Corporate Profile

GeoResources, Inc.

The GHS Conference – San Francisco

July 17-19, 2011

Forward-Looking Statements

Information included herein contains forward-looking statements that involve significant risks and uncertainties, including our need to replace production and acquire or develop additional oil and gas reserves, intense competition in the oil and gas industry, our dependence on our management, volatile oil and gas prices and costs, uncertain effects of hedging activities and uncertainties of our oil and gas estimates of proved reserves and resource potential, all of which may be substantial. In addition, past performance is no guarantee of future performance or results. All statements or estimates made by the Company, other than statements of historical fact, related to matters that may or will occur in the future are forward-looking statements.

Readers are encouraged to read our December 31, 2010 Annual Report on Form 10-K and any and all of our other documents filed with the SEC regarding information about GeoResources for meaningful cautionary language in respect of the forward-looking statements herein. Interested persons are able to obtain copies of filings containing information about GeoResources, without charge, at the SEC's internet site (http://www.sec.gov). There is no duty to update the statements herein.

Corporate Highlights

- ***Balanced Portfolio***
  - *Long-Term Growth* – 70,000 net acres in two premier U.S. liquids resource plays
  - *Strong Current Cash Flow/Profitability* – 5,090 Boe/d of production in 2010
  - 24 Mmboe proved reserves; 60% oil (1)

- ***Significant Producing Bakken Position***
  - 46,000 net acres (33,200 operated)
  - Continually leasing
  - Growing to 3 operated rigs around year end 2011

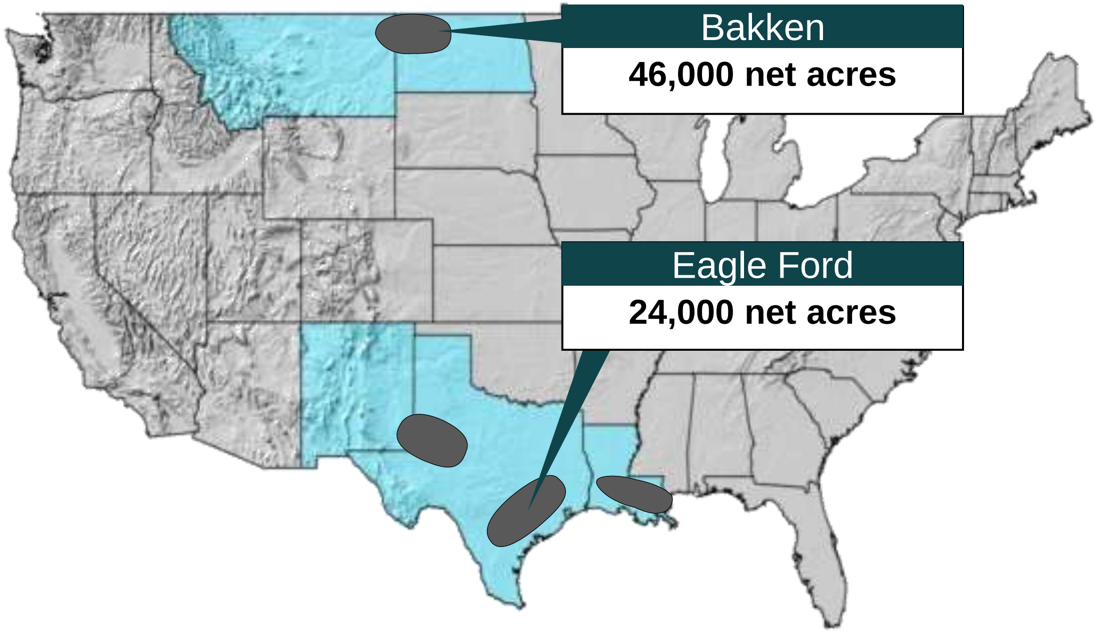
- ***Rapidly Expanding Eagle Ford Position***
  - 24,000 net acres (primarily operated)
  - Commitment for additional leasing
  - Growing to 3 operated rigs around year end 2011

Value Creation

(1) Does not include interests in affiliated partnerships. Reserves based on SEC pricing as of 1/1/11. See Additional Disclosures in Appendix.

Company Overview

- Independent oil and natural gas company focused in the Southwest, Gulf Coast and Williston Basin
- Significant upside potential through growing positions in liquids-rich resource plays:
  - Bakken – 46,000 net acres
  - Eagle Ford – 24,000 net acres
- 60% of 1st quarter 2011 production is oil and expected to increase through near-term development
- Operate approximately 75% of proved reserves
- Last twelve month EBITDAX of $71 MM[3]

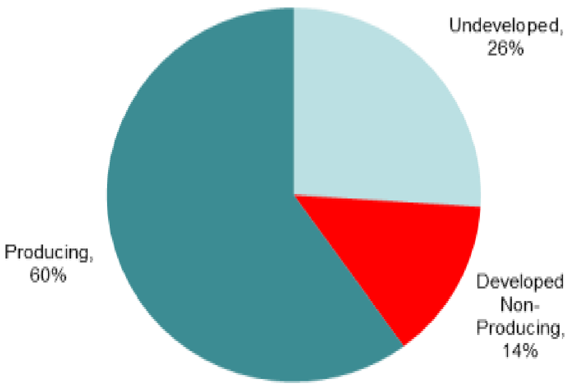


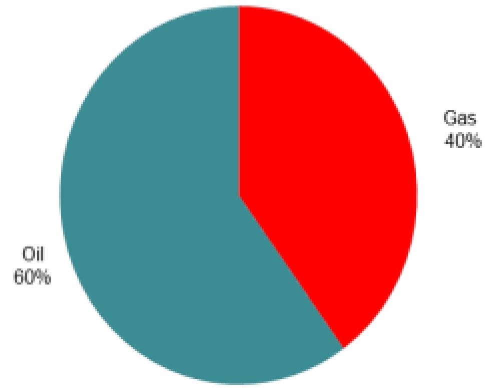
Company Highlights[1,2]	
Proved Reserves (MMBOE)	24.0
Oil (reserves)	60%
Proved Developed	74%
Production (Boe/d)	5,090
Oil (2010 average production)	57%
Operated Production	75%

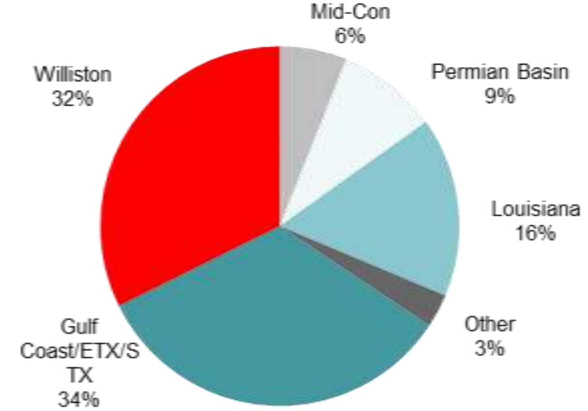
(1) As of December 31, 2010. Excludes interests in two affiliated partnerships. Reserves based on SEC pricing for 2010. See Additional Disclosures in Appendix.
(2) Represents the Company's average production rate for the year ended December 31, 2010.
(3) EBITDAX is a non-GAAP financial measure. Please see Appendix for a definition of EBITDAX and a reconciliation to net income.

Reserves and Production

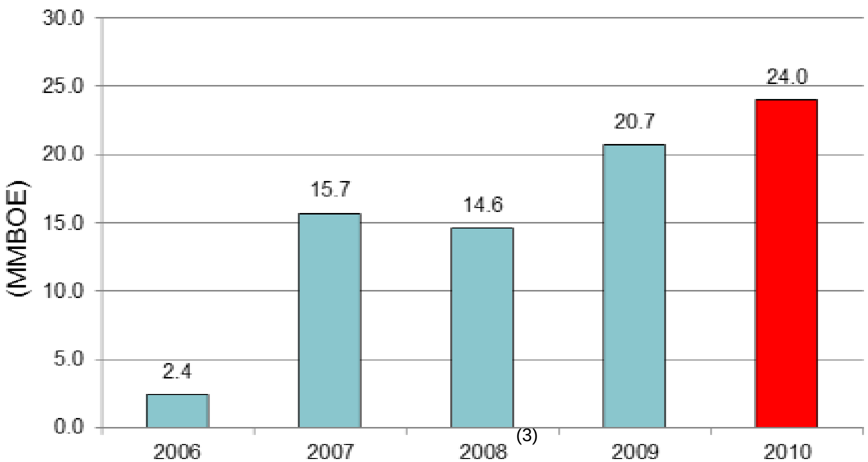
Current Proved Reserves – 24.0 MMBOE (1)



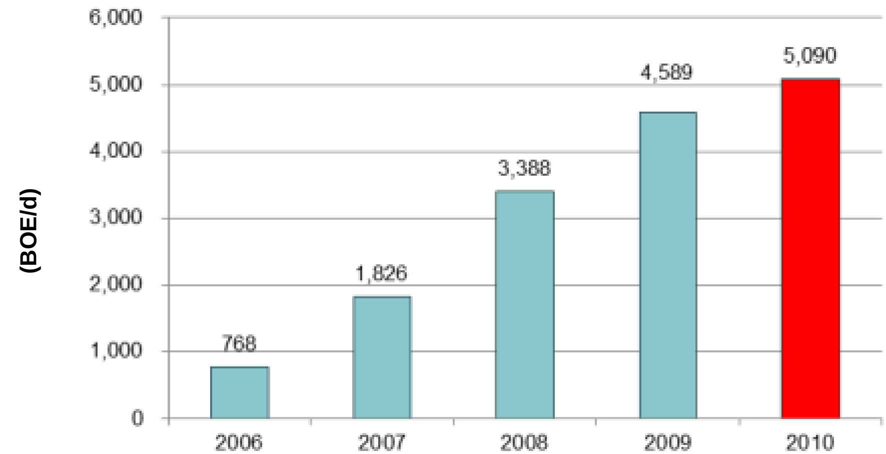




Proved Reserves (MMBOE)(2)



Average Daily Production (BOE/d)



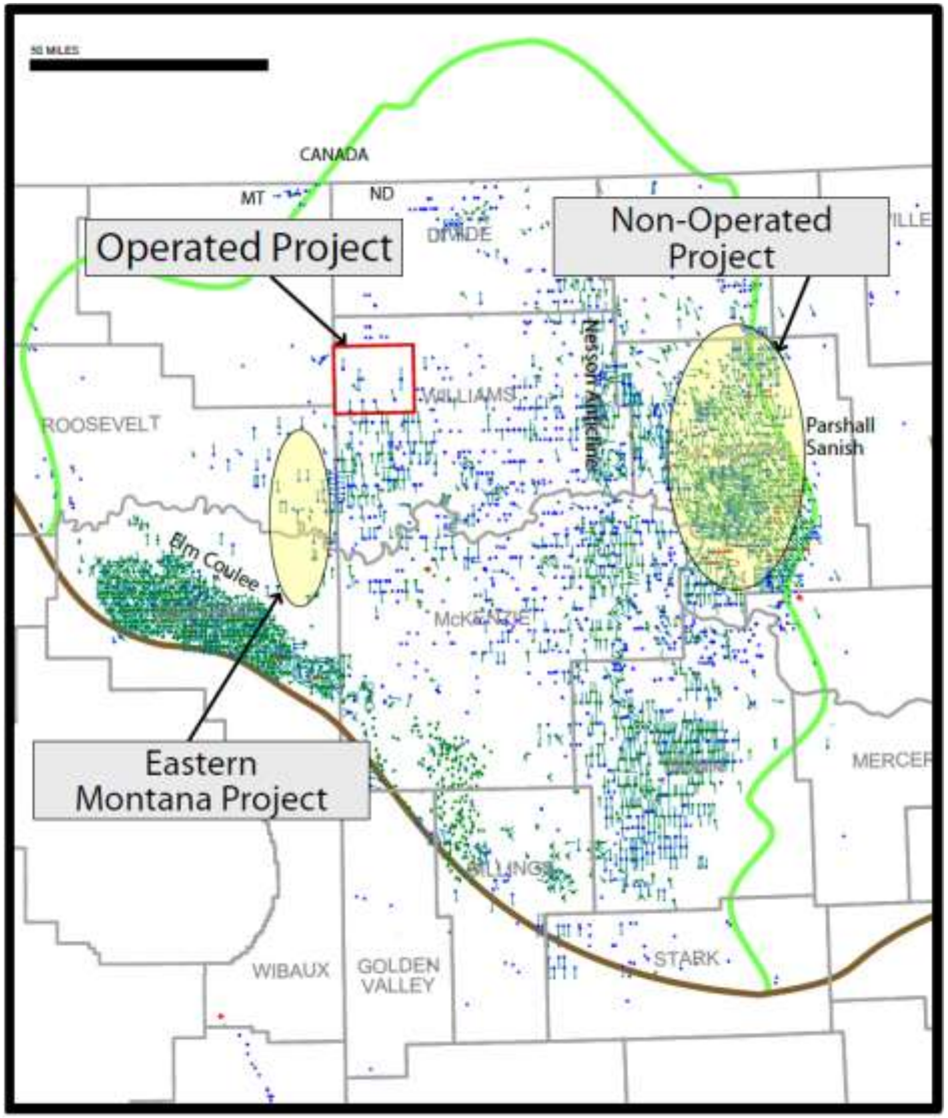
(1) As of January 1, 2011. Excludes partnership interests.
(2) 2006 – 2010 proved reserves based on SEC guidelines.
(3) 2008 reserves reflect lower prices and divestitures. See Additional Disclosures in Appendix.

GeoResources Asset Overview

Oil Weighted Development

Bakken Shale Overview

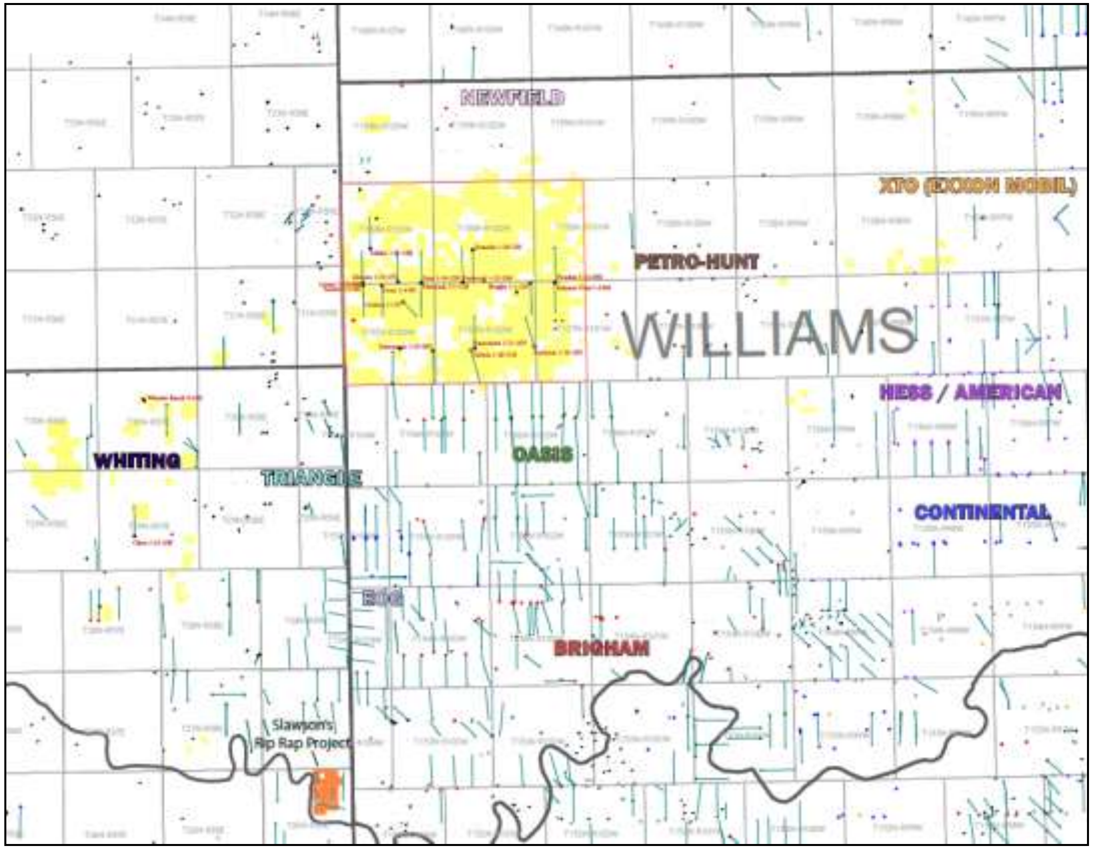
- 46,000 net acres in the Bakken trend
- Bakken operated project
  - 25,000 net acres in Williams County, ND
  - Drilling started in September 2010
  - 4 wells drilled
  - 2 dedicated rigs currently running
  - Interests in 100 spacing units (1,280 acres)
- Bakken non-operated project
  - Partnered with Slawson Exploration Company
  - 11,000 net acres primarily Mountrail County, ND
  - 4-5 rigs currently running
  - Significant driver of near-term production growth
- Eastern Montana
  - 10,000 net acres in Roosevelt/Richland County, MT
  - 8,200 operated / 1,800 non-operated acres
  - 17 operated 1,280 acre units
  - Will resume drilling 1st operated Bakken well in July 2011, Olson #1-21-16H with a 31.375% WI
  - Participated with Slawson in the Renegade 1-10H, Battalion 1-3H & Squadron 1-15-14H
  - Participated with Brigham in the Swindle 16-9 #1H



Note: Information as of July 2011. Symbols on map depict permitted or drilled Bakken locations.

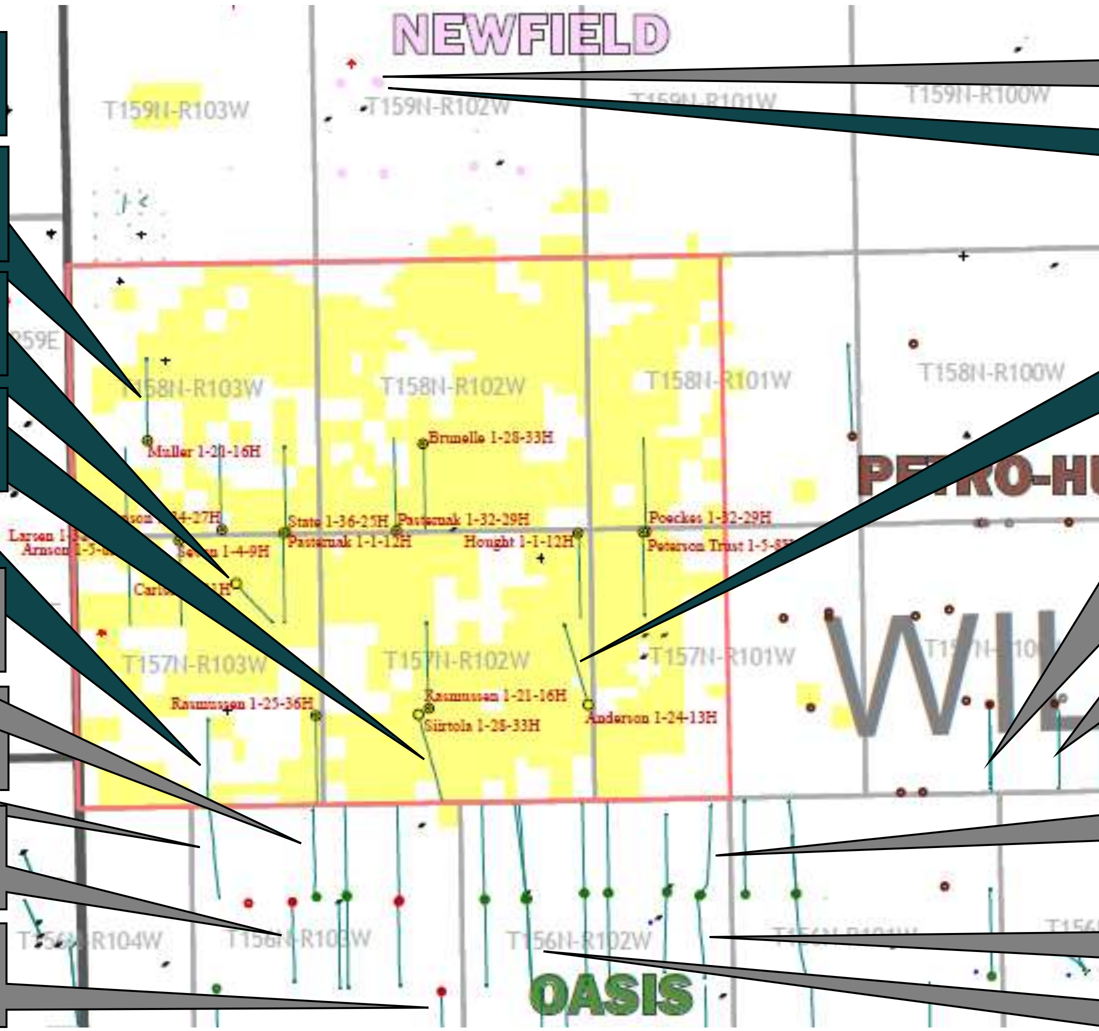
Bakken Shale – Operated

- 25,000 net acres in NW Williams Co., ND
  - 2011 drilling program averages ~30% WI
  - Interest in 100 spacing units
- Bakken AMI
  - Partnered with Resolute Energy in March '10
  - Retained 47.5% WI in project
- First 3 wells have de-risked acreage
  - *Carlson 1-11H* (640 acre): 685 Bo/d IP; 236 Bo/d 30 Day Avg.
  - *Siirtola 1-28-33H* (1280 acre): 840 Bo/d IP; 246 Bo/d 30 Day Avg.
  - *Anderson 1-24-13H* (1280 acre): 905 Bo/d IP; 372 Bo/d 30 Day Avg.
  - *Muller 1-21-16H* (1280 acre): Drilling out plugs
- Multi-year drilling inventory
  - 2 dedicated rigs currently running
  - Planning for 3 operated rigs by early '12
- Positive offset activity
  - 7 wells to south have NDIC-reported peak month average daily rates of 298-485 Bo/d
  - 4-5 rigs drilling in and around our AMI



Note: Information as of July 2011. 30 Day Avg. rate calculated as maximum average daily production rate of first four calendar months of production and excludes months with less than 20 days of production. Source of third party production data is NDIC website.

Williams County Operated Activity



GEOI Muller 1-21-16H
Drilling out plugs

GEOI Carlson 1-11H
30 Day Avg.: 236 Bo/d
(640 ac. unit - short lateral)

GEOI Siirtola 1-28-33H
30 Day Avg.: 246 Bo/d

OAS Grimstvedt 5703 42-34H
30 Day Avg.: 262 Bo/d
GEOI WI = 2.6%

OAS Horne 5603 44-9H
30 Day Avg.: 379 Bo/d

OAS Bean 5703 42-34H
30 Day Avg.: 298 Bo/d

BEXP BCD Farms 16-21
30 Day Avg.: 485 Bo/d

BEXP Kalil 25-36 1561-H
30 Day Avg.: 466 Bo/d

NFX Christensen 159-102-17-20-1H
30 Day Avg.: 326 Bo/d

NFX Christensen 159-102-8-5-1H
Drilling (GEOI WI 6.2%)

GEOI Anderson 1-24-13H
30 Day Avg.: 372 Bo/d

Petro-Hunt NJOS 157-100-28A-33-1H
30 Day Avg.: 215 Bo/d

Petro-Hunt NJOS 157-100-26B-35-1H
30 Day Avg.: 344 Bo/d

Petro-Hunt Forseth 157-100-25B-1H
30 Day Avg.: 325 Bo/d

OAS NJOS Federal 5602 11-13H
30 Day Avg.: 375 Bo/d

OAS Sandaker 5602 11-13H
30 Day Avg.: 440 Bo/d

OAS Somerset 5602 12-17H
30 Day Avg.: 352 Bo/d

Note: Information as of July 2011. 30 Day Avg. rate calculated as maximum average daily production rate of first four calendar months of production and excludes months with less than 20 days of production. Source of third party production data is HPDI and NDIC website.

Williams County Completion Comparison

	GeoResources Completions			Offset Completions
	Siirtola/Anderson (Avg.)	Next 3 Wells	Future Completions	(Estimated Avg.)
30 Day Avg. Oil Rate (bbl/d)	309	-	-	500
60 Day Cumulative Oil (bbls)	15,000	-	-	27,000
Days On Pump (1st 60 Days)	0	-	-	22
Lateral Length (feet)	9,800	~ 9,800	~ 9,800	9,500
Number of Frac Stages	30	38	34	34
Stage Length (Feet)	327	~250	~290	290
Frac Method	Sleeve & PnP	Plug 'n Perf	Plug 'n Perf	Plug 'n Perf
Sand Volume (MM lbs)	2.8	4.0	3.6	3.7
Sand Type	Sand & Resin-coated	Sand & Ceramic	Sand & Resin-coated	Sand & Ceramic
Current Water Cut (%)	54%	-	-	56%
Gas-Oil Ratio (cf/bbl)	589	-	-	675

Notes:

Comparison limited to 1280 acre unit completions in Williams County (T154-157, R100-104) occurring after June 2009

Water cut and GOR for offset completions are based on average of most recent monthly data from the wells in the area and will vary by well

Water cut and GOR for GeoResources are based on Carlson, Siirtola & Anderson wells current month averages

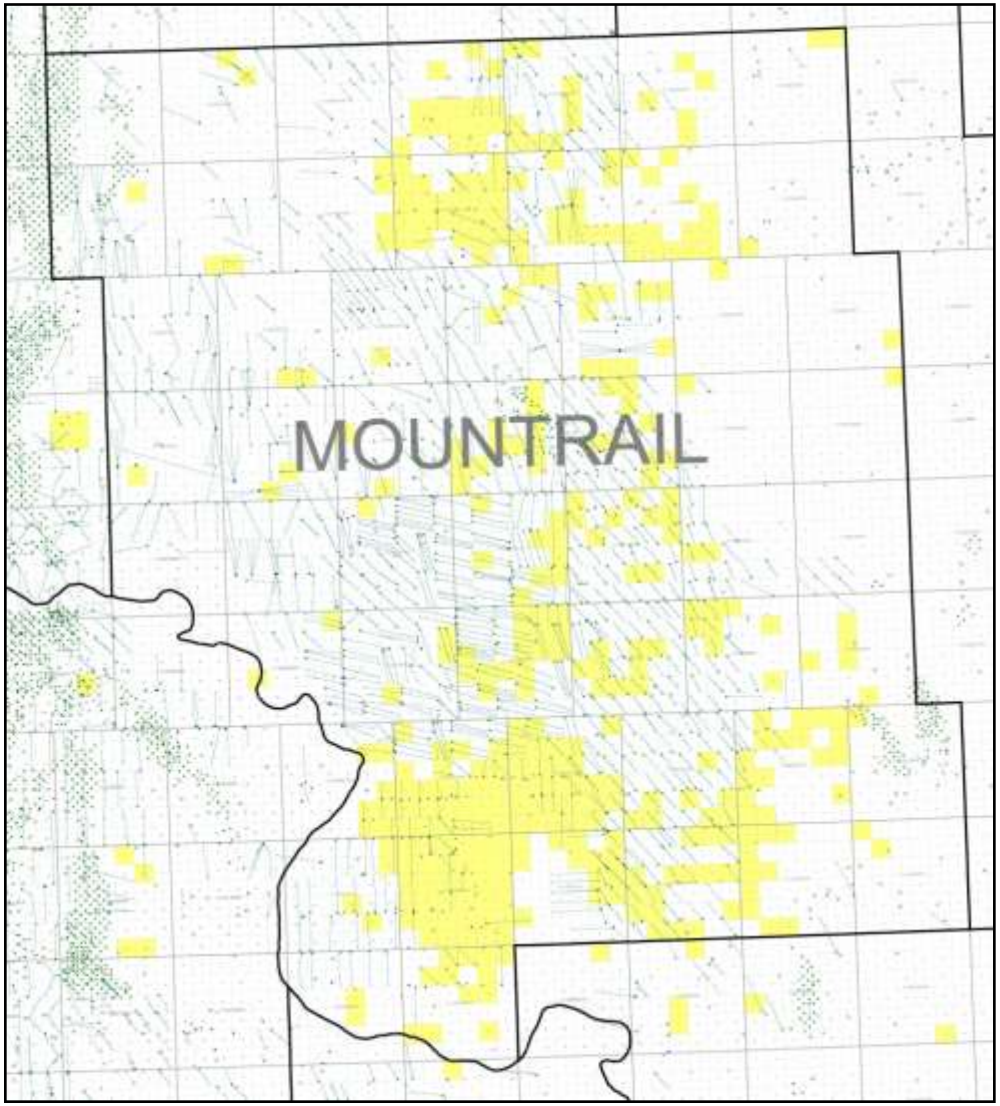
Source of offset completion data is NDIC website

Bakken Shale - Non-operated

- 11,000 net acres primarily in Mountrail County, ND
  - W.I. ranges from 1% to 18%
  - Average WI of ~8%

- Partnered with experienced operator - Slawson Exploration
  - Slawson has 4-5 rigs currently running
  - Currently have dedicated frac crews under contract
  - Drilled over 95 wells to date; 100% success

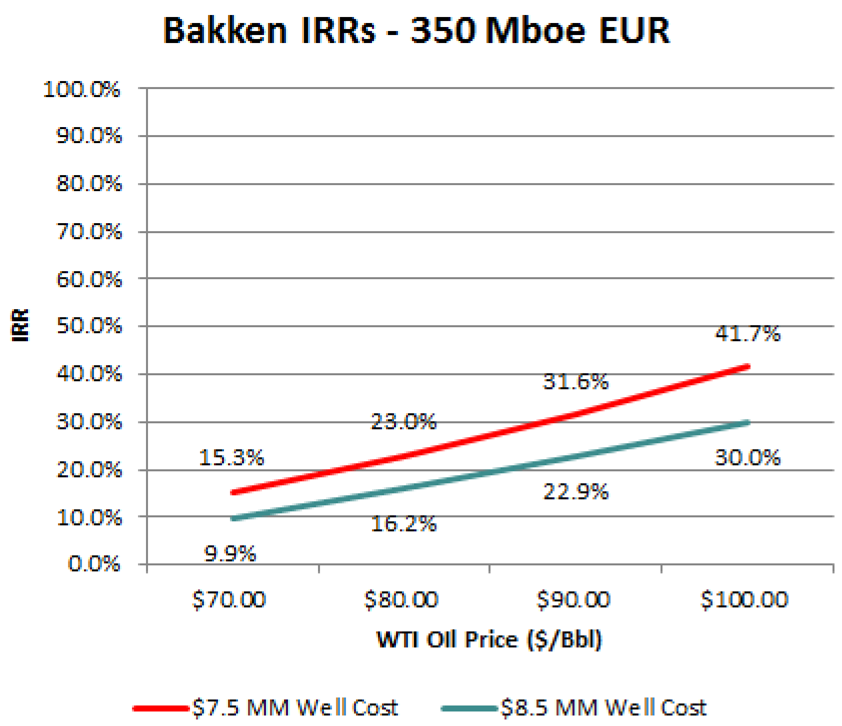
- Additional opportunities:
  - Slawson and others evaluating appropriate Bakken spacing and infill drilling with several drilling units containing second wells and proposals for third wells in the unit
  - Slawson evaluating Three Forks potential with two producers
  - Encouraging offset Three Forks results from EOG and Whiting where GEOI has minor working interests

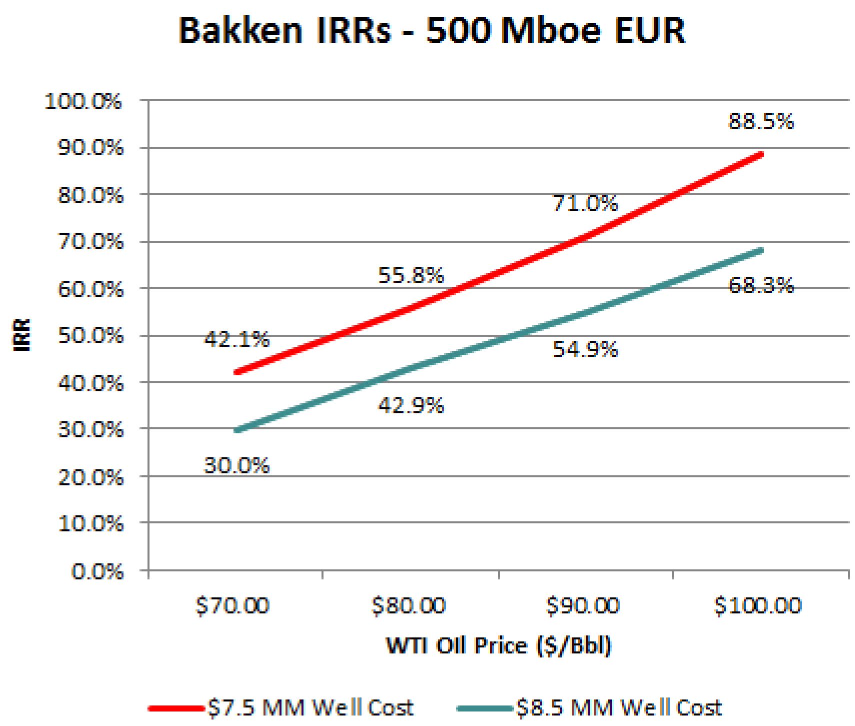


Note: Information, except for map, as of July 2011. Yellow-highlighted areas on map represent GEOI's acreage position.

Bakken Development Economics

Development Economics (1,280 Acre Unit)(1)(2)





(1) Assumes oil differential of (15%) and assumes gas shrinkage of (10%). Natural gas price held constant at $5/Mcf with no gas differential..
(2) EUR refers to management's internal estimates of reserves potentially recoverable from successful drilling of wells. See Additional Disclosures in Appendix.

Bakken Illustrative Resource Potential

Resource Potential (1)

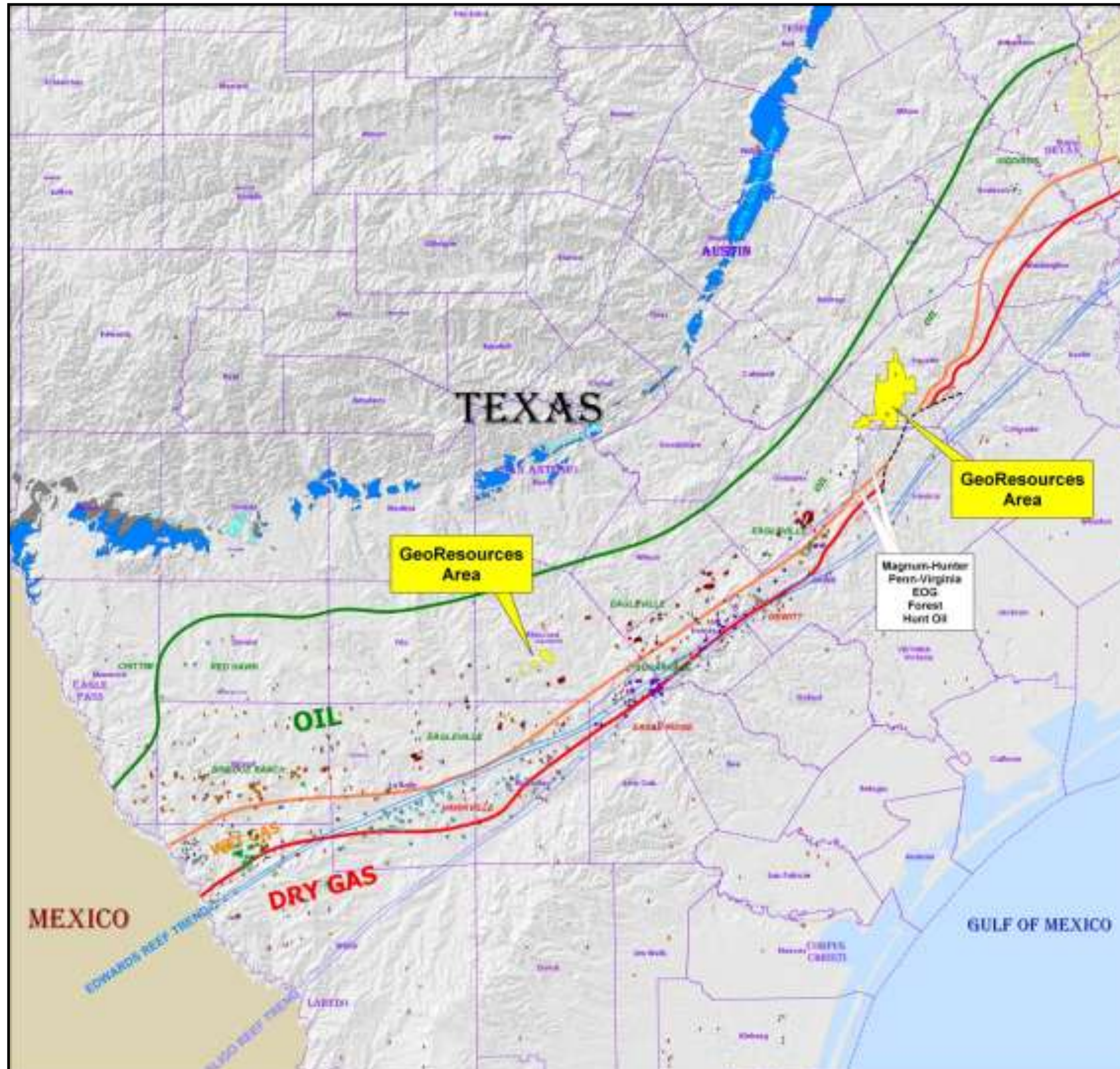
	Bakken (Williams Co. & Montana)		Bakken (Mountrail County)	
	350 Mboe	500 Mboe	400 MBOE	600 MBOE
Assumed Spacing Unit Size (Acres)	1,280	1,280	1,280	1,280
Estimated Remaining # Wells per Spacing Unit (Bakken Only)	3.0	3.0	1.5	1.5
# Acres per Well (Spacing Unit / # Wells per Unit)	427	427	853	853
GeoResources Net Acres	35,000	35,000	11,000	11,000
Number of Potential Net Drilling Locations	**82**	**82**	**13**	**13**
Estimated EUR per Well (Mboe)	350	500	400	600
Unrisked Illustrative Resource Potential (Mboe)	**28,711**	**41,016**	**5,156**	**7,734**

Undeveloped Bakken Acreage Provides Net Resource Potential of ~35 to ~50 MMboe

(1) Data is for illustrative purposes only and is based on management assumptions. EUR refers to management's internal estimates of reserves potentially recoverable from successful drilling of wells. See Additional Disclosures in Appendix.

Eagle Ford Shale

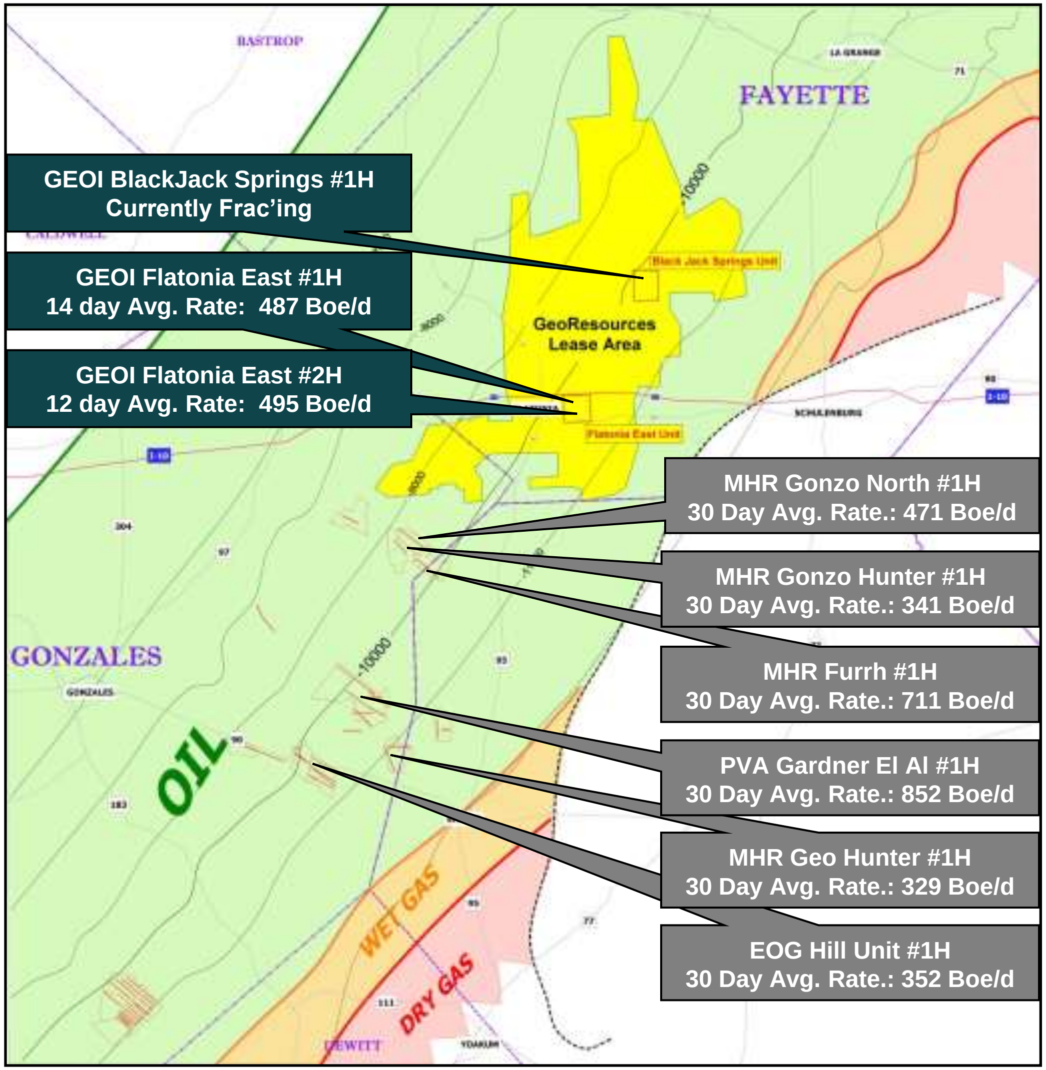
- 24,000 net acres primarily located in Southwest Fayette County, TX
  - 2011 drilling program averages ~45% WI
- Eagle Ford AMI
  - Ramshorn Investments, Inc., an affiliate of Nabors Industries, Ltd. purchased a 50% interest
    - Upfront cash payment
    - Will fund six horizontal wells
  - GEOI retains 50% WI and operations
- Leasehold continues to increase
  - Fayette County: 19,600 net acres
  - Gonzales County: 2,700 net acres
  - Atascosa & McMullen counties combined: 1,700 net acres



Note: Information as of July, 2011.

Eagle Ford Shale

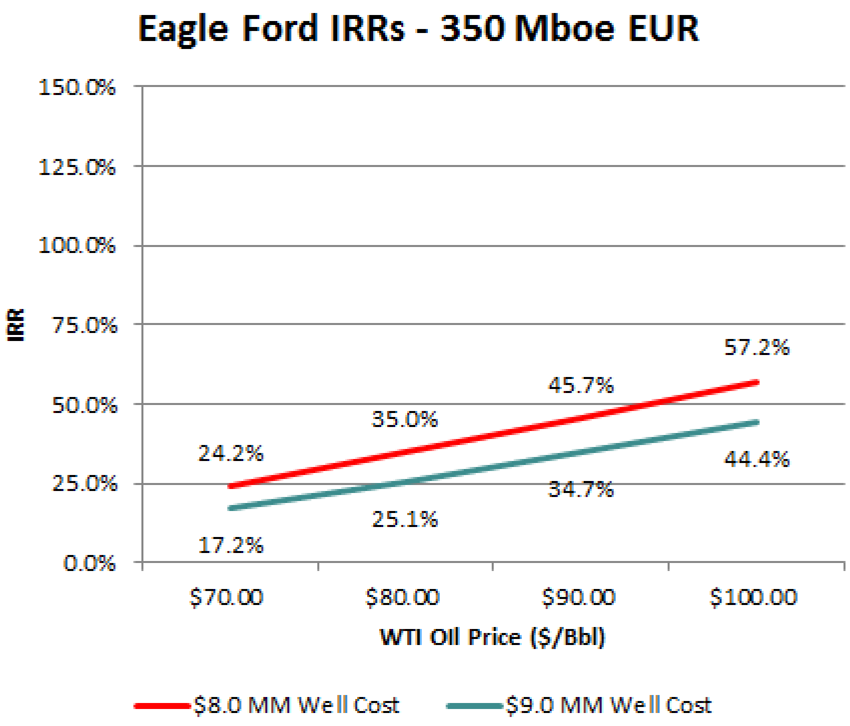
- Volatile oil window
  - On strike with operator activity in Gonzales County
- Successful recent drilling results
  - Completed first two wells in Fayette County in June 2011
    - Flatonia East Unit #1-H (~3,200' lateral, 10 stages): 1,204 Bo/d single day IP
    - Flatonia East Unit #2-H (~4,800' lateral, 14 stages): 1,242 Bo/d single day IP
  - Currently frac'ing Black Jack Springs Unit #1H (~5,900' lateral, 16 stages)
- Multi-year drilling inventory
  - 2nd operated rig coming Q3 2011
  - Planning for 3 operated rigs by early '12
- Positive offset operator activity
  - Magnum Hunter Resources, Penn Virginia and EOG have had multiple successful wells near our Acreage Position in Gonzales County with single day IPs ranging from 500 to 2,000 bo/d

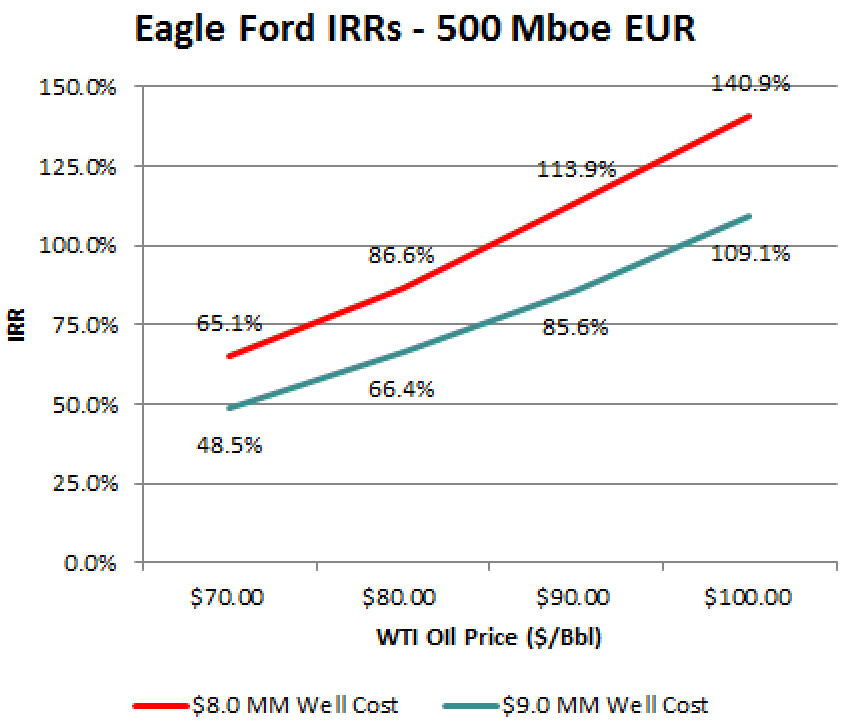


Note: 30 Day Avg. rate calculated as maximum average daily production rate of first four calendar months of production. Source of third party production data is Drilling Info and/or HPDI. Information as of July 2011.

Eagle Ford Development Economics

Development Economics (~5,000 ft. Lateral)(1)(2)





(1) Assumes oil differentials of (5%) and assumes gas shrinkage of (15%). Natural gas price held constant at $5/Mcf with a +20% gas differential.
(2) EUR refers to management's internal estimates of reserves potentially recoverable from successful drilling of wells. See Additional Disclosures in Appendix.

Eagle Ford Illustrative Resource Potential

Resource Potential [1]

	Eagle Ford Shale (Fayette Co., Texas)	
	350 Mboe	**500 Mboe**
Assumed Spacing Unit Size (Acres)	900	900
# Wells per Spacing Unit	6	6
# Acres per Well (Spacing Unit / # Wells per Unit)	150	150
GeoResources Net Undeveloped Acres	24,000	24,000
Number of Potential Net Drilling Locations	**160**	**160**
Estimated EUR per Well (Mboe)	350	500
Unrisked Illustrative Resource Potential (Mboe)	**56,000**	**80,000**

Undeveloped Eagle Ford Acreage Provides Net Resource Potential of ~55 to ~80 MMboe

(1) Data is for illustrative purposes only and is based on management assumptions. EUR refers to management's internal estimates of reserves potentially recoverable from successful drilling of wells. See Additional Disclosures in Appendix.

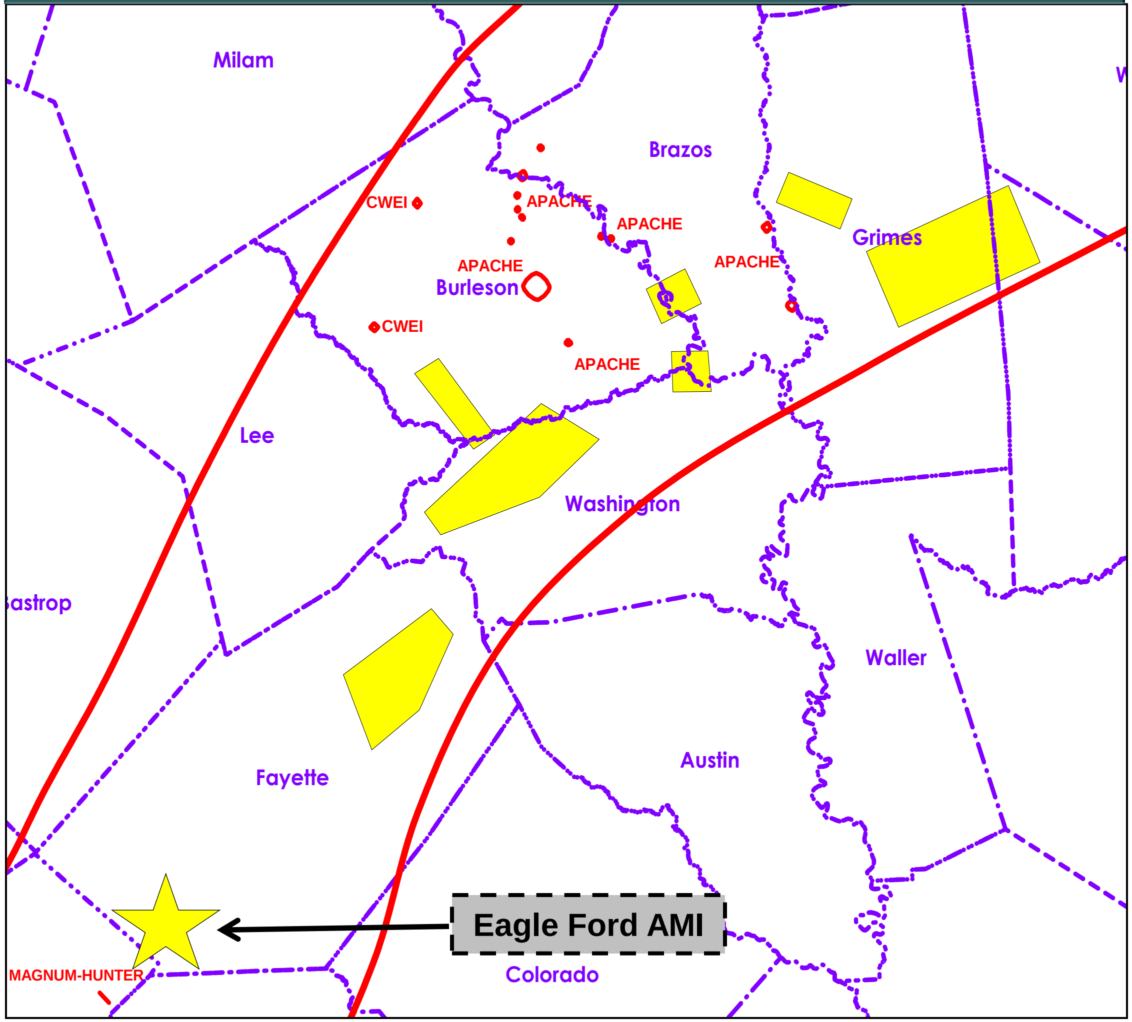
Additional Assets

GeoResources, Inc.

Giddings Field – Austin Chalk

- 29,000 net acres
  - 16 wells drilled – 100% success
  - 20 additional drilling locations
  - WI ranges from 37% - 53%
  - Operating control
  - Majority of acreage held-by-production
- Eastern Giddings development area
  - Eastern acreage in Grimes and Montgomery Counties is dry gas
  - Western acreage is liquids-rich gas and condensate
- Additional upside includes:
  - Eagle Ford, Georgetown and Yegua potential
  - Rate increase potential from slick water fracture stimulations
- Currently drilling W. Cannon Unit in NW Grimes County (oily location)

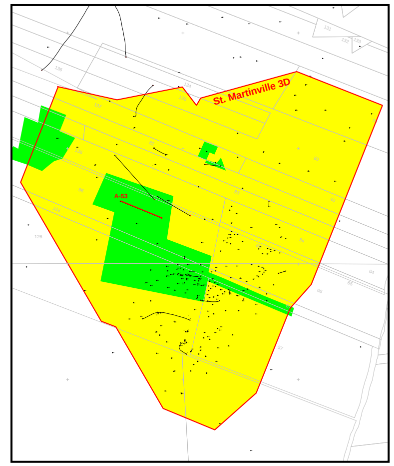
Giddings Field Acreage



Louisiana - St. Martinville & Quarantine Bay

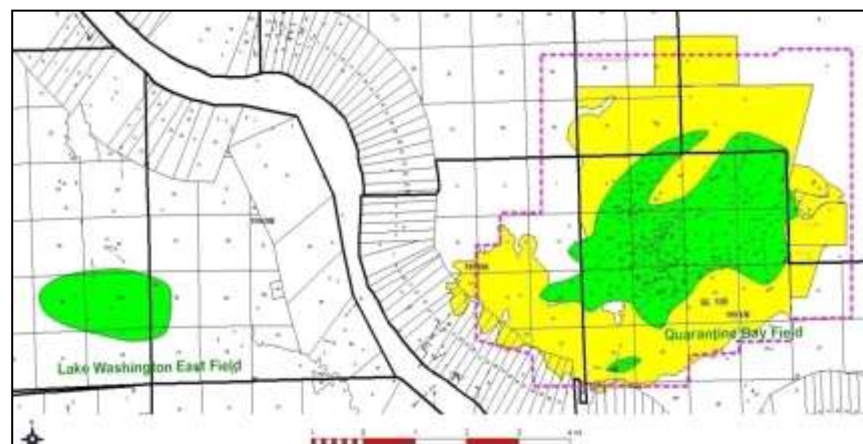
St. Martinville Field

- 2,585 net acres of HBP or leased (yellow), 534 net acres of owned minerals (green)
  - Average WI of 97% and NRI of 91%
- 2010 cash flow exceeded $3,000,000
- Multiple exploration and development objectives from 3,000' – 10,000'
  - Cumulative shallow production of 15.2 MMBO and 16.6 BCFG
  - Cumulative production over 125 Bcfe at 10,000'



Quarantine Bay Field

- 14,000 gross acres (13,000 HBP)
  - 33% WI below major field plays
  - Cumulative production of 180 MMBO and 285 BCF
- Recent Exploratory Success
  - Pelican prospect completed drilling in early May
  - 105' of net pay encountered
  - 22% W.I.
- Significant deep exploration potential (11,000 - 25,000'); plus sub-salt potential
  - Prospect DN: 16.0 MMBO + 40 BCFG at ~16,500'
  - Additional deeper prospects



Financial Overview

GeoResources, Inc.

Development Program

Capital Allocations

- Budget recently increased to take advantage of leasing success and strong project inventory
  - 2011 budget increased from $88 MM to $114 MM
  - 2012 budget estimated at $173 MM
- Current project allocations favor lower-risk, high cash flow oil-weighted projects
- Project inventory allows flexibility
  - Weighted towards oil and liquids
  - Oil and gas projects in inventory
  - Exploration and development projects in inventory
  - Held by long-term leases or production

2011 Capital Budget

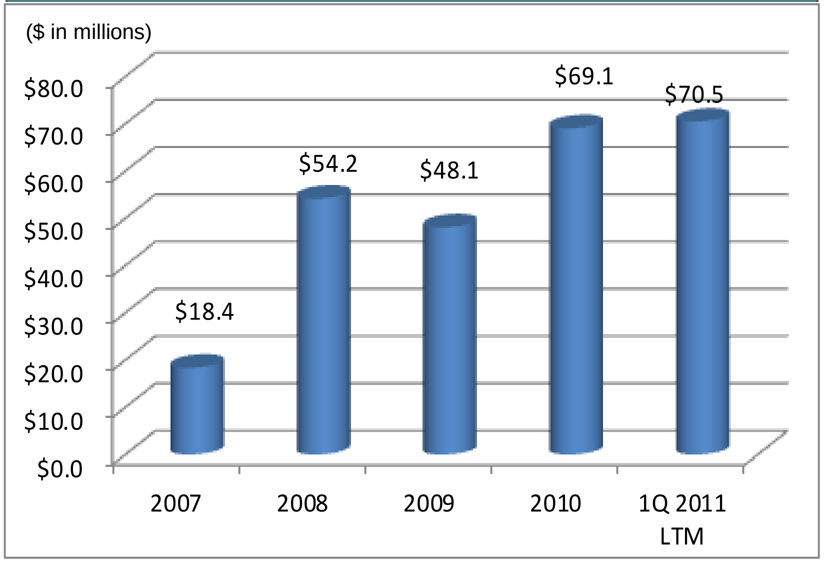
($ in millions)

Project	*Budgeted*	*Comments*
Bakken		
Operated	$29.5	18 wells + completions of 2010 drilling
Non-Operated	21.0	Slawson 3 rig program + minor interest wells
Eagle Ford	15.8	6 Carried Interest wells + 7 additional wells
Giddings & LA	16.1	Giddings = 3 wells LA = 8 wells
Acreage & Seismic	25.0	
Other	6.6	Non-Operated Drilling + Operations Capital
TOTAL	**$114.0**	

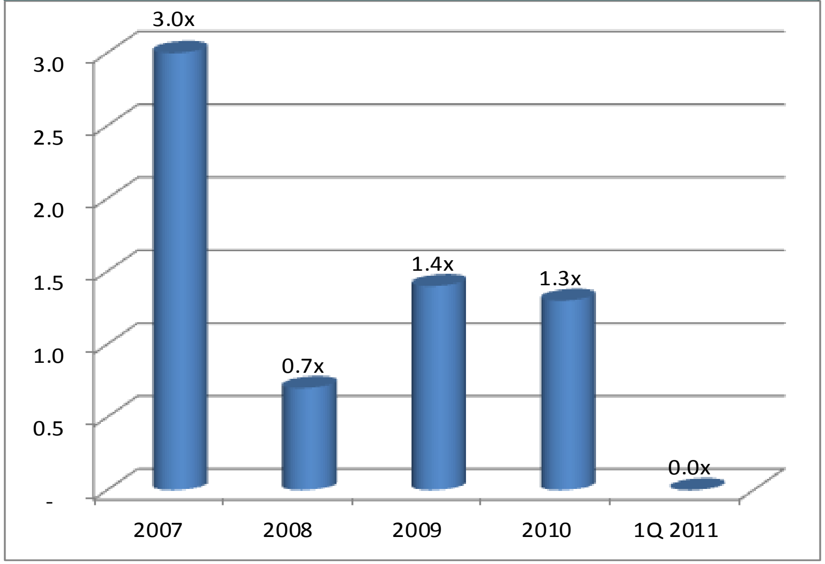
Strong Financial Position

- Ability to fund current capital budget with cash flow and undrawn debt capacity
- Conservative use of leverage to maintain strong balance sheet
  - $145 MM borrowing base
  - Last twelve months EBITDAX(1) = $70.5 MM
- No debt currently outstanding
  - Cash balance of $42.2 MM as of March 31, 2011

EBITDAX(1)



Debt / EBITDAX(1)



(1) EBITDAX is a non-GAAP financial measure. See reconciliation of net income to EBITDAX following in Appendix.

Investment Highlights

- **Significant upside from Bakken and Eagle Ford shale positions**
  - Bakken Shale - 46,000 net acres
  - Eagle Ford Shale - 24,000 net acres
  - Ongoing leasing program to further expand acreage

- **Solid proved reserve and production base**
  - 24 MMBOE of proved reserves(1) with bias towards liquids
  - High level of operating control
  - Additional upside identified in conventional assets

- **Strong financial position to execute development plans**
  - Significant free cash flow from existing assets to invest in shale development
  - Unlevered balance sheet

- **Experienced management and technical team with large ownership stake**
  - Successful track record of creating value and liquidity for shareholders
  - Cost effective operator with significant operating experience in unconventional resource plays
  - Board and management own approximately 22% of the company

Value Creation

(1) Does not include interests in affiliated partnerships. Reserves based on SEC pricing as of 1/1/11. See Additional Disclosures in Appendix.

Appendix

GeoResources, Inc.

Development Economics Table

Development Economics(2)

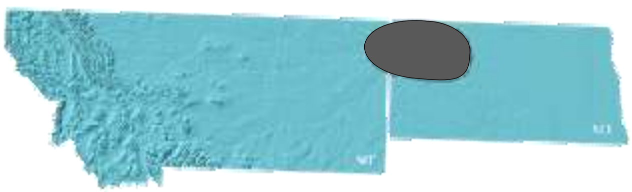
	Bakken Shale (Williams Co., North Dakota)		Eagle Ford Shale (Fayette Co., Texas)	
	350 Mboe	500 Mboe	350 Mboe	500 Mboe
Well Assumptions				
Drilling & Completion Cost ($M)	$8,500	$8,500	$9,000	$9,000
Lateral Length (feet)	10,000	10,000	5,000	5,000
WI	100%	100%	100%	100%
NRI	80.0%	80.0%	82.5%	82.5%
First 30 Day Average Oil IP (Bopd)	441	689	448	847
GOR (Scf/bbl)	600	600	1,000	1,000
Economics @ $80/bbl and $5/Mcf(1)				
NPV @ 10%	$1,335	$5,715	$2,979	$7,847
IRR	16.2%	42.9%	25.1%	66.4%
Payout (Yrs)	4.0	1.9	2.7	1.3
ROI	1.7	2.4	1.8	2.5
Price Sensitivity (IRR)(1)				
$100/Bbl (WTI)	30.0%	68.3%	44.4%	109.1%
$90/Bbl (WTI)	22.9%	54.9%	34.7%	85.6%
$80/Bbl (WTI)	16.2%	42.9%	25.1%	66.4%
$70/Bbl (WTI)	9.9%	30.0%	17.2%	48.5%

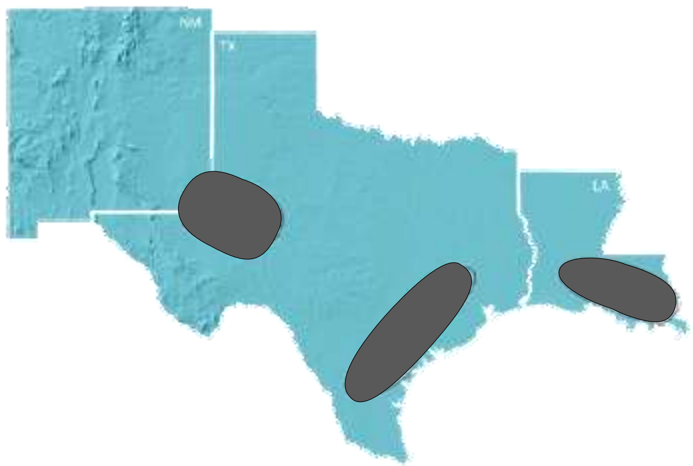
(1) Assumes Bakken and Eagle Ford oil differentials of (15%) and (5%), respectively. Assumes Bakken and Eagle Ford gas shrinkage of (10%) and (15%), respectively. Natural gas price held constant at $5/Mcf with an assumed differential of +20% in the Eagle Ford and no differential in the Bakken.

(2) EUR refers to management's internal estimates of reserves potentially recoverable from successful drilling of wells. These estimates do not necessarily represent reserves as defined under SEC rules and by their nature and accordingly are more speculative and substantially less certain of recovery and no discount or risk adjustment is included in the presentation. Actual locations drilled and quantities that may be ultimately recovered from the Company's interests could differ substantially.

Management History

- Track record of profitability and liquidity
- Extensive industry and financial relationships
- Significant technical and financial experience
- Long-term repeat shareholders
- Cohesive management and technical staff
  - Team has been together for up to 23 years through multiple entities





1992-1996
Hampton Resources Corp
Gulf Coast

SOLD TO BELLWETHER EXPLORATION

Preferred investors – 30% IRR
Initial investors – 7x return

1997-2001
Texoil Inc.
Gulf Coast, Permian Basin

SOLD TO OCEAN ENERGY

Preferred investors – 2.5x return
Follow-on investors – 3x return
Initial investors – 10x return

2001-2004
AROC Inc.
Gulf Coast, Permian Basin, Mid-Con.

DISTRESSED ENTITY TURNED AROUND AND MONETIZED

Preferred investors – 17% IRR
Initial investors – 4x return

2004- 2007
Southern Bay Energy, LLC
Gulf Coast, Permian Basin

REVERSE MERGED INTO GEORESOURCES, INC.

Proved Reserves

Proved Reserves – SEC Pricing at 1/1/11

($ in millions) **Corporate Interests**	**Oil** **MMBO**	**Gas** **BCF**	**Total** **MMBOE**	**% of** **Total**	**PV-10** [1]
PDP	8.9	33.0	14.4	60.0%	$239.6
PDNP	2.3	6.1	3.4	14.2%	68.5
PUD	3.2	18.4	6.2	25.8%	70.2
Total Proved Corporate Interests	14.4	57.6	24.0	100.0%	378.3
Partnership Interests	0.1	8.0	1.4		12.0
Total Proved Corporate and Partnerships	14.5	65.6	25.4		$390.3

Proved Reserves – Forward Strip Pricing at 1/1/11 [2]

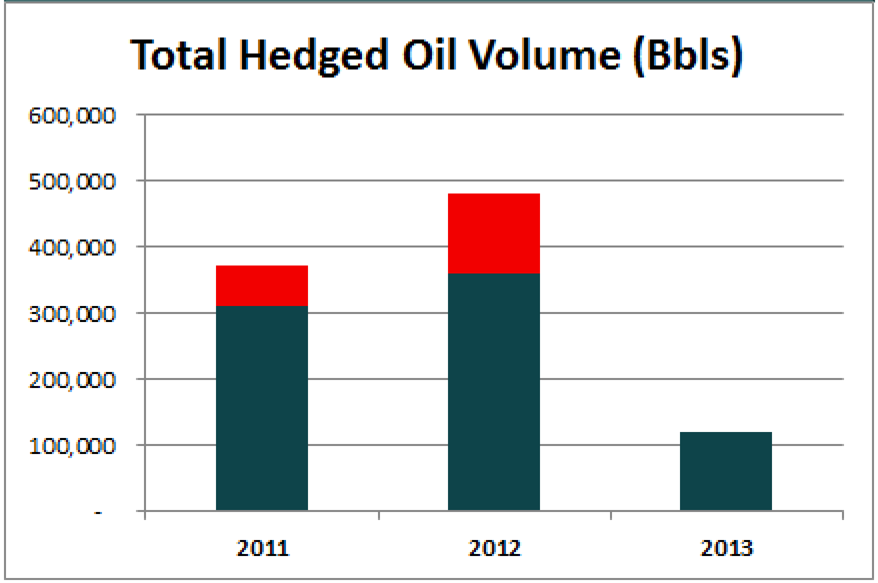
($ in millions) **Corporate Interests**	**Oil** **MMBO**	**Gas** **BCF**	**Total** **MMBOE**	**% of** **Total**	**PV-10**
PDP	9.2	35.2	15.1	60.2%	$303.6
PDNP	2.4	6.3	3.4	13.5%	83.7
PUD	3.3	19.6	6.6	26.3%	98.5
Total Proved Corporate Interests	14.9	61.1	25.1	100.0%	485.8
Partnership Interests	0.1	8.3	1.4		15.9
Total Proved Corporate and Partnerships	15.0	69.4	26.5		$501.7

(1) PV-10% is a non-GAAP financial measure. See reconciliation of SEC PV 10% to standardized measure in Appendix.
(2) Utilizing five year NYMEX forward prices at 1/1/11. See Additional Disclosures in Appendix.

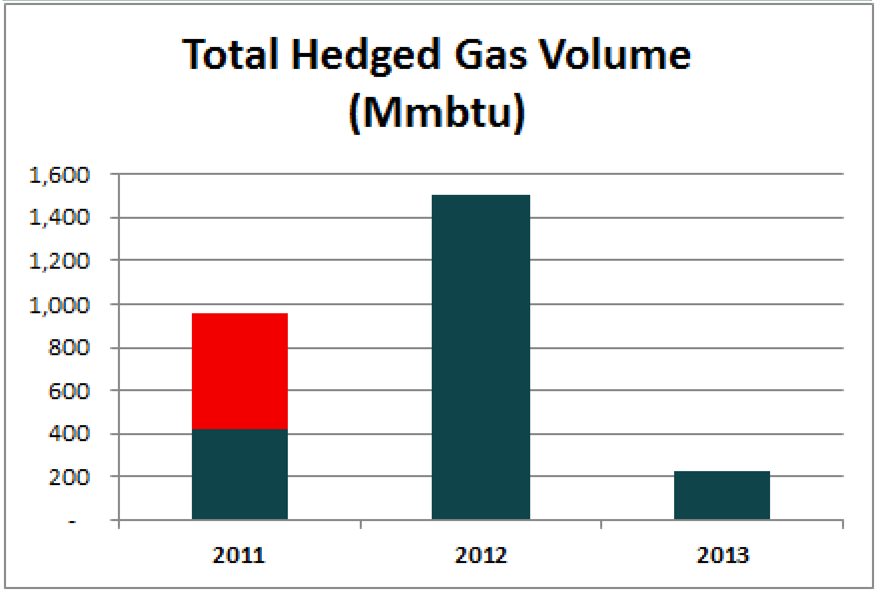
Hedge Portfolio

- GEOI uses commodity price risk management in order to execute its business plan throughout commodity price cycles

Oil Hedges



Natural Gas Hedges



Collar Swap

Weighted Average Oil Hedge Price

2011	2012	2013
$85.11	**$90.76**	**$101.85**

Weighted Average Gas Hedge Price

2011	2012	2013
$6.76	**$5.48**	**$4.85**

Note: 2011 hedge volume and weighted average price data is as of 7/1/2011.

Operating Performance

Historical Operating Data

	3 Mos Ended 3/31/2011	Years Ended December 31, 2010	2009	2008
Key Data:				
Average realized oil price ($/Bbl)	$ 85.37	$ 70.33	$ 61.09	$ 82.42
Avg. realized natural gas price ($/Mcf)	$ 5.20	$ 5.30	$ 3.97	$ 8.12
Oil production (MBbl)	250	1,060	851	743
Natural gas production (MMcf)	1,011	4,789	4,944	2,962
($ in millions except per share data)				
Total revenue	$ 28.6	$ 107.0	$ 80.4	$ 94.6
Net income before tax	$ 10.4	$ 35.3	$ 14.8	$ 21.3
Net income after tax	$ 6.3	$ 23.3	$ 9.8	$ 13.5
Earnings per share (diluted)	$ 0.26	$ 1.16	$ 0.59	$ 0.86
EBITDAX (1)	$ 70.5	$ 69.1	$ 48.2	$ 54.1

(1) EBITDAX is a non-GAAP financial measure. See reconciliation of net income to EBITDAX in Appendix.

Reconciliation of non-GAAP Measure

EBITDA Reconciliation

($ in millions)	3 Mos Ended 3/31/2011		Years Ended December 31, 2010		2009		2008	
Net Income	**$**	**6.1**	**$**	**23.3**	**$**	**9.8**	**$**	**13.5**
Add Back:								
Interest Expense	$	1.3	$	4.7	$	5.0	$	4.8
Income Taxes	$	3.8	$	11.9	$	5.1	$	7.8
Depreciation, depletion and amortization	$	6.4	$	24.7	$	22.4	$	16.0
Hedge and derivative contracts	$	(0.2)	$	(0.9)	$	0.3	$	0.4
Non-cash Compensation	$	0.2	$	1.1	$	1.4	$	0.7
Exploration and Impairments	$	0.5	$	4.3	$	4.2	$	10.9
EBITDAX	**$**	**17.9**	**$**	**69.1**	**$**	**48.2**	**$**	**54.1**

Reconciliation of Net Income to EBITBAX.
As used herein, EBITDAX is calculated as earnings before interest, income taxes, depreciation, depletion and amortization, and exploration expense and further excludes non-cash compensation, impairments, hedge ineffectiveness and income or loss on derivative contracts. EBITDAX should not be considered as an alternative to net income (as an indicator of operating performance) or as an alternative to cash flow (as a measure of liquidity or ability to service debt obligations) and is not in accordance with, nor superior to, generally accepted accounting principles (GAAP), but provides additional information for evaluation of our operating performance.

Standardized Measure

SEC PV-10 Reconciliation to Standardized Measure[1]

($ in millions)

	1/1/2011
Direct interest in oil and gas reserves:	
Present value of estimated future net revenues (PV-10%)	$378.3
Future income taxes at 10%	(101.3)
Standardized measure of discounted future net cash flows	$277.0
Indirect interest in oil and gas reserves: [2]	
Present value of estimated future net reserves (PV-10%)	$12.0
Future income taxes at 10%	(4.0)
Standardized measure of discounted future net cash flows	$8.0

(1) PV-10% is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP. Our calculations of PV-10% and standardized measure of discounted future net cash flows at July 1, 2010 are based on our internal reserve estimates, which have not been reviewed or audited by our independent reserve engineers.

(2) Through two affiliated partnerships.

Additional Disclosures

The disclosures below apply to the contents of this presentation:

- In April 2007, GeoResources, Inc. ("GEOI" or the "Company") merged with Southern Bay Oil & Gas, L.P. ("Southern Bay") and a subsidiary of Chandler Energy, LLC and acquired certain oil and gas properties (collectively, the "Merger"). The Merger was accounted for as a reverse acquisition of GEOI by Southern Bay. Therefore, any information prior to 2007 relates solely to Southern Bay.
- Cautionary Statement – The SEC has established specific guidelines related to reserve disclosures, including prices used in calculating PV 10% and the standardized measure of discounted future net cash flows. PV 10% is not a measure of financial or operating performance under General Accepted Accounting Principles (GAAP), nor should it be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP. In addition, alternate pricing methodologies, such as the NYMEX forward strip price curve, are not provided for under SEC guidelines and therefore do represent GAAP.
- PV-10% is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP. PV-10 % for SEC price calculations are based on the 12-month unweighted average prices at year-end 2010 of $79.43 per Bbl for oil and $4.37 per Mmbtu for natural gas. These prices were adjusted for transportation, quality, geographical differentials, marketing bonuses or deductions and other factors affecting wellhead prices received. For the Strip Price reserve case, five year NYMEX strip pricing at 12/30/10 was utilized for 2011 – 2015. NYMEX oil strip ranged from $93.85 per Bbl to $92.48 per Bbl and then constant thereafter. NYMEX gas strip ranged from $4.59 per Mmbtu to $5.64 per Mmbtu and then held constant thereafter. These prices were adjusted for transportation, quality, geographical differentials, marketing bonuses or deductions and other factors affecting wellhead prices received. Actual realized prices will likely vary materially from the NYMEX strip. The Company's independent engineers are Cawley, Gillespie & Associates, Inc.
- BOE is defined as barrel of oil equivalent, determined using a ratio of six MCF of natural gas equal to one barrel of oil equivalent.
- IP (BO/d or BOE/d) (24 hour rate) is defined as the peak oil volume produced on a daily basis through permanent production facilities that occur within the first few days of initial production from the well.
- EUR estimates do not necessarily represent reserves as defined under SEC rules and by their nature and accordingly are more speculative and substantially less certain of recovery and no discount or risk adjustment is included in the presentation. Actual locations drilled and quantities that may be ultimately recovered from the Company's interests could differ substantially.