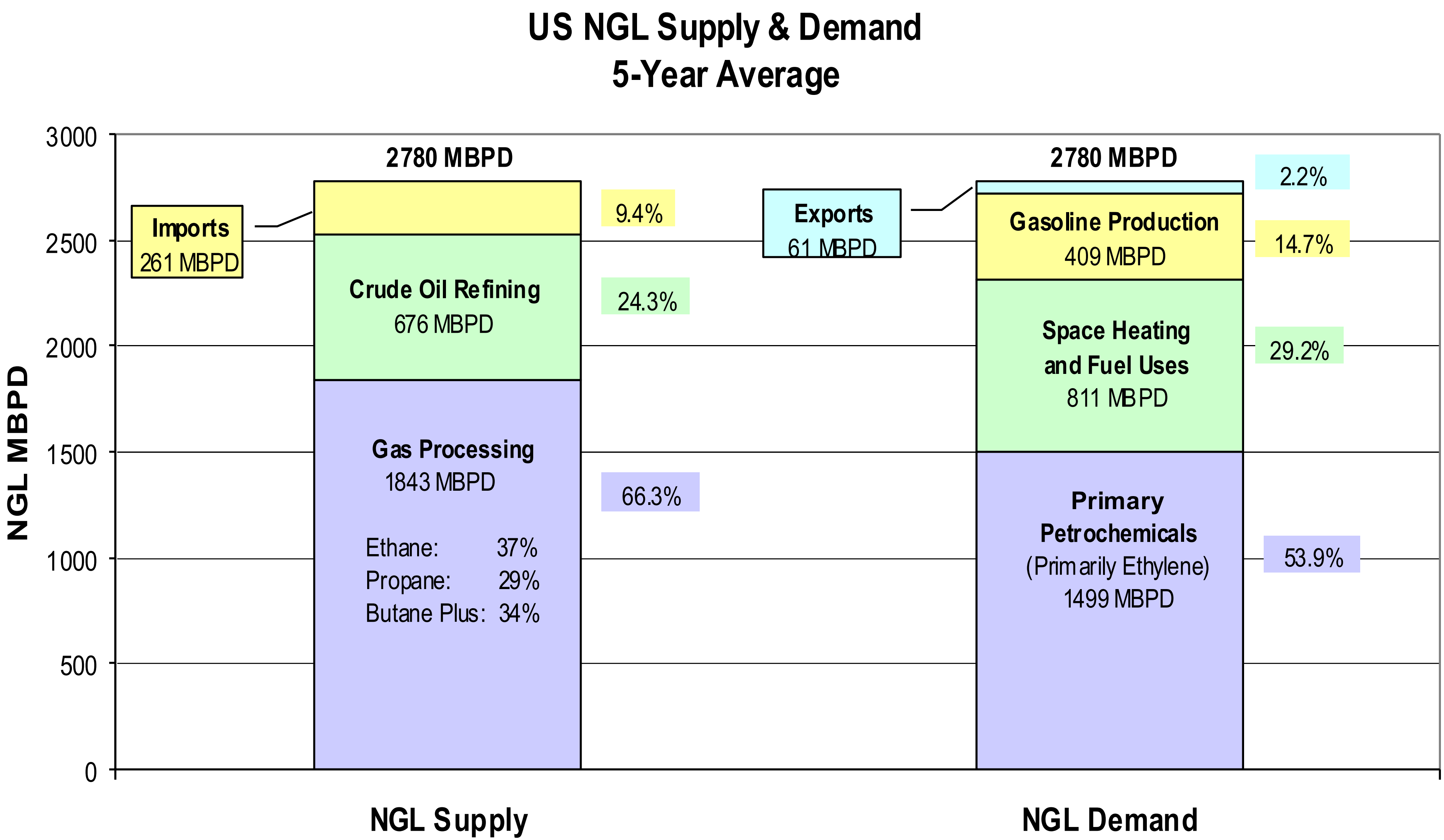
Industry Overview

Supply Side

To gain an appreciation of the fundamentals driving NGL supply, demand and pricing, an overview of the primary supply sources and market end uses will be provided.

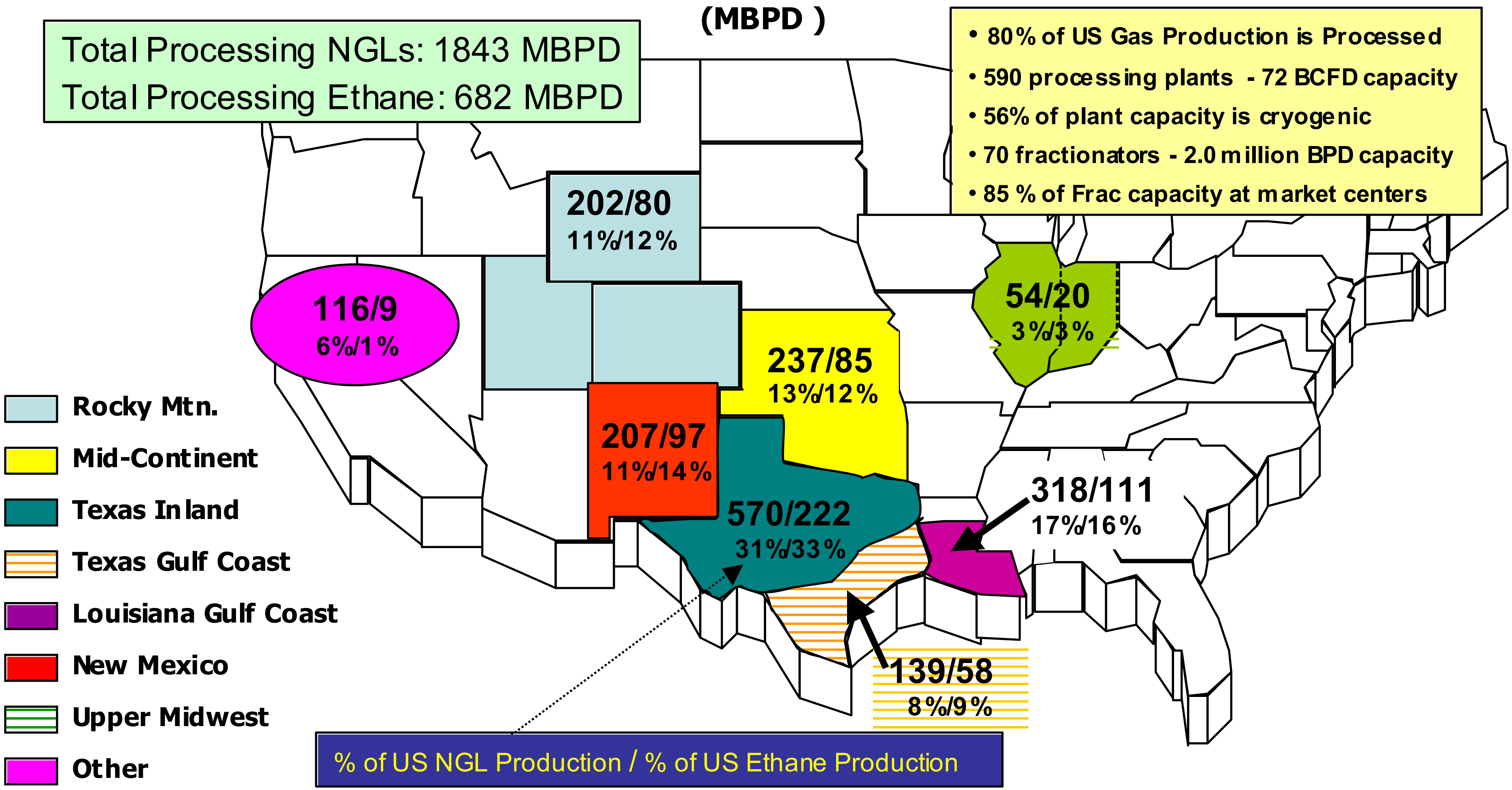


Two thirds of U.S. NGL Supply comes from Gas Processing; Ethylene Production accounts for 54% of NGL Demand.

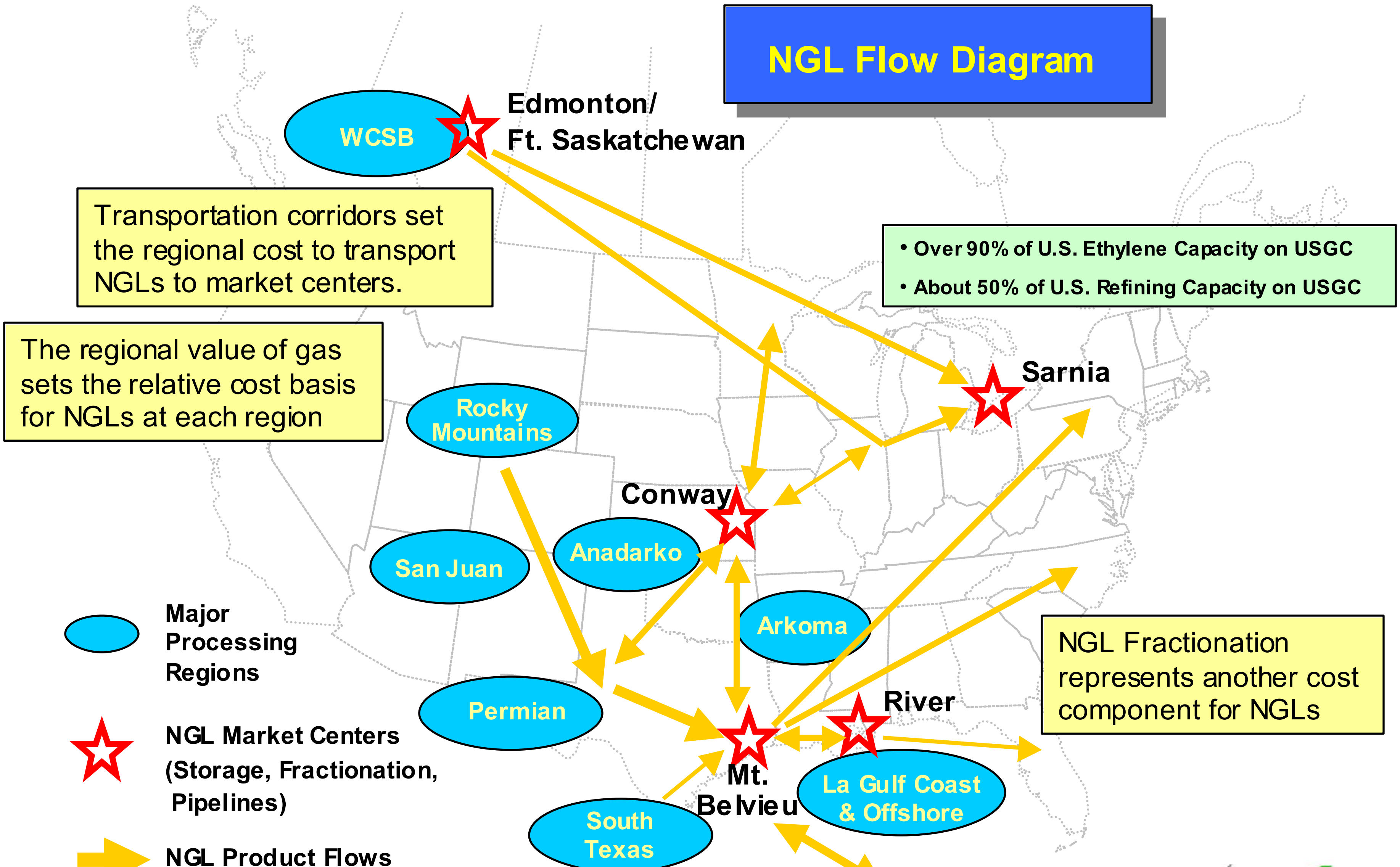


US NGL Production from Gas Processing corresponds with the location of the largest natural gas reserves.

5-Year Average NGL/Ethane Regional Production from Processing (MBPD)



Major Processing Regions are linked to NGL Market Centers by Specific Transportation Corridors.



NGL production is primarily non-discretionary. However, ethane extraction from gas processing is discretionary and the most economically sensitive NGL component.

NGL/RGL	Gas Processing	Crude Oil Refining
Ethane	Discretionary [1]	By-product
Propane	Mostly Non-Discretionary [2]	By-product
N-Butane	Non-Discretionary [2]	By-product
I-Butane	Non-Discretionary [2,3]	By-product/ Discretionary [3]
Natural Gasoline Pentanes	Non-Discretionary [2]	By-product

[1] Average U.S. ethane yields can vary from 34% to 46% if economics dictate.
If ethane extraction is minimized it only reduces total NGL volumes by 10% to 20%.

[2] Most propane & virtually all butane plus must be recovered to meet gas pipeline specs.

[3] Iso-Butane is a refinery by-product, but is also a discretionary product produced by the isomerization of normal butane from gas processing and refining.

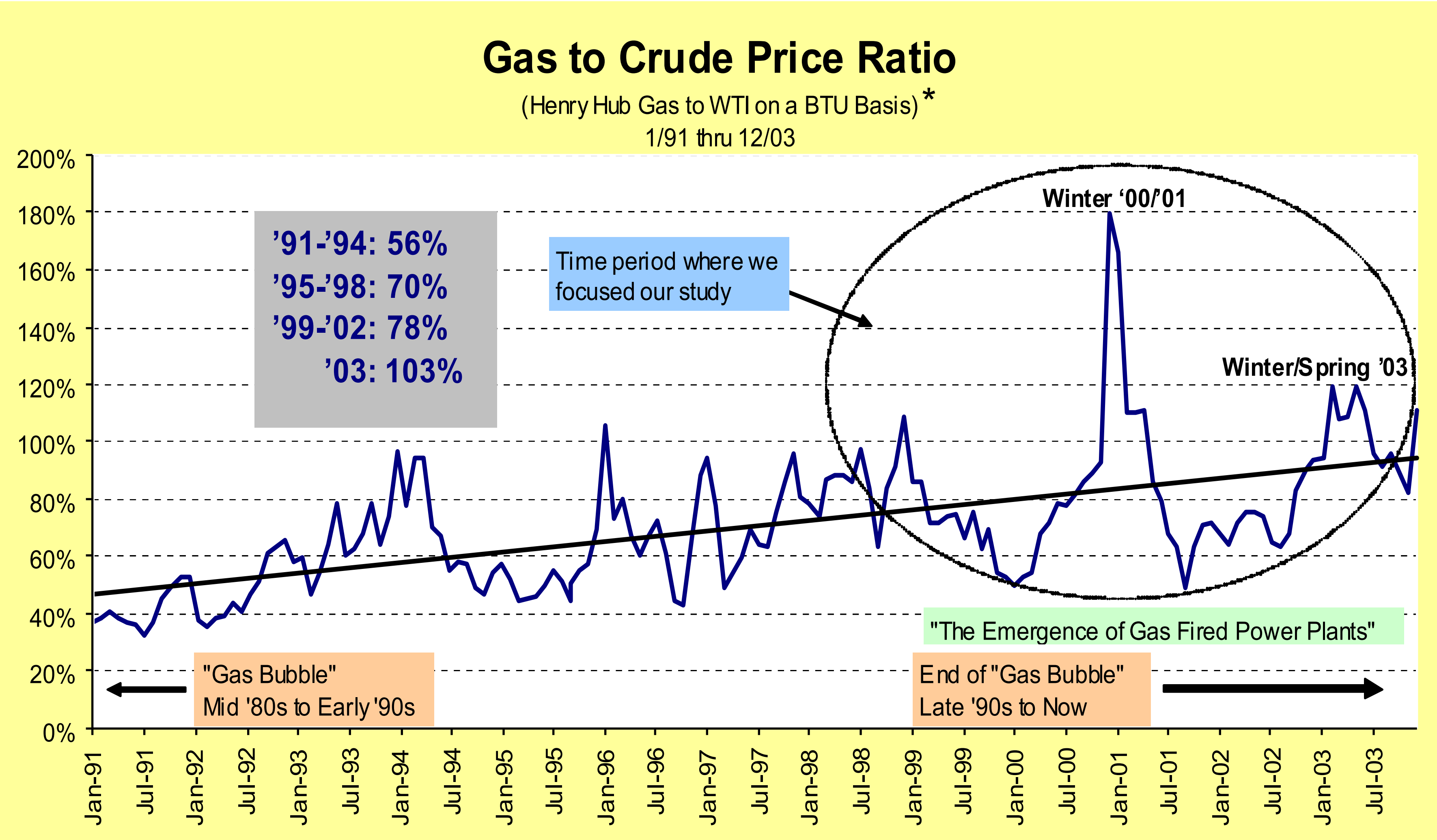
Petrochemical & Fuel Markets set U.S. NGL prices in competition with petroleum derived products. Natural Gas sets the relative cost for NGLs.

NGL	Primary Market(s)	Competing Products	Secondary Market(s)	Competing Products	5-yr Avg. Price Ratio to Crude[3]
Ethane % of Demand:	Ethylene Production 100%	• Propane • N-Butane • Naphtha • Gas Oils	Retained in Natural Gas	• Residual Fuel • No 2 Fuel Oil • Propane	53% +/- 10%
Propane % of Demand:	Ethylene Production 41%	• Ethane • N-Butane • Naphtha • Gas Oils	• Space Heating[1] • Other Fuel Uses[1] 59%	• Natural Gas • No 2 Fuel Oil	75% +/- 8%
N-Butane % of Demand:	• Gasoline[1] • Isomerization 63%	• Other Gasoline Blendstocks	• Ethylene Prod. • Other Fuel Uses[1] 37%	• Other Ethylene Feedstocks or Fuels	88% +/- 5%
I-Butane % of Demand:	Gasoline Additives 59%	• Other Gasoline Blendstocks	Petrochemicals 41%		91% +/- 4%
Nat'l Gaso % of Demand:	Gasoline 54%	• Other Gasoline Blendstocks	• Ethylene Prod. • Crude Blending 46%	• Other Ethylene Feedstocks	97% +/- 4%

[1] Seasonal Market [2] Being Phased Out [3] On a $/Bbl basis

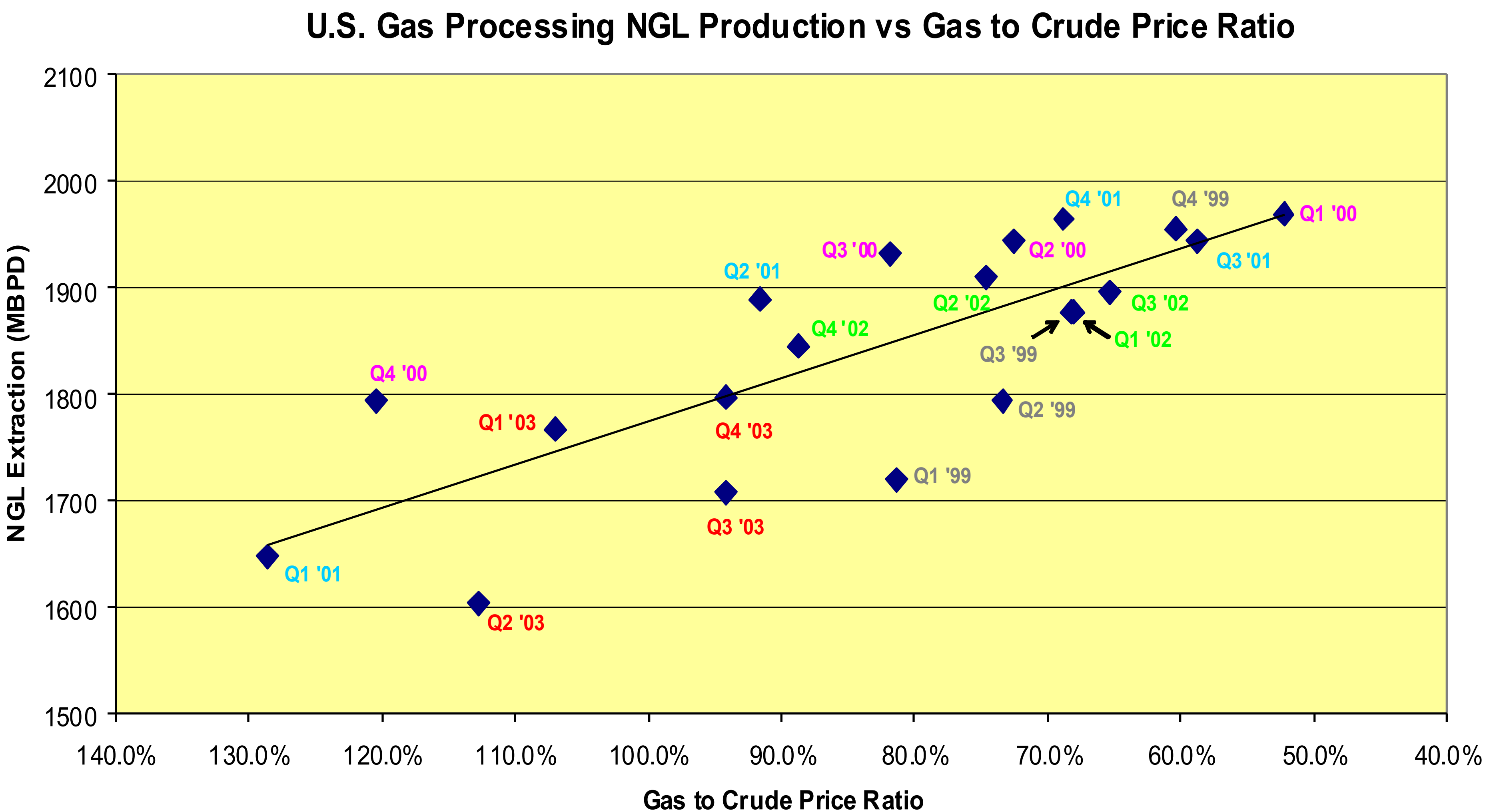
envantage

Therefore, the relative value of gas to crude plays an important role in driving U.S. NGL supply/demand, particularly for ethane.

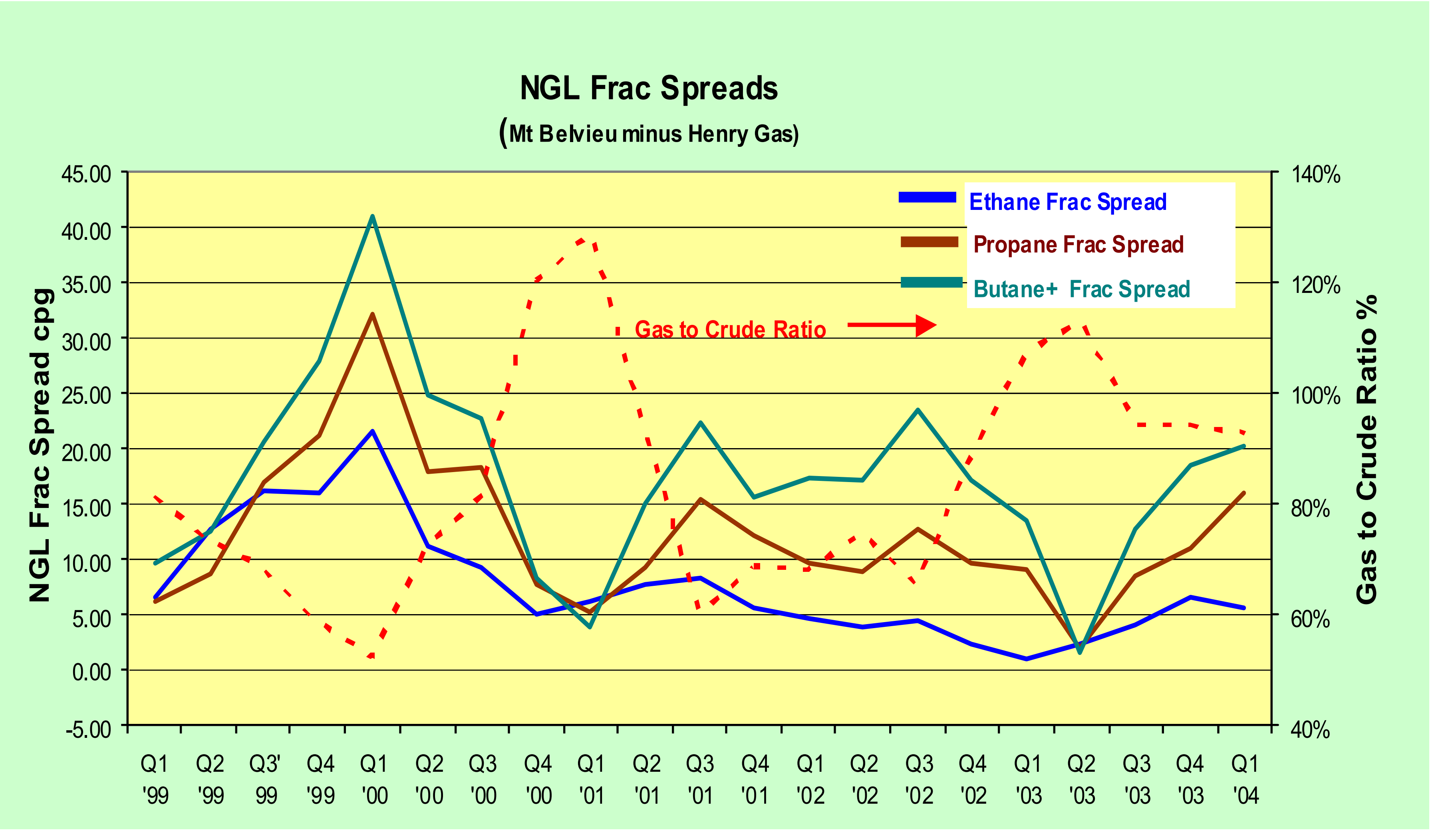


* Based on 5.8 MM BTU/Bbl

NGL production from Gas Processing is inversely related to the gas to crude price ratio……



…..because NGL frac spreads are inversely correlated to the gas to crude price ratio.



Frac spread volatility has caused NGL production swings to be severe but temporary. Volume swings greatest for Ethane.

Monthly Min-Max Range of NGL Production from Processing (MBPD)															
	1999			2000			2001			2002			2003		
Component	**Avg**	**Min**	**Max**	**Avg**	**Min**	**Max**	**Avg**	**Min**	**Max**	**Avg**	**Min**	**Max**	**Avg**	**Min**	**Max**
Ethane	**668**	537	761	**716**	541	782	**691**	435	797	**699**	594	779	**625**	503	750
Propane	**524**	465	564	**538**	452	576	**535**	415	591	**548**	504	580	**505**	439	549
Butane Plus	**641**	604	664	**654**	563	681	**638**	518	683	**633**	599	667	**587**	551	617
Total NGLs	**1833**	1606	1989	**1909**	1556	2039	**1864**	1368	2071	**1881**	1698	2027	**1718**	1493	1916

Observations:

1. Ethane production swings of 100 to 200 MBPD or about 15% to 30% of its average annual production have occurred due to rising and falling extraction economics and its economic attractiveness as an ethylene feedstock.
2. Propane and Butane Plus production swings have not been as severe, but have often coincided with severe gas price spikes.
3. Average annual production levels closer to maximum levels than minimum levels.
4. Current estimated maximum NGL production from processing: Ethane – 760 MBPD; Propane - 565 MBPD; Butane Plus – 670 MBPD; Total NGLs – 2,000 MBPD

Processing Agreements Are Being Retooled to Minimize Risks to Independent Processors which will moderate the effects of Frac Spread volatility on NGL production.

High → Risk to Processor → Low

Keep Whole	Margin Sharing	% of Liquids (POL)	% of Proceeds (POP)	Processing Fee
Processor keeps extracted NGLs as fee for processing Must purchase and return to producer merchantable gas to replace fuel & shrinkage	Producer and processor share value delta between NGLs and gas, i.e.. 50%/50%.	Processor paid a % of NGLs as processing fee. Producer keep their % of NGLs in kind or have processor sell NGLs and receive cash. Could have keep whole provisions	Processor paid a % of NGLs & gas as processing fee Producer keep their % of NGLs & gas in kind or have processor sell NGLs & gas and receive cash. Could have keep whole provisions	Producer pays processor a processing or conditioning fee. Fee is market base and could be POL or POP or cash.

Low ← Risk to Producer ← High

envantage

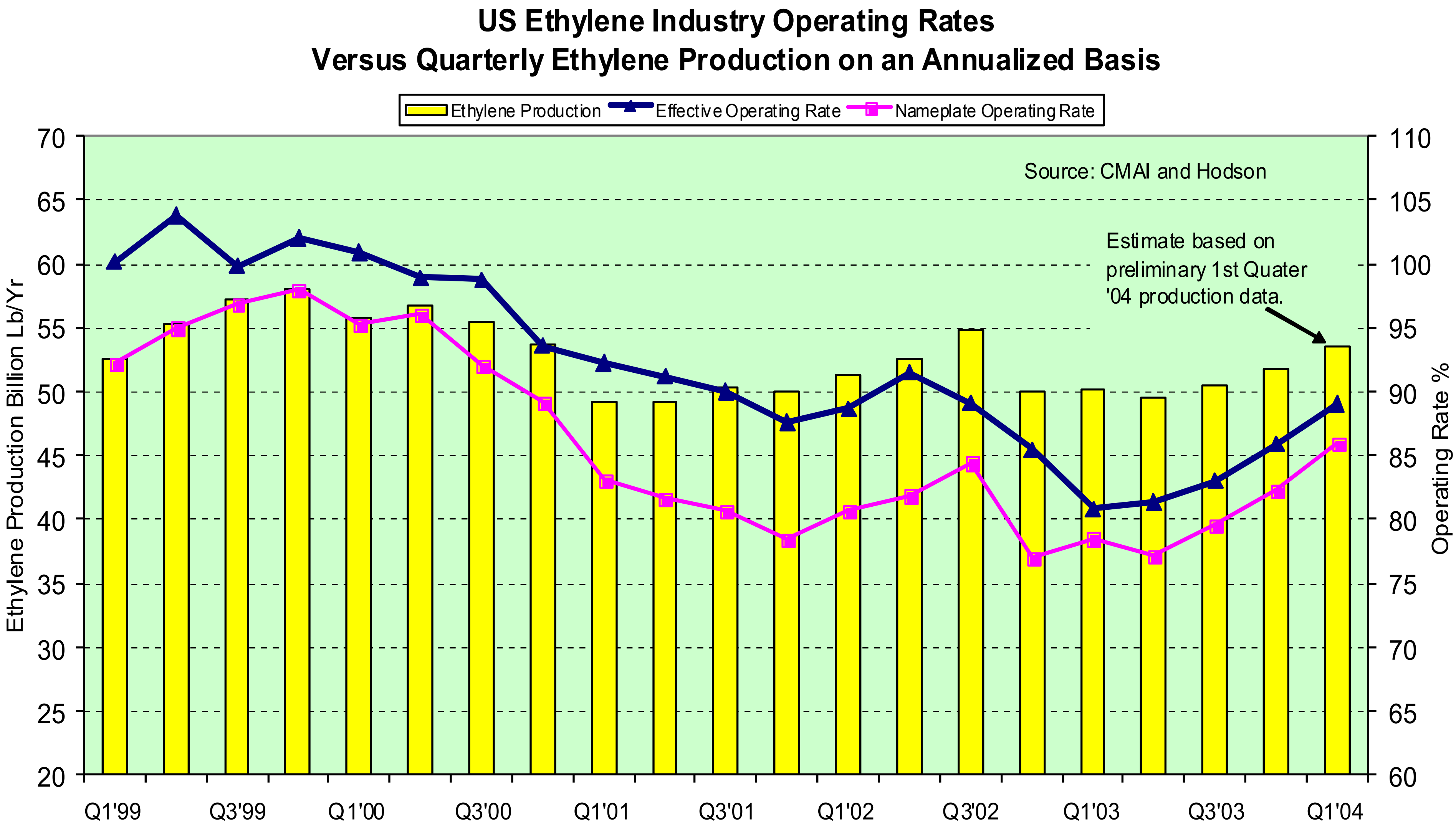
….This will have positive implications for Enterprise

- More stable NGL production at Enterprise’s gas processing plants.
- More stable NGL volumes through Enterprise’s transportation and fractionation systems.
- More emphasis on NGL storage to handle supply and demand imbalances.

Industry Overview

Demand Side

U.S. Ethylene Production & Operating Rates are Rebounding from the mid-year 2003 troughs.



Effective U.S. Ethylene Capacity is 61 Billion Lbs/Yr of which the Top 7 Ethylene Producers Control 80%.

2004 Ethylene Capacity Market Share

- Equistar 17.6%
- ExxonMobil[1,2].......... 15.5%
- Dow[1] 13.6%
- Chv Phillips[1,2].......... 11.5%
- Shell[1,2]..................... 10.7%
- Formosa[1].................. 5.4%
- BP[1,2].........................5.3%
- Huntsman................. 3.5%
- BASF/ATOFINA[2] 3.4%
- Others[3]...................13.5%

80% (top 7)

[1] Own & Operate Midstream Assets; [2] Integrated with Refining Operations
[3] DuPont, Eastman Chemicals, Sasol NA, Sunoco, Westlake, Williams

There are 4 Basic Types of Ethylene Plants that make-up the U.S. Ethylene Industry.

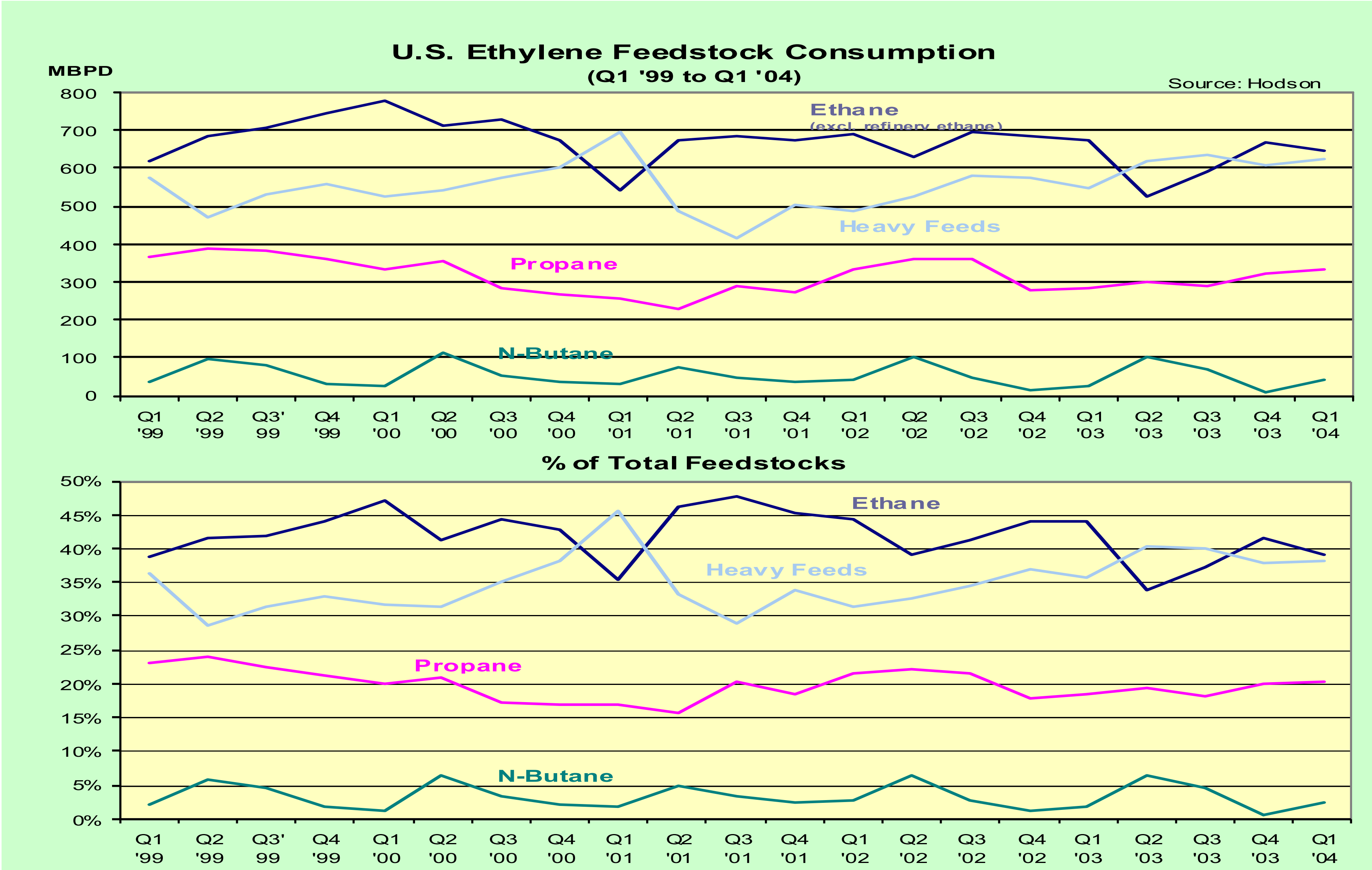
U.S. Ethylene Plants					
	Effective Capacity[1]	Feedstock Range			
Basic Types of Plants	(Billion Lb/Yr)	Ethane	Propane	Butanes	Heavy Feeds[2]
Purity Ethane Crackers	6.5	95% to 100%	0% to 5%	----	----
E/P Crackers	18.9	50% to 90%	10% to 50%	----	----
Flexi Crackers	27.2	5% to 35%	5% to 35%	0% to 5%	20% to 80%
Heavy Crackers	8.4	0% to 5%	0% to 5%	0% to 5%	85% to 95%
Total Effective Capacity	61.0				
	[1] 1st Qtr Capacity #'s	[2] Natural Gasoline, Naphtha, Condensate, Gas Oils			

For ethylene plants with feedstock flexibility, cracking one feedstock over another is dependent on feedstock cost and on the value of the co-products produced from each feedstock.

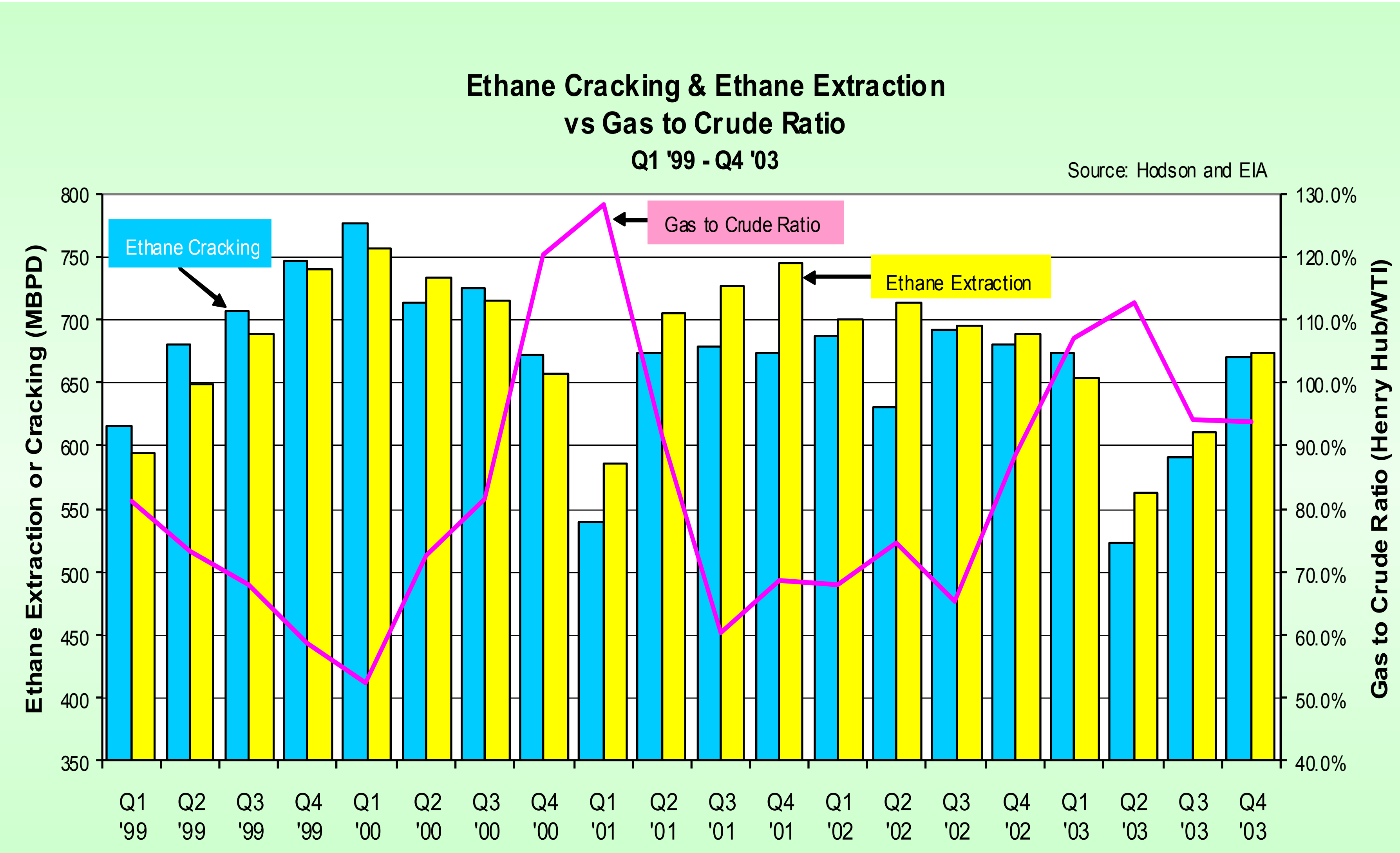
Product Yields for Ethylene Feedstocks
(Weight %)

Yield	Ethane	Propane	N-Butane	Naphthas[1]	Gas Oils
Ethylene	80%	46%	37%	29%	25%
Propylene	2%	15%	18%	17%	15%
C4 Olefins	2%	3%	8%	9%	10%
Fuel Gas	14%	28%	24%	20%	20%
Pygas	2%	8%	13%	20%	10%
Pyrolysis Oil	-	-	-	5%	20%
				[1] Includes Natural Gasoline	

The flexibility to swing feedstocks is used to optimize olefin production & profits.



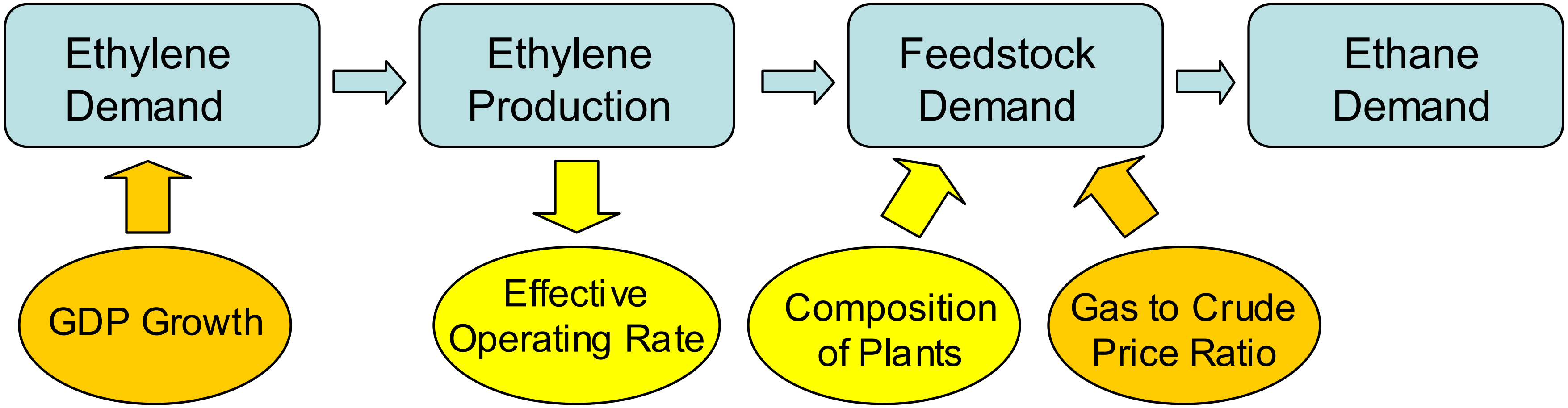
Ethane extraction closely tracks ethane cracking influenced, in part, by the gas to crude price ratio.



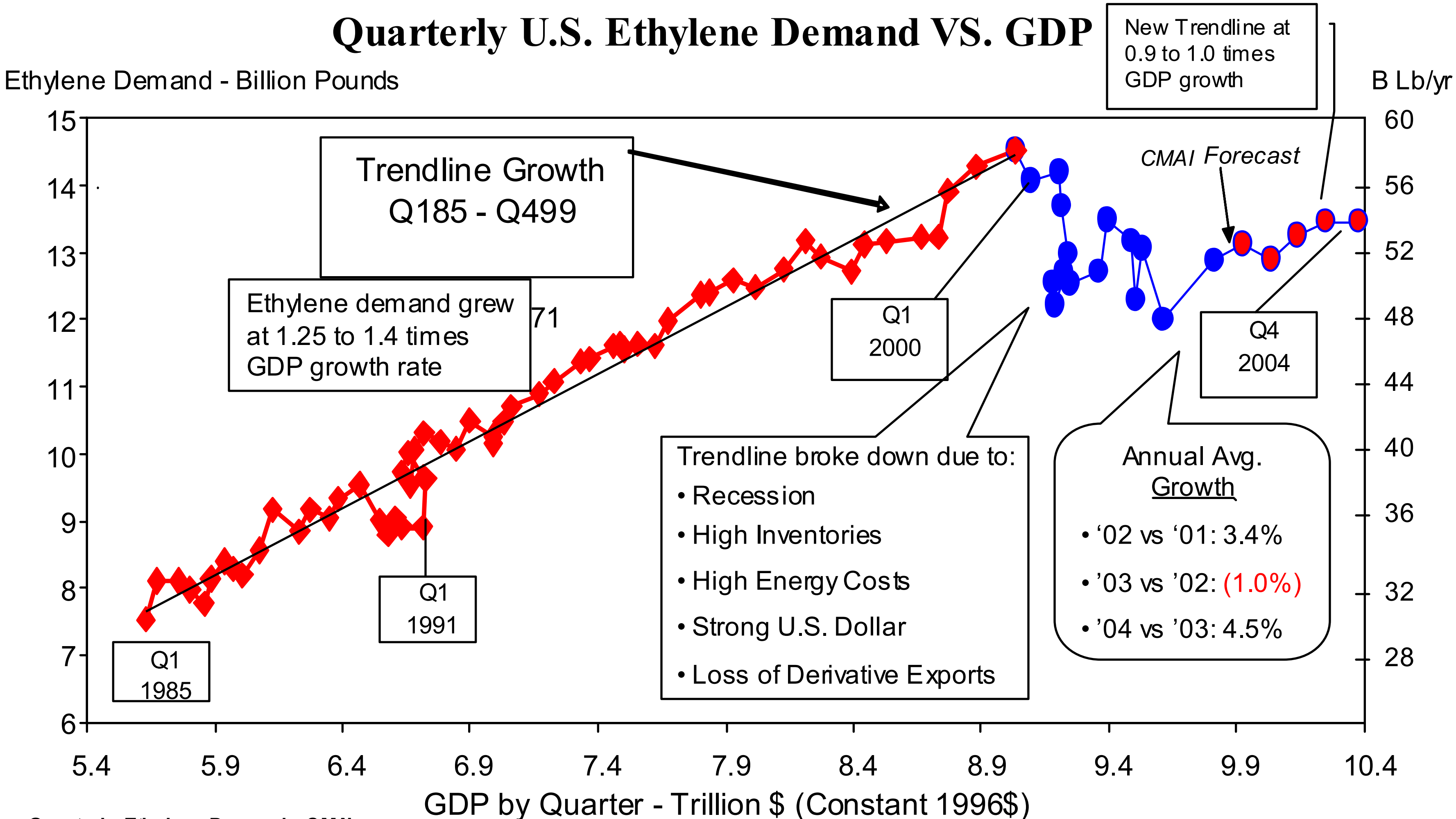
Short Term Market Outlook

Demand and Supply Side

Key Factors driving Ethylene Demand for NGLs, particularly for Ethane.



Historical Relationship between GDP & Ethylene Demand is Changing. Expect 54 B Lb/yr production by 4th Qtr '04.



Quarterly Ethylene Demand - CMAI
GDP source - U.S. Dept. of Commerce

envantage

Short Term Fundamentals continue to be positive for U.S. Ethylene Producers.

- U.S. and other major world ethylene markets appear strong.
  - Tightening supply/demand balances
  - 1st quarter '04 effective utilization rate ~ 90% for U.S. ethylene producers with annualized production averaging over 53.5 billion lbs/yr.
- Despite $6 natural gas prices, rising crude prices have made ethane and propane cracking in U.S. very competitive on a global basis.
  - U.S. exports of ethylene monomer and derivatives are starting to reappear.
- Evidence is building that fundamental recovery is sustainable.
  - Last year, recovery lost momentum. This year, U.S. economy appears to be re-entering a period of strong growth.
  - Major petrochemical companies are seeing purchases of their ethylene derivative products increasing and expect sustainability in 2004.
  - Concerns – continued increases in crude prices and geopolitical uncertainties derail economic growth.

As Ethylene production rebounds, analysis indicates the following implications for ethane demand which will be demonstrated on the next 2 charts:

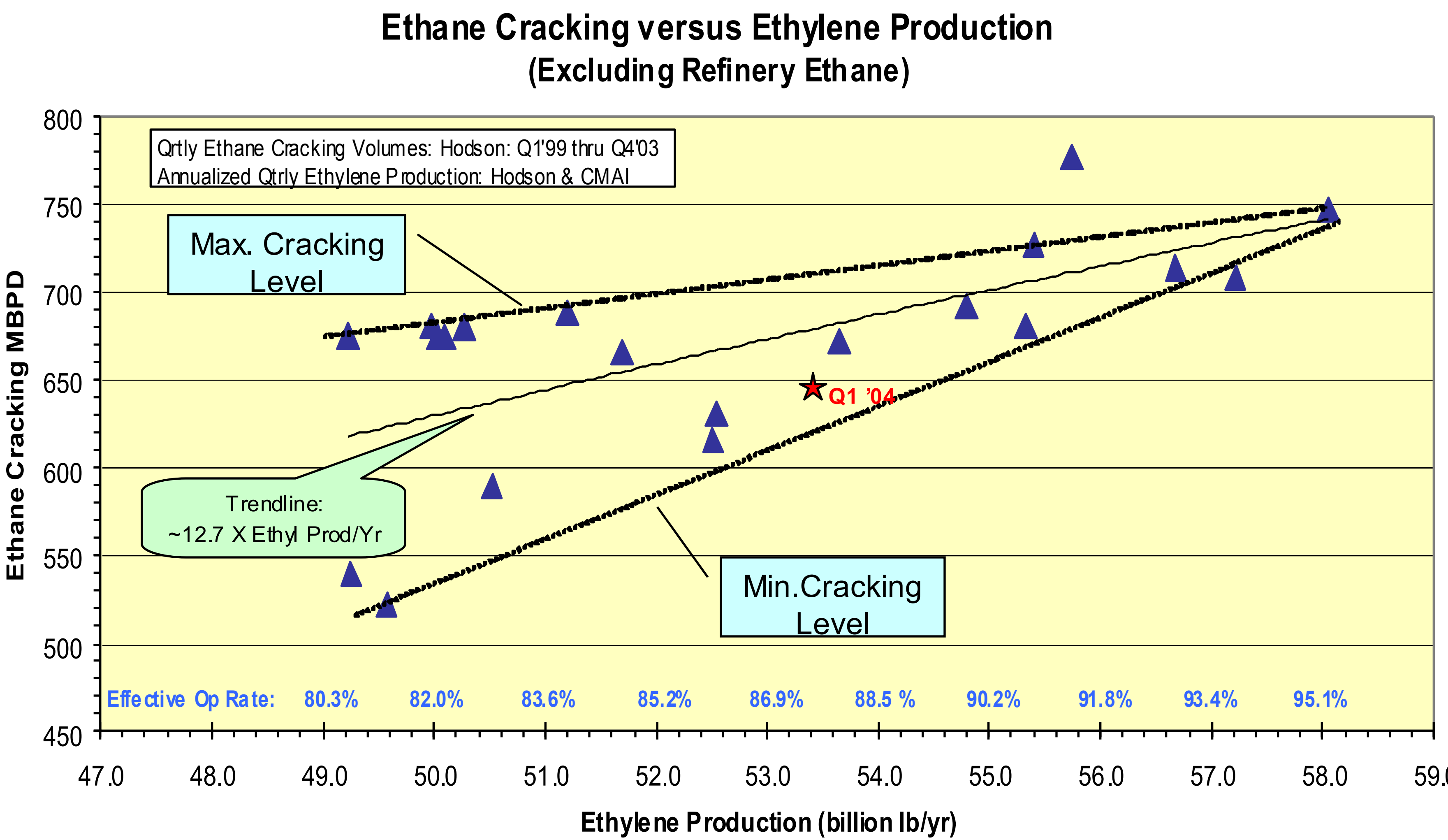
1. The flexibility to crack less ethane diminishes as ethylene production increases and a higher range of ethane volumes are required to produce higher levels of ethylene.

Ethylene Production	**Effective Utilization**	**Ethane Cracking Levels (MBPD)**			
(B Lb/Yr)	(%)	Min.	Max.	Flex. Range	Trendline
49	80.3	510	670	160	615
51	83.6	560	690	130	644
53	86.9	610	710	100	672
55	88.5	660	725	65	700
57	93.4	710	740	30	729

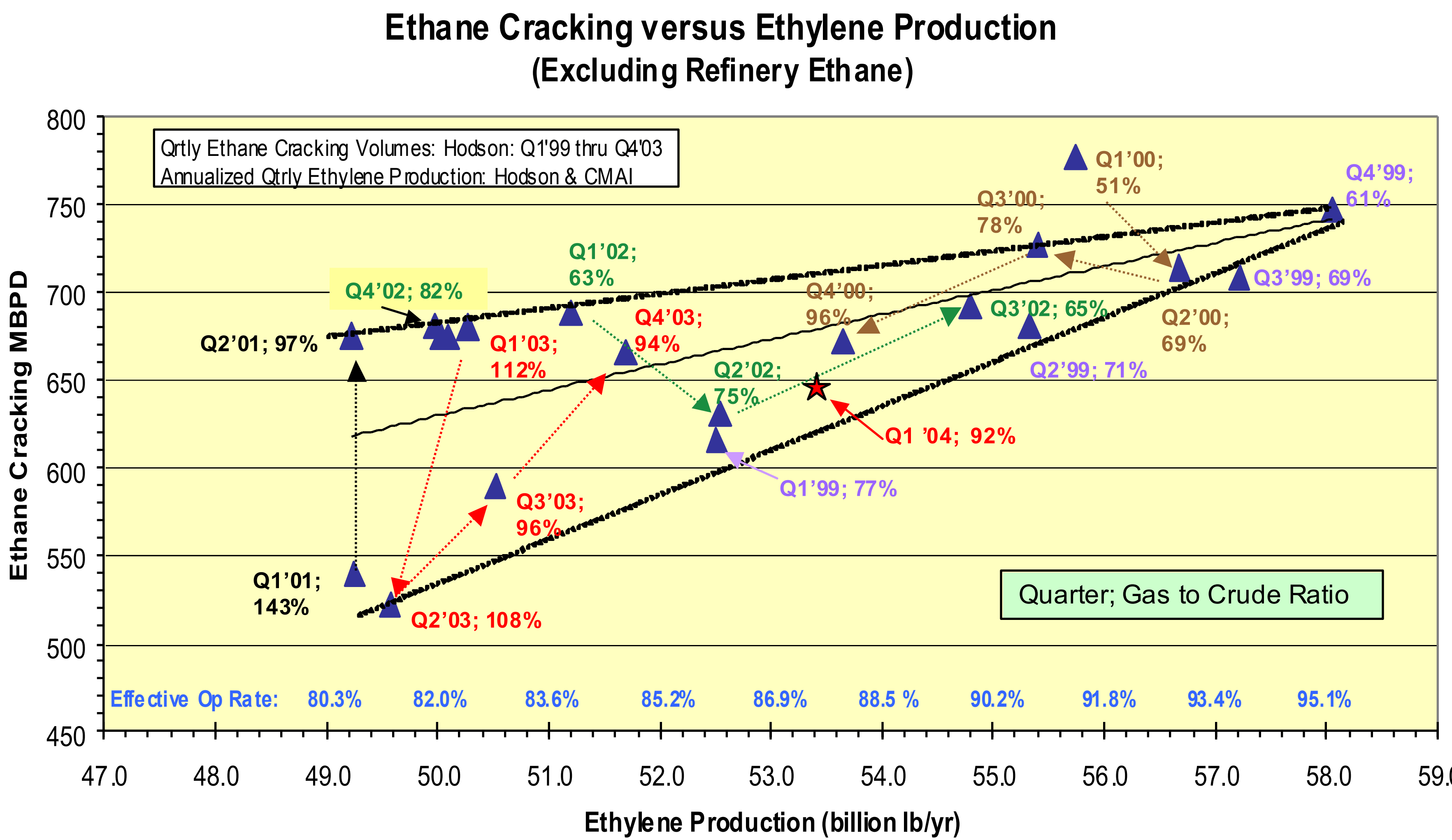
2. It appears that the U.S. Ethylene Industry can not stay at minimum ethane cracking levels for more than 1 Quarter without creating a surplus of ethylene co-products.

3. While the level of ethylene production is the primary driver, the gas to crude price ratio is another factor influencing ethane cracking levels. Lower ratios at or below 90% increase the probability of maximizing ethane cracking.

As Ethylene Production Increases Past 53 Billion Lbs/Yr, Flexibility to Switch Off Ethane Diminishes.

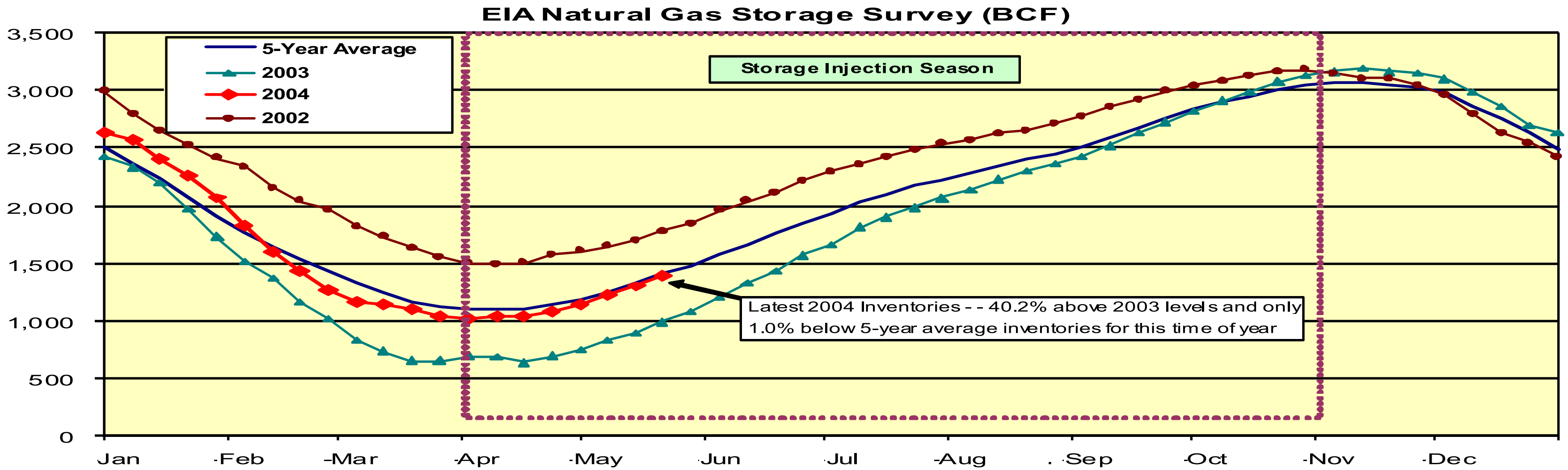


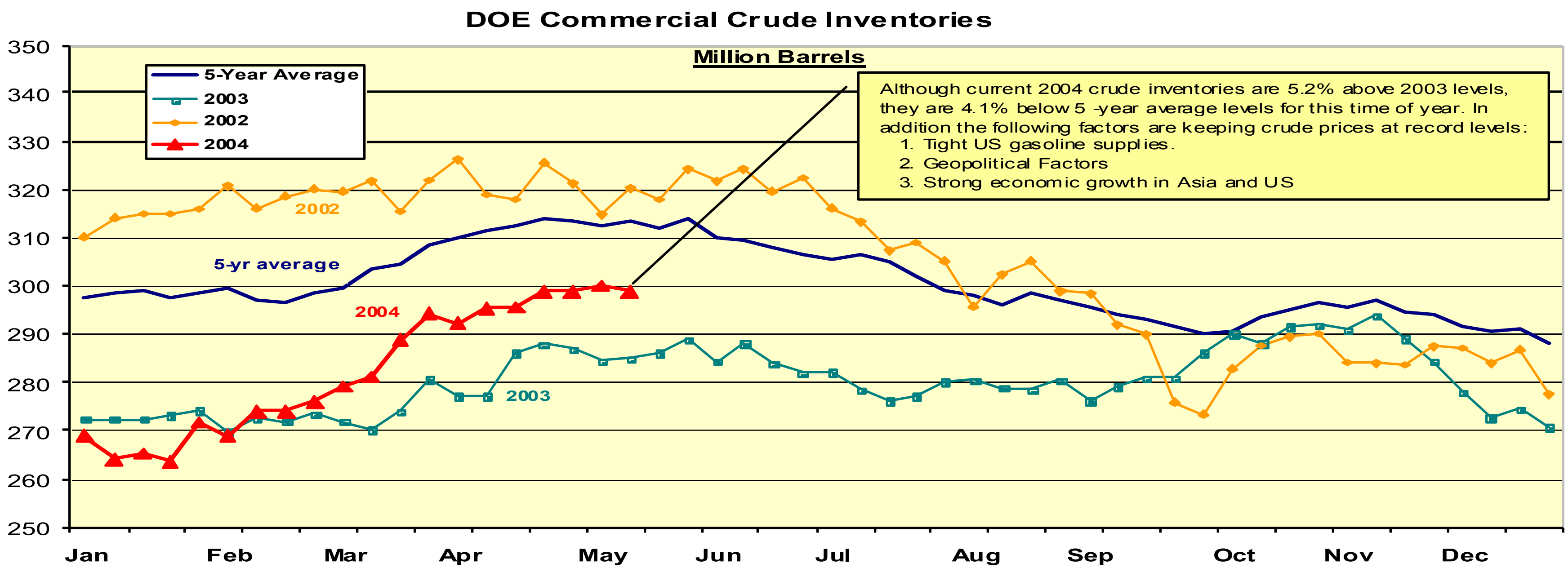
Minimum ethane cracking levels are not sustained more than 1 quarter without creating a surplus of ethylene co-products.



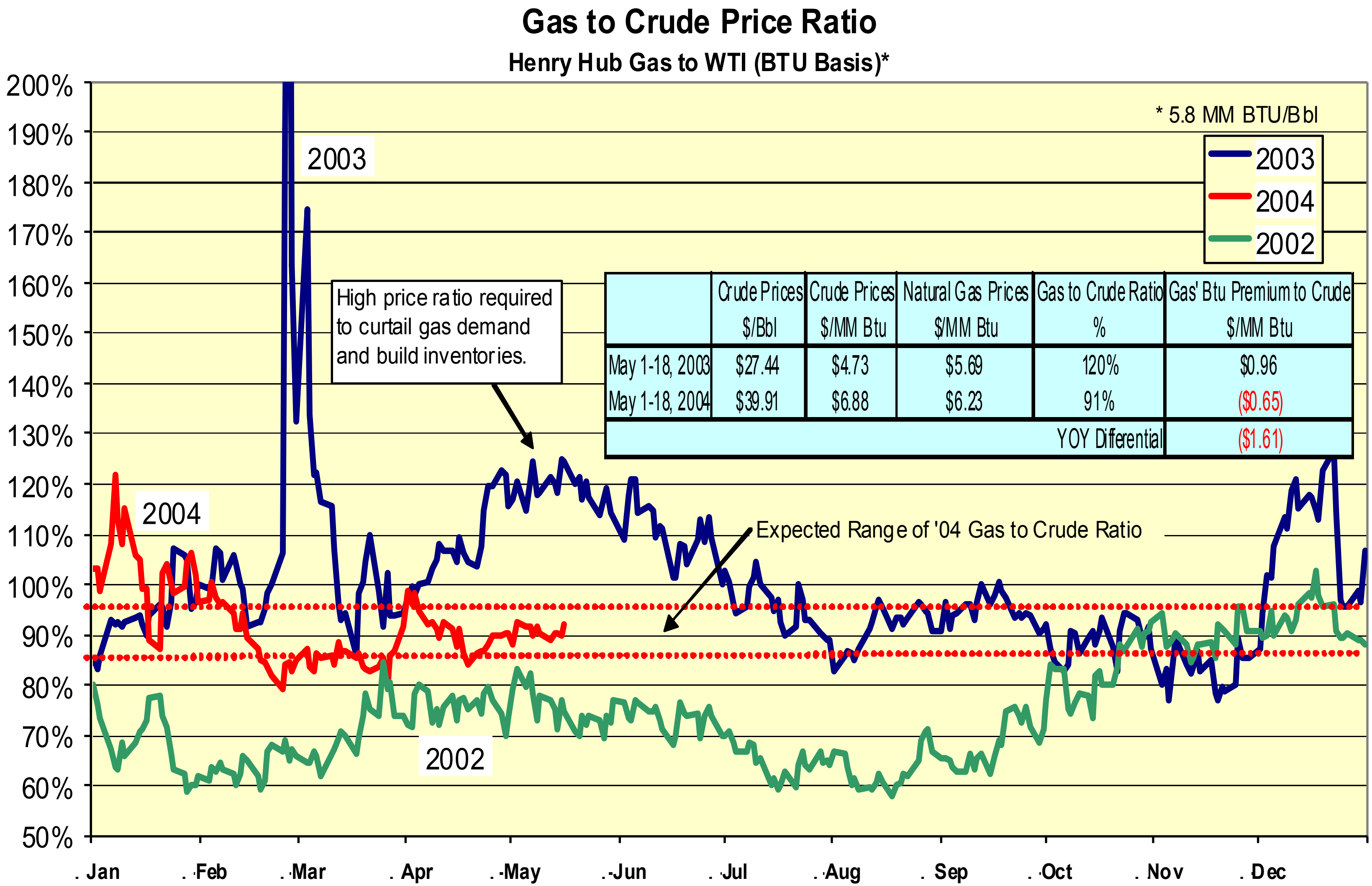
envantage

Gas Fundamentals should be weaker in '04 relative to Crude....





…..resulting in a lower average Gas to Crude price ratio in ‘04



	Crude Prices $/Bbl	Crude Prices $/MM Btu	Natural Gas Prices $/MM Btu	Gas to Crude Ratio %	Gas' Btu Premium to Crude $/MM Btu
May 1-18, 2003	$27.44	$4.73	$5.69	120%	$0.96
May 1-18, 2004	$39.91	$6.88	$6.23	91%	($0.65)
				YOY Differential	($1.61)

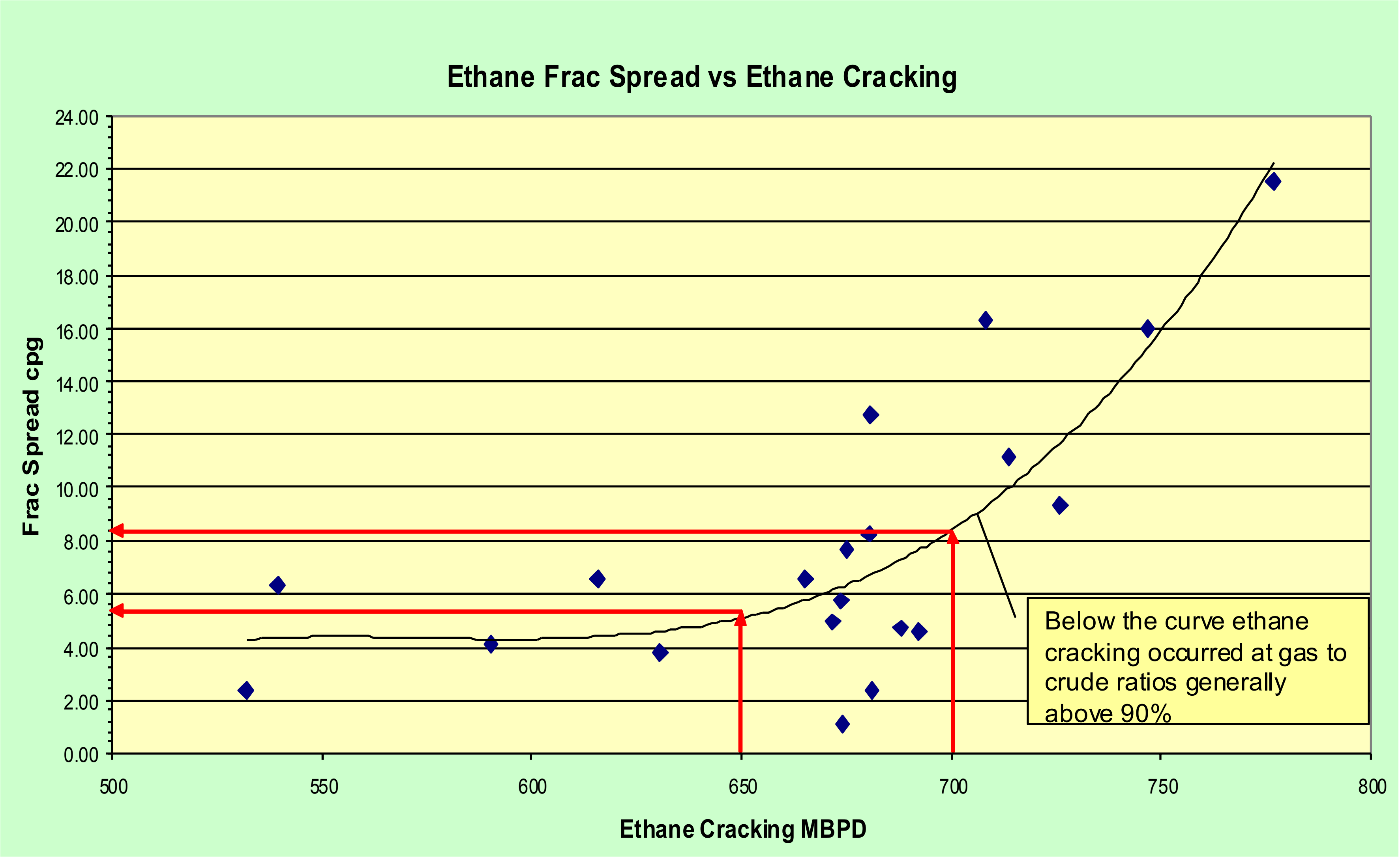
envantage

See a better environment for ethane cracking in '04 and a paradigm shift could be underway if crude prices stay high.

Gas to Crude Price Ratio	Ethylene Production: Below 53 B LB/YR	Ethylene Production: Above 53 B LB/YR
At or Below 90%	Ethane Cracking Swings Between 500 -700 MBPD Are Possible with a Bias to Maximize Ethane Cracking	High Probability of Sustainable Ethane Cracking at or Above 650 MBPD
Above 90%	High Probability of Ethane Cracking Swings Between 500 -700 MBPD with a Bias to Minimize Ethane Cracking as long as Co-Product Production is Not an Inhibitor	At 53-55 B Lb/yr, Moderate to Good Probability of Ethane Cracking at or above 650 MBPD. Gas to Crude Ratio Less of a Factor at Production Rates above 55 B Lb/yr

envantage

To support greater ethane cracking levels, the ethane “frac” spread increases to encourage more ethane extraction.



Long Term Market Outlook

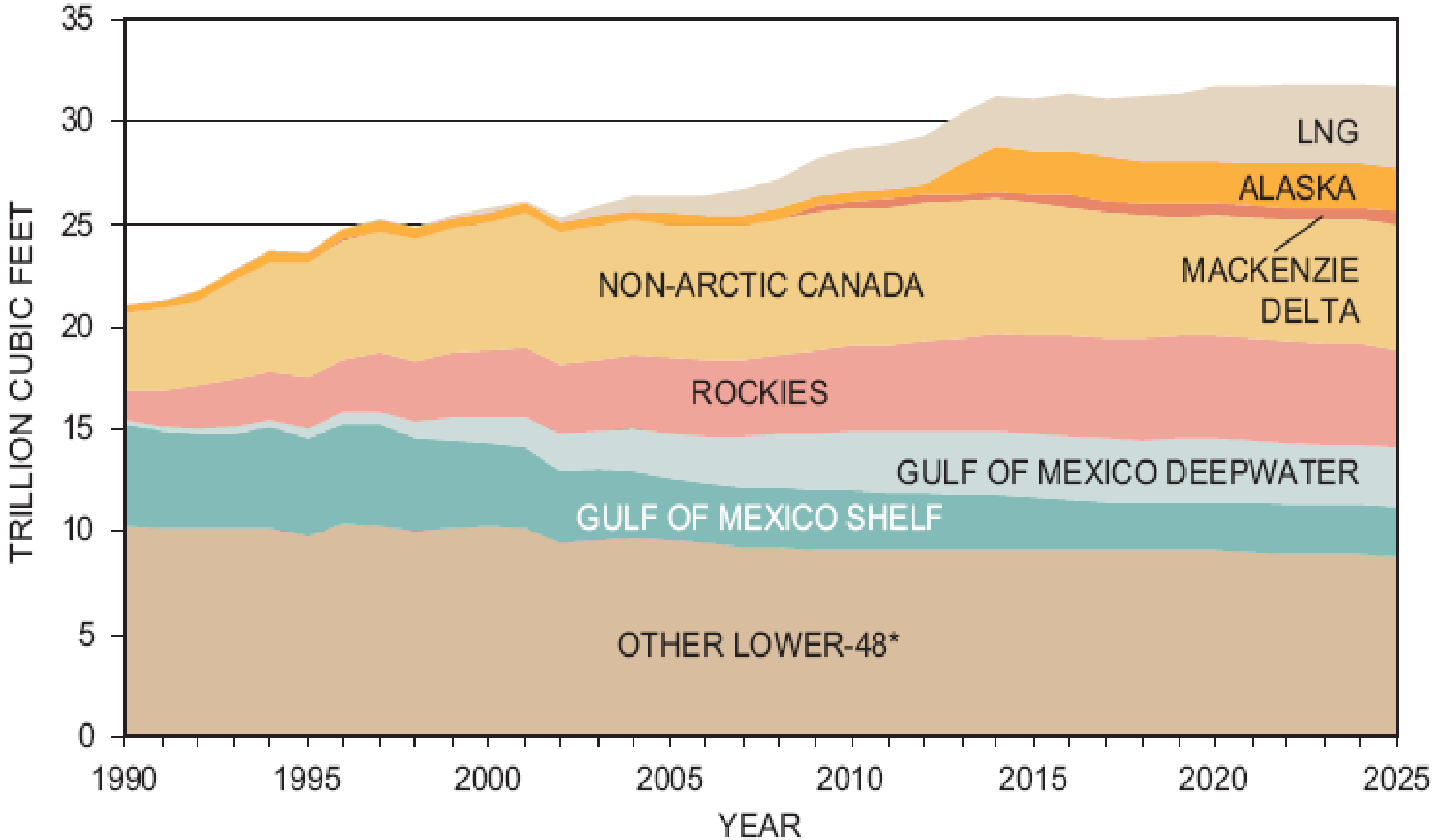
Demand and Supply Side

Ethylene production should track GDP growth rate at a 0.9 to 1.0 factor. Forecast ethane demand to be ~ 750 MBPD by '07.

Forecast of Ethylene Production and Ethane Cracking				
Period	U.S. GDP AGR	U.S. Ethylene AGR	U.S. Ethylene Production	U.S. Ethane Cracking[1]
			Billion Lbs/Year	MBPD
Q1 '85 - Q4 '99	3.0%	4.0%	55.8 [3]	688
2000	3.7%	-0.8%	55.4	722
2001	0.2%	-9.2%	50.3	642
2002	2.1%	3.4%	52.1	673
2003	3.1%	-1.0%	51.2	613
2004	4.5% [2]	4.5%	53.5	679
2005	4.0%	3.6%	55.4	706
2006	3.2%	2.9%	57.0	729
2007	2.5%	2.3%	58.3	747
2008	2.5%	2.3%	59.6	766
2009	2.5%	2.3%	61.0	785
2010	2.5%	2.3%	62.3	805
	[2] Federal Reserve Forecast is 5%		[3] 1999 Production	[1] Excl Ref Ethane

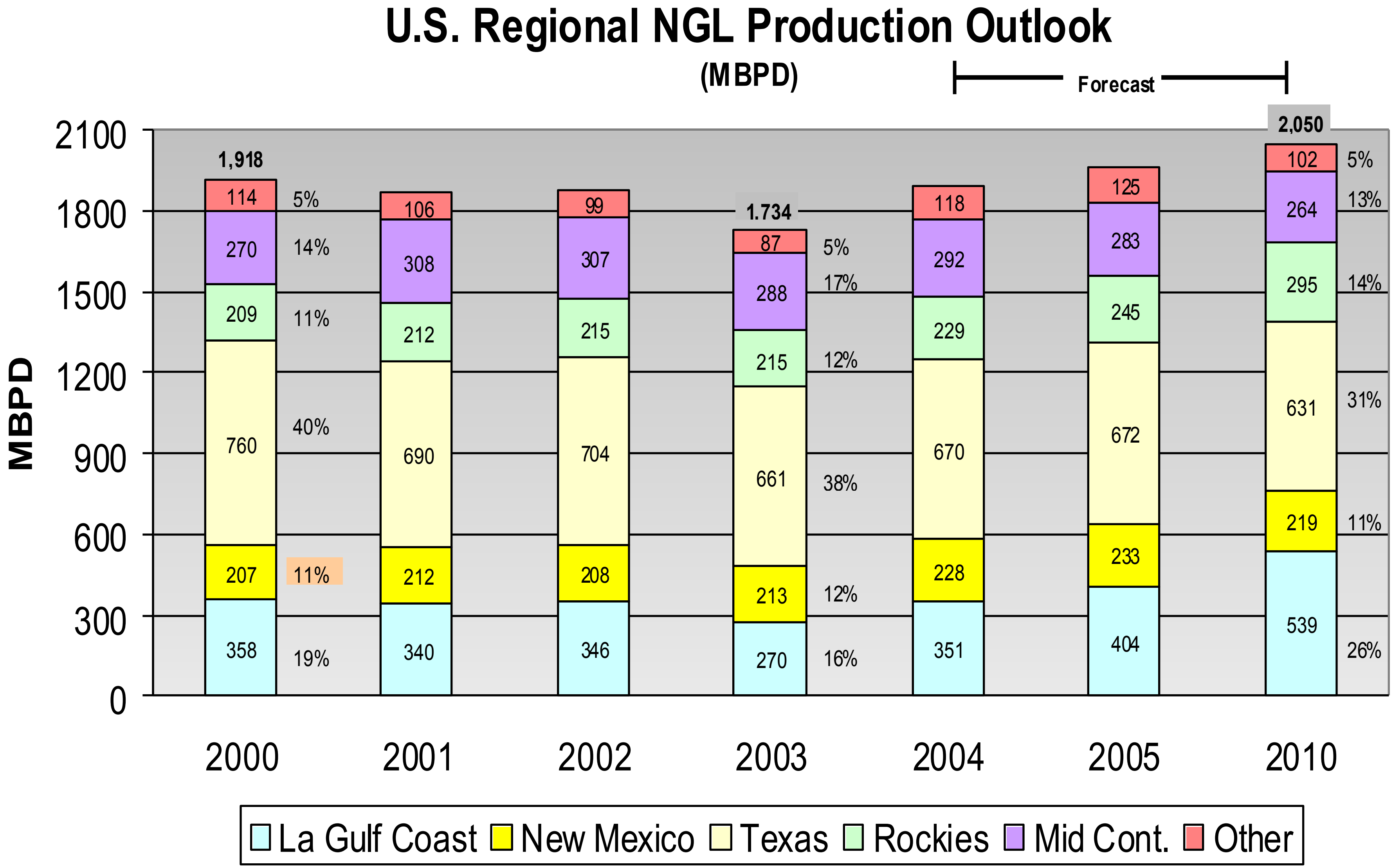
In the Lower-48, growth in Rockies and Deepwater GOM will offset declines in virtually all other U.S. mature basins.

NPC Report 9/25/03



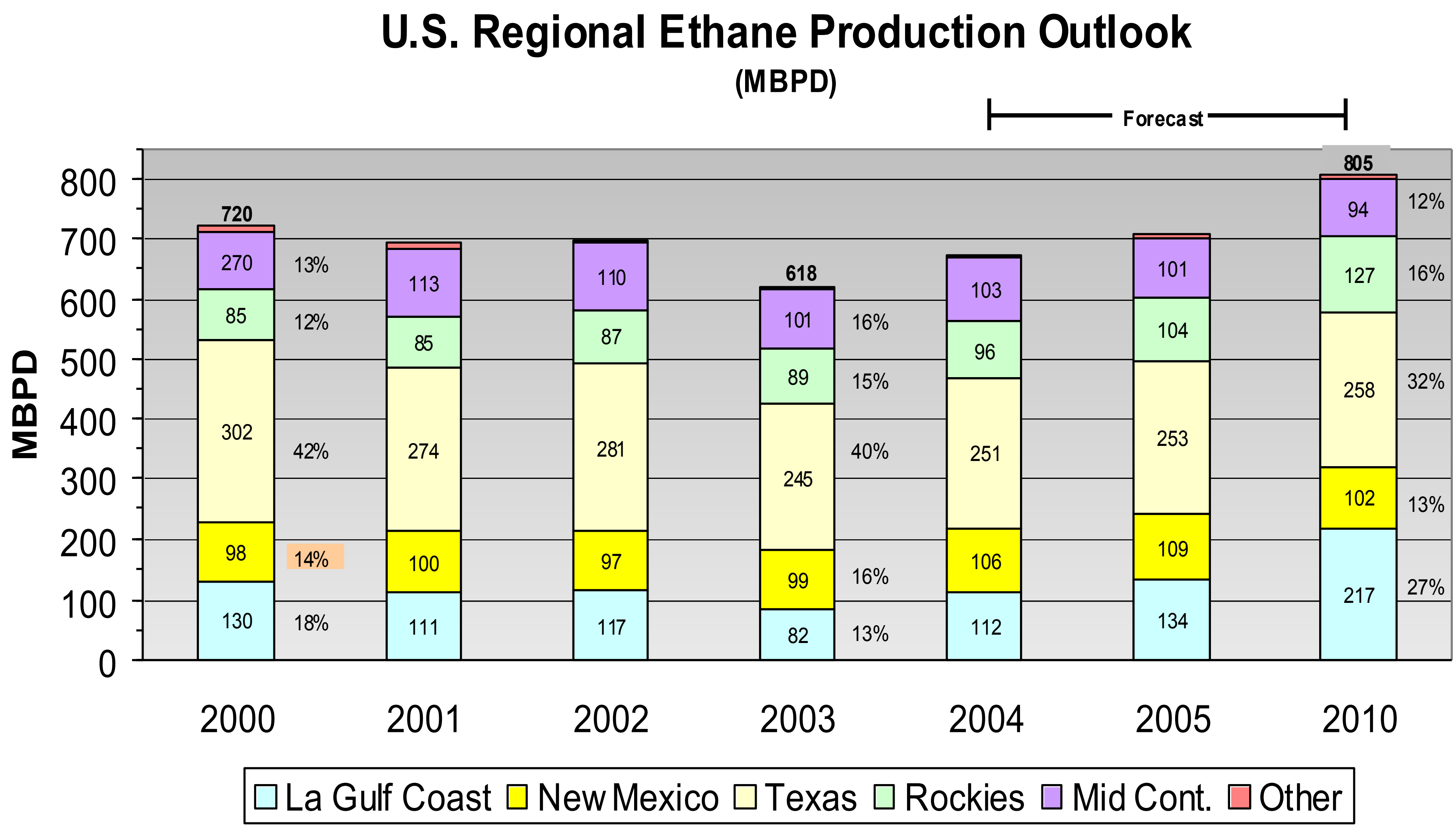
* Includes lower-48 production, ethane rejection, and supplemental gas.

U.S. NGL production should grow to accommodate production trends and market demands.



Source: DOE, En*Vantage

La GC and Rockies will be the incremental producers of ethane in the ’05 to ’10 time period.



Source: DOE, En*Vantage

Summary of Operating Conditions & Outlook

- Market conditions for NGLs should continue to improve in ’04.
  - The ‘04 demand for ethane from processors is expected to be between 650 to 700 MBPD, an increase of 40 MBPD to 90 MBPD over ‘03 levels.
  - Ethylene production rising to ~ 54 billion Lbs in ’04 as a result of U.S. GDP growth of 4.5%.
  - Gas to crude price ratio remaining in the high 80% to low 90% range.
- NGL Production in 2004 increases from 2003 levels by about 8% or 130 MBPD.
- Longer term fundamentals are favorable for EPD.
  - Incremental ethane supplies must be extracted from La GC and the Rockies to meet future demand for ethane.
- “Trough” conditions for ethane can occur when ethylene production levels are low (49 to 51 Billion Lbs/yr) and gas to crude ratios are well above 90%.
- During “trough” conditions ethylene producers usually minimize ethane cracking. However, minimum ethane cracking levels can not be sustained for more than 1 quarter without creating a surplus of co-products.
  - When ethane extraction is minimized during “trough” conditions, ethane production can decrease 25% to 30% or about 200 MBPD from historical average extraction levels.
  - Total NGL production, however, only drops 10% to 20% due to need to extract propane and butane plus to meet gas pipeline quality specifications.

Operating Income Sensitivity Cases

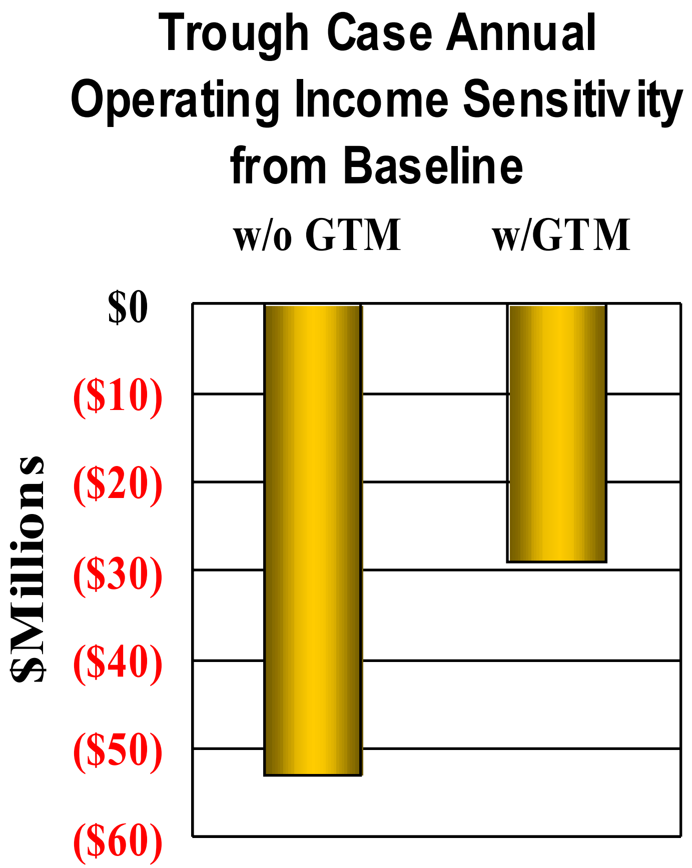
Sensitivity Cases

- **Baseline Case** – assumes "Project Miramar" price deck based on 2004 PIRA forecast and represents the recovery phase of the Ethylene Industry's business cycle.
- **Trough Case** – annualizes mid-2003 market conditions reflecting ethylene cycle bottom, high relative price of natural gas, and minimum ethane cracking levels.
- **Low Price Case** – uses a low natural gas and crude price deck supplied by S&P.

	Units	Baseline Case	Trough Case	Low Price Case [1]
Ethylene Industry Conditions				
Ethylene Production	B Lb/yr	53 to 55	49 to 51	53 to 55
Effective Operating Rate	%	~ 90%	Low 80%	~ 90%
Ethane Cracking Range	MBPD	650 to 700	500 to 625	650 to 700
Henry Hub Gas Price	$/MMBtu	**3.94**	**5.25**	**3.25**
Crude Price (WTI)	$/Bbl	**26.65**	**29.61**	**21.00**
Mt. Belvieu NGL Prices				
Ethane	¢/Gal	33.20	38.10	28.60
Propane	¢/Gal	47.60	53.40	37.50
Iso-Butane	¢/Gal	58.30	62.80	46.50
N-Butane	¢/Gal	55.80	59.70	44.00
Natural Gasoline	¢/Gal	61.60	66.40	48.50
Relationships				
Gas to Crude Ratio (Btu basis)	*%*	***86***	***103***	***90***
Ethane to Gas Spread	¢/Gal	7.0	3.3	7.00
Propane to Crude	%	75.0	75.7	75.0
N-Butane to Crude	%	87.9	84.7	88
Iso-Normal Spread	¢/Gal	2.5	3.1	2.5
Natural Gasoline to Crude	%	97.0	94.0	97.0
Composite NGL Frac Spread	*¢/Gal*	***11.9***	***5.1***	***8.9***

[1] It is assumed that the economy will benefit from low energy prices and Ethylene Industry conditions will be the same or better than the industry conditions assumed in the Baseline Case.

Combination Reduces EPD’s Sensitivity to Higher Natural Gas Prices in Trough Case.

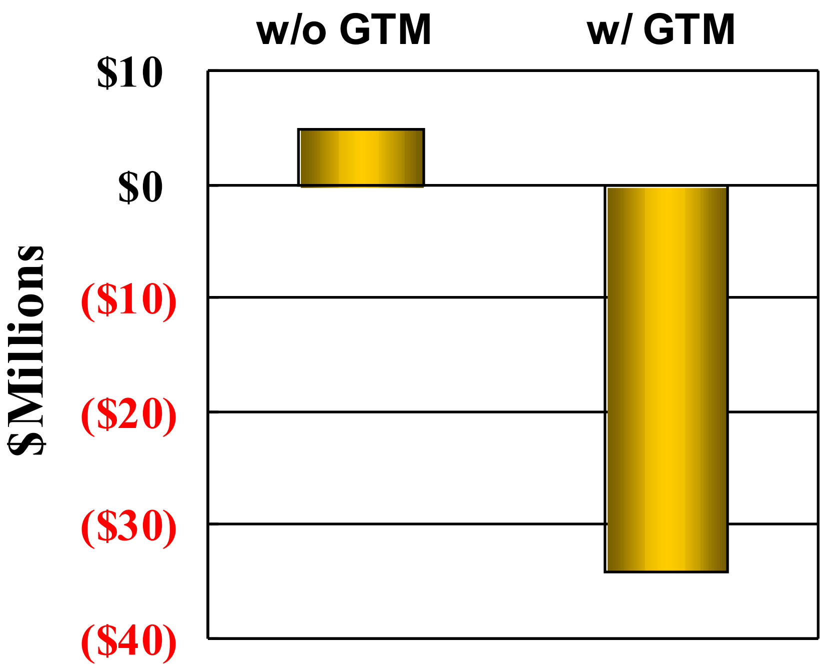


- Trough conditions for an entire year, negatively impacts EPD’s operating income approx. $53MM from its Baseline operating income.
  - EPD’s Louisiana NGL assets and the MAPL/Seminole Pipeline, show the greatest sensitivity to an ethylene industry downturn due to reduced ethane volumes transported and fractionated. Recent changes in processing agreements help offset lower processing margins in Louisiana.
- Under “Trough Case”, GTM benefits from higher energy prices and its operating income increases by $25MM from its Baseline operating income.
- As a result, the combined operating income of EPD and GTM is only reduced by approx. $29MM.

envantage

Combination Slightly Increases EPD's Sensitivity to Lower Natural Gas Prices.

Low Price Case Annual Operating Income Sensitivity from Baseline



- The Low Price Case actually benefits EPD's operating income marginally, due to the following factors:
  - Lower energy prices benefit economic growth and ethane demand specifically.
  - Higher volumes through EPD's NGL systems and the amended Shell contract offset lower processing margins for EPD.
- GTM's operating income decreases by approximately $39MM under the Low Price Case due to POP contracts (assuming no hedges are in place).
- As a result, the combined operating income of EPD and GTM is reduced by approximately $34MM under the low price case.

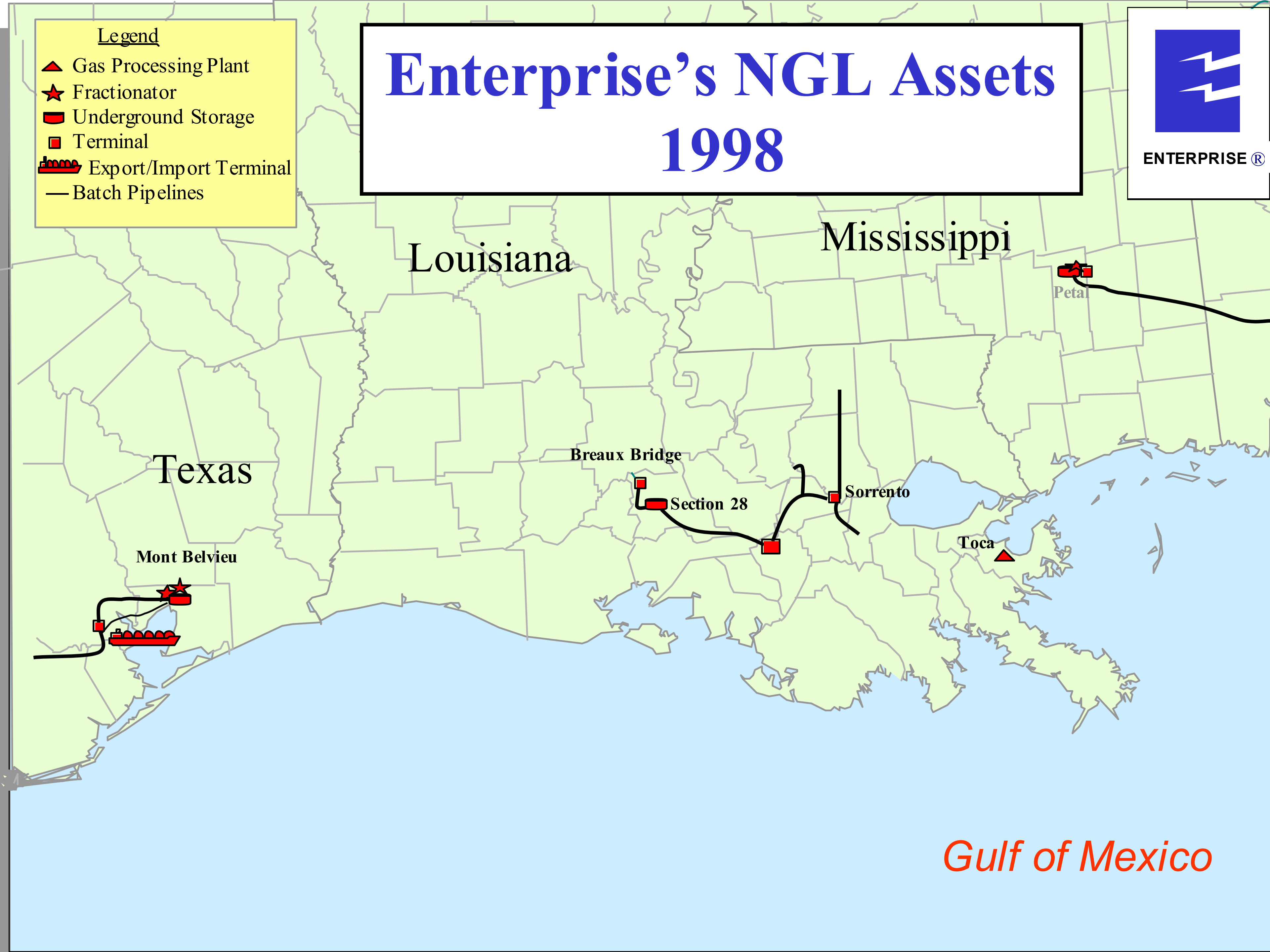
NGL Business

Business Strategy

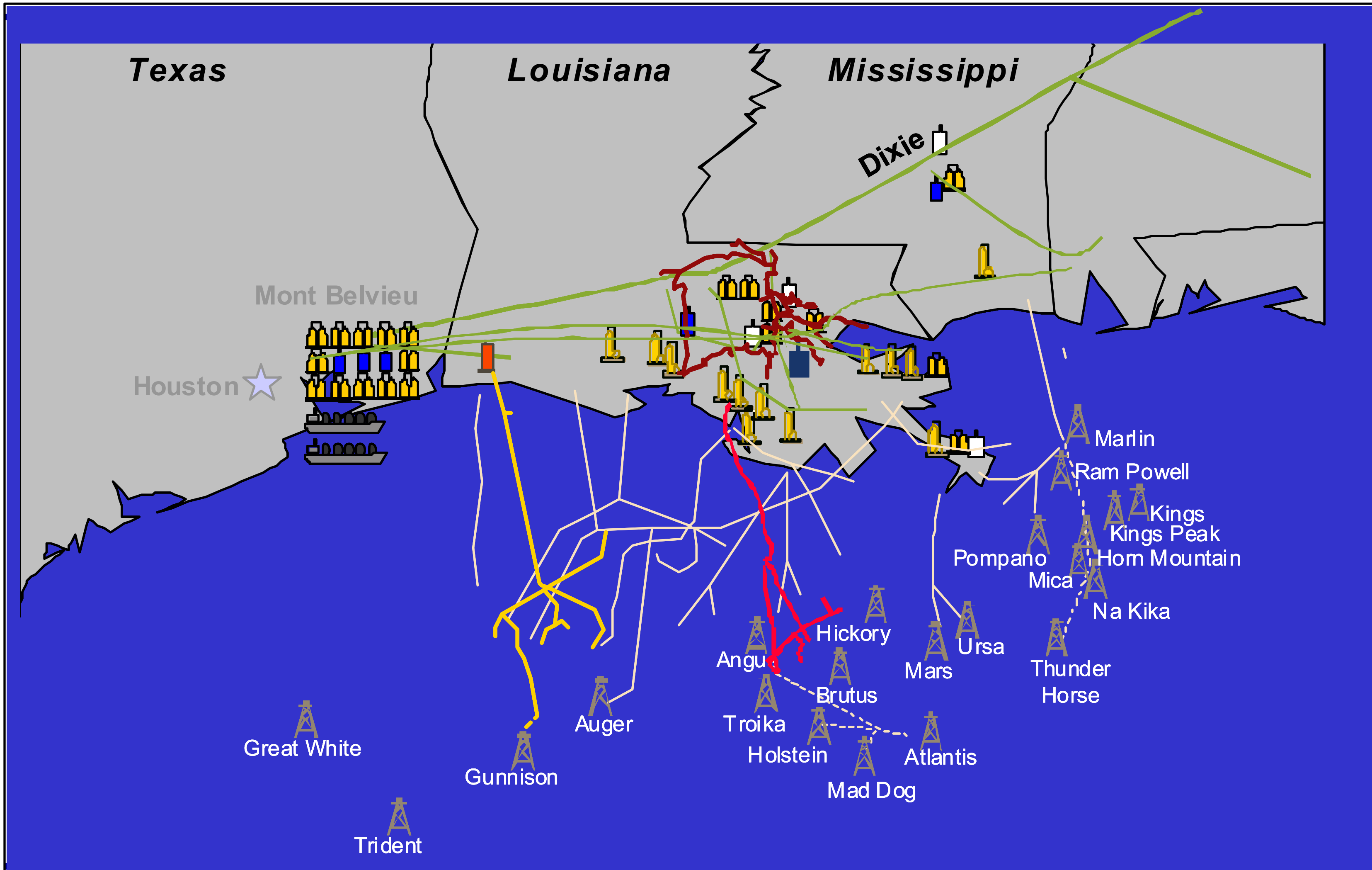
- Build an integrated midstream NGL business, not a collection of assets
- Capitalize on organic growth opportunities to serve natural gas and NGL production
- Partner with customers in joint venture projects to gain access to feedstock and market for products
- Expand asset base through acquisitions of complementary midstream assets

Enterprise's NGL Assets 1998

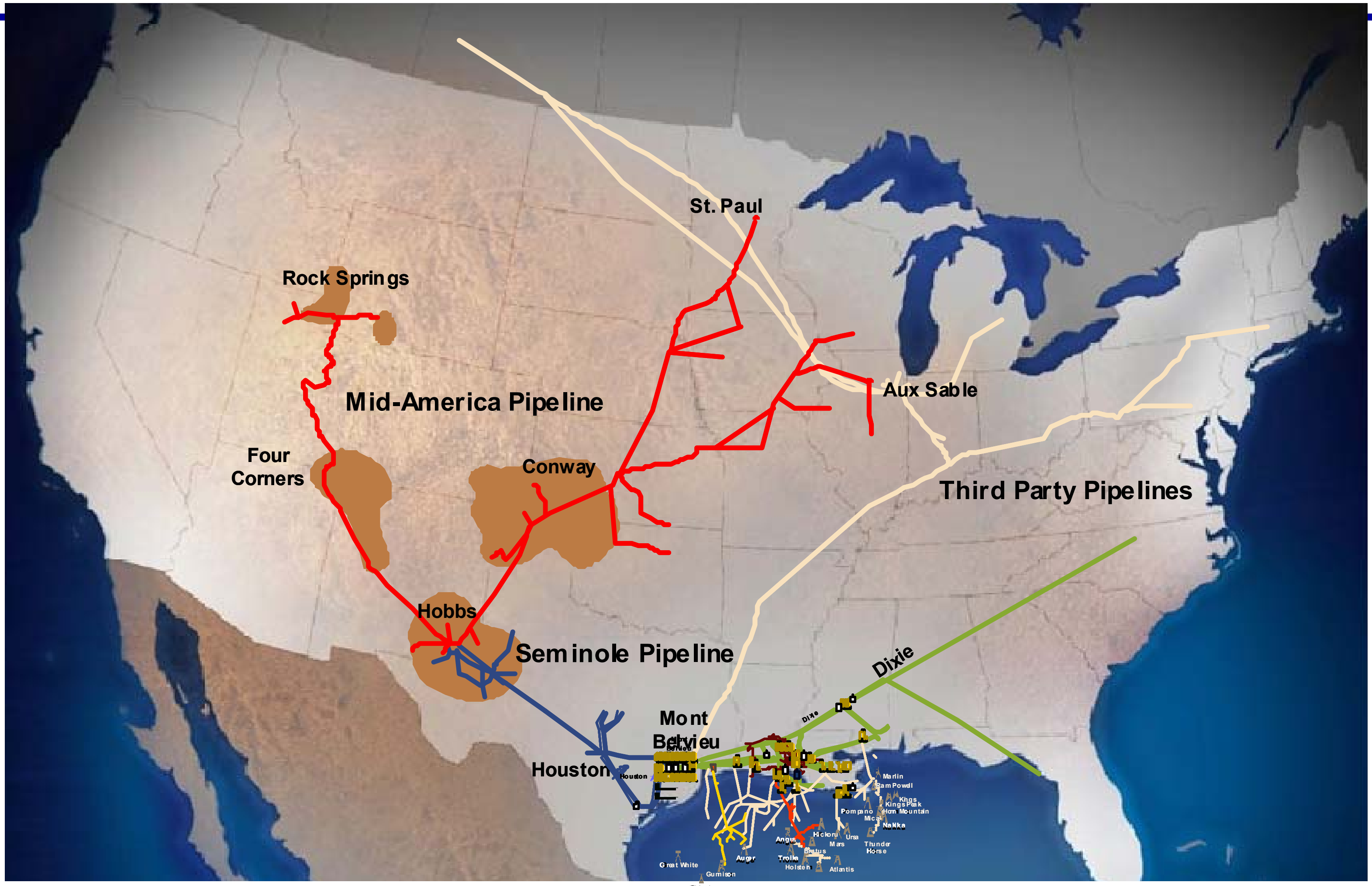
ENTERPRISE ®



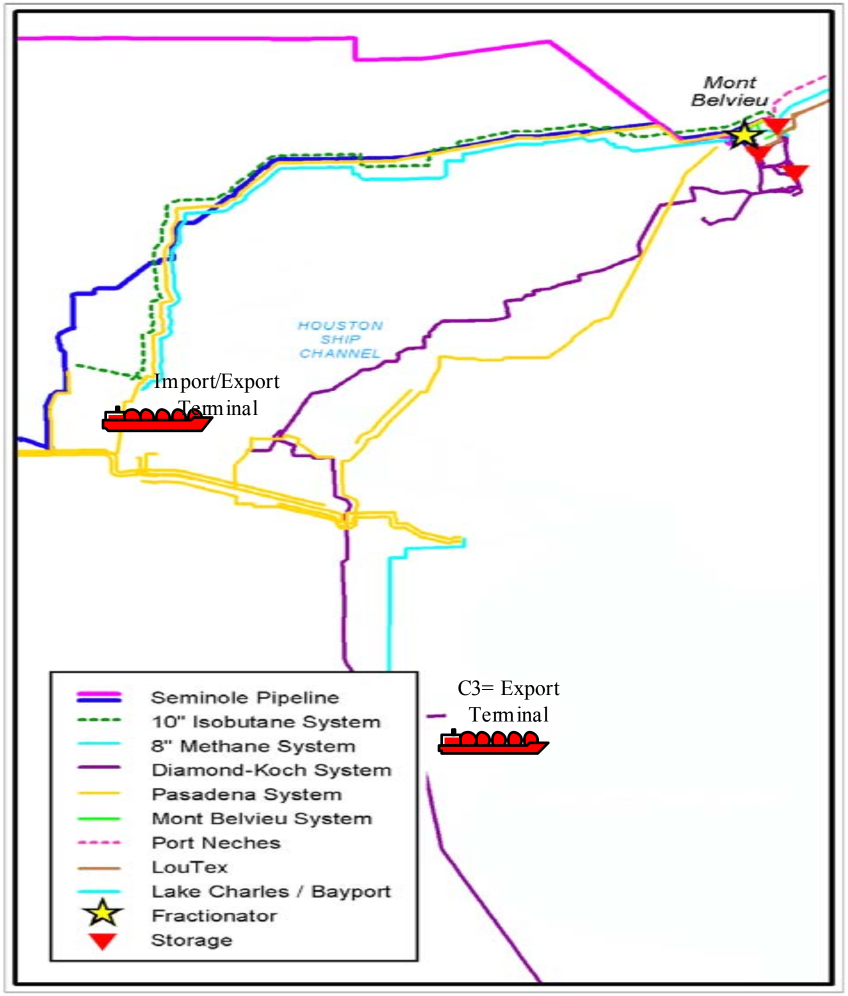
Successful Execution of Growth Strategy



Successful Execution of Growth Strategy



EPD's MTBV Complex, Terminals and Houston Ship Channel Pipeline System



- Largest NGL fractionator at Mont Belvieu - 210M/BPD
- Largest storage position at Mont Belvieu petrochemical and refinery feedstock franchises
- Largest butane isomerization & DIB system in U.S.
- World-Scale propylene fractionation capacity
- Connections to all mixed NGL pipelines into Mont Belvieu
- Comprehensive distribution pipeline system
- Fastest offloading import terminal on Gulf Coast
- Only U.S. world class fully-refrigerated NGL export terminal

Global Marketplace Access

- Enterprise links all major United States and Canada production areas to Mont Belvieu via its NGL pipeline system (MAPL/Seminole/Lou-Tex)
- Enterprise links deep sea LPG markets via import/export terminals on Houston Ship Channel to Mont Belvieu. Throughput of 73 MPBD in 2003
- Enterprise Import/Export Advantages
  - A combined loading rate of 7,500 BPH of full and semi-refrigeration capability
  - Connected to largest salt dome storage complex in the world
  - Direct loading/unloading from high rate wells in Mont Belvieu
  - World pricing increasingly driven off Mont Belvieu
    - Mont Belvieu has become not just NGL Hub of North America, but key market in the world's NGL balance

EPD's Access to Supply

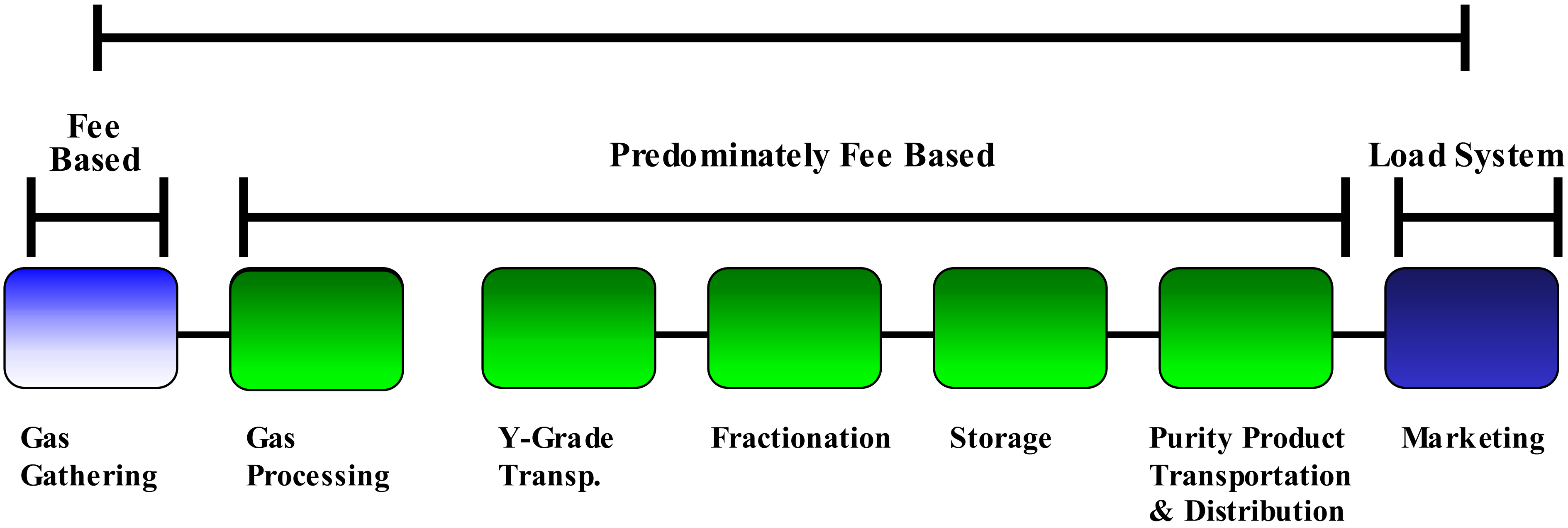
- Only NGL evacuation route out of Rocky Mountains & San Juan
- Access to Permian & Mid-Continent produced NGL's
- Only NGL Pipeline route out of Canada
- Primary NGL processor, fractionator, and distributor of GOM produced NGL's
- World class LPG Import Facility

EPD's Access to Markets

- Pipeline access to 97% of U.S. ethylene capacity
- Pipeline access to world's largest concentration of refineries
- Access to international LPG markets through the only fully refrigerated LPG Export Facility in U.S.
- Pipeline access to Midwest retail propane markets through Mid-America Pipeline and Southeast retail propane markets with Dixie Pipeline

Value Chain

Linking & Leveraging across the Value Chain to Manage Risk and Maximize Value …



Ranking Along the NGL Value Chain

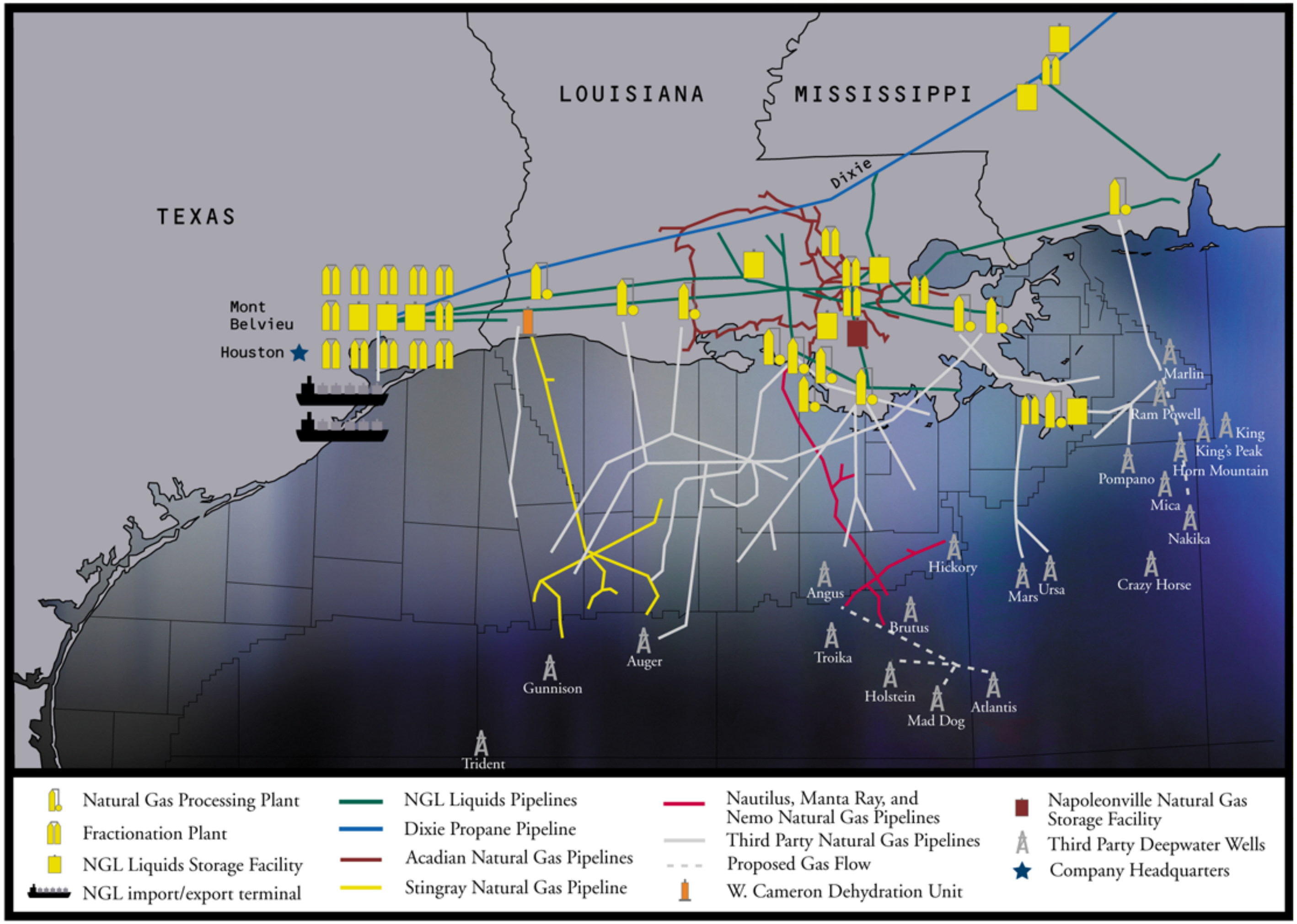
Gas Processing	Raw Mix Pipeline	Fractionation	Salt Dome Storage	Import Terminal	Export Terminal	Distribution
Duke FS	Enterprise	Koch	Enterprise	Dow	Enterprise	Enterprise
BP	TEPPCO	Enterprise	TEPPCO	Enterprise	Dynegy	Dow
El Paso	ChevronTexaco	ConocoPhillips	Dow	Dynegy	ChevronTexaco	ConocoPhillips
Williams	Dynegy	Dynegy	Dynegy	Trammo		TEPPCO
ExxonMobil	BP	El Paso	Williams			Koch
Enterprise	El Paso	ExxonMobil	ConocoPhillips			KinderMorgan
ONEOK	ExxonMobil	BP	BP			ChevronTexaco
ConocoPhillips	ConocoPhillips	ONEOK	ExxonMobil			Dynegy
Devon		Duke	El Paso			El Paso
Dynegy		Williams	ONEOK			ExxonMobil

2003/2004 Achievements/Objectives

- Reduce margin sensitivity to high natural gas prices
  - restructure gas processing contracts to reduce exposure to keepwhole processing economics and increase fee-based and % of liquids processing volumes
  - capture incremental economics through product flow incentives
- Increase system margins & volume
  - attract new supplies to EPD's integrated system
  - maximize utilization of highest margin assets
  - development of new programs
  - secure incremental margins from existing business
- Capitalize on new opportunities
- Increase ownership % in key assets

Enterprise
Eastern NGL System

Enterprise Eastern System Map



Enterprise Eastern NGL System Natural Gas Processing

- Interest in twelve major plants covering key deepwater Gulf of Mexico gas evacuation routes (operate four)
- Gross gas processing capacity of 12.4 BCFD (net 3.5 BCFD)
- Current capacity utilization approximately 60 percent
- Expansions complete at Neptune and Pascagoula
- Contract Mix: Fee, NGL retainage (% NGLs) and hybrid "margin band"/fee based gas processing contracts

Enterprise Eastern NGL System
NGL Fractionation

- Interest in five major fractionators connected to key gas processing plants serving Gulf of Mexico production (operate four)
- Gross fractionation capacity of 340 MBPD (net 163 MBPD)
- Current capacity utilization approximately 60-65 percent
- Expansion complete at Norco
- Contract Mix: Fee (with gas price escalators) and NGL retainage based fractionation contracts

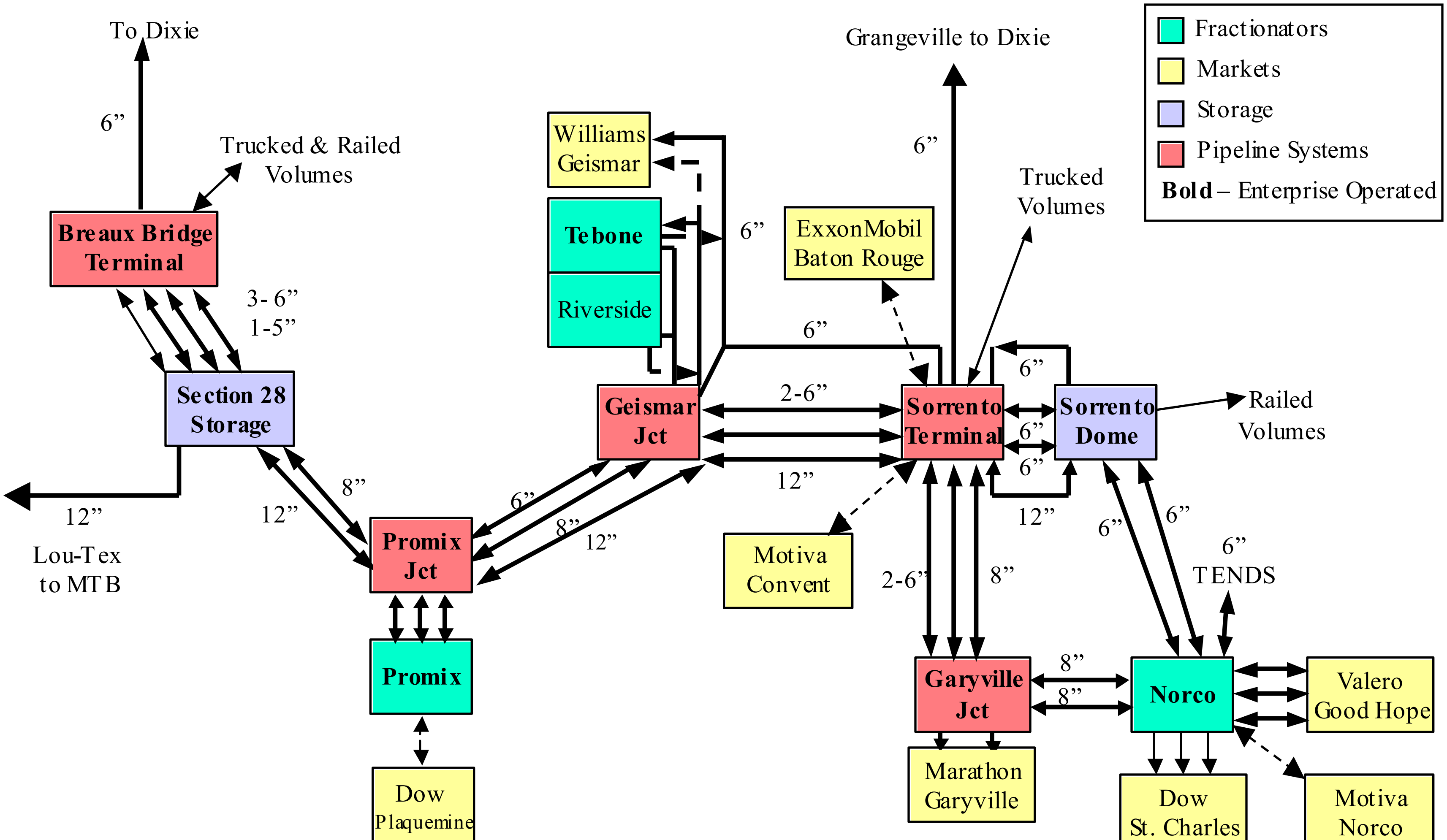
Enterprise Eastern NGL System
NGL Storage

- 34 salt dome storage caverns
- Gross storage capacity of 38 MM barrels (net 20.7 MM barrels)
- Store NGL products, Y-Grade, commercial butane and refinery grade butanes/propylene
- Capacity utilization at peak storage volumes less than 50 percent
- Brine system at Section 28 recently expanded/ upgraded
- Contract Mix: Fee based storage contracts

Enterprise Eastern NGL System
NGL Pipelines

- Over 2,800 miles of various diameter pipelines
- Transport finished NGL products, Y-grade, commercial butanes and refinery grade butanes/ propylene
- Current capacity utilization estimated at 60-65 percent
- Batch and continuous operation
- Lou-Tex recently expanded to 70 MBPD with further system expansion opportunities available
- Contract Mix: Fee (tariff) based transportation contracts

Enterprise Eastern NGL System
Louisiana Product Distribution Pipelines



Enterprise Eastern NGL System Focus on Restructuring and Growth

During the period from 2002-2004 our primary focus has been to:

- Restructure Our Gas Processing Contract Portfolio
  – Shell Conveyance
  – Others
- "Feed" Our NGL system ("organic" growth)
  – Develop new supply sources
  – Maximize day-to-day supply
- Acquire complementary assets

Enterprise Eastern NGL System Shell "Conveyance" (August 1999)

- Shell assigned Enterprise gas processing rights and title to recovered NGLs for existing and future natural gas production in the Gulf of Mexico.
- Once assigned, Enterprise retained rights and title for the life of the lease regardless of subsequent sale or transfer of the lease.
- Enterprise retained 100% of recovered NGL's and reimbursed Shell for plant thermal reduction ("keepwhole") via:
  - a cash payment based on an index-based gas price and PTR volume, or
  - physical make-up of the PTR volume.
- Enterprise had certain rights to withhold processing services and an overall "economic out" provision.
- Term of 20+ years.

Enterprise Eastern NGL System Shell "Conveyance" (March 2003)

- Established floor and ceiling processing margins ("margin band") for Enterprise, but retained "keepwhole" characteristics within the band.
- Assured Enterprise of at least a nominal cash margin considering all operating expenses.
- Assured Shell that its gas will be processed, subject to certain conditions.
- Preserved certain of Enterprise's rights to withhold processing services and overall "economic out" provision.

Enterprise Eastern NGL System Shell "Conveyance" (Current)

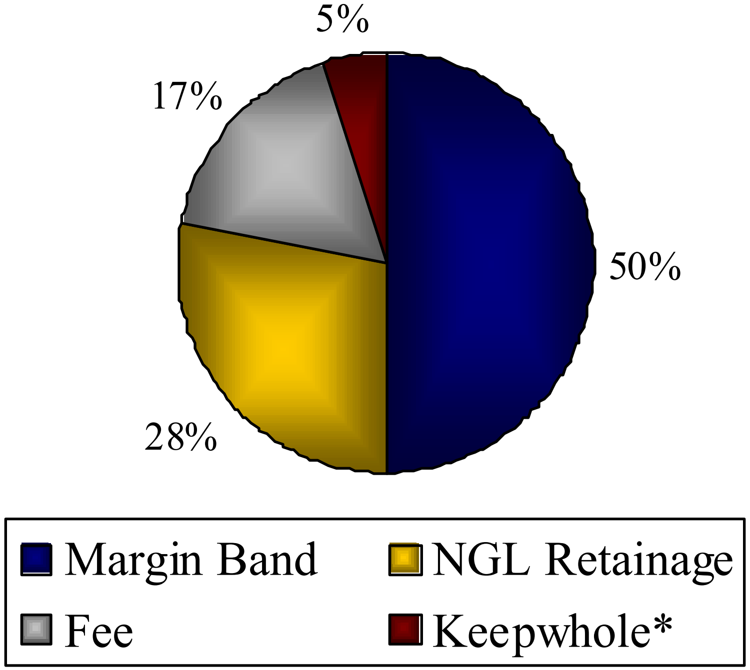
- Completed amendment of the Shell gas processing contract that provides Enterprise with both fair compensation and return on investment related to processing services provided to Shell.
- Provides Shell with assurance that their gas will be processed as necessary to meet pipeline quality specifications.
- Effective April 1, 2004
- Retains "margin band" concept with new floor and ceiling processing margins.
- Incorporates a fixed "fee based" component based upon gas production volumes which results in reduced operating expenses.

Enterprise Eastern NGL System
Other Gas Processing Agreements

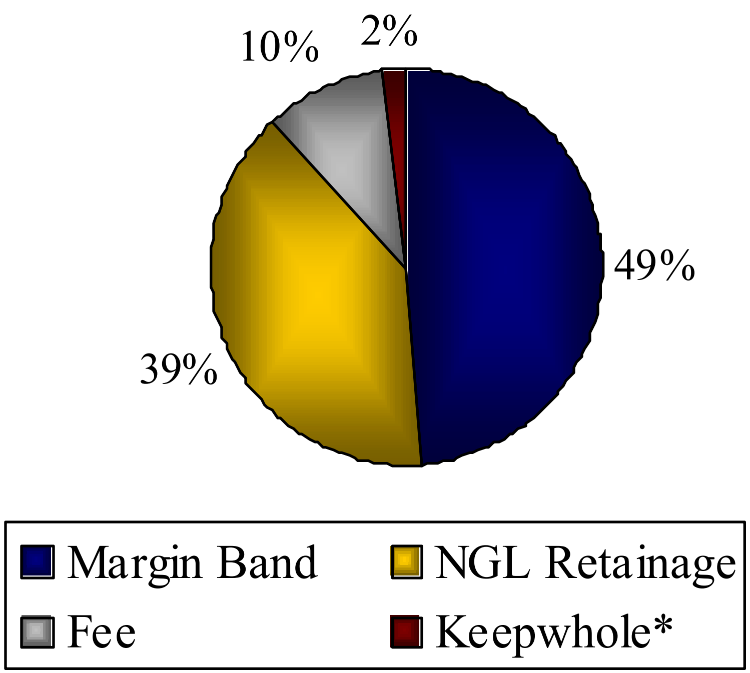
- Converted legacy keepwhole agreements to fee-based contracts where Enterprise receives a toll based on gas volumes (approximately 340 MMCFD and 8100 BPD of NGLs) .
- Remainder of agreements are primarily NGL retainage contracts (approximately 560 MMCFD and 32,000 BPD of gross NGLs).
- Retain few “keep whole” contracts (approximately 100 MMCFD and 2000 BPD of NGLs w/ 75% discretionary)
- Volume estimates based on 2004 forecast.

Enterprise Eastern NGL System
2004 Effective GPA Contract Mix

Based on Gas Throughput
2.0 BCFD



Based on Gross NGLs
Produced 83 MBPD



* 75% Discretionary

Enterprise Eastern NGL System Example Gross Spread Calculation

Gas Price $5.00 /MMBtu

Relationships (cpg):

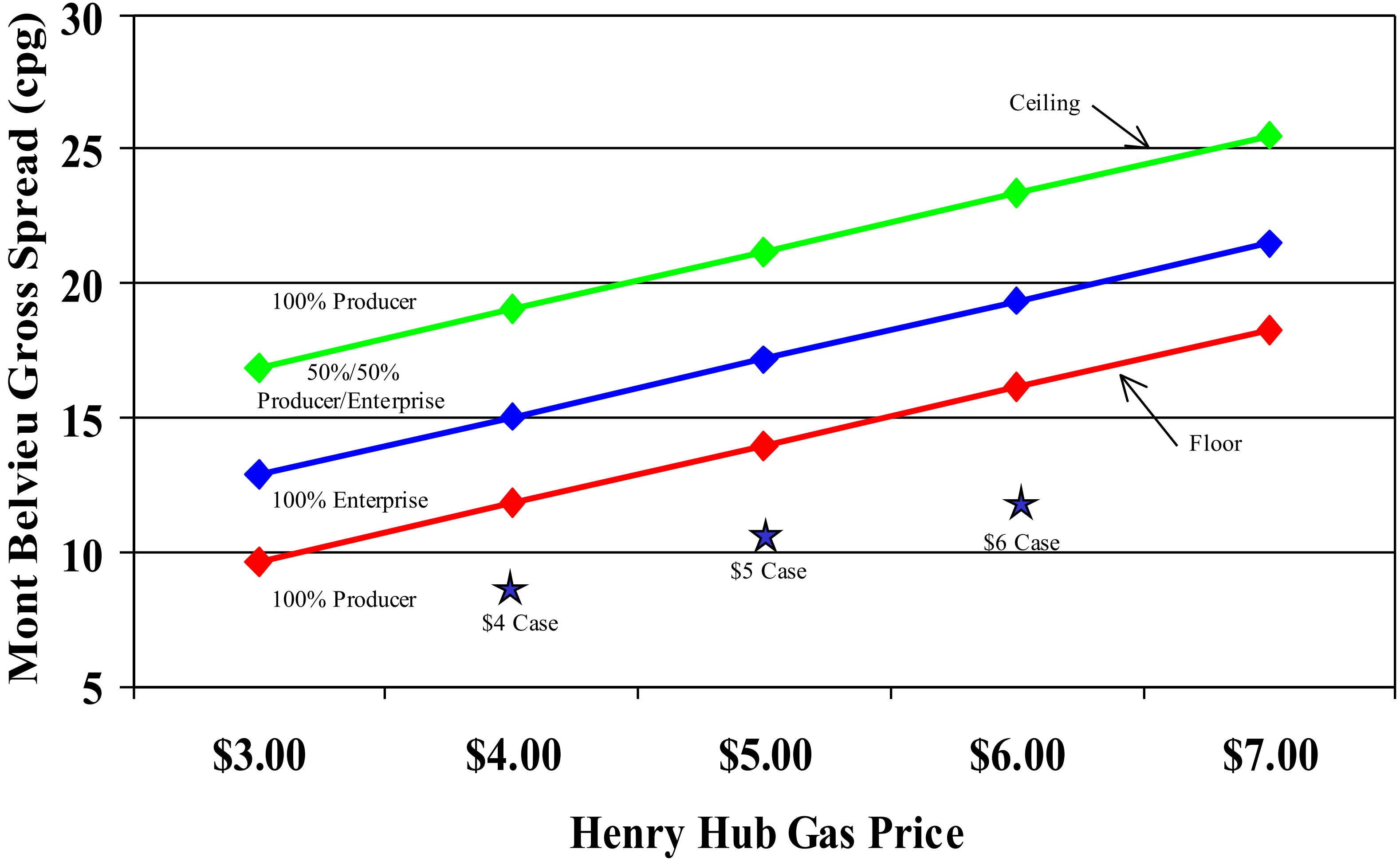
C2	5.00	+ Shrink
C3	1.22	* Gas on BTU basis
i-C4	2.50	+ n-C4
n-C4	1.26	* Gas on BTU basis
C5+	1.24	* Gas on BTU basis

	Price (cpg)	%	Price Contribution (cpg)	Shrink Factor (BTU/gal)	Shrink (Btu)	Shrink Cost $/MMBtu	Spread (cpg)	Spread Contribution (cpg)
C2	38.18	30%	11.45	66,369	19,911	5.00	5.00	1.50
C3	55.80	35%	19.53	91,599	32,060	5.00	10.00	3.50
i-C4	67.98	8%	5.44	99,652	7,972	5.00	18.15	1.45
n-C4	65.48	12%	7.86	103,724	12,447	5.00	13.61	1.63
C5+	71.43	15%	10.71	115,000	17,250	5.00	13.93	2.09
Composite			54.99		89,639			10.18
Less: Cost of Plant Fuel				11,000	Btu/gal			(5.50)
Gross Spread after Fuel								4.68

Eastern NGL System
Natural Gas Price Sensitivities

Price Assumptions:			
Henry Hub Natural Gas ($/Mmbtu):	$ 4.00	$ 5.00	$ 6.00
NGLs (cpg):			
Ethane	31.50	38.20	44.80
Propane	44.60	55.80	67.00
Isobutane	54.90	68.00	81.10
Normal Butane	52.40	65.50	78.60
Pentanes+	57.10	71.40	85.70
Gross Spread	8.50	10.20	11.90
Gross Spread after fuel	4.30	4.70	5.60
Gross Operating Margin ($MM):			
Gas Processing Plants	$ 33.9	$ 39.5	$ 44.7
Norco Fractionator	25.0	31.4	37.7
Total	$ 58.9	$ 70.9	$ 82.4

Eastern NGL System
Margin Band Sensitivities



Enterprise Eastern NGL System Enterprise Net Volumes

- 1,375 MMCFD under fixed “fee-based” terms (cents per MCF produced) – no price or spread exposure
- 38,000 BPD of NGLs under “margin band” terms
- 2,900 BPD in gas processing NGL retainage
- 3,600 BPD in fractionation NGL retainage
- 2,000 BPD under traditional “keep-whole” terms (75% discretionary)
- Volume estimates based on 2004 forecast

Enterprise Eastern NGL System
Feeding the System

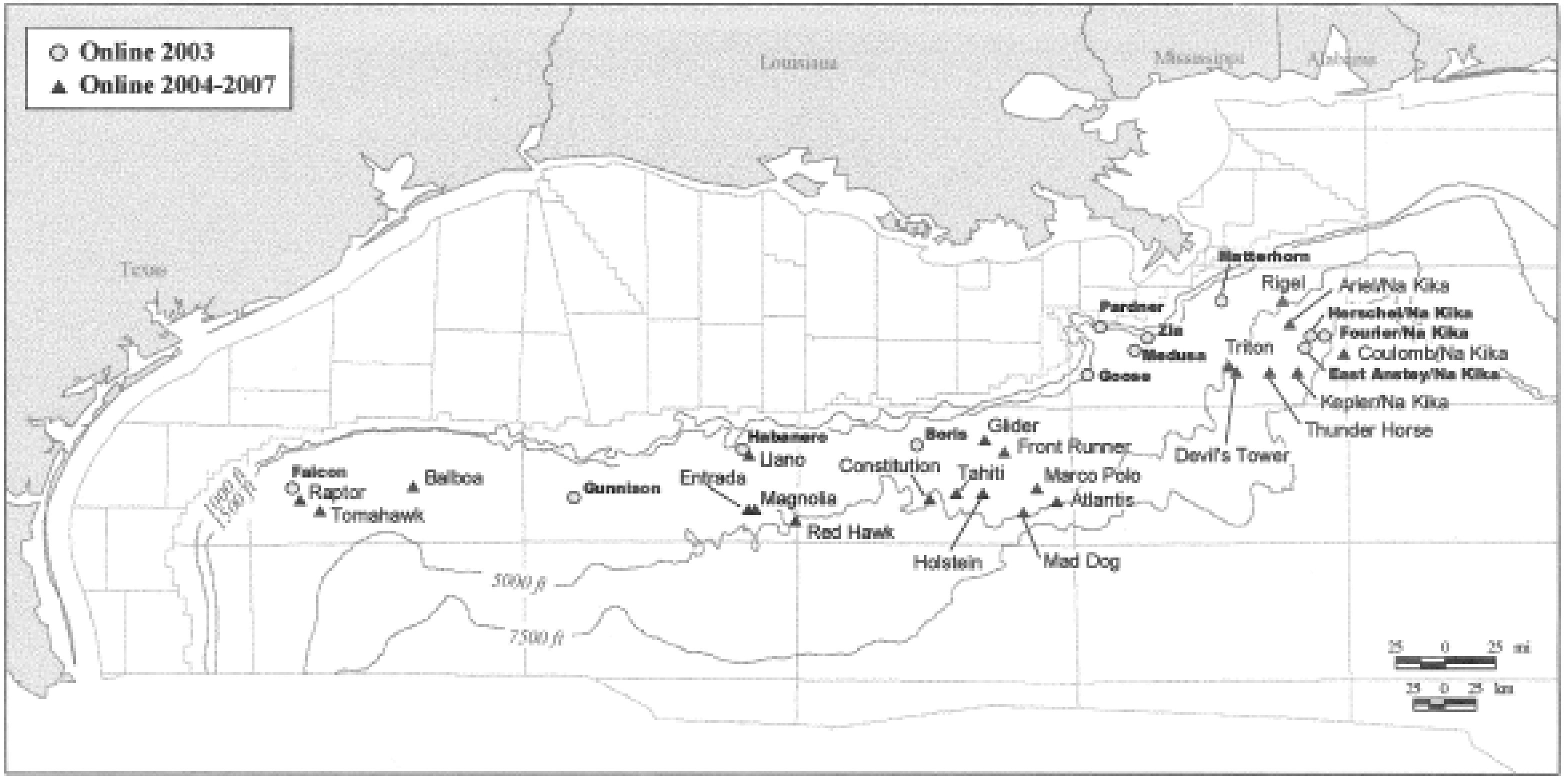


Figure 71. Deepwater projects that began production in 2003 and those expected to begin production by yearend 2007.

Source: MMS

Enterprise Eastern NGL System
Feeding the System

Deepwater Development	First Production	Natural Gas Gathering	Natural Gas Processing	Y-Grade Transportation	NGL Fractionation	NGL Distribution
Matterhorn	2003	**GTM**	√	√	√	√
Medusa	2003	**GTM**	√	√	√	√
Habanero	2003		√	√	√	√
Gunnison	2004	√				
Marco Polo	2004	**GTM**				
Magnolia	2004			√	√	√
Red Hawk	2004	**GTM**				
Front Runner	2004					
Devils Tower	2004			√	√	√
NaKika	2004		√	√	√	√
Holstein	2004	√	√	√	√	√
Mad Dog	2004	√	√	√	√	√
Glider	2004	√	√	√	√	√

Enterprise Eastern NGL System
Feeding the System

Deepwater Development	First Production	Natural Gas Gathering	Natural Gas Processing	Y-Grade Transportation	NGL Fractionation	NGL Distribution
Llano	2004		√	√	√	√
Atlantis	2005	√	√	√	√	√
Thunder Horse	2005		√	√	√	√
Coulomb	2005		√	√	√	√
K2	2005	**GTM**				
Entrada	2006	**TBD**				
Shenzi	2006	**TBD**				
Ticonderoga	2006	**TBD**				
Neptune	2006	**TBD**				
Constitution	2006	**GTM**	**TBD**			
Atwater Valley	2006/2007	**TBD**				
Tahiti	2007	**TBD**				

Enterprise Eastern NGL System
New Supply Sources

- Finalized Southern Green Canyon Project Dedications:
  - Executed binding, life-of-lease dedications with BP for their share of Holstein, Mad Dog and Atlantis in late 2001.
  - Shell's share of Holstein dedicated under prior agreements.
  - Executed similar dedications with other interest owners (BHP and Unocal) in 2003/2004.
  - Involves every component of Enterprise's midstream value chain (gas gathering, processing, fractionation, pipelines, storage and gas transportation)
  - Provides "straw" into area with very active deep water exploration via producer owned Cleopatra Pipeline.
  - Completed expansion of Neptune plant from 300 to 650 MMCFD in early 2004.
  - First production 4Q04 with ultimate NGL production expected to reach 20-25 MBPD by 2006.

Enterprise Eastern NGL System New Supply Sources

- Consolidated Toca-Western Plant with Norco and Toca JV Facilities:
  - Purchased Toca-Western gas processing plant and fractionator from WGR in mid-2002.
  - Renegotiated long term fractionation agreement with Yscloskey gas processing plant owners to move volumes to Norco.
  - Renegotiated gas processing agreements to move gas to Toca JV plant under Enterprise direct and JV plant agreements.
  - Shut down Toca-Western facility on August 1, 2003.
  - Added 8-10 MBPD under NGL retainage based fractionation contracts at Norco and 60 MMCFD of gas under NGL retainage and fee based processing contracts at Toca JV plant.
  - Provides ongoing operating cost savings at Norco, Toca JV and Yscloskey plants.

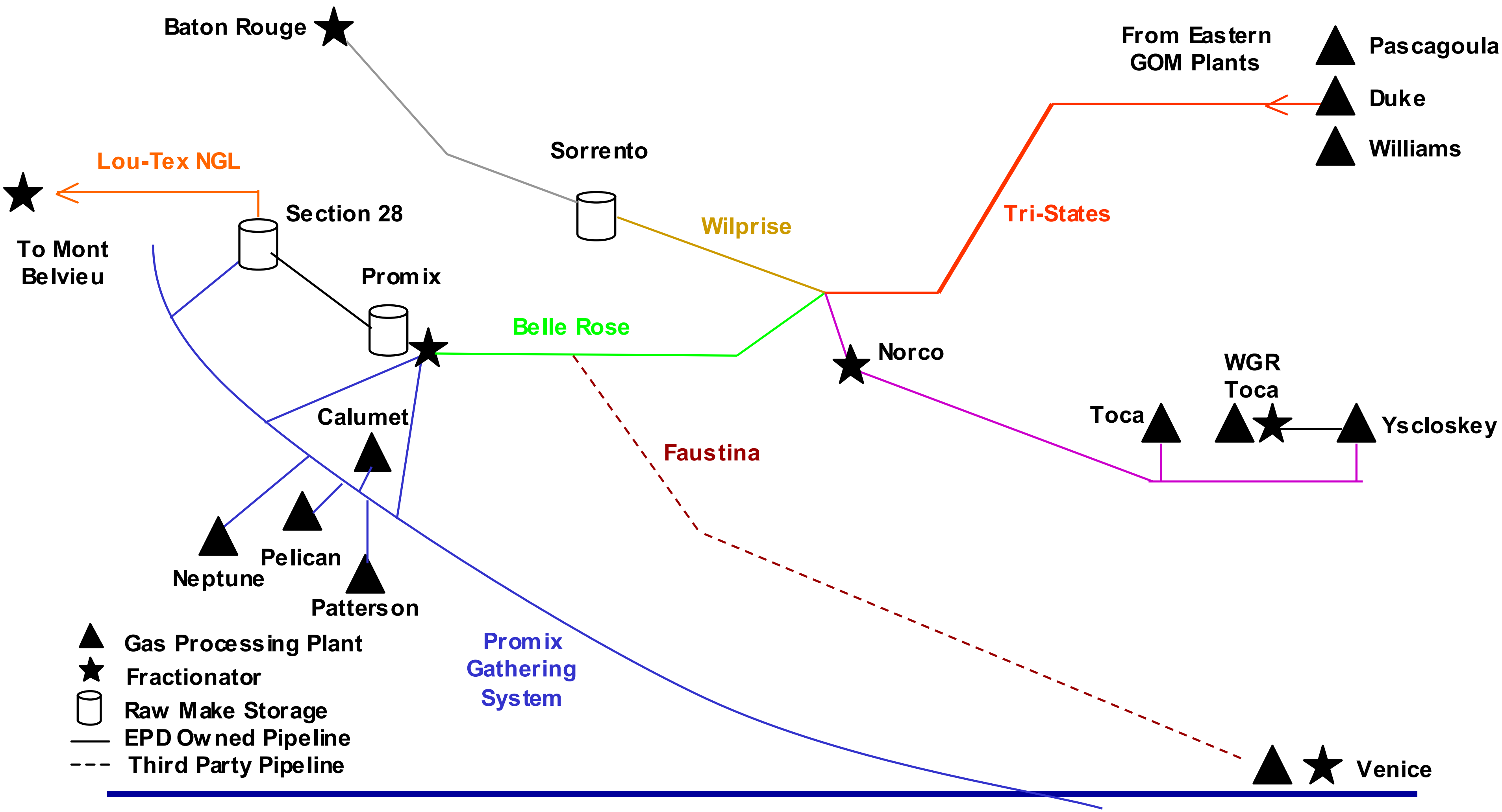
Enterprise Eastern NGL System
New Supply Sources

- Executed Venice NGL Supply Agreements:
  - Executed amendment to Enterprise's Venice gas processing agreement to take our raw make "in kind".
  - Agreed to have this raw make transported on new CVX "VP" pipeline from Venice to new connection with Enterprise's Norco system.
  - Executed agreements to purchase other raw make produced but not fractionated at Venice.
  - Initiated receipts into Norco system on September 1, 2003.
  - Volumes have been averaging 10-15 MBPD.

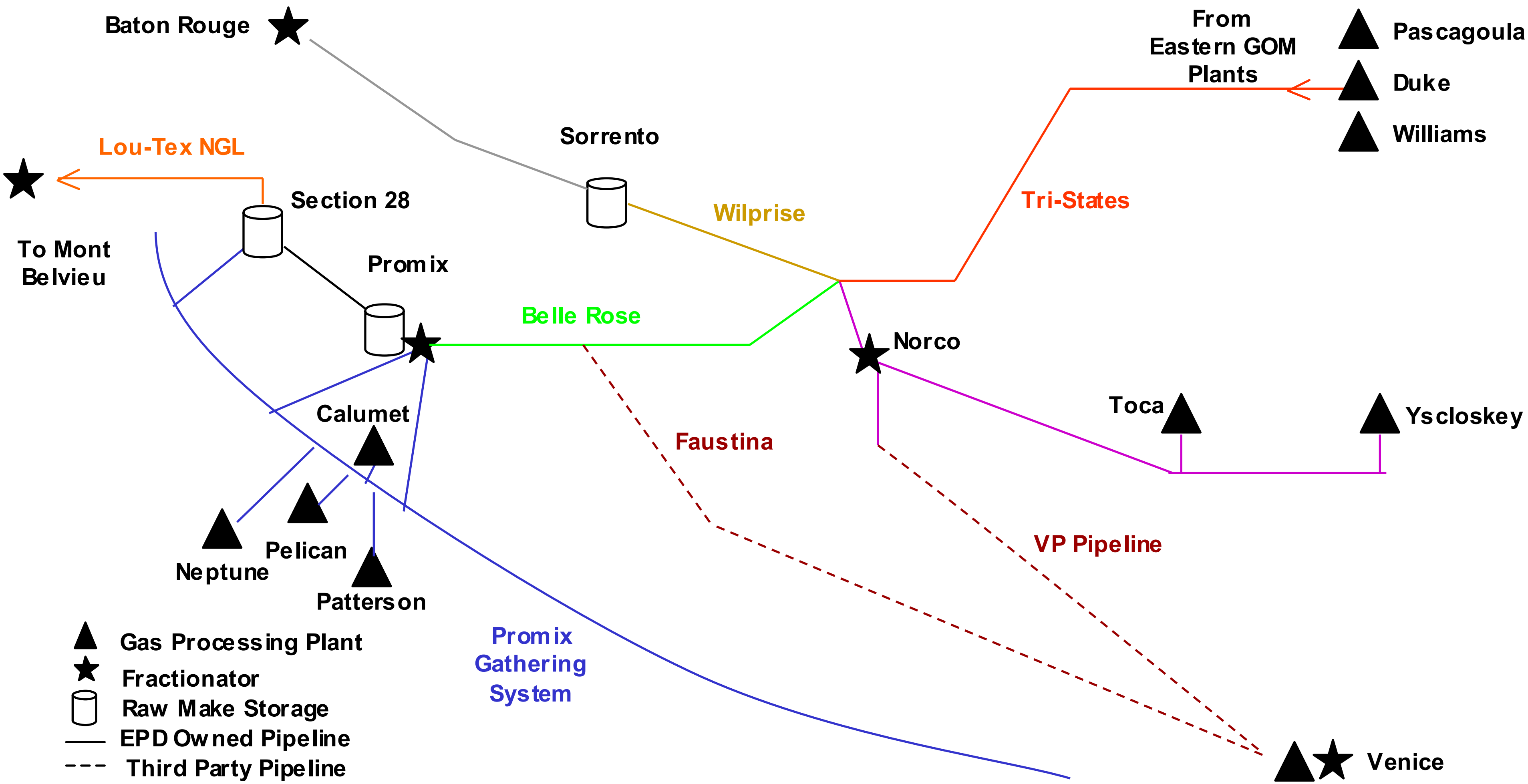
Enterprise Eastern NGL System
New Supply Sources

- Completed expansion of Norco fractionator:
  - C2 capacity 75 MBPD/C3+ capacity 90 MBPD.
  - Prior capacity @ typical composition was approximately 50 MBPD.
  - Expansion completed in late October, 2003.
  - Renegotiated fee based contract with Valero Refinery to fractionate C3+ volumes (seasonally up to 5 MBPD).
  - Initiated trucking of C3+ volumes from Petal, MS vs.Mont Belvieu (averaging 2 MBPD)
  - Acquired/constructed new product distribution pipeline between Garyville and Sorrento and increased butane storage at Norco.
  - Averaged over 63 MBPD throughput during 1Q04.

EPD’s Louisiana Mixed-NGL System (Past)



EPD's Louisiana Mixed-NGL System (Current)



Eastern NGL System
Maximize Day-to-Day Supply

- Established indexed NGL exchange fee on incremental ethane production from the Sea Robin gas processing plant (approximately 8,000 bpd):
  - Fee adjusts daily to ensure positive ethane recovery economics for plant.
  - No ethane rejection experienced during 1Q04.
  - Remains in place on a month-to-month basis.

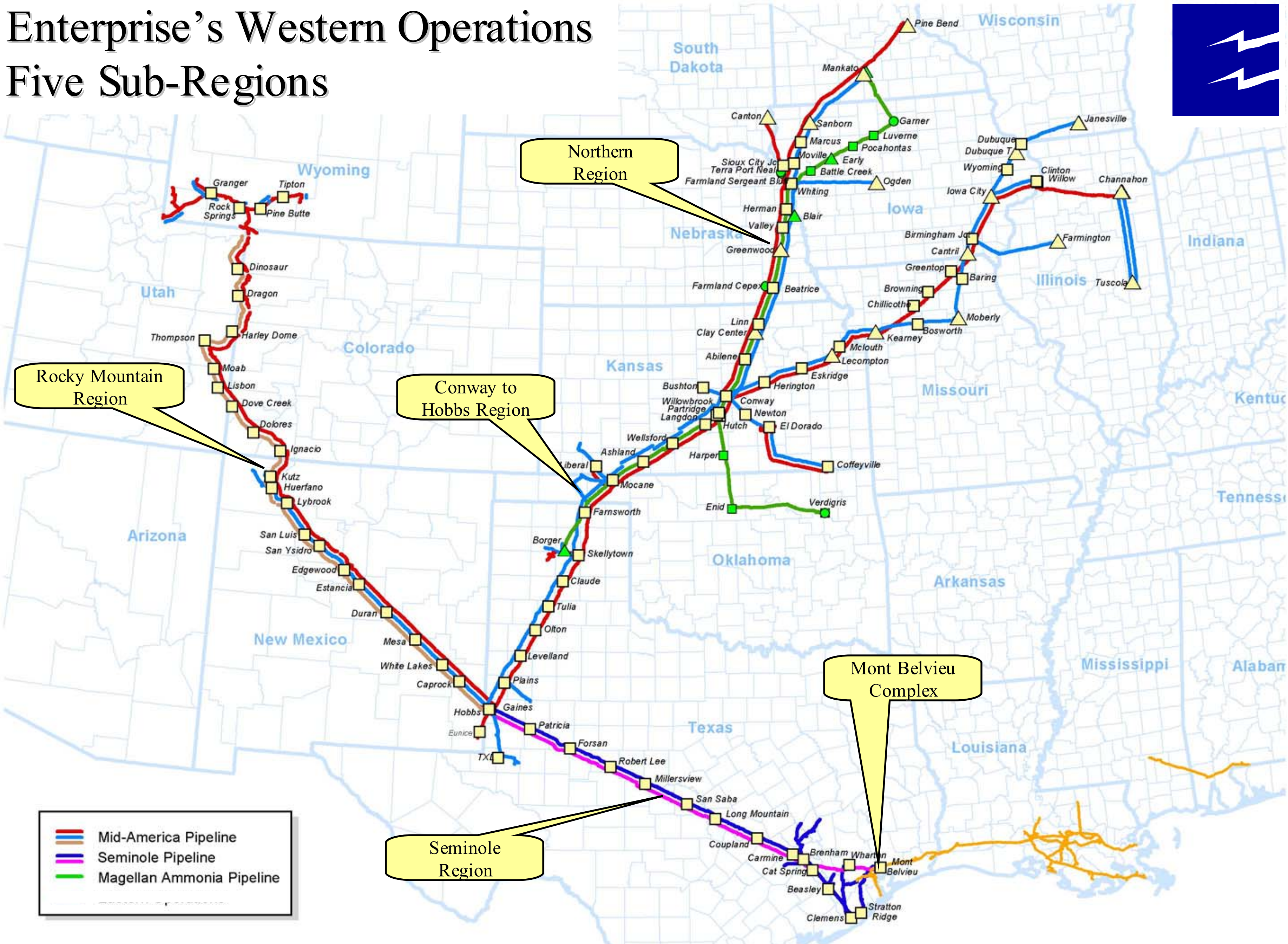
Enterprise Eastern NGL System Acquire Complementary Assets

- Purchased Williams 16.7% interest in the Tri-States and 37.4% interest in the Wilprise NGL pipelines effective October 1, 2003.
- Purchased Koch's 16.7% interest in Tri-States effective April 1, 2004.
- Current Tri-States interest is 66.7% and Wilprise interest is 74.7%.
- Acquired additional interest estimated to be 20% of the Yscloskey plant with significant volume (>100 MMCFD) of rich gas committed under % of NGL or hybrid contracts with life-of-lease terms.

Western NGL Assets

Mid-America Pipeline
Seminole Pipeline
Enterprise Terminals and Storage
Mont Belvieu Fractionator
Import/Export Terminal

Enterprise's Western Operations
Five Sub-Regions



Rocky Mountain System

Physical Features

- Over 1,000 miles of pipeline corridor
- Major Producing Basins Served
  - Overthrust (WY)
  - Greater Green River (WY)
  - Wamsutter (WY)
  - Uintah (UT)
  - Piceance (CO)
  - San Juan (NM)
- 27 Active plant connections
- Capacities
  - 125 MBPD out of Wyoming
  - 200 MBPD out of western Colorado
  - 225 MBPD across New Mexico

Illustration of Ethane Processing Economics Opal, Wyoming

$/Gallon	May 2004	April 2004	1Q2004	4Q2003	3Q2003	2Q2003
Mont Belvieu Ethane Price ($/gallon)	$ 0.4599	$ 0.4172	$ 0.4301	$ 0.4019	$ 0.3654	$ 0.3956
Mid-America/Seminole Joint Tariff (Undiscounted)	(0.0723)	(0.0723)	(0.0723)	(0.0723)	(0.0723)	(0.0723)
Fractionation Fee in Mont Belvieu	(0.0230)	(0.0230)	(0.0230)	(0.0230)	(0.0230)	(0.0230)
Net Back Ethane Price at Opal	$ 0.3646	$ 0.3219	$ 0.3348	$ 0.3066	$ 0.2701	$ 0.3003
Natural Gas Shrinkage Cost						
Opal/Kern River Natural Gas Posting $/MMBtu	$ 5.36	$ 5.02	$ 5.02	$ 4.59	$ 4.41	$ 4.24
Ethane Energy content (MMBtu/gallon)	0.066369	0.066369	0.066369	0.066369	0.066369	0.066369
Natural gas shrinkage cost	$ (0.3557)	$ (0.3332)	$ (0.3334)	$ (0.3044)	$ (0.2927)	$ (0.2814)
Ethane Processing Spread	$ 0.0089	$ (0.0113)	$ 0.0014	$ 0.0022	$ (0.0226)	$ 0.0189

Rocky Mountain System

Growth Opportunities/Energy Savings

- Product Flow Enhancement (Incentive Tariff)
  - Effective February 2004, FERC approved an ethane incentive tariff whereby MAPL's Rocky Mountain tariff is re-established on a daily basis using the difference between our current tariff and the sum of our incremental cost of transporting a barrel and a minimum profit in order to encourage ethane recovery in the Rocky Mountain region
  - During first few months, throughput increased 28 MBPD
  - Compared to 2003, annual operating income could increase by $4-$9 MM
- Piceance Basin Lateral and Plant Connections (1 - 2 Years)
  - Piceance Basin growth opportunities rival Green River
  - Existing processing insufficient for gas growth
  - Opportunity for cryogenic processing of up to 1 Bcfd of gas
  - 30-40 MBPD of liquids possible of which 15-20 MBPD is C3+

Rocky Mountain System

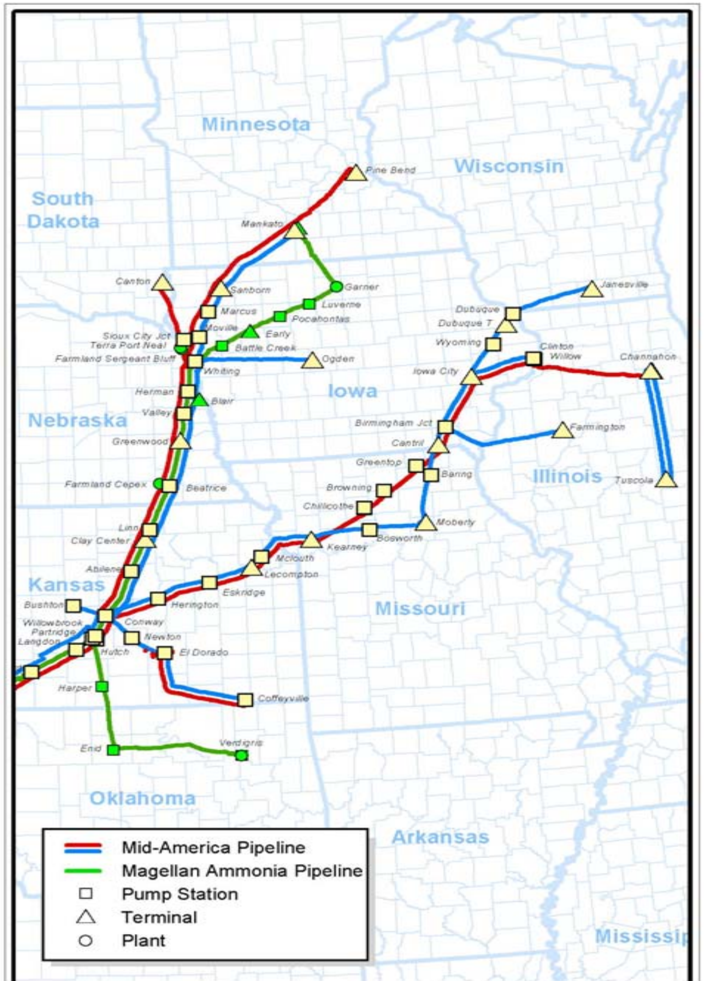
Growth Opportunities (cont'd)

- Opal Plant Expansions
  - Additional 250 MMcfd train at existing plant started in February 2004 (TXP-4)
  - Plant will initially reject ethane and produce 7.5 MBPD of C3+
  - $5 million investment will provide additional 10 MBPD of ethane extraction capacity
  - Williams is already considering TXP-5

- Pump Station Conversions
  - MAPL is investing $6.8 million to convert 9 natural gas turbines to electric motors
  - Assuming gas prices range between $4.00 & $5.00/MMBtu operating expenses would be reduced by $1.2-2.0 million/yr, yielding a 18-29% return on investment

Northern System

Physical Features



- West Blue:
  - 8” Bi-directional from Conway to Mankoto
  - Propane only
  - 50% utilization rate
  - Capacity (MBPD): from Conway 49, into Conway 33.6
- West Red:
  - 8” from Conway to Pine Bend
  - Batch line for:
    - C3 to Pine Bend area terminals
    - C4 and C5 to Northern refineries
    - 75 - 80% utilization rate
    - Capacity(MBPD): 43- C3, 32- C4 / C5
- East Red:
  - 10” from Conway to Morris
  - EP Mix
  - Bi-directional
  - Capacity Utilization 90%
  - Capacity (MBPD): North – 75, South – 43
- East Blue:
  - 8” Conway to Iowa City, 6” Iowa City to Janesville
  - Propane
  - Bi-directional from Conway to Iowa City
  - Capacity Utilization 50%
  - Capacity (MBPD):
    - Conway to Iowa City: North – 67, South –34
    - Iowa City to Janesville - 30

Northern System

Existing Business

- Propane Business
  - 22 million barrels/year
  - 15 non-regulated terminals
  - 5 satellite terminals (not company owned)
  - Two supply sources: Cochin Pipeline & Conway
- Ethane/Propane (EP) Mix Supply
  - Sole supplier to two Midwest ethylene plants
  - Long-term take or pay transportation agreement
  - Two supply sources: Aux Sable (92/8 Mix) and Conway (80/20 Mix)
- Pine Bend Refineries
  - Deliver products to the Koch's Pinebend and Marathon Ashland's St. Paul refineries

Northern System

New Business

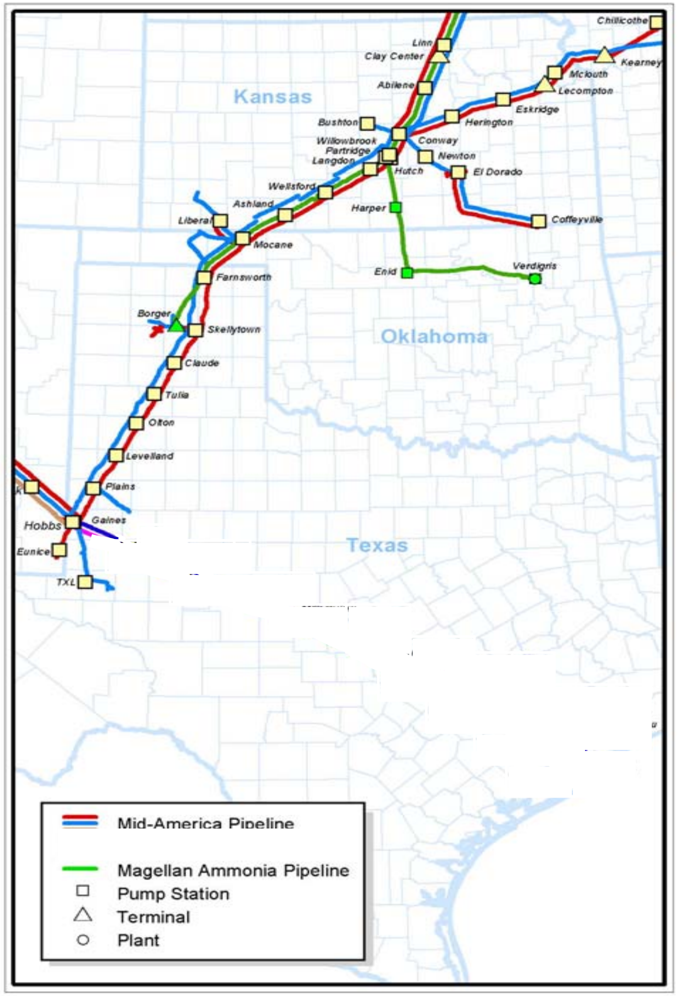
- Eliminated Virtual Storage, April 2003
  - Volumes decreased by 7.75 MBPD
  - Margin increased by 24¢/bbl or $4.1MM/yr of incremental operating income
- Propane Assurance Program
  - MAPL purchased and provided 700M barrels of propane for the pipeline's line-fill requirement
  - Created an on-demand system (barrel-in/barrel-out) by allowing shippers to take immediate delivery of their propane
  - Implemented a per barrel surcharge which generates incremental operating income of approximately $1.5MM/yr
  - Realized additional mainline tariffs while competitors' pipelines experienced service interruptions.

Northern System
New Business (cont'd)

- Re-negotiated EP-Mix Transportation Agreements
  - Extended term for ten years
  - Tariff increased by $0.0266 per barrel per year plus inflation for four years ($0.562/bbl to $0.6950/bbl)
  - Increased the reliability bonus payment by $500M/yr
  - For a total annual impact, in 2008, of $3.2MM in incremental operating income
- Terminated incentive tariff for feedstock's delivered to the northern refineries
  - – Increased operating income by $1MM/yr

Conway to Hobbs

Physical Features



Blue Line	Pipe Size	Capacity (MBPD)	Capacity Utilization
Hobbs to Skellytown	10"	72	68%
Skellytown to Mocane	10"	72	63%
*Mocane to Conway	10"	96	47%

Red Line			
Hobbs to Skellytown	8"	46	22%
Skellytown to Conway	10"	72	39%

*2 partial loops of approximately 45 miles exist between Skellytown and Conway

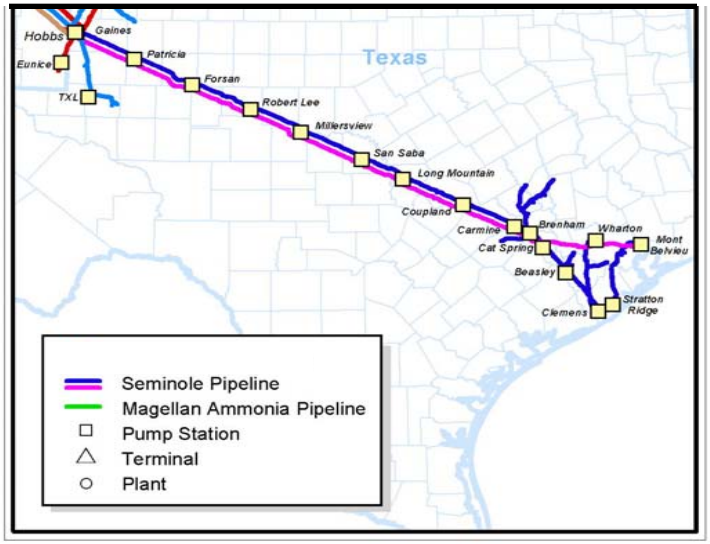
Conway to Hobbs

Growth Opportunities

- Borger to Conway Y-grade Movements
  - Customer diverting 20 MBPD from Borger to fractionators at Conway, increasing operating income by approximately $3.1 MM/yr
- Increase in butane deliveries by 4 MBPD generating additional $1.0MM/yr of operating income
- Rio Grande Expansion
  - Propane deliveries to Mexico are expected to increase by 5-7 MBPD by end of 2004, increasing operating income by $1.8 to $3.1 MM/yr
  - Opportunities for pipeline deliveries of propane deeper into Mexico could add an additional 20 MBPD (operating income of $8.3MM/yr) by 2005 or 2006

Seminole Pipeline Company

Physical Features



- C-corp structure
- Underlying Ownership
  - 78% Enterprise
  - 10% ChevronTexaco
  - 10% BP
  - 2% Williams
- Red Line
  - Demethanized Mix From Hobbs to Mont Belvieu
  - 544 Miles of Pipe, 14” in Diameter
  - 29,000 Horsepower
  - 125 MBPD Capacity
- Blue Line
  - Batch Line From Hobbs to Mont Belvieu
  - 737 Miles of Pipe, 14” to 16” in Diameter
  - 23,000 Horsepower
  - 125 MBPD Capacity
  - 500 MBBL Storage at Stratton Ridge

Seminole Pipeline Company

Existing business

- Positioned to benefit from Rocky Mountain volume growth
- Incremental opportunities available with BP at Stratton Ridge which will generate new revenue of $1MM/yr
- 25 MBPD capacity expansion available for $1.5 – $2.5 MM
- Evaluating the restructuring of Seminole to a more tax efficient entity

Mont Belvieu Fractionation

Physical Features

- Three trains
- Capacity 210 MBPD
- Jointly Owned
  - Enterprise 75%
  - Burlington Resources 12.5%
  - Duke Energy 12.5%
- Raw Make Supply Connections:
  - Black Lake
  - Chevron
  - Dean
  - Chaparral
  - Koch
  - Lou-Tex
  - SPL
  - Panola
- Finished Product Distribution:
  - ConocoPhillips
  - Dixie
  - Dynegy
  - Link (EOTT)
  - Equistar
  - Exxon
  - Lyondell
  - TEPPCO

Mont Belvieu Fractionation

Existing business

- Competitive market
- Capacity is fully contracted
- 19 contracted customers

New business

- A new, 10-year 40–60 MBPD fractionation agreement starts in October 2004, which is expected to increase EPD's operating income by $3.0 - $4.5MM/yr.

Enterprise Import/Export Terminal

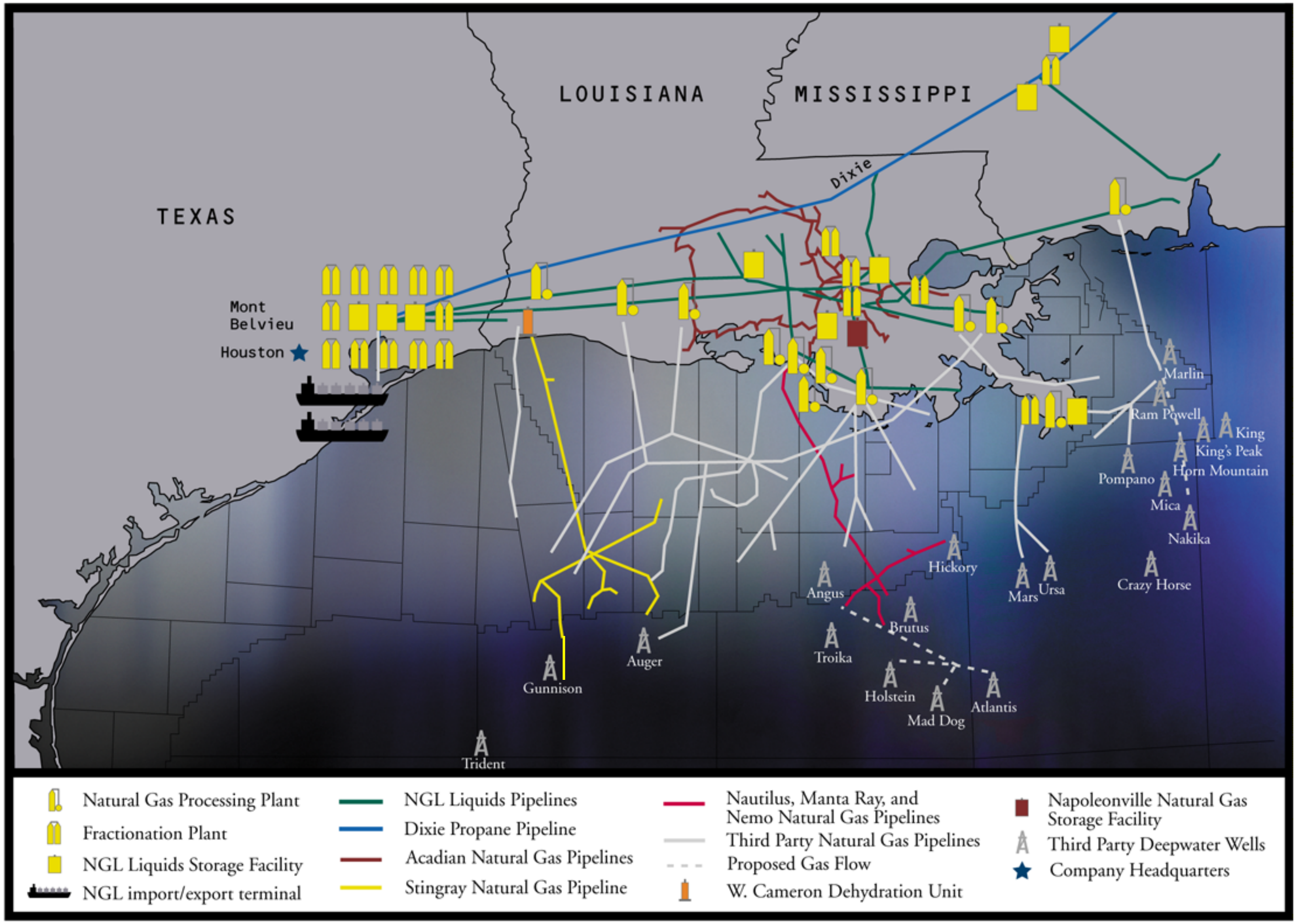
- Capabilities of Terminal
  - Loading rate 6,000 BPH of fully refrigerated cargos
  - Simultaneous loading of semi-refrigerated cargos at 2,500 BPH
  - Unload 10,000 BPH Ships
  - Unload 2,000 BPH Barges
- Facility
  - 15,000 HP refrigeration unit
  - 3,000 HP refrigeration unit
  - 16” pipeline connect to high rate wells in Mont Belvieu
  - Two docks and loading arms
  - Unloading heaters
  - Product Dehydrators and Treaters

Natural Gas Pipeline Business

Profile

- Entered the natural gas business in 2001
- Purchased Acadian Gas, LLC from Shell
  - Intrastate Louisiana gas pipeline involved in the purchase, sale and transportation of natural gas
  - Three systems that comprise over 1,000 miles of pipe
  - Own a gas storage facility with 3 Bcf of capacity
  - Links supplies of natural gas from offshore Gulf of Mexico to industrial, electric and LDC customers in Louisiana
- Purchased equity interests in five offshore pipeline systems in the Gulf of Mexico from El Paso – 739 miles of pipe with a gross capacity of 2.9 Bcf/d
  - Provides a vital link between deepwater developments in the Gulf of Mexico and our onshore midstream assets
  - Strategically located to serve new deepwater discoveries in the central and western Gulf

Enterprise Eastern System Map



Strategic Benefits of Natural Gas Pipelines

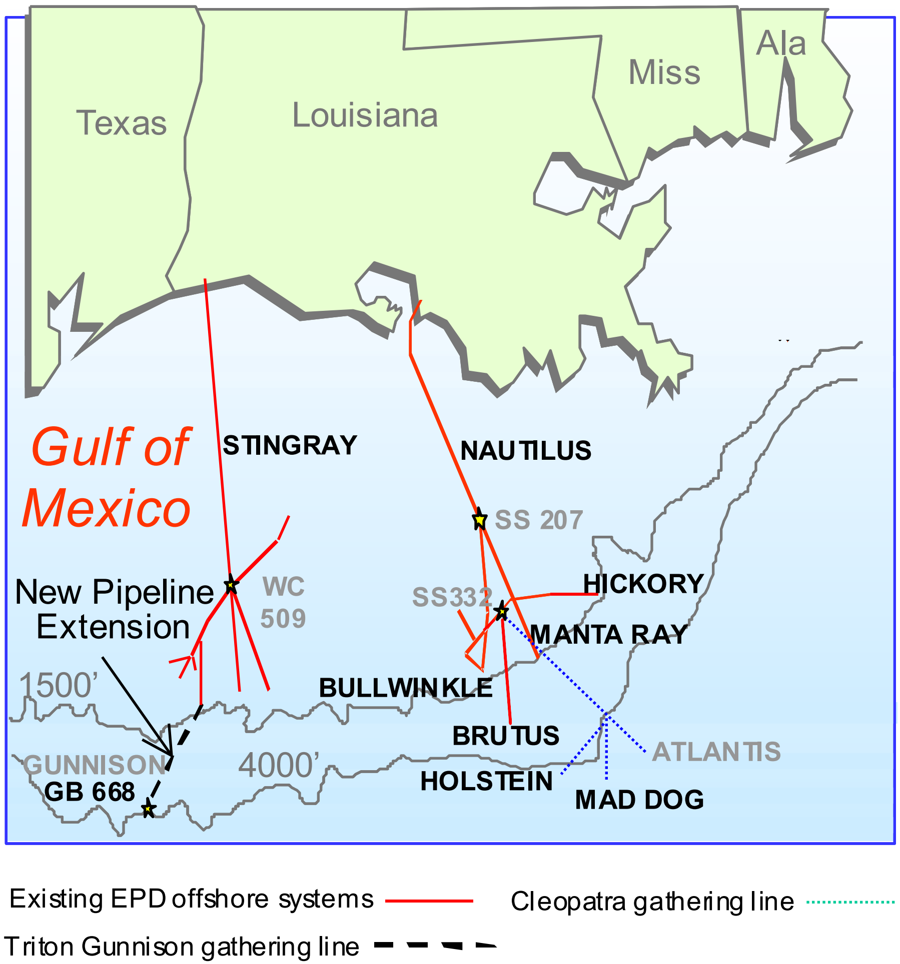
- Broadens and diversifies EPD's midstream energy business; provides new avenues for organic growth
- Integrates with EPD's extensive NGL value chain
- Provides foundation to build or acquire additional natural gas pipeline assets
- Extends midstream energy service relationship with long-standing NGL customers: producers, petrochemicals and refineries
- Attractive growth attributes given expected long-term increase in natural gas demand for power generation and industrial uses
- New component for offering bundled services
- Increases percentage of cash flows from fee-based activities
- Provides evacuation routes for regasified LNG

Offshore Gas Pipelines

Southern Green Canyon Development

- BP will construct 120 miles of pipeline/gathering systems (Cleopatra) to link Holstein, Atlantis and Mad Dog discoveries to Manta Ray at Ship Shoal 332
- Manta Ray/Nautilus modifying their systems to accommodate increased liquids
- Expanded Neptune processing plant by 350 MMcf/d
- Other producers include Shell, BHP and Unocal

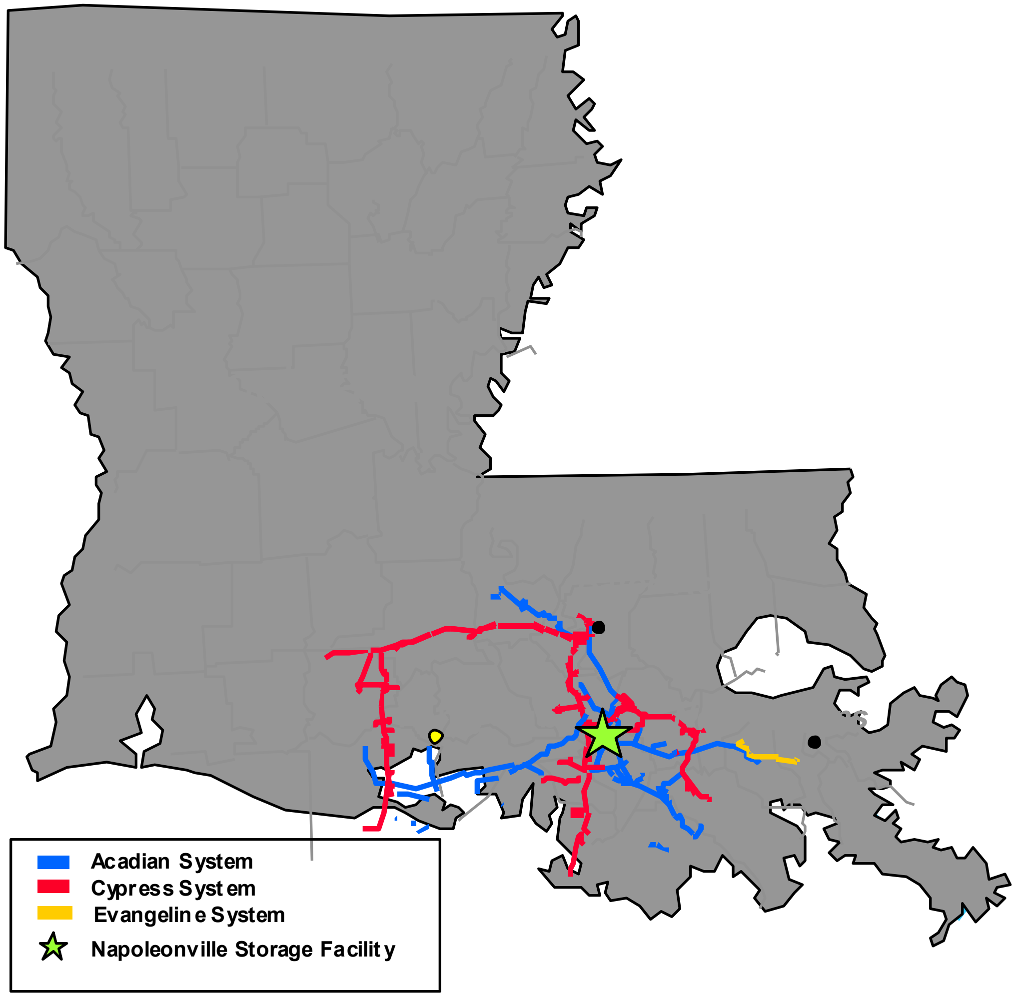
Gunnison Project



- Triton has constructed over 40 miles of 16" pipeline with a capacity of 275 MMcf/d from the Gunnison, Durango and Dawson developments (Garden Banks 667/668 blocks) to Stingray
- Over 10 blocks dedicated life of production to Triton and Stingray
- Dawson Deep

Acadian Pipelines

Acadian Gas, LLC



Three onshore pipeline systems; Acadian, Cypress & Evangeline

- Over 1,000 miles of pipe with a throughput capacity of 1 Bcf/d
- Salt dome storage facility at Napoleonville, La. with a withdrawal capacity of 220 MMcf/d; injection capacity of 80 MMcf/d
- Over 160 physical end-user market connections; connected to Henry Hub and 16 third party pipelines through 50 interconnects
- Nautilus - 450 MMcf/d receipt capacity

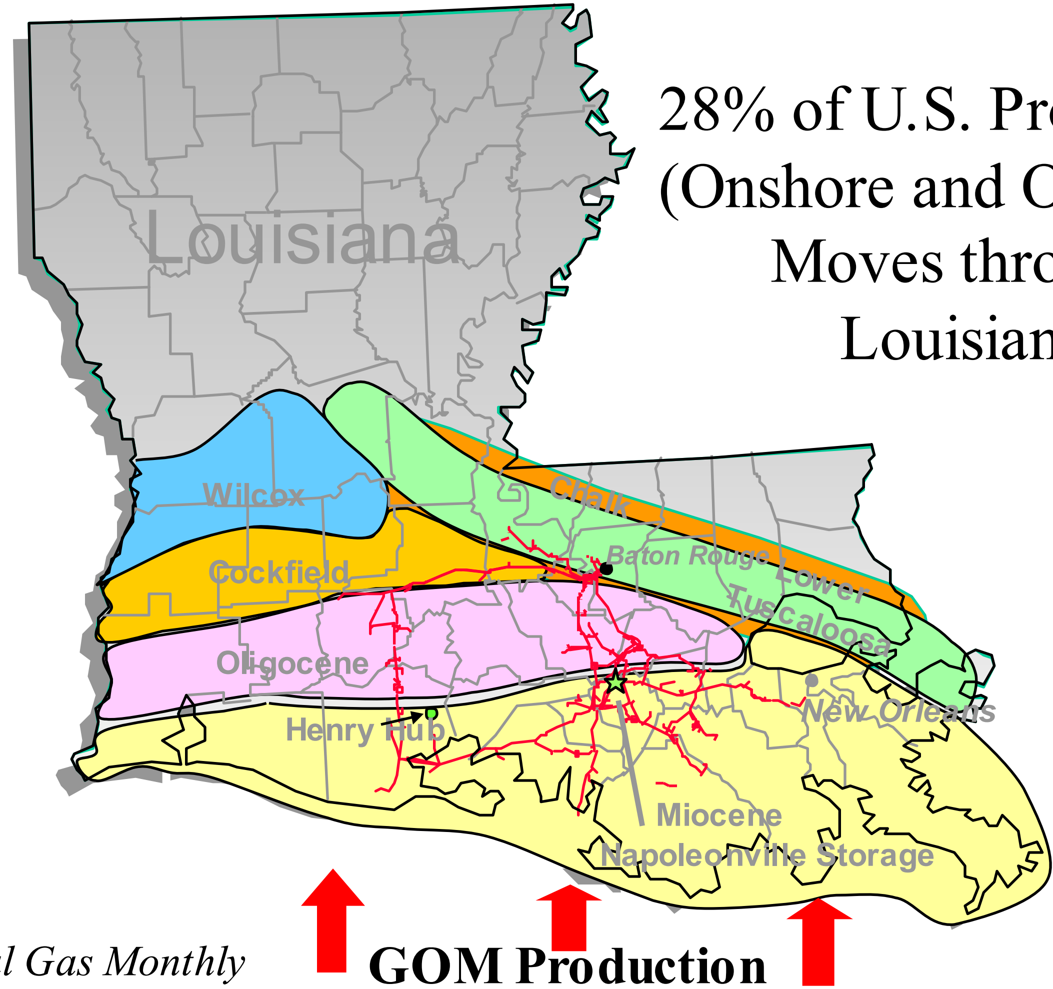
Business Philosophy

Pre-Enterprise		**Today**
Merchant-Preferred	→	Highest Margin
Risk-Inclined	→	Risk Averse
Sold Optionality	→	Maximize Capacity
MTM	→	Quality Margin

Business Environment

- Increased Onshore Drilling
- Continued Industry Consolidation
- New Power Generation
- LNG Development

Major Producing Trends



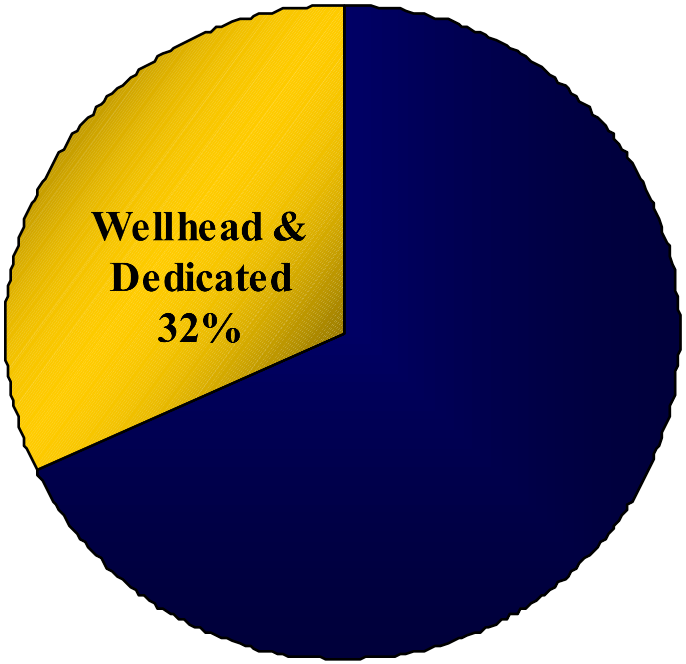
28% of U.S. Production (Onshore and Offshore) Moves through Louisiana

GOM Production

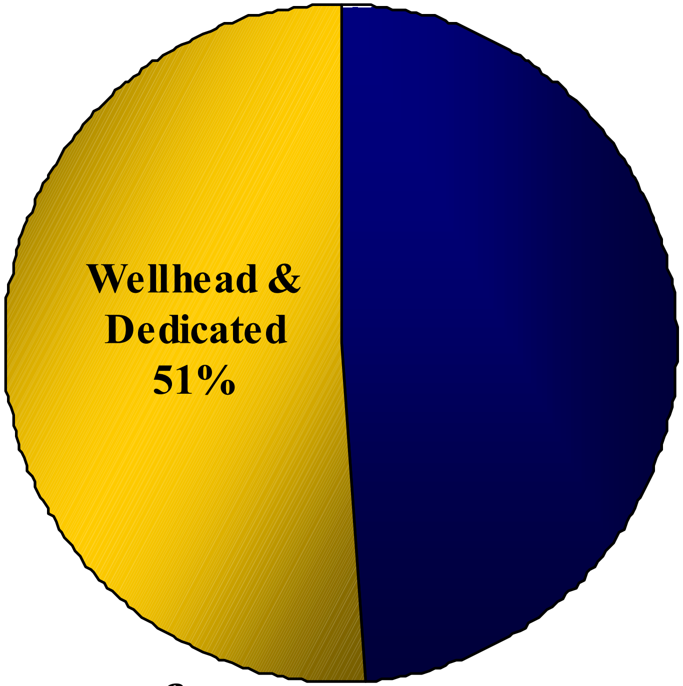
Source: *EIA, Natural Gas Monthly*

Continue Aggressive Wellhead/ Field Connections

September 2000



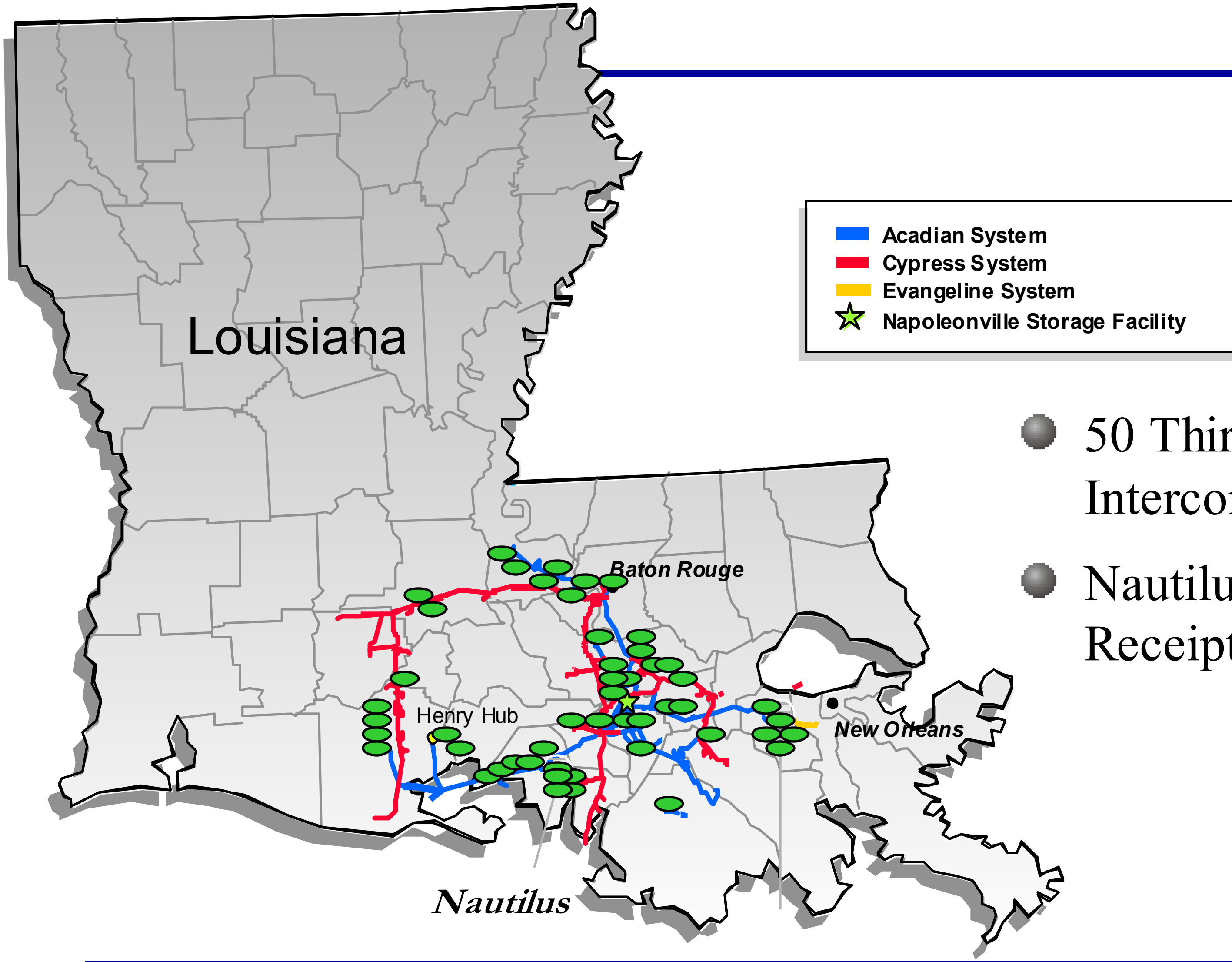
Today



Lowers overall cost of gas

Extends infrastructure further into producing trends

Multiple Interconnects



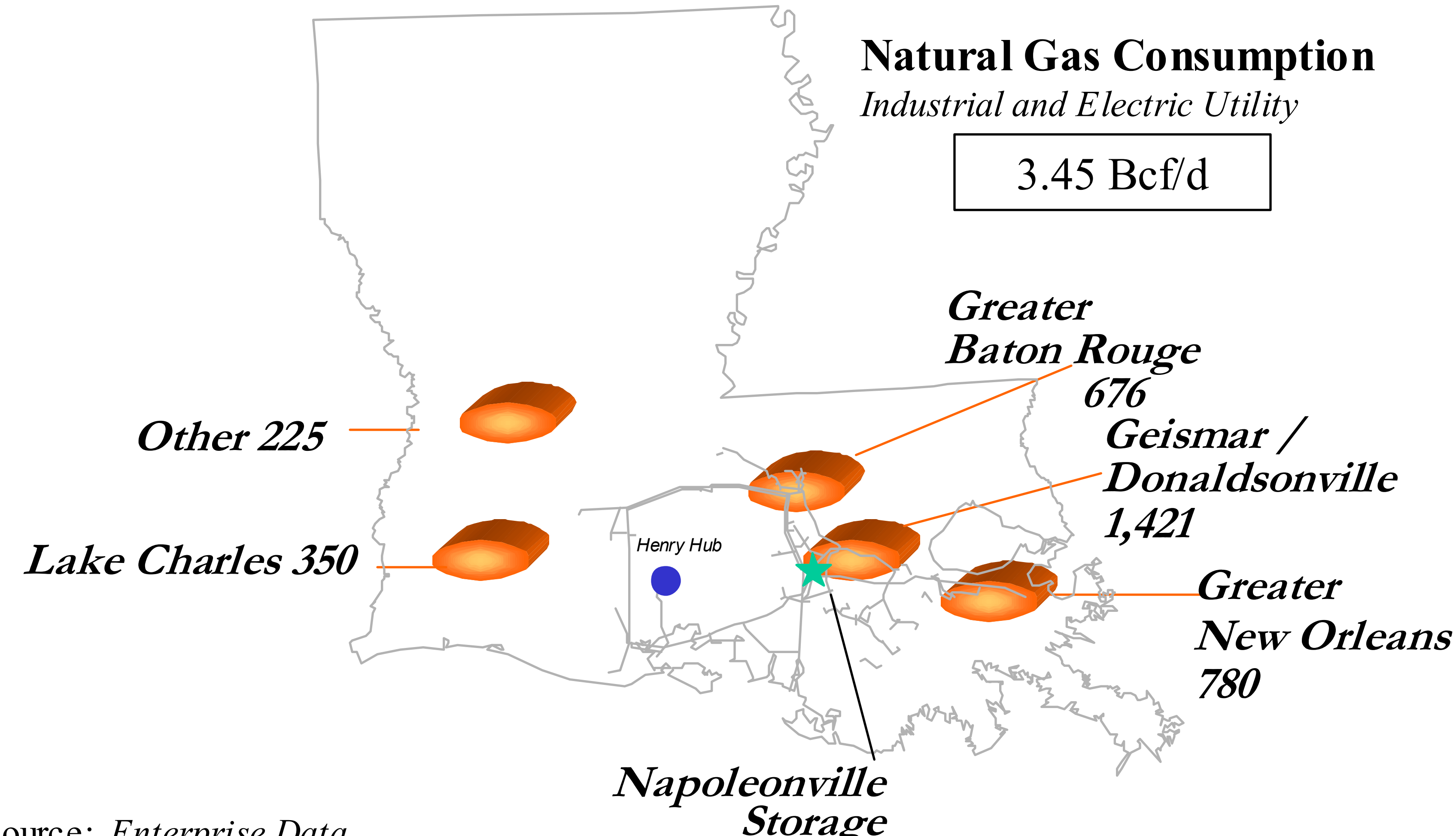
- 50 Third Party Pipeline Interconnects
- Nautilus – 450 MMcf/d Receipt Capacity

Louisiana Major Market Areas (MMcf/d)

Natural Gas Consumption

Industrial and Electric Utility

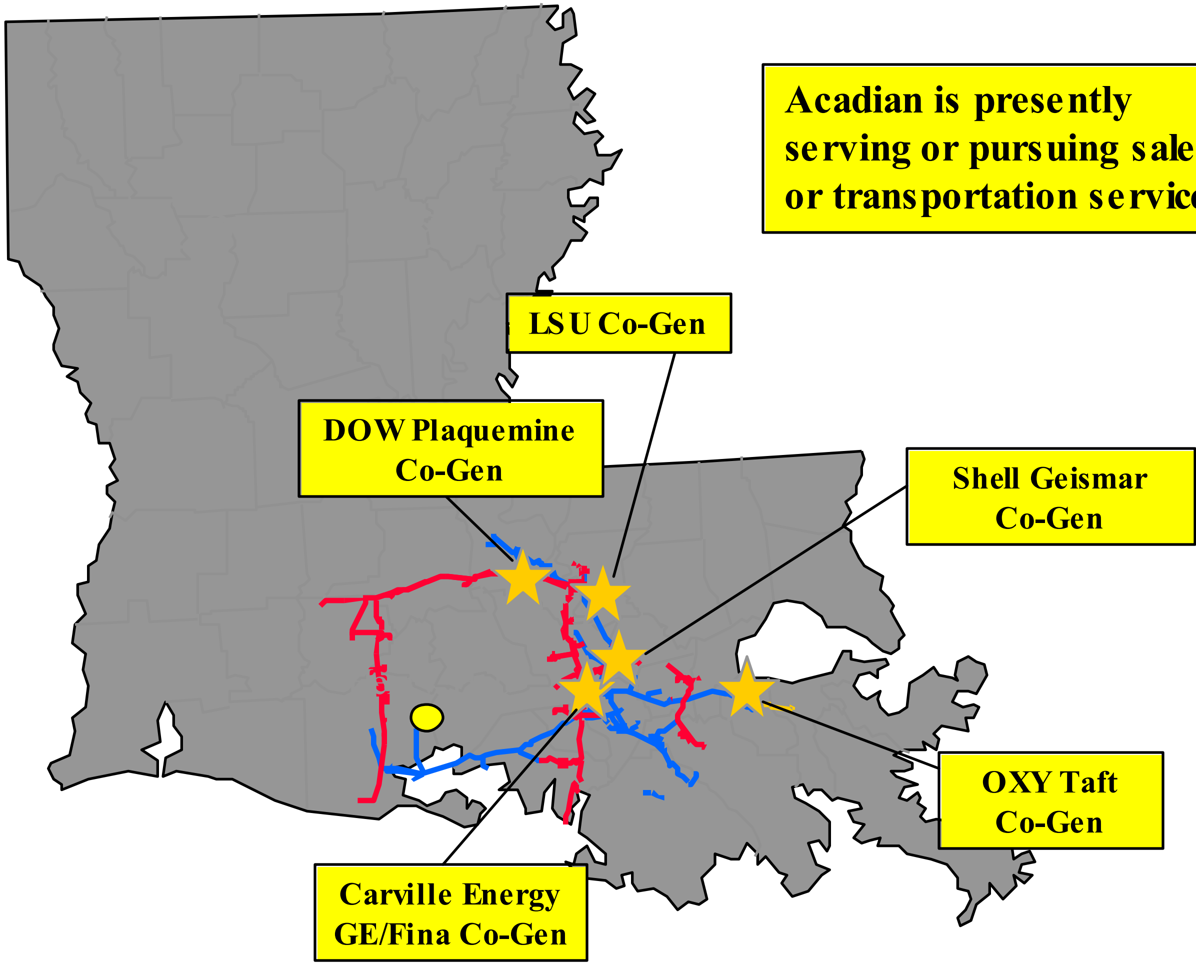
3.45 Bcf/d



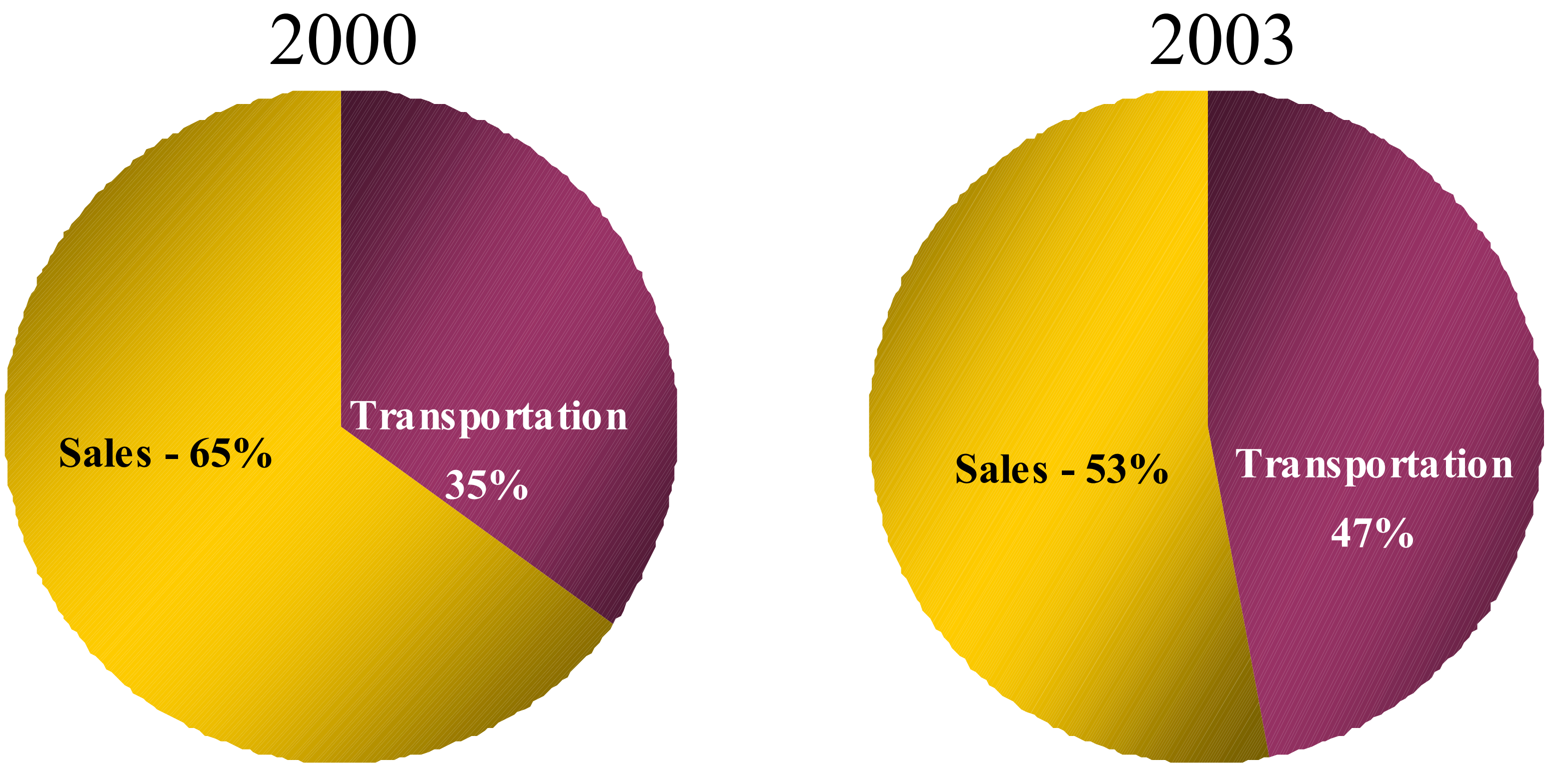
Source: *Enterprise Data*

New Gas-Fired Power Generation Projects

Acadian is presently serving or pursuing sales or transportation services.



"Increase Transportation Portfolio"



Reduces credit and performance risk

Alleviates volatile commodity risk

Acadian Connected Market Profile

Market Type:

	Connections
Electric Utility	***6***
Industrial	***65***
Other	***97***
Total	***168***

- *Acadian Active Delivery Point Load Factor = 96%*
- *40% Market Share of Non-Electric Generation Market*

Maintain Long-Term Commercial Relationships

Consolidation

- LP&L + GSU
- NOPSI + BR Distribution
- Exxon + Mobil
- BP + Amoco
- LGS + Atmos

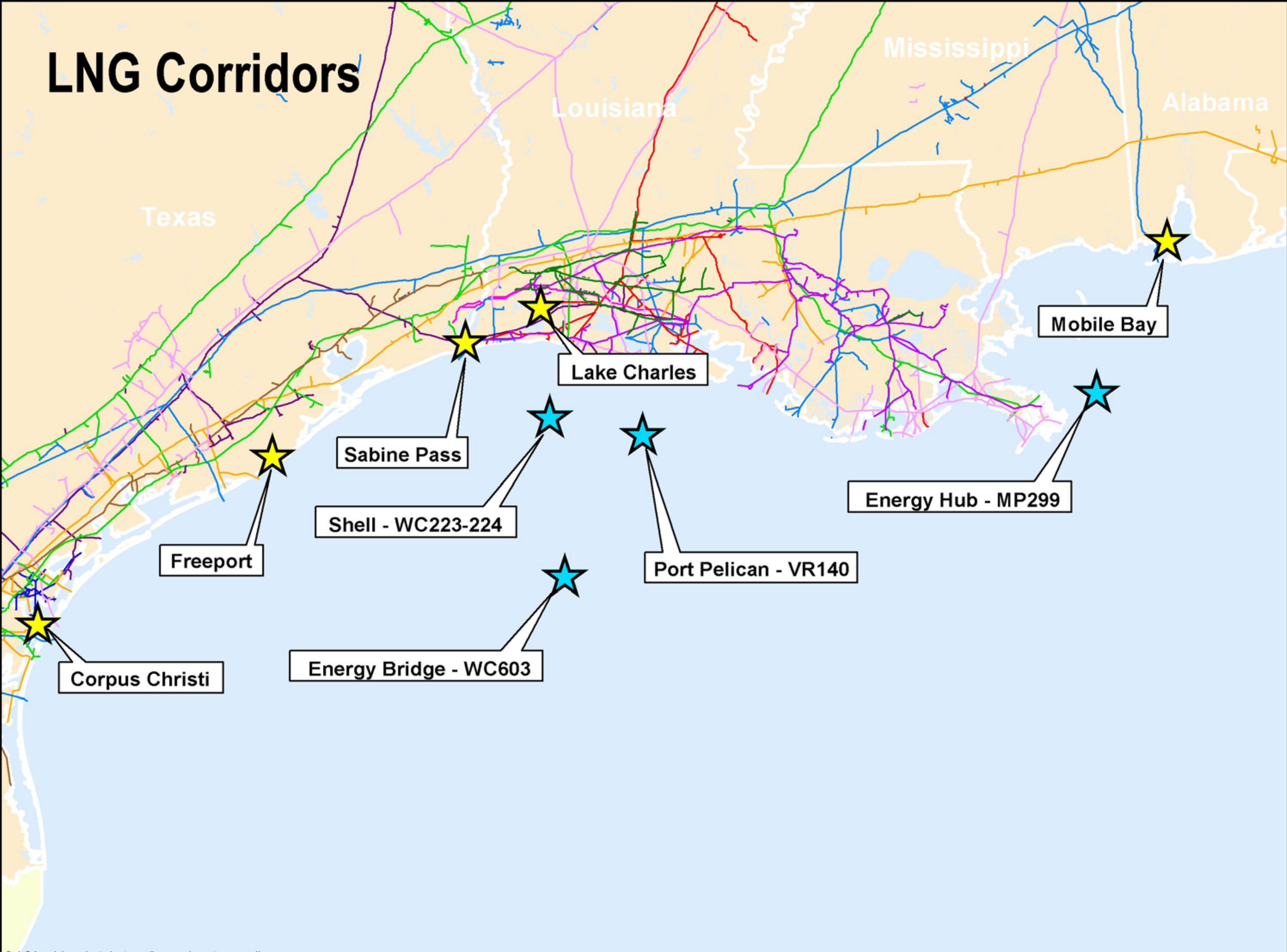
Acadian/Cypress Pipelines Of Choice

Forward Strategy

Strategy	**Benefit**
Continue aggressive wellhead/field connections to create advantage within the merchant segment	Controls supply base Improves cost of gas Provides long-term security of supply
Maintain long-term commercial relationships	Pipeline of choice
Leverage the header-like structure of the pipeline system to create service options for new gas-fired power generation	Increases fee-based transportation
Extend pipelines into presently unconnected metropolitan areas	Grows "human needs" market share
Increase transportation segment within the business portfolio	Reduces credit and performance risk Alleviates volatile commodity risk

LNG Development

LNG Corridors



2-4-04 v:/gisprojects/nat-gas/lng.apr layout - overall

Petrochemical Services Business

Petrochemical Group Overview

Petrochemical group consists of 5 businesses

- **Under the Fractionation Segment**
  - Butane isomerization (116 MBPD)
  - Propylene fractionation (EPD share is 4.4 billion pounds or 65 MBPD)
- **Under the Pipeline Segment**
  - Mont Belvieu hydrocarbon storage (91 MMbbls of usable capacity)
  - Propylene Pipelines
- **Octane enhancement (16,500 BPD)**

Butane Isomerization Service

Butane Isomerization

- The process of converting normal butane to high purity isobutane. EPD has a combined capacity of 116 MBPD
- 78,000 BPD (67%) is committed under long-term processing fee contracts with escalation provisions on the fees
- Variations in volumes caused by plant turnarounds and spot opportunities, but overall results are very steady
- **Historical Results**

	2001	2002	2003
Isom Volumes (MBPD)	80	84	77
Unit Margin ($/Gallon)	$ 0.047	$ 0.042	$ 0.048

Isomerization Business Drivers

- Stable demand from long-term contracts base loads isomerization business.
- EPD has available capacity to service future growth in isobutane demand and seasonal demand for gasoline without investing new capital.
- Expect increase in demand for isobutane as MTBE is phased out and other premium gasoline components such as iso-octane and alkylate will be required (isobutane is major component of iso-octane and alkylate).

Propylene Fractionation Service

What Is Propylene?

- Propylene is used in manufacturing plastic consumer products as well as solvents, pharmaceuticals, detergents and additives.

  Examples are:
  - Carpet Backing
  - Fabrics (Clothing)
  - Automotive Parts
  - Packaging (Potato Chips)
  - Containers (Bottles, Tubs, Caps)
  - Electrical Household Items (Vacuum Cleaners, Hair Dryers)
  - Garden Furniture
  - Office Supplies and Computers

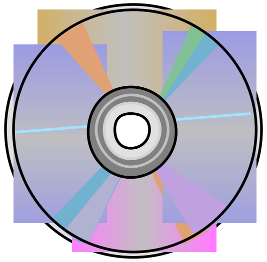
- Demand is increasing domestically and worldwide at 4-6%

Propylene - Thermoplastics

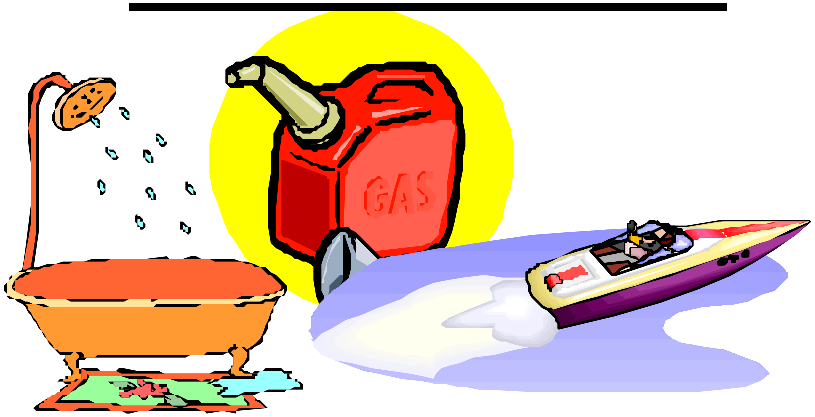
POLYPROPYLENE

POLYURETHANE

POLYCARBONATE



POLYESTER RESIN



ABS

Propylene - Fibers

POLYPROPYLENE

ACRYLICS

NYLONS

Propylene - Additives

SOLVENTS

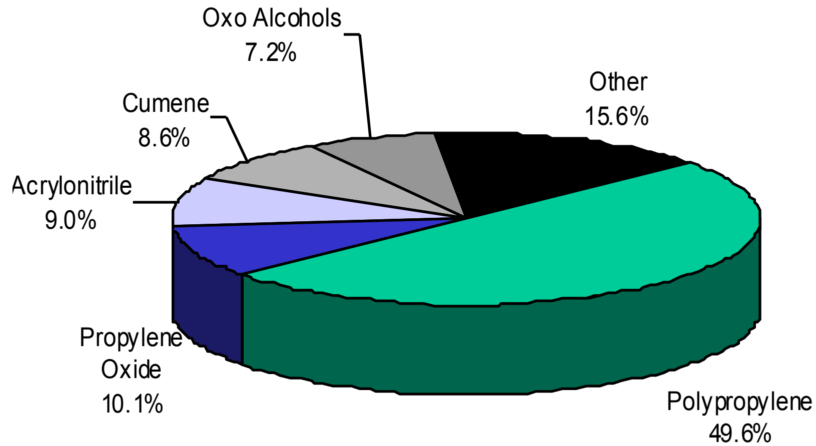
PHARMACEUTICALS

DETERGENTS

ADDITIVES

Propylene Demand Summary

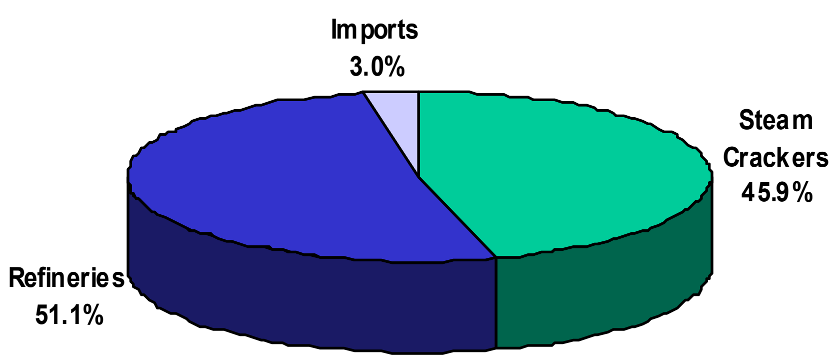
- Total domestic U.S. demand for all grades of propylene grew by 4.0% annually from 1996 to 2002 and by 3.0% in 2003.
  - Growth rate for '96 to '02 includes a 2.0% decrease in demand in 2001 due to the economic downturn.
  - Growth for '03 was better than the overall petrochemical industry.
  - Growth rates so far in '04 have averaged 5% and are expected to remain at this pace for the year. [1]
- Polypropylene demand (our primary customer segment) grew by 3.0% in 2003.
  - Expected to average in the 5.0-6.0% range for 2004 through 2008 [1].



Total U.S. Demand – 35.2 billion pounds

[1] per CMAI forecast

Propylene Supply Summary

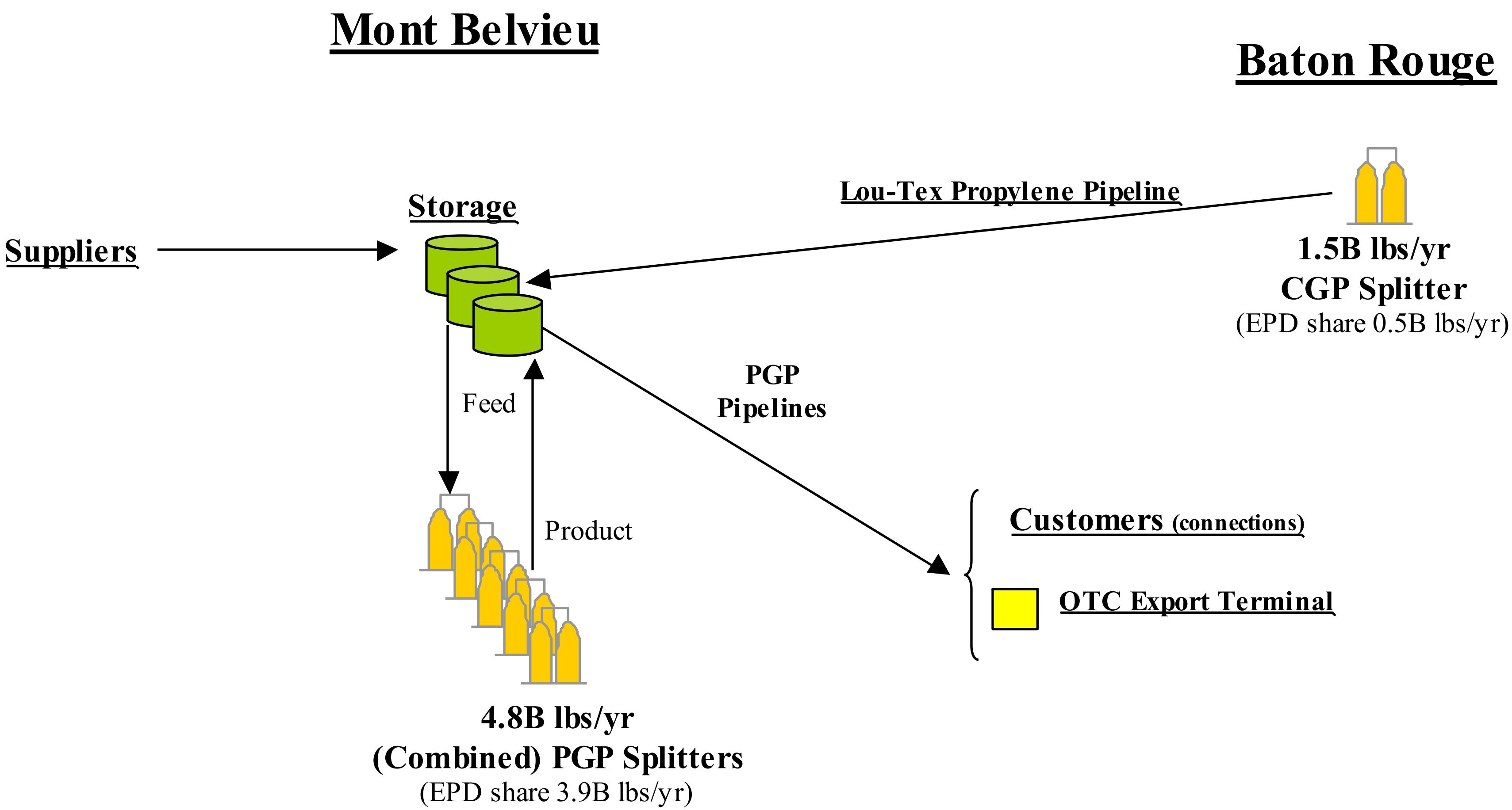


- Propylene is a byproduct of ethylene production
  - Projected production growth from ethylene steam crackers will not meet projected propylene demand growth
- Propylene/Propane (P/P) mix is a byproduct of crude oil refining
  - Splitting refinery-sourced P/P mix will be required to meet market demand
  - Refineries have capability to increase P/P mix production by use of special catalysts

Propylene Assets

- **Own & operate 3 polymer grade propylene fractionation facilities with approximately 4.8 billion pounds per year (72 MBPD) of polymer grade propylene production capacity**
  - Basell (a Shell subsidiary) owns approximately 45% of Splitter 1 and leases this capacity to us. They also have long-term off-take agreements for 700 MM lbs/yr
  - Atofina owns 33% of Splitter 3 and takes its share of production to its polypropylene facility in LaPorte
  - These 3 facilities are located at EPD's Mont Belvieu site and are integrated into EPD's other facilities and underground storage
- **Own a 30% interest in a 1.5 billion pounds per year (22.5 MBPD) chemical grade propylene splitter at Baton Rouge**
  - EPD designed, constructed & operates
  - ExxonMobil has 70% ownership, is the business manager, supplies the feedstock to the facility and is the major customer

Propylene Business



Propylene Business

Historical Results

Splitters	2001	2002	2003
Total Net Volumes (MBPD)	31	55	57
Unit Margin ($/Gallon)	$ 0.048	$ 0.055	$ 0.044

(D-K assets acquired in Feb '02)

Pipelines			
Volumes (MBPD)			
• Lou-Tex	27	25	29
• Sabine	0	11	11

Propylene Business

- **Mont Belvieu**
  - Toll processing fee agreements – 20% of capacity
    - No exposure to commodity price volatility
  - Implicit fee arrangements – 55% of capacity
    - Back-to-back long-term P/P mix purchase contracts and long-term propylene sales contracts with a common reference price
  - Variable margin opportunities – 25% of capacity
    - Floating margin volume that varies with the market
  - **Very little change in this mix since 2002. Working to add more processing type contracts from the integrated companies (ExxonMobil & Shell) to further limit floating margin exposure. A slow process.**
- **Baton Rouge PCU (30% ownership)**
  - Processing fee based on volume
- **Propylene Pipelines**
  - Lou-Tex and Sabine Pipelines
    - Exchange fee with take or pay minimums

Propylene Business Drivers

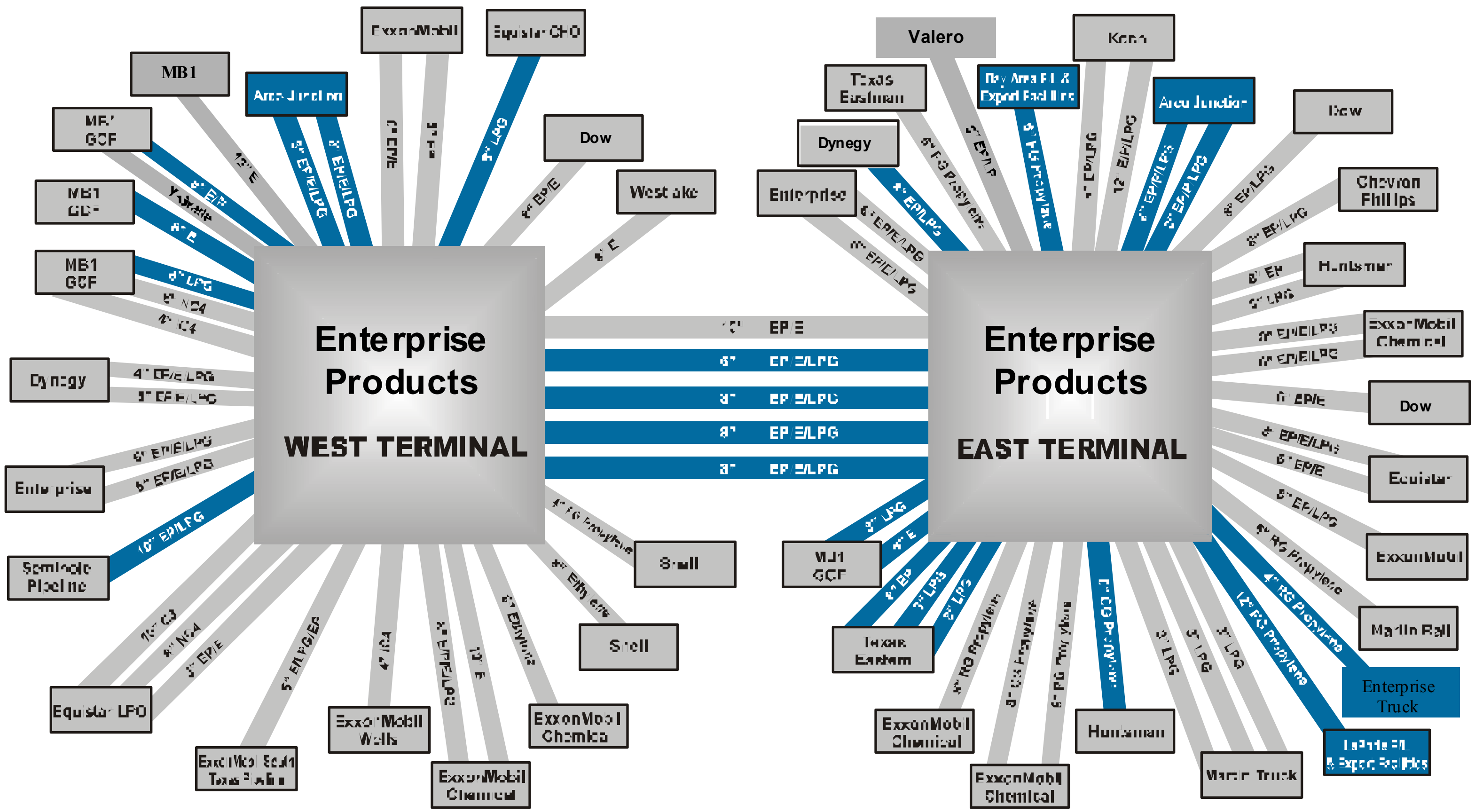
- Propylene demand is expected to continue to grow by 5% (1.8 billion pounds for ‘04 in the U.S.).
- Securing additional P/P Mix feed from refineries a critical step to Enterprise’s growth in this business.
- Enterprise has key assets in place with available capacity to upgrade this feed as well as permit and infrastructure to support a new splitter at Mont Belvieu
- Continued growth of our customers is important as well.
  - Two of our major customers/partners (Atofina and Basell) have plans for expansions in the ‘05-’06 time frame and they will be looking to us for additional supply
- Short-term growth - Maximize existing splitter and pipeline capacity
- Long-term growth - Expand splitter capacity

Mont Belvieu
Hydrocarbon Storage Services

Mont Belvieu Hydrocarbon Storage

- Own and operate 91 million barrels of underground storage capacity at Mont Belvieu
- These storage facilities are interconnected by multiple pipelines to other producing and offtake facilities throughout the gulf coast as well as connections to the Rocky Mountain and Midwest regions via Seminole.
- Focal point in the gulf coast for purity ethane, EP mix, propane, normal butane, isobutane, and propylene
- Very stable operating margins from reservation fees (82%) and throughput fees (18%)

East & West Facilities Connections



- Enterprise Pipeline
- Pipelines Owned by Others

E - Purity Ethane

EP - 80/20 Mix

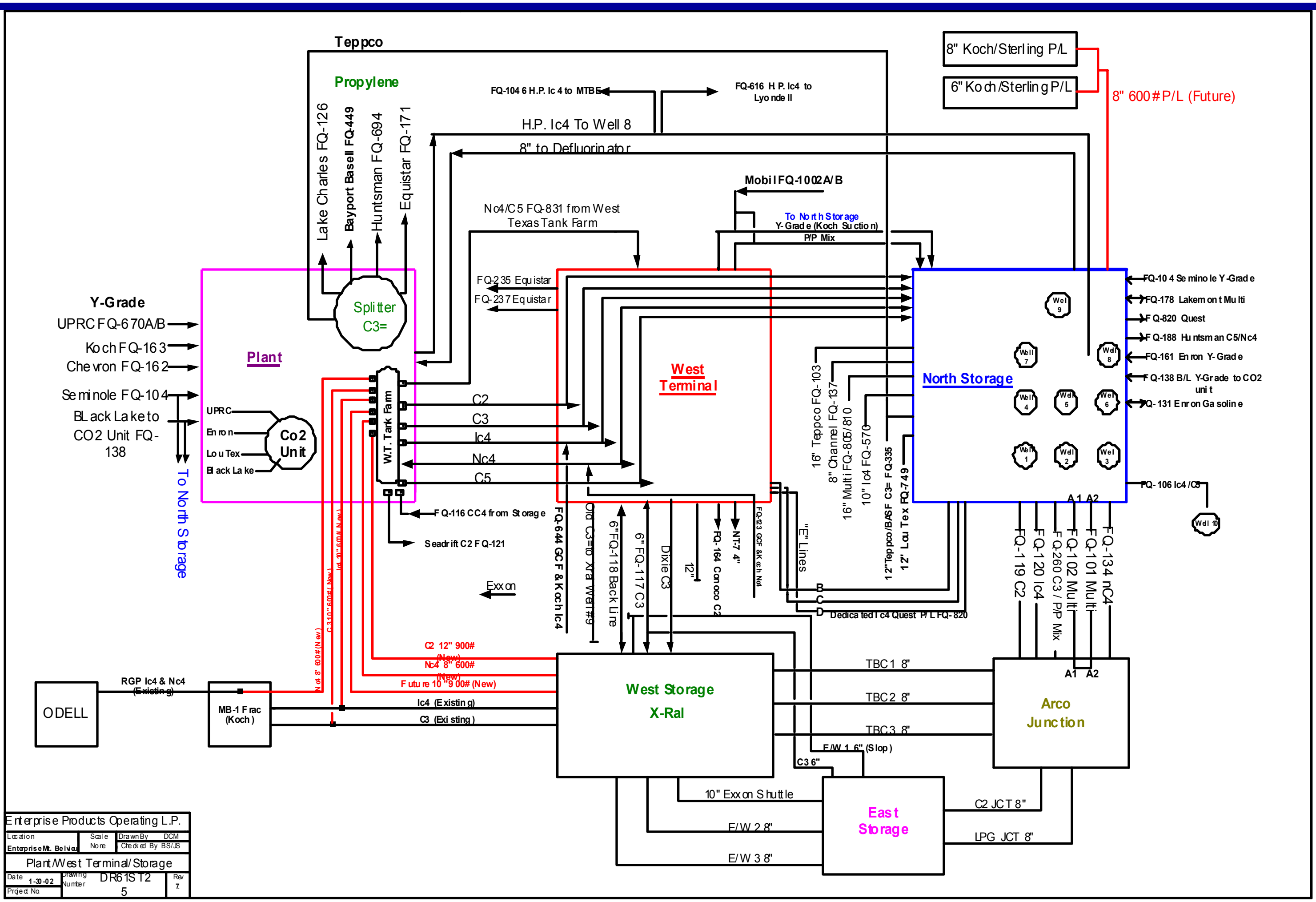
LPG - Propane, Isobutane, Normal Butane

RG - Refinery Grade Propylene

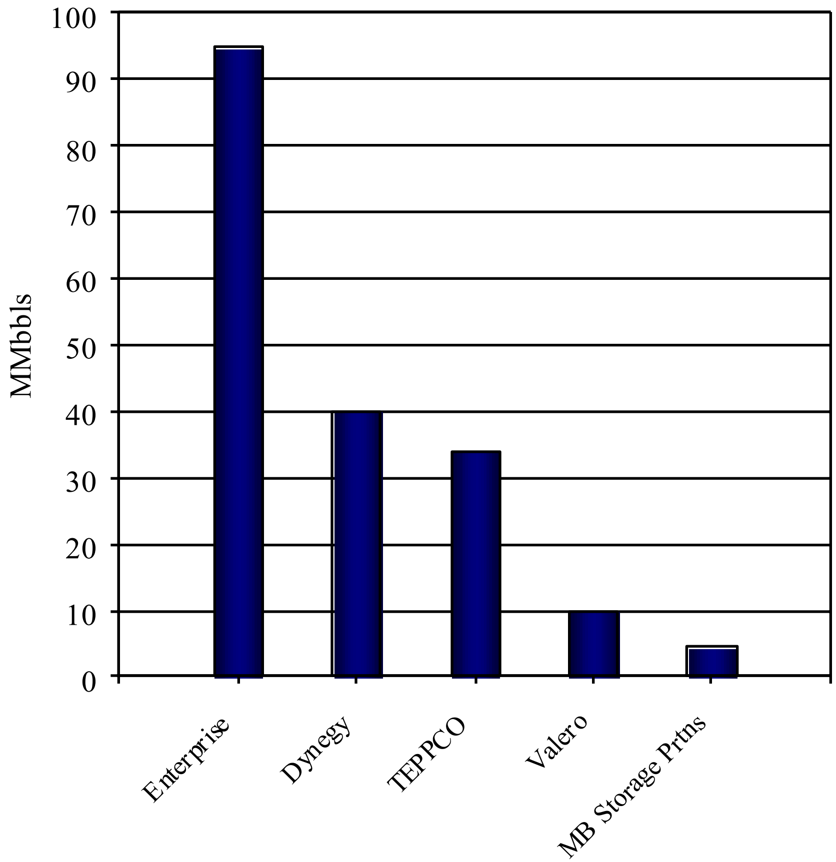
CG - Chemical Grade Propylene

PG - Polymer Grade Propylene

North Facility Pipeline Connections



Mont Belvieu Storage Facilities and Products Stored



- Purity ethane
- HD 5 propane
- Export propane
- Ethane propane mix
- Fractionation grade butane
- High purity isobutane
- GPA isobutane
- Natural gasoline
- De-methanized mix & pipeline interfaces
- Ethylene
- Refinery, polymer and chemical grade propylene

Mont Belvieu Storage Business Drivers

- Provide critical logistical services for our customers
- Growth tied to petrochemical, refinery and NGL fractionation markets
- Very steady cash flows with limited competitors having similar capabilities
- Connections and service are key to success
- Brine production to dedicated consumer (Oxy)
- Unequaled flexibility with a full range of integrated services offered, including treating, fractionation and distribution

Octane Enhancement

Octane Enhancement (BEF)

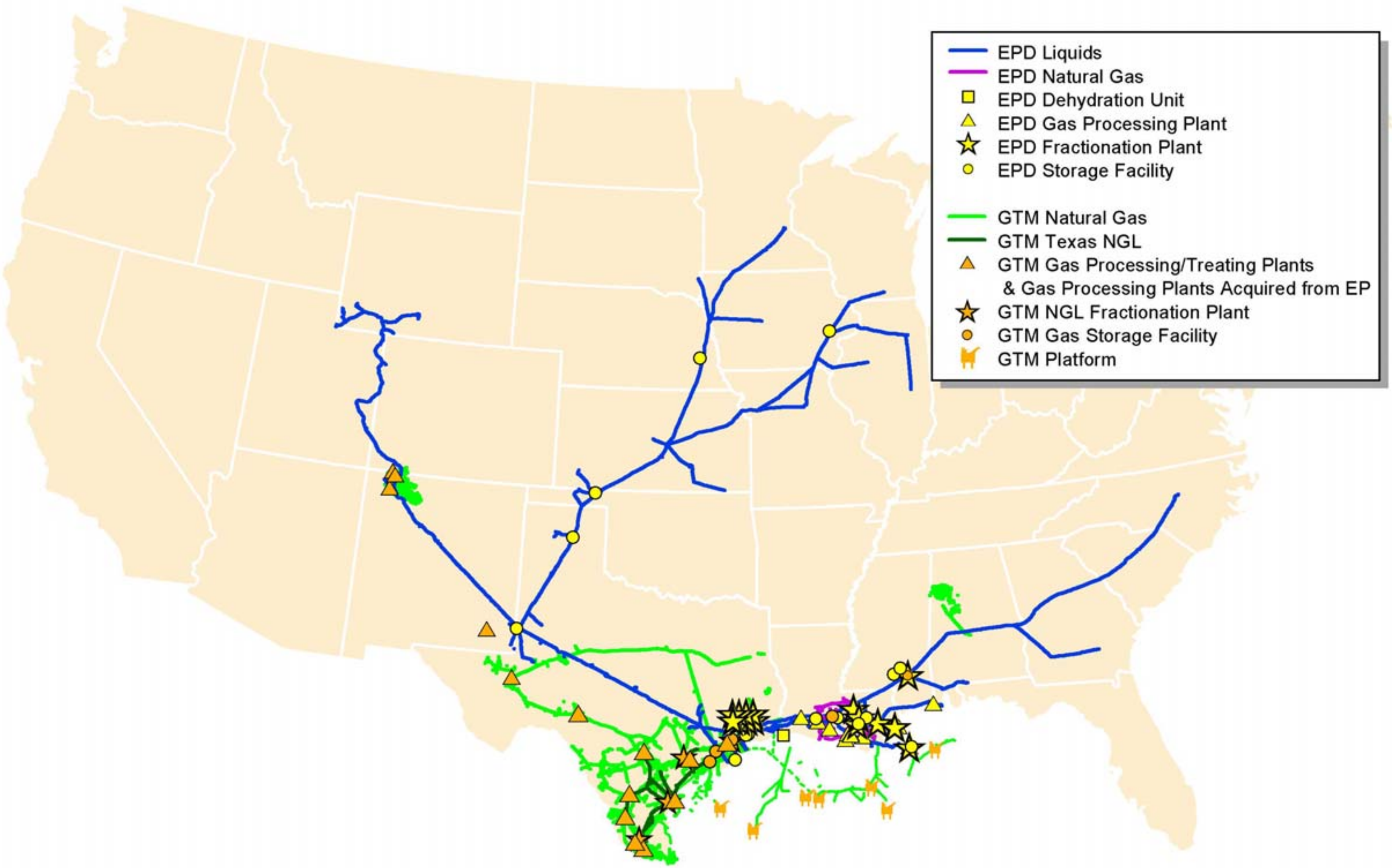
- EPD owns 2/3 and Sunoco owns 1/3 of Belvieu Environmental Fuels (BEF), a joint venture that produces octane additives for motor gasoline.
- Currently producing MTBE, which is used as a source of oxygen and octane in gasoline, and isobutylene, which is used to produce gasoline additives
- BEF is modifying the plant to add capability of producing iso-octane.
  - Estimated capital costs to modify the plant: $30MM (EPD's share: $20MM)
  - Iso-Octane Production Capacity: 12.3 BPD (EPD's share: 8.2 MBPD)
  - Estimated Completion date: 4Q2004
  - Expected gross margin from iso-octane: $10.0-$15.0MM/yr (EPD's share: $6.7-$10MM)

Enterprise & GulfTerra Combination

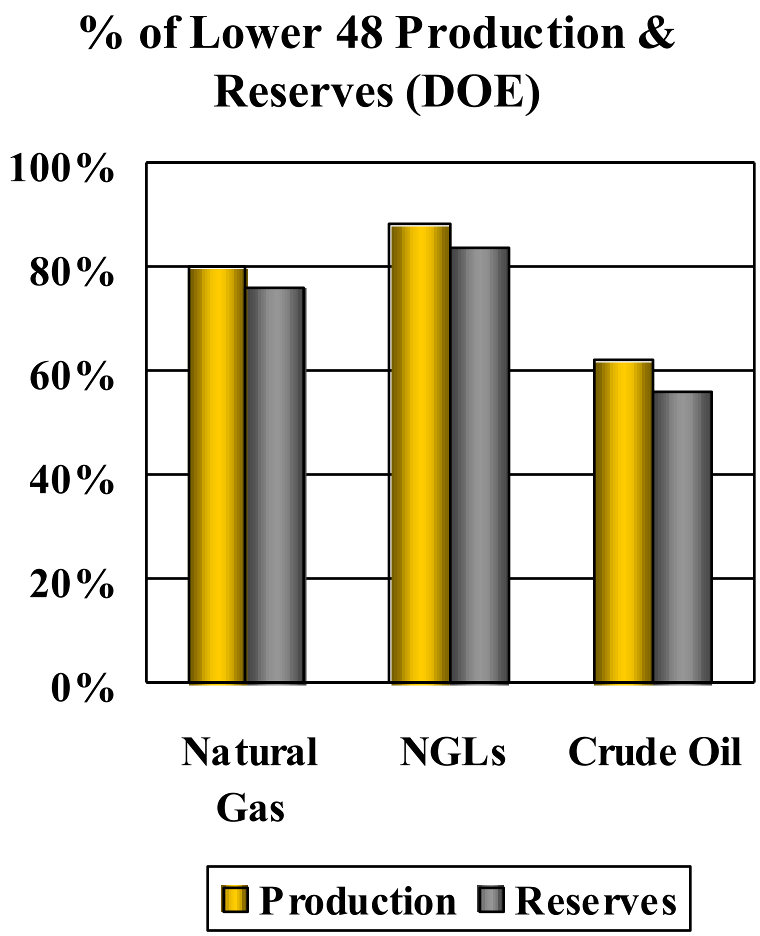
ENTERPRISE®

GulfTerra

Combined EPD and GTM System Map



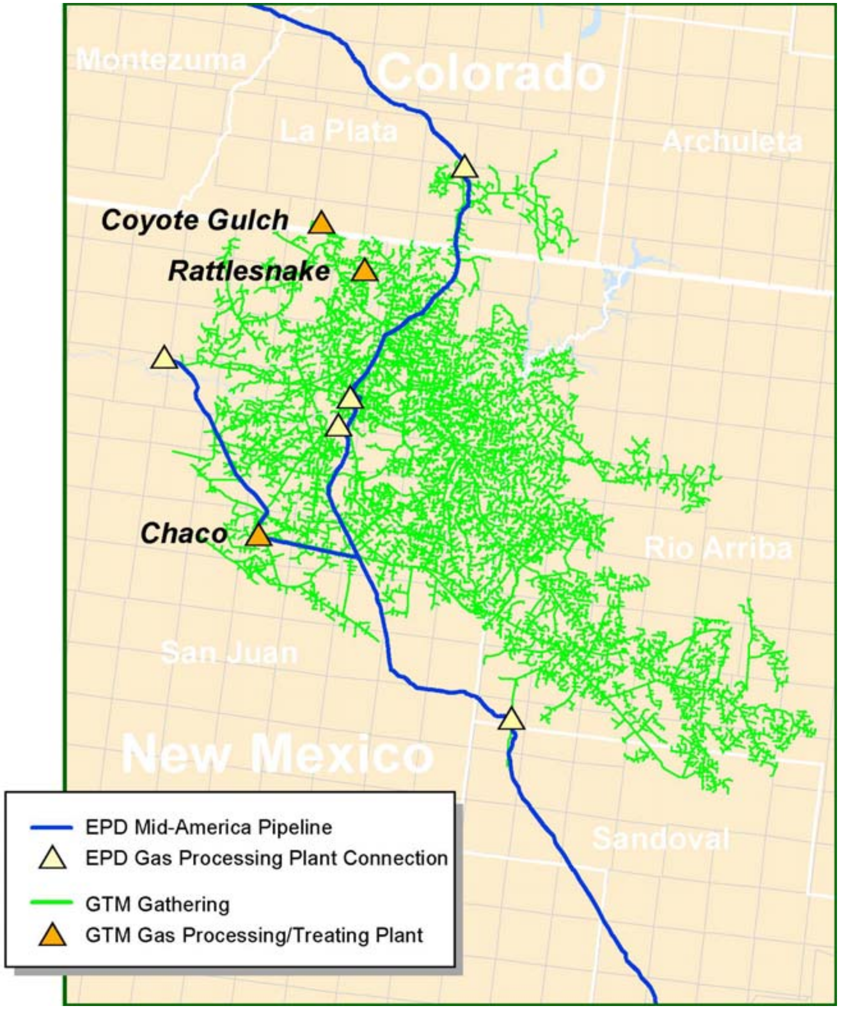
Organic Growth from Serving Major Producing Basins



- Provides integrated services to the largest producing basins in the Lower 48
- Strong Rocky Mountain and deepwater Gulf of Mexico franchise
- Diversifies EPD into crude oil and platform services
  - GOM currently accounts for 32% of U.S. crude and condensate production. Expected to account for 43% by 2010 and 48% by 2015

Complementary Assets

MAPL - San Juan Basin Gathering/Processing



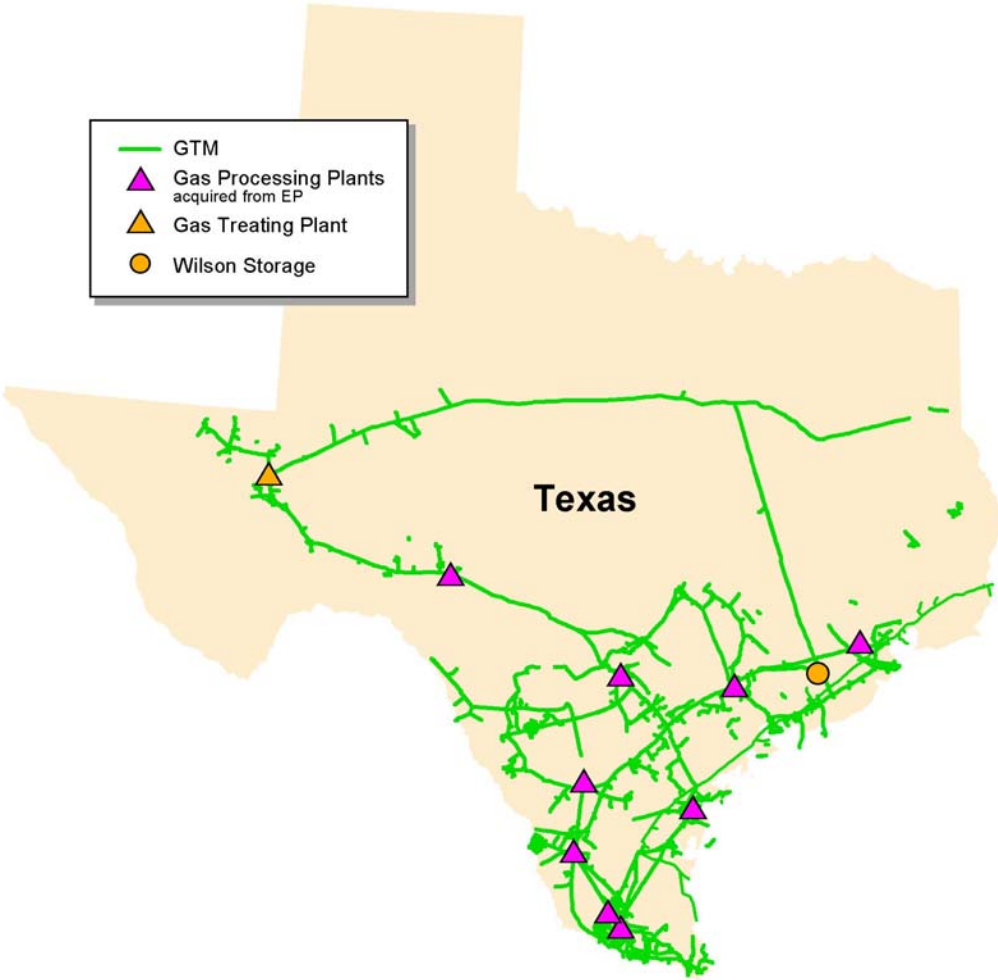
- Mid-America Pipeline – Rocky Mountain System
  - 2,548 miles of pipe
  - 120 MBPD capacity from Rock Springs, WY to 4-Corners; 225 MBPD capacity 4-Corners to Hobbs
- San Juan System Volumes
  - 1.2 MMDth/d gathered
  - 44 MBPD NGLs produced
- Gathering contracts
  - 83% indexed to natural gas prices (natural hedge to EPD)
  - 17% fixed fee
- Conventional gas reserves
  - 30 yrs Proved & Probable
  - 44 yrs Proved, Probable & Potential

GTM Contract Structure

- San Juan Natural Gas Gathering
  - Gather ~ 1,200 MMDth/d
  - 83% of volume have fees that are a % of natural gas index price
  - 17% of volume have fixed fees
- Chaco Gas Processing
  - Process 665 MMBtu/d
  - Recover 44 MBPD NGLs
  - 24% of gas processed under fixed fees (per MMBtu)
  - 76% NGL retainage
  - GTM's share is ~ 8 MBPD
- Permian Gas Processing
  - Process/treat 270 MMBtu/d
  - 10% fixed fees
  - 90+% NGL retainage
  - GTM's share ~ 4 MBPD

Complementary Assets

Texas Intrastate Natural Gas Pipeline



- 9,300 miles of pipeline
- 3.35 Bcf/d 2002 volume
- 7 Bcf storage capacity
- 1,260 receipt and delivery meters
- 137 Intrastate, interstate and municipal connections
- Firm contracts account for
  - 50% of pipeline capacity
  - 97% of storage capacity
  - Fee based
- 9 natural gas processing/treating plants with a capacity of 1.89 Bcfd (to be purchased from EP in Step 2)

GTM Contract Structure

- South Texas
  - Process ~ 1,450 MMDth/d
  - Recover 70 MBPD NGLs in full recovery
  - 30% fixed fees (per MMBtu)
  - 16% NGL retainage
    - GTM share ~ 1.8 MBPD
  - 16% keepwhole (primarily wellhead purchases)
  - 38% NGL retainage with "conditioning election" for producer

GTM Contract Structure

- South Texas “Conditioning election”
  - Producers can elect reduced ethane recoveries and convert to a fixed fee for processing
  - GTM can elect to recover incremental ethane on a keepwhole basis or reduce plant recoveries
  - GTM share of NGLs
    - ~ 3.1 MBPD if producers elect recovery, or
    - ~ 6.7 MBPD of ethane if producers elect “conditioning mode” and plants are run in full recovery mode
  - Estimates reflect producers electing “conditioning mode” with GTM recovering incremental ethane

Gross Spread Assumptions
Price/Spread Assumptions

Henry Hub Natural Gas Price ($/Mmbtu)	$	4.00	$	5.00	$	6.00
NGLs (cpg):						
Ethane		31.5		38.2		44.8
Propane		44.6		55.8		67.0
Isobutane		54.9		68.0		81.1
Normal Butane		52.4		65.5		78.6
Pentanes+		57.1		71.4		85.7
Mont Belvieu Gross Spread		8.5		10.2		11.9
Gross Spread after fuel		4.3		4.7		5.6
S. Texas Basis ($/MMBtu)	$	0.13	$	0.13	$	0.13
San Juan Basis ($/MMBtu)	$	0.50	$	0.50	$	0.50

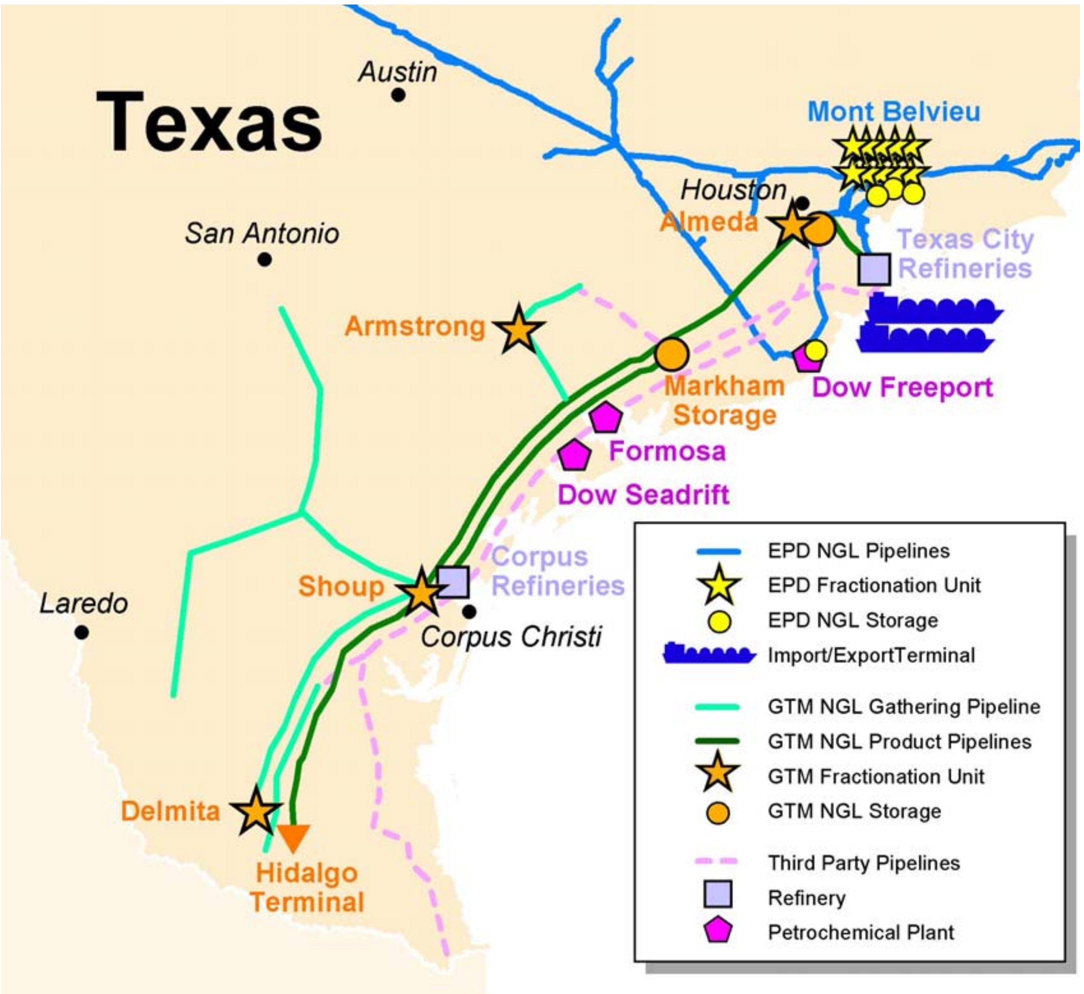
Gross Operating Margin Sensitivities

$Millions, unless noted

Reference Case ($/Mmbtu)	$ 4.00	$ 5.00	$ 6.00
EPD:			
Gas Processing Plants	$ 33.9	$ 39.5	$ 44.7
Norco	25.0	31.5	37.7
Wholesale Propane	15.0	15.0	15.0
GTM:			
San Juan Gathering	108.6	123.2	137.8
Chaco Processing	46.2	58.4	70.5
Permian Processing	20.6	25.9	31.3
South Texas Processing Plants	34.3	38.4	42.5
Combined:			
Net Gas Position	-	3.2	6.4
Total	$ 283.6	$ 335.1	$ 385.9

Complementary Assets

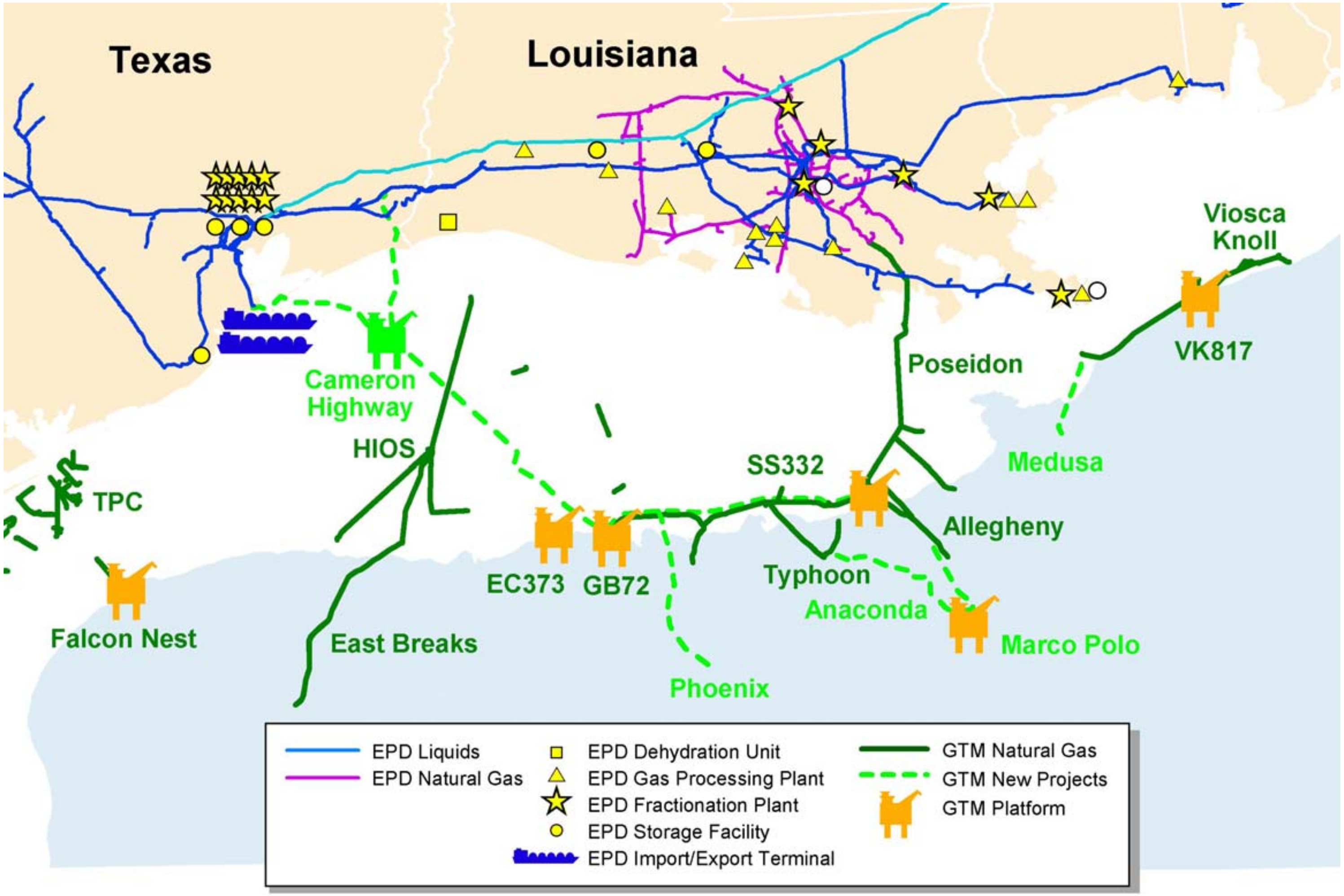
TX NGL Transportation and Fractionation



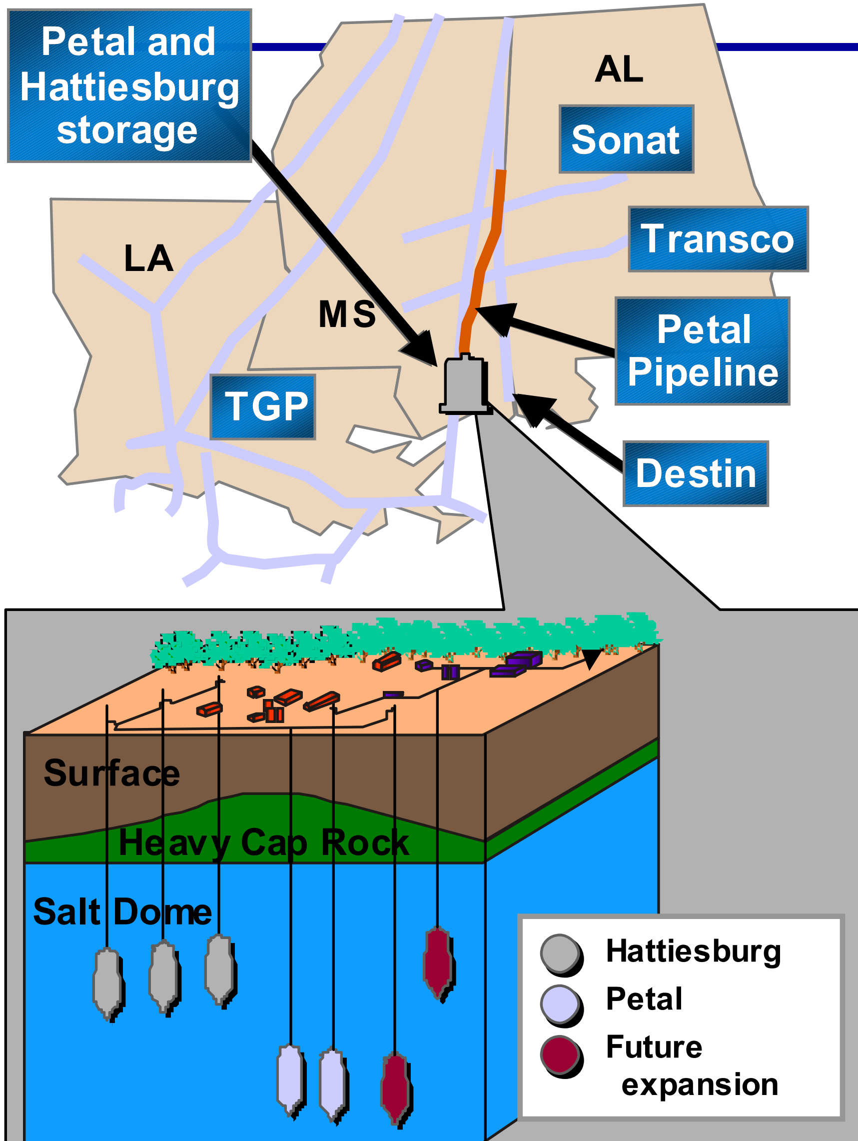
- GTM South Texas integrated NGL pipeline and fractionation assets
  - 1,000 miles of NGL pipelines
  - Capacity 96 MBPD
  - 2002 throughput 70 MBPD
- 9 South Texas natural gas processing/treating plants to be purchased from EP in Step 2 are an important source of NGLs to downstream system
  - 1.89 Bcfd capacity

Complementary Assets

EPD & GTM's Gulf of Mexico Position



Natural Gas Storage: Highlights



- Strategically located in Southeast
- 13.5 Bcf high deliverability salt dome storage facility
  - 2003 revenues of $3.5MM from interruptible contracts
  - All available capacity is subscribed
  - 52% subscribed beyond 2021
- FERC authority for 8 Bcf expansion
  - Convert 1.8 Bcf – Commitments on 83%, outstanding proposals on rest
  - Create 5 Bcf – Signed LOI with SNG to build and sell, along with interest in the Petal Pipeline
  - 1.2 Bcf expansion of existing cavern

Ranking Along the Value Chain After Merger

Gas Gathering	Gas Processing	Raw Mix Pipeline	Fractionation	Salt Dome Storage	Import Terminal	Export Terminal	Distribution
Duke FS	Duke FS	Enterprise	Enterprise	Enterprise	Dow	Enterprise	Enterprise
Enterprise	BP	TEPPCO	Koch	TEPPCO	Enterprise	Dynegy	Dow
Williams	Enterprise	Koch	ConocoPhillips	Dow	Dynegy	ChevronTexaco	ConocoPhillips
BP	Williams	ChevronTexaco	Dynegy	Dynegy	Trammo		TEPPCO
Oneok	ExxonMobil	Dynegy	El Paso	Williams			Koch
ConocoPhillips	ONEOK	BP	ExxonMobil	ConocoPhillips			KinderMorgan
Devon	ConocoPhillips	El Paso	BP	BP			ChevronTexaco
Dynegy	Devon	ExxonMobil	ONEOK	ExxonMobil			Dynegy
	Dynegy	ConocoPhillips	Duke	El Paso			El Paso
			Williams	ONEOK			ExxonMobil

Governance & Merger Update

Actions to Safeguard EPD & EPD GP Prior to Merger with GTM

- Prior to the closing of Step 2, EPD GP is 95% owned by EPCO, a privately-held company owned by the Duncan family, and 5% owned by Dan Duncan LLC.
- Upon closing of merger with GTM, EPD GP will be owned 85.595% by EPCO, 4.505% by Dan Duncan LLC and 9.9% by EP. After the merger, all of the directors of EPD GP will be appointed by Dan Duncan LLC. Initially, there will be seven directors of EPD GP, a majority of which will be comprised of Independent Directors.
- EPD GP is taking the actions outlined on the following page to safeguard EPD GP, and indirectly EPD, from EPCO until the merger with GTM is closed.

Actions to Safeguard EPD & EPD GP Prior to Merger with GTM

- Enterprise Products GP, LLC, the sole general partner of Enterprise Products Partners L.P. has five directors, three of which meet the qualifications prescribed by the NYSE as independent directors.

- The affirmative unanimous vote of the Independent Directors would be required before EPD GP, EPD or any of their respective subsidiaries may take any of the following actions:
  - Any amendment to any provisions of the governing documents dealing with (i) delegation of powers, (ii) purpose and business and (iii) separateness provisions.
  - The engagement in any business other than permitted under the governing documents; and
  - The merger, consolidation or combination of EPD or EPDGP with any other entity

- EPD GP's Limited Liability Company Agreement will provide that EPD GP will not institute any proceeding or take any action to adjudicate itself or EPD as bankrupt or insolvent, consent to the institution of bankruptcy or insolvency proceedings against itself or EPD.

- Formation of a Governance Committee, a majority of the members of which will be independent directors, that will have the initial responsibility to establish and monitor compliance with governance guidelines.

Post Merger Governance of GP

- **Board Composition** – The Board of EPD's GP will consist of 7 members. Dan Duncan LLC will each designate all of the members of the Board. The Limited Liability Agreement of EPD GP will require that a majority of its directors be comprised of persons who meet the independence requirement of the NYSE. The initial 3 insider Board members will be the current Chairman of EPD's GP, the current CEO of EPD's GP and the current CEO of GTM.

- **Audit and Conflicts Committee** – Dan Duncan LLC will designate 3 of the 4 appointed independent directors (who would all be independent for SEC and NYSE rules) to serve on a 3-member Audit and Conflicts Committee of EPD's GP. The approval of the Audit and Conflicts Committee would be required for EPD's GP or EPD to enter into any transaction with an affiliate of EPCO or El Paso (other than any arm's length commercial transaction in the ordinary course).

- **Governance Committee** – solely comprised of independent directors, will have the initial responsibility to establish and monitor compliance with governance guidelines.

Post Merger Governance of GP (continued)

- The following items (among others) would require approval by El Paso:
  - any merger or consolidation involving EPD's GP;
  - any merger or consolidation involving EPD in respect of which EPD would not be the surviving entity in the transaction;
  - any sale, lease, transfer or disposition of all or substantially all of the properties or assets of EPD's GP or EPD;
  - any declaration of distributions in respect of membership interests in EPD's GP (other than distributions equal to the cash received on the general partner interests held by EPD's GP in EPD, less reserves for costs and expenses);
  - voluntarily filing for bankruptcy or taking any other action to dissolve or wind up EPD's GP or EPD; or
  - amending or repealing the LLC Agreement or the certificate of formation of EPD's GP.
- Any other matters that are brought before the Board must be approved by a majority of the 7-member Board.

Merger Update

- Federal Trade Commission
  - Filed HSR on January 21
  - Initial response from FTC
  - Second Request from FTC received February 20
  - FTC approval expected 3Q2004
- Proxy Statement and Unitholder Approval
  - Filed Form S-4 proxy with SEC on May 10
  - Expect unitholder meetings in late July or early August
- Closing expected 3Q2004

Financial Overview

Overview of First Quarter Results

($ in millions)

	First Quarter 2003	Fourth Quarter 2003	First Quarter 2004	Percent Change 4Q03 - 1Q04
Gross Operating Margin by Segment:				
Pipelines	$71.9	$72.3	$83.0	15%
Fractionation	29.0	37.3	30.3	(19%)
Processing	30.0	4.6	18.1	293%
Octane Enhancement	(3.4)	(4.8)	(1.3)	N.M.
Other	(1.0)	(0.4)	(0.4)	N.M.
Total Gross Operating Margin	**$126.5**	**$109.0**	**$129.7**	**19%**
EBITDA	**$113.2**	**$99.9**	**$123.3**	**23%**
Net Income	**$40.5**	**$34.2**	**$58.5**	**71%**

Debt to Pro Forma Lender Performance Measure (LPM) [1]

($000s)		2Q2003	3Q2003	4Q2003	1Q2004	LTM	Annualized [2]
Consolidated Net Income (Loss)		$ 33,577	$ (3,008)	$ 34,910	$ 58,982	$ 124,461	
Less:	Equity Earnings in Affiliates	228	18,040	(2,687)	(13,398)	2,183	
Plus:	Interest expense (including amortization component)	33,281	32,559	32,811	32,618	131,269	
	Other depreciation and amortization	27,872	28,293	31,958	30,519	118,642	
	Distributions from unconsolidated affiliates	5,239	4,838	6,179	15,682	31,938	
	Provision for income taxes	476	1,023	665	1,625	3,789	
Quarterly Totals		$ 100,673	$ 81,745	$ 103,836	$ 126,028	$ 412,282	$ 504,112

Pro Forma Adjustment for Acquisition of 50% interest in GulfTerra GP on December 15, 2003 (50% of Cash distributions paid by GTM to its GP)

	LTM	Annualized
2Q2003	7,950	0
3Q2003	9,000	0
4Q2003	10,600	0
Pro Forma March 31, 2004 LTM LPM	$ 439,832	$ 504,112
March 31, 2004 Debt Balance	$ 2,210,876	$ 2,210,876
March 31, 2004 Debt to Pro Forma LTM LPM	5.0x	4.4x
March 31, 2004 Net Debt to Pro Forma LTM LPM	4.9x	4.3x
As Adjusted March 31, 2004 Debt to Pro Forma LTM LPM [3]	4.1x	3.6x
As Adjusted March 31, 2004 Net Debt to Pro Forma LTM LPM [3]	4.0x	3.5x

(1) LPM is a performance measure defined in EPD's multi-year and 364-day bank credit facilities.
(2) 1Q2004 financial results are annualized by multiplying by 4.
(3) Annualized LPM for first quarter 2004 adjusted for May 2004 equity offering and monetization of interest rate hedging program.

Funds Flow from Operations Interest Coverage

Funds Flow from Operations Interest Coverage:

($000s)	2Q2003	3Q2003	4Q2003	1Q2004	LTM	1Q2004 Annualized [1]
Cash flow from Operations	$ (21,291)	$ 102,413	$ 196,940	$ 29,605	$ 307,667	
Adjust for changes in restricted cash	$ 2,775	$ (6,877)	$ (804)	$ (5,825)	(10,731)	
Adjust for changes in working capital	91,564	(45,011)	(116,944)	68,431	(1,960)	
Fund flow from Operations	$ 73,048	$ 50,525	$ 79,192	$ 92,211	$ 294,976	$ 368,844
Add Interest expense	$ 33,280	$ 32,559	$ 33,056	$ 32,618	$ 131,513	$ 130,472
Funds Flow from Operations plus Interest Expense	$ 106,328	$ 83,084	$ 112,248	$ 124,829	$ 426,489	$ 499,316
Divided by Interest Expense	$ 33,280	$ 32,559	$ 33,056	$ 32,618	$ 131,513	$ 130,472
Funds Flow from Operations Interest Coverage					3.2x	3.8x

(1) 1Q2004 financial results annualized by multiplying by 4.

Capitalization Pro Forma for Merger

($ in millions)	December 31, 2003 Historical	As Adjusted [1]	Pro Forma As Adjusted [2]
Cash	$ 44.3	$ 148.8	$ 123.3
Current Maturities of Debt	240.0	15.0	496.5
Long-term Debt	1,899.5	1,817.5	3,826.6
Minority Interests	86.4	86.4	88.2
Partners' Equity	1,705.9	2,116.4	5,024.3
Total Capitalization	$ 3,931.8	$ 4,035.3	$ 9,435.6
% Debt to Total Capitalization	54.4 %	45.4 %	45.8 %
% Net Debt to Net Capitalization	53.9 %	43.3 %	45.1 %

(1) Historical adjusted for May equity offering and proceeds from monetization of interest rate hedging program.

(2) As Adjusted capitalization pro forma for the acquisition of GulfTerra and purchase of S. Texas gas plants.

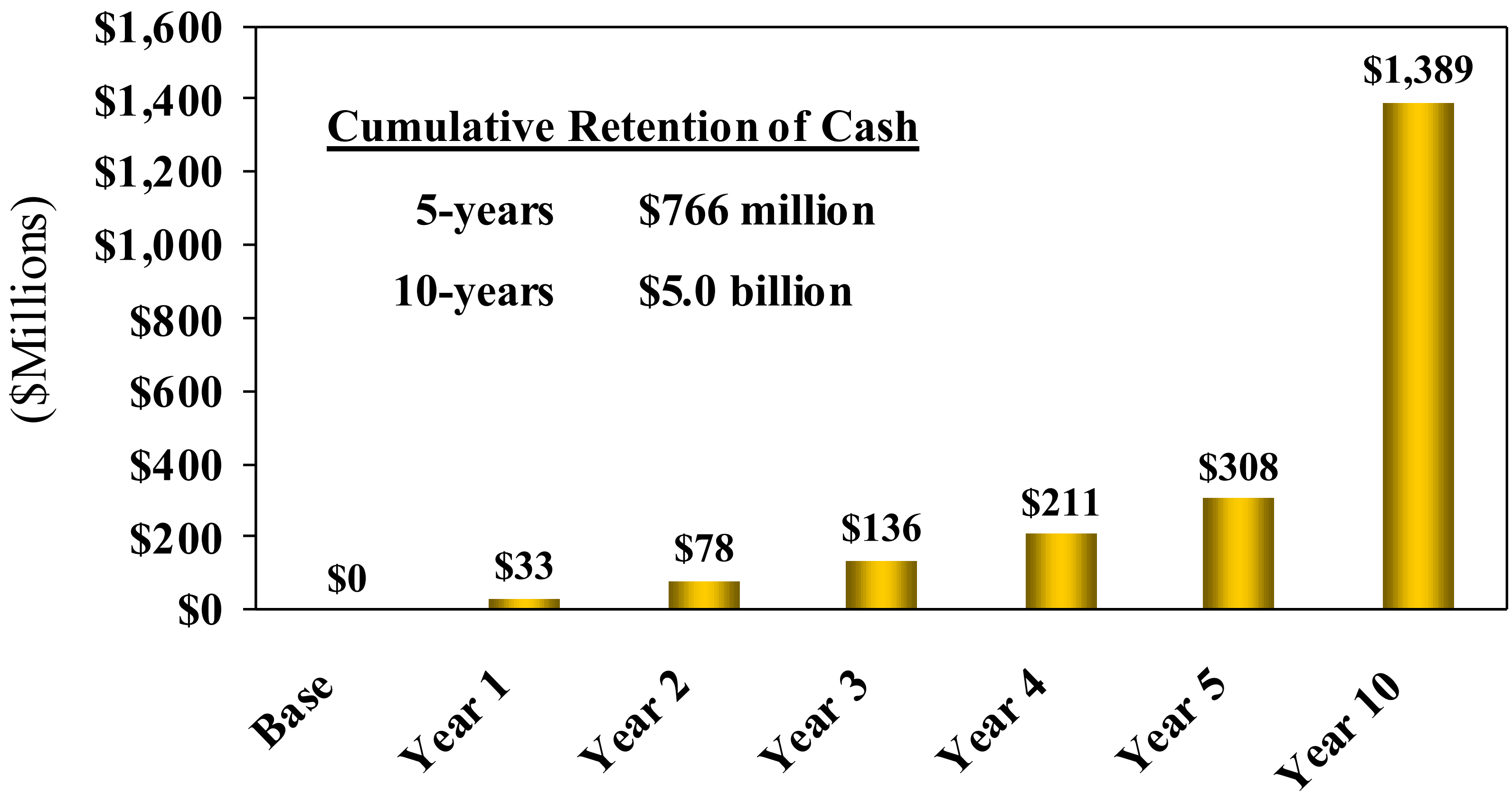
Ownership Pro Forma for Merger

(Units in millions)	LP Units	Ownership % LP Units	Ownership % Total
Public	161.8	47.8%	46.8%
EPCO & affiliates	122.4	36.1%	35.4%
Shell	41.0	12.0%	11.9%
El Paso	13.5	4.0%	3.9%
	338.7	99.9%	98.0%
General Partner			2.0%
			100.0%

Historical as of December 31, 2003 adjusted for April 2004 equity offering and pro forma for acquisition of GulfTerra.

MLP Math: 50% vs. 25% Splits

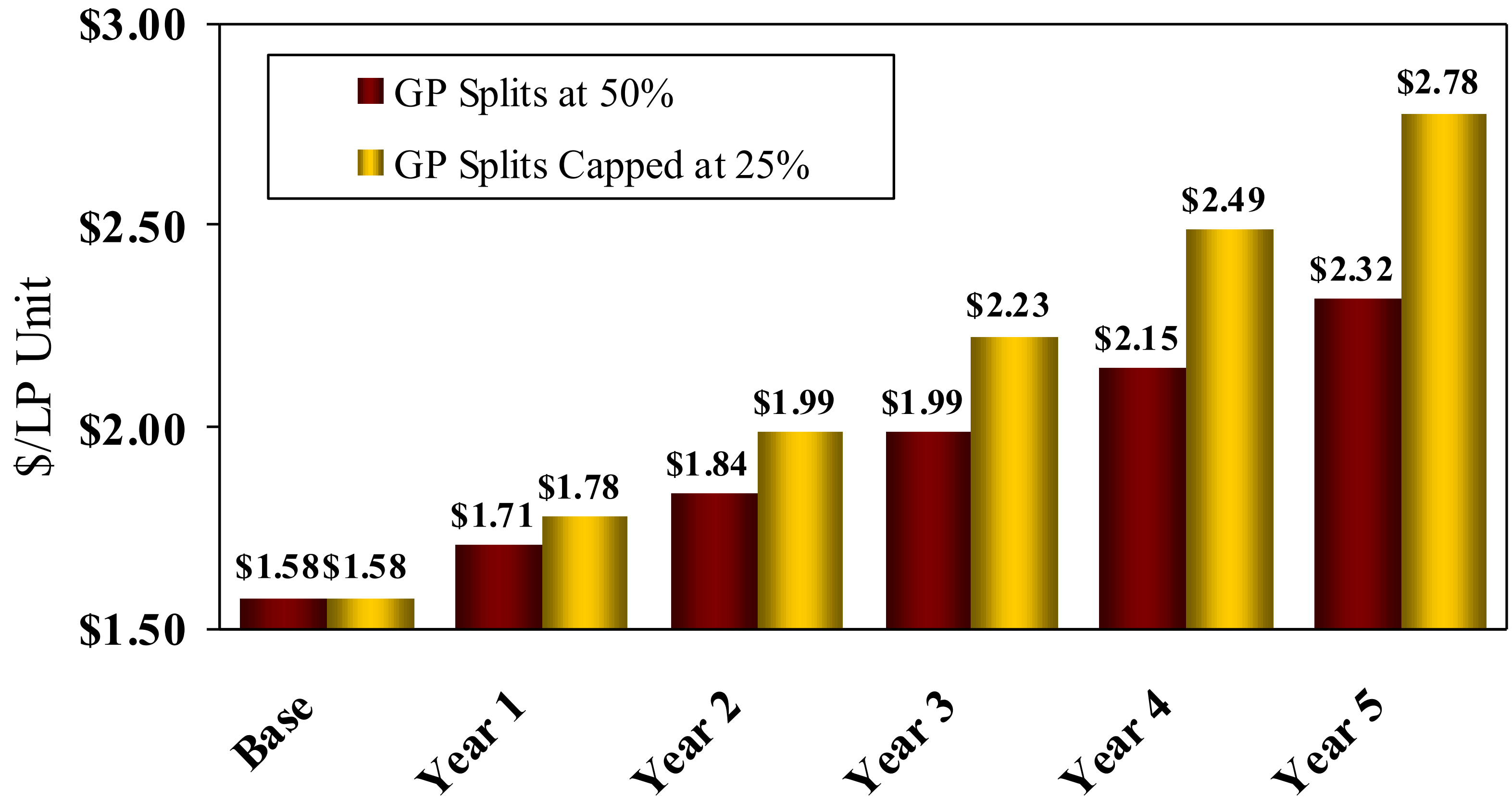
Cash Retained in MLP (annually)



Based on hypothetical 8% growth rate for cash distribution rate to partners.

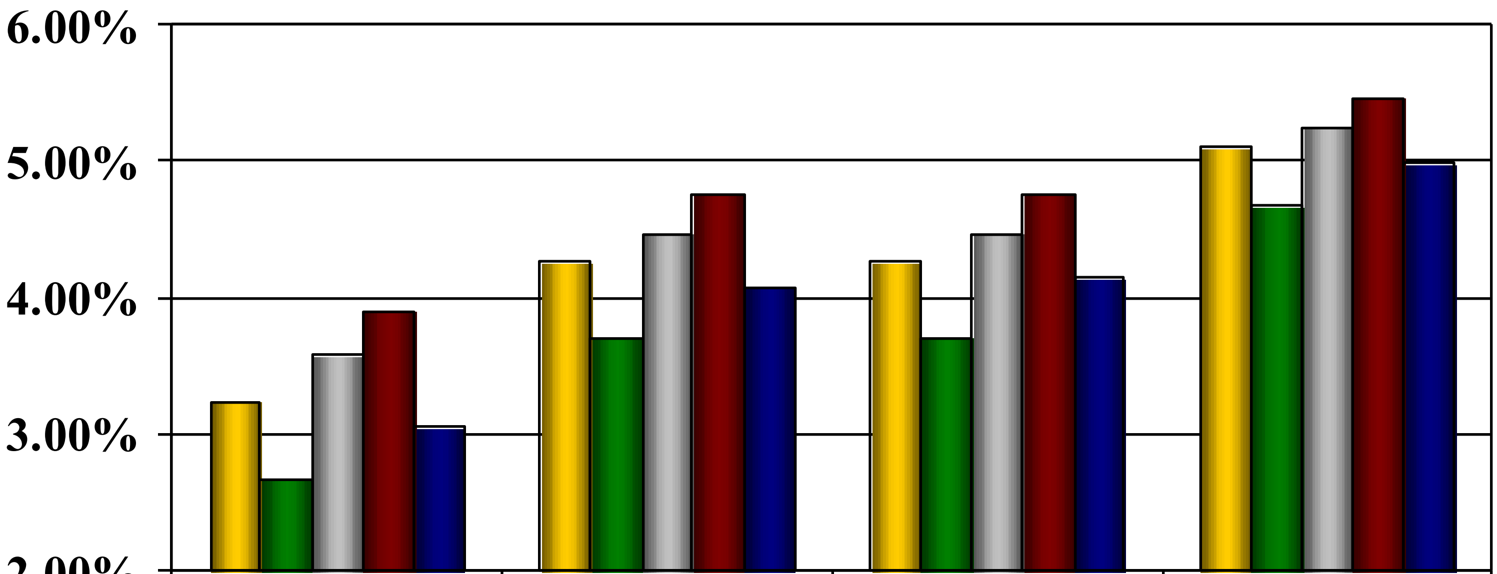
MLP Math: 50% vs. 25% Splits

Annualized Cash Distribution Rate to LP Units



Hypothetical 8% Growth w/50% Splits = 12% Growth w/25% Splits

Treasury Rate Comparisons
Effect of Interest Rate Hedge



	5-year	10-year	15-year	30-year
12/15/2003	3.24%	4.26%	4.26%	5.10%
3/17/2004	2.67%	3.71%	3.71%	4.67%
4/23/2004	3.57%	4.46%	4.46%	5.24%
5/21/2004	3.90%	4.76%	4.76%	5.46%
5/21/04 Effective	3.05%	4.07%	4.15%	4.98%

Financial Objectives

- Maintain a capital structure that supports investment grade debt ratings
- Increase the amount of gross operating margin earned from fee-based businesses
- Manage capital to provide financial flexibility for partnership while providing our partners with an attractive total return
- Prudently invest to expand the partnership through organic growth, acquisitions and joint ventures with strategic partners

Key Investment Considerations

- Strategically located assets serving the most prolific basins for natural gas, crude oil and NGLs in the U.S.
- Focus on continued growth
- Stable cash flow substantially from fee-based assets
- Long-term relationships with major industry participants
- GP/management's interests aligned with LP
- Increasing cash distributions leading to superior returns
- Experienced and deep management team

Enterprise Products Partners L.P.
Use of Financial Measures

GAAP financial measures

Incremental Operating Income

In those instances where we forecast incremental operating income for our business as a whole or for a grouping of related assets, we have assumed that certain expenses such as depreciation and amortization and selling, general and administrative expenses and related costs remain constant throughout the scenarios presented. As a result, the change in operating income would be the difference between an assumed baseline amount and a forecasted amount. This change is also referred to as "operating income sensitivity."

Non-GAAP financial measures

The accompanying slide presentation also includes the non-generally accepted accounting principle ("non-GAAP") financial measures of gross operating margin and lender performance measure. The following information provides quantitative and qualitative information to reconcile these non-GAAP financial measures to their most directly comparable financial measure calculated and presented in accordance with accounting principles generally accepted in the United States of America ("GAAP"). Our non-GAAP financial measures should not be considered as alternatives to GAAP measures such as net income, operating income, operating activities cash flows or any other GAAP measure of liquidity or financial performance.

Gross Operating Margin

We evaluate our financial performance based on the non-GAAP measure of gross operating margin. Gross operating margin is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by senior management in deciding how to allocate capital resources. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating financial results. The GAAP measure most directly comparable to total gross operating margin is total operating income.

In general, we define total gross operating margin as operating income before: (1) depreciation and amortization expense; (2) operating lease expenses for which we do not have the payment obligation; (3) gains and losses on the sale of assets; and (4) selling, general and administrative expenses. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest, cumulative effect of changes in accounting principles and extraordinary charges. At the business segment level, gross operating margin is calculated by subtracting segment operating costs and expenses (net of adjustments noted above) from segment revenues, with both totals before the elimination of intercompany transactions. In accordance with GAAP, intercompany accounts and transactions are eliminated in consolidation.

This slide presentation contains references to the forecasted gross operating margin of selected assets, which are components of our business segments. At this level of financial analysis, gross operating margin is primarily the difference between forecasted asset revenues and related operating costs. Asset-level operating expenses exclude the same categories as noted in the previous paragraph (i.e., depreciation expense, amortization expense, etc.). Certain expense categories such as selling, general and administrative expenses are not allocated to individual assets; therefore, it is impractical to reconcile asset-level gross operating margin to asset-level operating income. In addition, we have measured gross operating margin for only selected assets and not for all our operations, which would be required to calculate total gross operating margin on a forecast basis. If we allocated such expenses at an asset-level, operating income for each asset would be less than the asset-level gross operating margins shown in the attached presentation. For an example of the reconciliation of total gross operating margin to total operating income, please see the reconciliation under item 10 "*Financial Review*" included in the following Listing of Non-GAAP Financial Measures Used.

In addition, we also utilize a related non-GAAP performance measure referred to as "unit margin." This financial measure is derived by dividing asset-level gross operating margin by asset-level volumetric data (i.e., plant production or processing rates or pipeline throughput rates). Management uses this measure as an indicator of the gross operating margin per gallon or other volumetric measure of an asset's performance. This measure is also useful to management and investors as an indicator of underlying trends in an asset's profitability.

Lender Performance Measure & Funds Flow from Operations

Our lenders and ratings agencies evaluate our financial performance using various financial ratios defined in our credit agreements. Among the most widely used is the lender performance measure (or "LPM"). LPM is defined as net income or loss plus interest expense; provision for income taxes; depreciation and amortization expense; and distributions from unconsolidated affiliates less earnings from equity method unconsolidated affiliates. This measure also allows for certain retroactive adjustments associated with business acquisitions or significant asset purchases.

The ratio of LPM (on a trailing twelve-month basis) and consolidated debt at a given point in time provides our lenders with an indication of (1) the financial performance of our assets without regard to financing methods, capital structures or historical cost basis and (2) our operating performance and return on capital as compared to other companies in the midstream energy sector without regard to financing or capital structure. The GAAP measure most directly comparable to LPM is total net income.

Our ratings agencies use the non-GAAP financial measure of Funds Flow from Operations. We define Funds Flow from Operations as cash flow from operating activities adjusted for changes in restricted cash and the net effect of changes in operating accounts. This measure is primarily used to measure the ability of our assets to generate cash sufficient to pay interest costs. The GAAP measure most directly comparable to Funds Flow from Operations is operating activities cash flows.

EBITDA

We define EBITDA as net income or loss plus interest expense, provision for income taxes and depreciation and amortization expense. EBITDA is used as a financial measure by management and by external users of financial statements, such as investors, commercial banks, research analysts and rating agencies to assess (on a combined basis): (1) the financial performance of our assets without regard to financing methods, capital structures or historical cost basis; (2) the ability of our assets to generate cash sufficient to pay interest cost and support our indebtedness; (3) our operating performance and return on capital as compared to those of other companies in the midstream energy sector without regard to financing and capital structure; and (4) the viability of projects and the overall rates of return on alternative investment opportunities. Because EBITDA excludes some, but not all, items that affect net income or loss and these measures may vary among other companies, the EBITDA data presented in the slide presentation may not be comparable to similarly titled measures of other companies. The GAAP measures most directly comparable to EBITDA are net income and operating activities cash flows.

Net Debt

We define the non-GAAP financial measure of "Net Debt" as consolidated debt less consolidated cash and cash equivalents at a certain date. Management, equity analysts and investors, fixed-income analysts and investors and ratings agencies view this non-GAAP credit statistic as a reflection of a company's leverage after the application of cash on hand to reduce debt. The GAAP measure most directly comparable to Net Debt is total consolidated debt.

Within the same context of slides presenting the non-GAAP financial measure of Net Debt, we also utilize the non-GAAP financial measures of Adjusted Debt and Adjusted Net Debt. Adjusted Debt is defined as consolidated total debt less cash proceeds from our May 2004 equity offering and the monetization of our interest rate hedging programs. Adjusted Net Debt is defined as Net Debt (as defined in the previous paragraph) less cash proceeds from our May 2004 equity offering and the monetization of our interest rate hedging programs. The non-GAAP financial measures of Adjusted Debt and Adjusted Net Debt are utilized in the same fashion as Net Debt. The GAAP measure most directly comparable to Adjusted Debt and Adjusted Net Debt is consolidated total debt.

Listing of Non-GAAP Financial Measures Used and Descriptions and Related Information by Presentation

1. Introduction

None used.

2. Enterprise's Operating and Business Environment

None used.

3. NGL Business - Introduction

None used.

4. Enterprise Eastern NGL System

Page 27. This slide presents hypothetical asset-level gross operating margin for Enterprise's gas processing plants and Norco NGL fractionator based on three sets of pricing assumptions (for natural gas and NGLs). As discussed in "*Non-GAAP Financial Measures – Gross Operating Margin*," it is impractical to reconcile an asset-level gross operating margin estimate to its comparable asset-level operating income amount.

5. Western NGL Business

None used.

6. Natural Gas Pipeline Business

None used.

7. Petrochemical Services Business

Page 83. This slide references to a non-GAAP asset-level unit margin financial measure for isomerization. As discussed in "*Non-GAAP Financial Measures – Gross Operating Margin*," it is impractical to reconcile an asset-level gross operating margin estimate (in total or per unit) to its comparable asset-level operating income amount.

Page 94. This slide references to a non-GAAP asset-level unit margin financial measure for our propylene business. As discussed in "*Non-GAAP Financial Measures – Gross Operating Margin*," it is impractical to reconcile an asset-level gross operating margin estimate (in total or per unit) to its comparable asset-level operating income amount.

Page 104. This slide presents hypothetical asset-level gross operating margin from iso-octane production. As discussed in "*Non-GAAP Financial Measures – Gross Operating Margin*," it is impractical to reconcile an asset-level gross operating margin estimate to its comparable asset-level operating income amount.

8. Enterprise and GulfTerra Combination

Page 114. This slide presents hypothetical combined asset-level gross operating margin for both Enterprise and GulfTerra on a post-merger basis based on three sets of pricing assumptions (for natural gas and NGLs). As discussed in "*Non-GAAP Financial Measures – Gross Operating Margin*," it is impractical to reconcile an asset-level gross operating margin estimate to its comparable asset-level operating income amount.

9. Governance/Merger Update

None used.

10. Financial Review

Page 126. This slide presents an overview of Enterprise's first quarter of 2004 compared to the first quarter of 2003 and fourth quarter of 2003. Included in this slide are references to consolidated gross operating margin and EBITDA. Reconciliations of these non-GAAP measures to their most directly comparable financial measure calculated and presented in accordance with GAAP are as follows:

	For the Three Months Ended March 31,		Dec. 31,
	2004	**2003**	**2003**
	(Unaudited, Dollars in Millions)		
Reconciliation of Non-GAAP "Total Gross Operating Margin" to GAAP "Operating Income"			
Operating Income	$ 87.3	$ 85.0	$ 66.1
Adjustments to derive Total Gross Operating Margin:			
Depreciation and amortization in operating costs and expenses	30.5	27.7	31.9
Retained lease expense, net, in operating costs and expenses	2.3	2.3	2.3
Loss (gain) on sale of assets in operating costs and expenses	0.1		0.1
Selling, general and administrative costs	9.5	11.5	8.6
Total Gross Operating Margin	$ 129.7	$ 126.5	$ 109.0
Reconciliation of Non-GAAP "EBITDA" to GAAP "Net Income" and GAAP "Operating Activities Cash Flows"			
Net income	$ 58.5	$ 40.5	$ 34.2
Adjustments to derive EBITDA:			
Interest expense (including amortization component)	32.6	41.9	33.1
Provision for income taxes	1.6	3.1	0.7
Other depreciation and amortization	30.6	27.7	31.9
EBITDA	$ 123.3	$ 113.2	$ 99.9
Interest expense	(32.6)	(41.9)	(33.1)
Amortization in interest expense	0.8	11.6	0.5
Provision for income taxes	(1.6)	(3.1)	(0.7)
Provision for impairment of asset			1.2
Earnings from unconsolidated affiliates	(13.4)	(1.6)	(2.7)
Distributions from unconsolidated affiliates	15.7	15.6	6.2
Loss (gain) on sale of asset	0.1		0.1
Operating lease expense paid by EPCO (excluding minority interest portion)	2.3	2.2	2.2
Other expenses paid by EPCO			(0.2)
Minority interest	2.9	2.3	(0.5)
Deferred income tax expense	1.7	2.7	6.4
Changes in fair market value of financial instruments			
Cumulative effect of change in accounting principle	(7.0)		
Change in restricted cash	5.8	(10.0)	0.8
Net effect of changes in operating accounts	(68.4)	50.5	116.9
Operating activities cash flows	$ 29.6	$ 141.5	$ 197.0

Page 127. This slide presents Enterprise's LPM for the trailing twelve month period ending March 31, 2004 and a forecast of such measure on an annualized basis using first quarter of 2004 information. A reconciliation of this non-GAAP measure to net income (its GAAP counterpart) is shown on the referenced slide.

In addition, this slide incorporates the non-GAAP financial measures of "Net Debt," "Adjusted Debt" and "Adjusted Net Debt." The following table shows (1) the reconciliation of these non-GAAP financial measures to their most directly comparable financial measures calculated and presented in accordance with GAAP and (2) the method used to calculate each LPM-derived financial ratio.

	LTM	Annualized
March 31, 2004 Debt to Pro Forma LTM LPM		
GAAP consolidated total debt at March 31, 2004:		
Long-term debt	$ 2,195.9	$ 2,195.9
Current maturities of long-term debt	15.0	15.0
Total debt	$ 2,210.9	$ 2,210.9
LTM LPM (as shown on slide)	$ 439.8	$ 504.0
March 31, 2004 Debt to Pro Forma LTM LPM	5.0	4.4
March 31, 2004 Net Debt to Pro Forma LTM LPM		
GAAP consolidated total debt at March 31, 2004:		
Long-term debt	$ 2,195.9	$ 2,195.9
Current maturities of long-term debt	15.0	15.0
Total debt	2,210.9	2,210.9
Less cash and cash equivalents	(44.8)	(44.8)
Net Debt	$ 2,166.1	$ 2,166.1
LTM LPM (as shown on slide)	$ 439.8	$ 504.0
March 31, 2004 Net Debt to Pro Forma LTM LPM	4.9	4.3
March 31, 2004 Adjusted Debt to Pro Forma LTM LPM		
GAAP consolidated total debt at March 31, 2004:		
Long-term debt	$ 2,195.9	$ 2,195.9
Current maturities of long-term debt	15.0	15.0
Total debt	2,210.9	2,210.9
Less: Net proceeds from May 2004 equity offering	(307.0)	(307.0)
Less: Monetization of interest rate hedging program	(104.5)	(104.5)
Adjusted Debt	$ 1,799.4	$ 1,799.4
LTM LPM (as shown on slide)	$ 439.8	$ 504.0
March 31, 2004 Adjusted Debt to Pro Forma LTM LPM	4.1	3.6
March 31, 2004 Adjusted Net Debt to Pro Forma LTM LPM		
GAAP consolidated total debt at March 31, 2004:		
Long-term debt	$ 2,195.9	$ 2,195.9
Current maturities of long-term debt	15.0	15.0
Total debt	2,210.9	2,210.9
Less: Cash and cash equivalents	(44.8)	(44.8)
Less: Net proceeds from May 2004 equity offering	(307.0)	(307.0)
Less: Monetization of interest rate hedging program	(104.5)	(104.5)
Adjusted Net Debt	$ 1,754.6	$ 1,754.6
LTM LPM (as shown on slide)	$ 439.8	$ 504.0
March 31, 2004 Adjusted Net Debt to Pro Forma LTM LPM	4.0	3.5

Page 128. The slide presents Enterprise's Funds Flow from Operations for the trailing twelve month period ending March 31, 2004 and a forecast of such measure on an annualized basis using first quarter of 2004 information. A reconciliation of this non-GAAP measure to operating activities cash flows (its GAAP counterpart) is shown in the referenced slide.

Enterprise Products Partners L.P.
Capitalization Pro Forma for Merger Reconciliation

Page 129. This slide presents certain adjusted and pro forma as adjusted information relating to Enterprise's capitalization at December 31, 2003. The pro forma as adjusted shown in the slide information is derived from the information contained in the Pro Forma Condensed Consolidated Balance Sheet shown on page F-6 under Item 5 of our Current Report on Form 8-K filed with the SEC on April 26, 2004. A reconciliation between the pro forma amounts presented in the Form 8-K disclosure and the amounts shown in the slide presentation is shown in the following tables. We also have included information showing how the financial ratios presented on this slide were calculated.

	At December 31, 2003		
	Historical	**Adjustments**	**As Adjusted per Slide**
Cash	$ 44.3	$ 104.5 (a)	$ 148.8
Current maturities of long-term debt	$ 240.0	(225.0) (b)	$ 15.0
Long-term debt	1,899.5	(82.0) (b)	1,817.5
Minority interest	86.4		86.4
Partners' equity	1,705.9	104.5 (a)	2,116.4
		306.0 (b)	
Total capitalization	$ 3,931.8		$ 4,035.3
% Debt to Total Capitalization:			
Current maturities of long-term debt	$ 240.0		$ 15.0
Long-term debt	1,899.5		1,817.5
Total Debt	$ 2,139.5		$ 1,832.5
Capitalization	$ 3,931.8		$ 4,035.3
% Debt to Total Capitalization	54.4%		45.4%
% Net Debt to Total Capitalization:			
Current maturities of long-term debt	$ 240.0		$ 15.0
Long-term debt	1,899.5		1,817.5
Total Debt	2,139.5		1,832.5
Less cash and cash equivalents	(44.3)		(148.8)
Net Debt	$ 2,095.2		$ 1,683.7
Capitalization (net of cash)	$ 3,887.5		$ 3,886.5
% Debt to Total Capitalization	53.9%		43.3%

Notes: (a) Reflects monetization of interest rate hedging program in April 2004
(b) Reflects proceeds and related adjustments for May 2004 equity offering

	At December 31, 2003				
	Pro Forma As Adjusted from Form 8-K	Adjustments		Pro Forma As Adjusted per Slide	
Cash	$ 123.3	$ 104.5	(a)	$ 123.3	
		(104.5)	(b)		
Current maturities of long-term debt	$ 601.0	(104.5)	(b)	$ 496.5	
Long-term debt	3,826.6			3,826.6	
Minority interest	88.2			86.4	
Partners' equity	4,919.8	104.5	(a)	5,024.3	
Total capitalization	$ 9,435.6			$ 9,433.8	
% Debt to Total Capitalization:					
Current maturities of long-term debt				$ 496.5	
Long-term debt				3,826.6	
Total Debt				$ 4,323.1	
Capitalization				$ 9,433.8	
% Debt to Total Capitalization				45.8%	
% Net Debt to Total Capitalization:					
Current maturities of long-term debt				$ 496.5	
Long-term debt				3,826.6	
Total Debt				4,323.1	
Less cash and cash equivalents				(123.3)	
Net Debt				$ 4,199.8	
Capitalization (net of cash)				$ 9,310.5	
% Debt to Total Capitalization				45.1%	

Notes: (a) Reflects monetization of interest rate hedging program in April 2004
(b) Reflects use of monetization proceeds to reduce debt