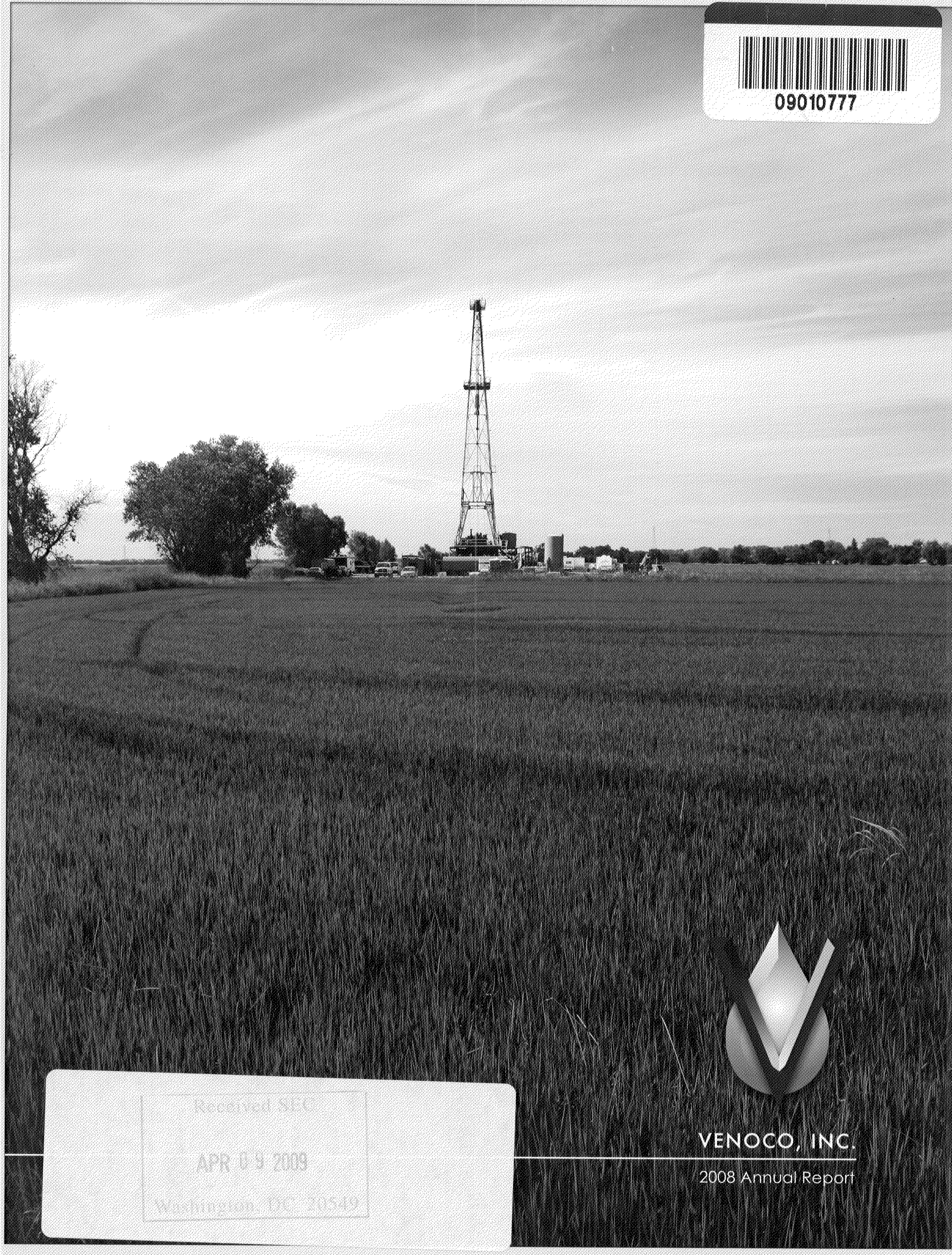


VENOCO, INC.

2008 Annual Report

Selected Financial and Operating Data

Years Ended December 31 ($ in thousands, except per share amounts)	2006	2007	2008
Production Volumes (MBOE)	5,797	7,130	7,933
Daily Average Production Volume (BOE/Day)	17,349	19,535	21,674
Proved Reserves (MMBOE)	87.9	99.9	97.5
Standardized Measure of Discounted Future Net Cash Flows	$ 819,302	$ 1,655,641	$ 610,096
Oil and Natural Gas Sales	$ 268,822	$ 373,155	$ 555,917
Total Revenue	$ 274,292	$ 376,510	$ 559,520
Income (Loss) from Operations	$ 89,136	$ 116,630	$ (418,729)
Net Income (Loss)	$ 23,951	$ (73,372)	$ (391,132)
Earnings Per Share - Basic	$ 0.71	$ (1.58)	$ (7.75)
Earnings Per Share - Diluted	$ 0.69	$ (1.58)	$ (7.75)
Current Assets	$ 86,168	$ 116,572	$ 115,965
Net Property, Plant and Equipment	$ 774,253	$ 1,131,032	$ 702,734
Other Long-Term Assets	$ 32,772	$ 17,881	$ 45,555
Total Assets	$ 893,193	$ 1,265,485	$ 864,254
Current Liabilities	$ 86,761	$ 172,436	$ 112,884
Long-Term Debt	$ 529,616	$ 691,896	$ 797,670
Other Liabilities	$ 86,500	$ 155,551	$ 88,867
Stockholders' Equity	$ 190,316	$ 245,602	$ (135,167)
Total Liabilities and Stockholders' Equity	$ 893,193	$ 1,265,485	$ 864,254

Adjusted EBITDA Reconciliations

Years Ended December 31 ($ in thousands), Unaudited	2006	2007	2008
Net Income (Loss)	$ 23,951	$ (73,372)	$ (391,132)
Interest, Net	$ 48,795	$ 60,115	$ 54,049
Realized Interest Rate Derivative (Gains) Losses	$ 96	$ (135)	$ 10,231
Income Taxes	$ 15,650	$ (46,200)	$ 11,200
DD&A	$ 63,259	$ 98,814	$ 134,483
Ceiling Test Impairment	$ –	$ –	$ 641,000
Amortization of Deferred Loan Costs	$ 3,776	$ 4,197	$ 3,344
Loss on Extinguishment of Debt	$ –	$ 12,063	$ –
Share-Based Payments	$ 3,050	$ 3,278	$ 3,064
Amortization of Derivative Premiums and Other Comprehensive Loss	$ 8,181	$ 11,546	$ 7,694
Unrealized Commodity Derivative (Gains) Losses	$ (21,079)	$ 122,779	$ (184,459)
Unrealized Interest Rate Derivative (Gains) Losses	$ 494	$ 17,312	$ 10,336
Adjusted EBITDA	$ 146,173	$ 210,397	$ 299,810

Adjusted Earnings Reconciliations

Years Ended December 31 ($ in thousands), Unaudited	2006	2007	2008
Net Income (Loss)	$ 23,951	$ (73,372)	$ (391,132)
Unrealized Commodity Derivative (Gains) Losses	$ (21,079)	$ 122,779	$ (184,459)
Unrealized Interest Rate Derivative (Gains) Losses	$ 494	$ 17,312	$ 10,336
Write-Off of MLP Offering Costs	$ –	$ –	$ 2,690
Early Extinguishment of Debt	$ –	$ 12,063	$ –
Ceiling Test Impairment	$ –	$ –	$ 641,000
Tax Effects	$ 8,135	$ (58,788)	$ (23,185)
Adjusted Earnings	$ 11,501	$ 19,994	$ 55,250

Letter To Stockholders

Since our founding in 1992, we have worked through the highs and lows of the energy-industry cycle – always emerging with more certainty that being prepared for low prices when prices are high is just as important as being prepared for high prices when prices are low.

We will remember 2008 as a year of extremes – record high oil prices and record oil price declines – and for the complete implosion of the financial markets. As the dust settled on the year, we evaluated our position and charted our direction for 2009 and beyond. With 100% of our 2009 forecast production protected for the remainder of the year with hedges averaging more than $55 per barrel for crude oil and $7 per thousand cubic feet (MCF) for natural gas, we know our base is solid. While we expect the next year or more will be challenging, we're prepared to weather the global economic storm, and we are poised to take advantage of opportunities.

In 2008, we achieved production growth throughout the company, in both California and Texas, for both our natural gas assets and our oil fields. We finished the year by averaging 22,674 barrels of oil equivalent per day (BOE/d) in the fourth quarter – an all-time high for the company. The fourth quarter results helped us meet our 2008 production guidance by averaging 21,674 BOE/d – an all-time high and an 11% increase from 2007.

Despite the large decline in crude oil prices from $147 per barrel in June to $40 per barrel in December, we ended the year with $212 million in operating cash flow, a 32% increase over 2007. Adjusted Earnings were up 176% to $55 million in 2008 compared to $20 million in 2007, and Adjusted EBITDA was up 43% to $300 million from $210 million in 2007.(1)

In September of 2008, Denbury Resources exercised its option to purchase the Hastings Complex from us. The sale closed in early February 2009 for a price of $201 million – or about $80,000 per daily barrel of production. We retained the deeper rights in the complex as well as a 2% override in the productive horizon that we sold. Denbury is obligated to initiate a carbon dioxide (CO_2) flood of the complex, and we can back-in to a 22.3% working interest after Denbury recovers certain costs. Though we don't have any booked reserves related to the CO_2 flood, we could add up to 30 million net barrels if the CO_2 flood is successful.

Our year-end 2008 Proved Reserves were 97.5 million barrels of oil equivalent (MMBOE). Pro forma for the sale of the Hastings Complex, the Proved Reserves were 89.8 MMBOE – an increase of 13% from year-end 2007 pro forma reserves and a replacement rate of 161% of pro forma production (2008 production was 7.9 MMBOE, while pro forma production was 7.0 MMBOE). We added 5.7 MMBOE of proved reserves in our Southern California assets and 7.8 MMBOE in the Sacramento Basin. Pricing had a significant negative impact in Texas, where we lost 8.0 MMBOE – the majority (5.8 MMBOE) in Hastings.

Price-related revisions between year-end 2007 and year-end 2008 reduced reserves by 11.0 MMBOE, while performance-related revisions added 5.0 MMBOE, for net negative revisions of 6.0 MMBOE.

The pre-tax PV-10 of our reserves, using year-end prices of $44.60 per barrel for oil and $5.62 per Million British Thermal Units for natural gas, was $616.7 million. Our estimate of proved reserves using the December 31, 2008 NYMEX 5-year strip pricing is 108.2 MMBOE, with a pre-tax PV-10 of $1.6 billion.(2)

Pro forma for the Hastings sale, our 2008 all-in finding and development costs, net of future asset retirement obligations, were $25.49 per BOE. Excluding price-related revisions, pro forma F&D costs were $19.62 per BOE. Pro forma organic F&D costs (which excludes proved and unevaluated property acquisitions and leasehold costs) were $22.66 per BOE; excluding price-related revisions, they were $17.26 per BOE.

Our 2008 capital expenditures for development and other spending on the properties were $301 million, including $211 million for drilling and rework activities and $51 million for facilities. We also spent $14 million for acquisitions in our core areas. The total costs in 2008 for development, acquisition, seismic, leasehold, capitalized G&A costs and asset retirement obligations were $340 million.

We reduced our debt position from $800 million on December 31, 2008 to $665 million in March 2009 with the proceeds from the Hastings sale. Our remaining debt consists of a $494 million Second Lien Term Loan facility (due September 2011), $150 million of 8.75% Senior Notes (due December 2011), deferred derivative premiums of $15 million and $6 million on our revolver. If we refinance the Senior Notes by September 2011, the maturity of the Term Loan will extend to May 2014.

Prior to closing the Hastings sale, we proactively sought a redetermination of the borrowing base under our revolving credit facility. Consequently, effective with the sale of the Hastings Complex, our borrowing base was redetermined from $200 million down to $125 million. We utilized a portion of the proceeds from the Hastings sale to repay all amounts outstanding under the facility, and we currently have only about $6 million drawn. We are pleased with our current liquidity position and, with cash on hand, we do not anticipate having to draw down the revolver significantly to fund our 2009 exploration, exploitation and development capital expenditures.

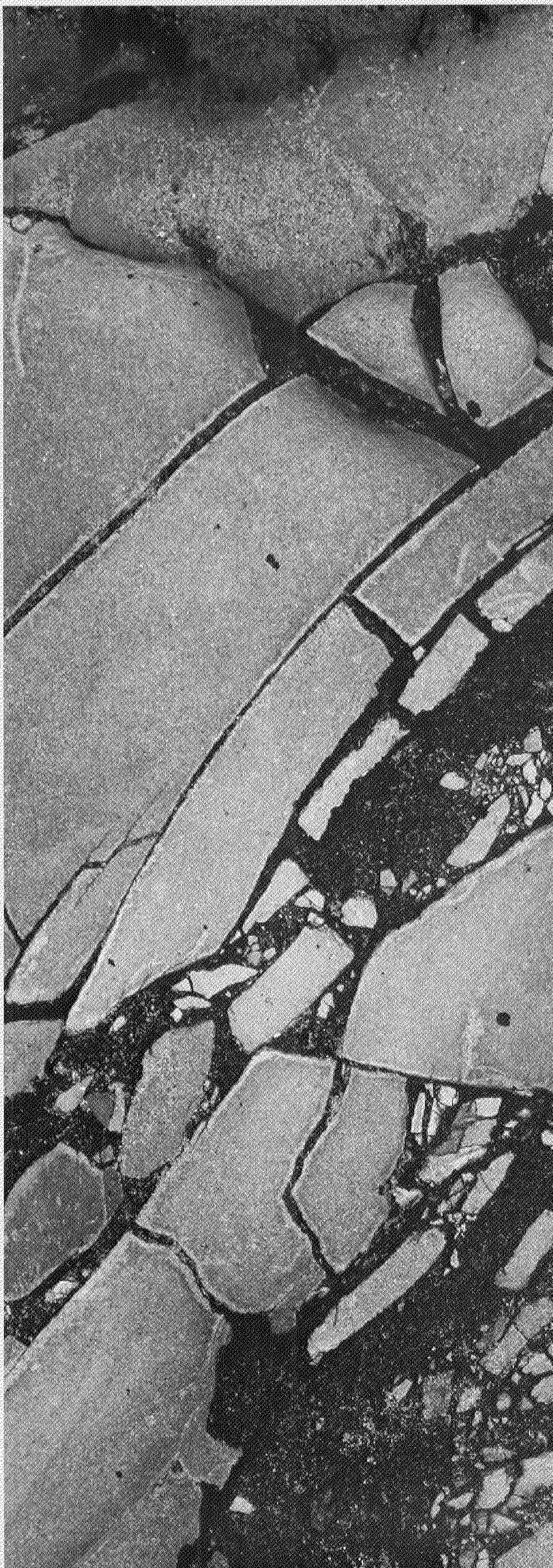
It's been almost seventeen years since I founded Venoco, and I am more excited than ever for the future of our company. We are fortunate to have a dynamic, experienced and engaged group of employees, who are problem-solvers that take great pride in making Venoco better. Combine them with our liquidity, solid hedges, great long-lived assets and some very promising exploration opportunities, and we are all looking forward to an outstanding 2009.

Thank you for your support.

Timothy Marquez
Chairman and Chief Executive Officer

(1) See inside front cover for definition of Adjusted Earnings and Adjusted EBITDA and a reconciliation to net income (loss).

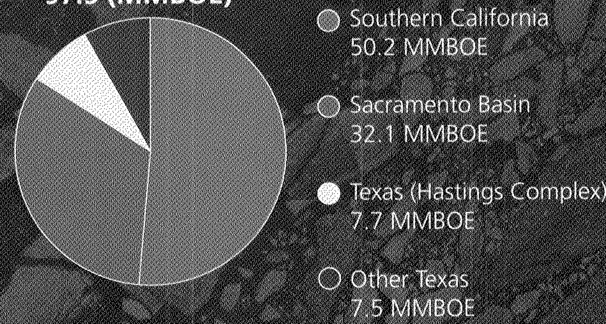
(2) Our definition of PV-10, and a reconciliation of a standardized measure of discounted future net cash flows to PV-10, is set forth in "Management's Discussion and Analysis of Financial Condition and Results of Operation – PV-10" in the enclosed Form 10-K.



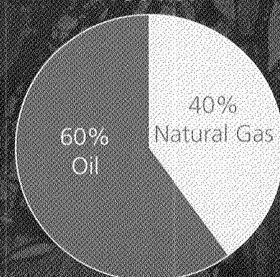
Naturally fractured Monterey Shale.

- Long-lived Reserves
- Oil Weighted
- Growing Production

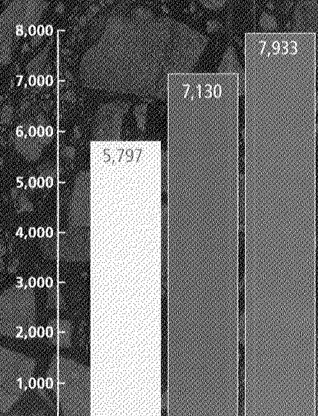
Proved Reserves Values 97.5 (MMBOE)



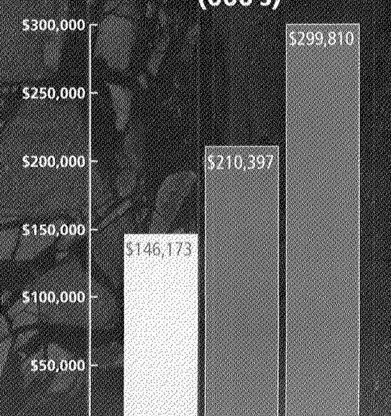
Proved Reserves by Product



Production (MBOE)



Adjusted EBITDA[1] (000's)



(1) See inside front cover for definition of Adjusted EBITDA and a reconciliation to net income (loss).

Operations: Sacramento Basin

Venoco is the largest gas producer in the Sacramento Basin and has drilled more than 300 wells in the area since 2005. With more than 200,000 net acres under lease, more than 600 existing wells and an inventory of 530 drilling locations, the Sacramento Basin is a core area with lots of running room. We first acquired positions in Willows and Grimes from Mobil in late 1996, with gross production of approximately 7 million cubic feet per day (MMCF/d). We acquired additional acreage from Chevron in the Sacramento Delta in 1998 that added about 2 MMCF/d of production. In 2006 we solidified our holdings in the basin by buying Marquez Energy and by acquiring around 70,000 gross acres and about 18 MMCF/d of production with our purchase of TexCal.

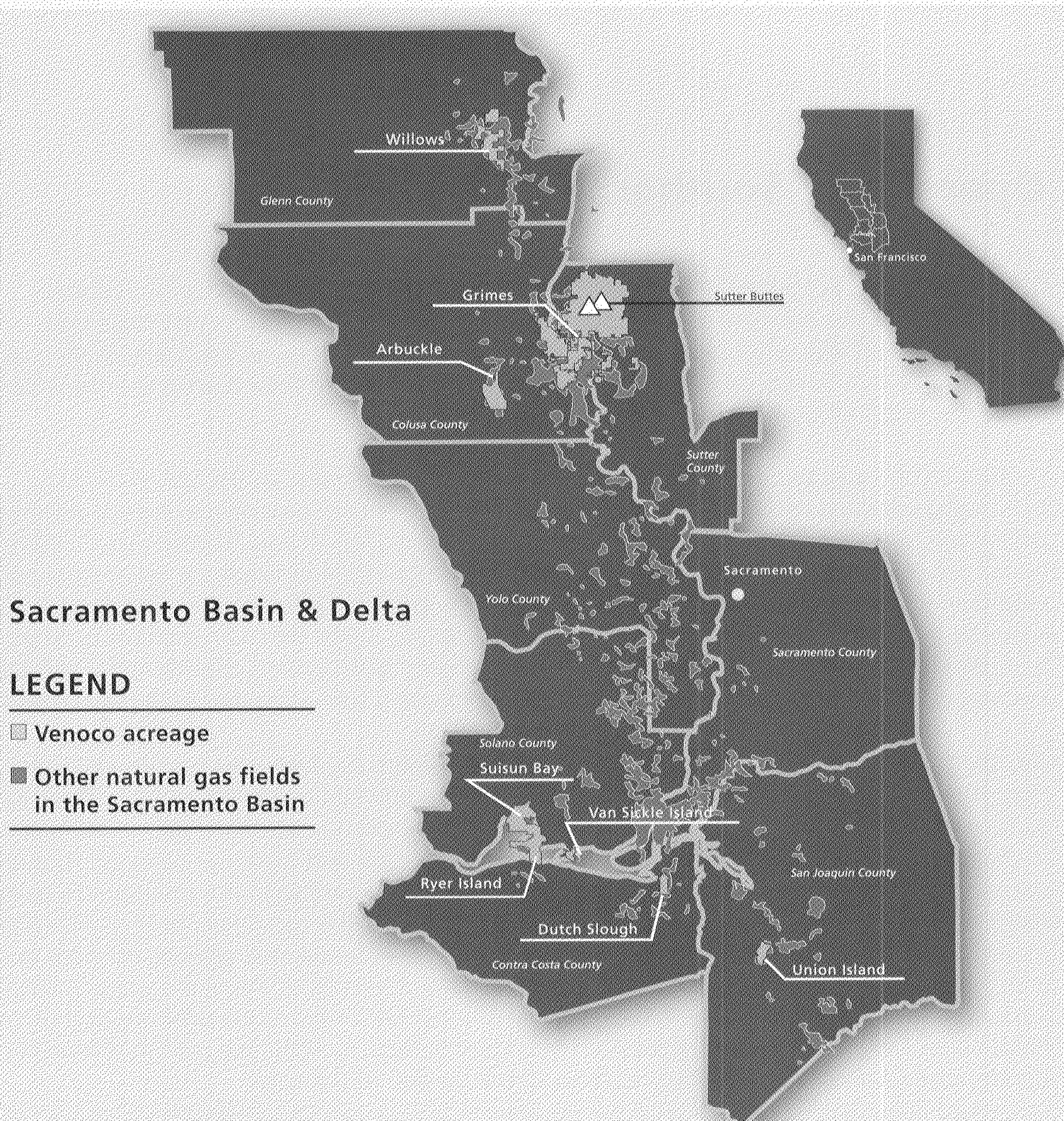
During 2008, we drilled 112 gross wells and performed 144 workovers and recompletions, operating five drilling rigs and five workover/completion rigs. By the end of 2008, we were producing over 80 MMCF/d (gross) and significant upside still exists from our inventory of drilling locations and from applying new recompletion technology and techniques to existing wells.

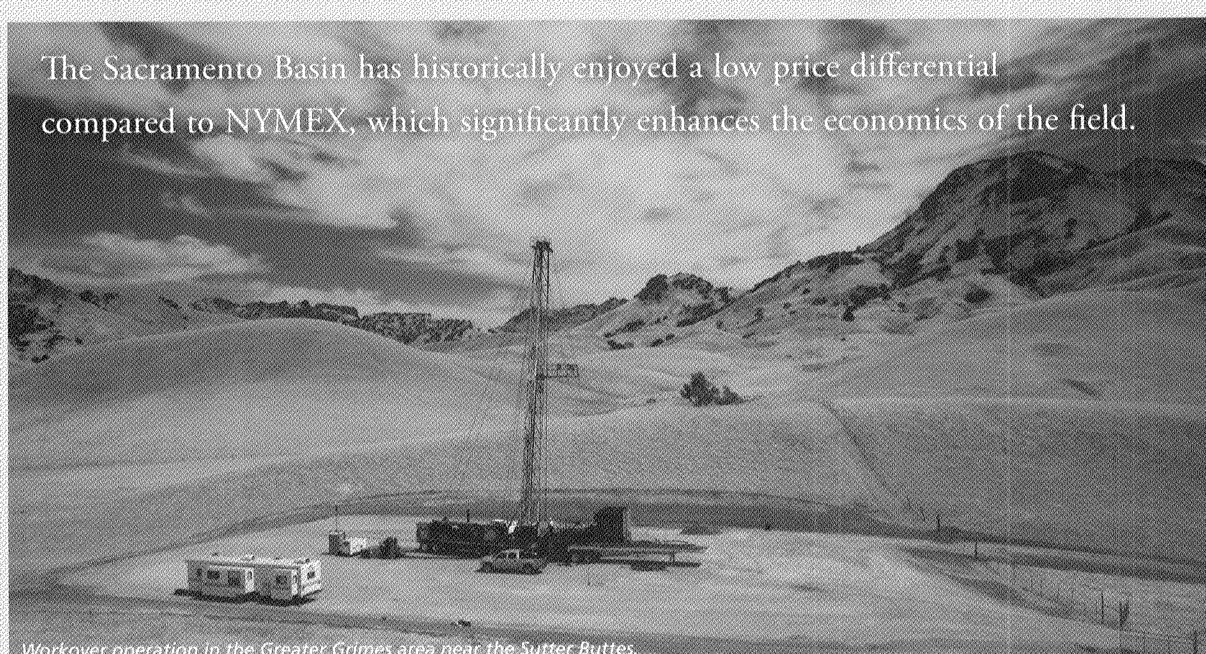
In 2000, when California natural gas prices were spiking, we decided to drill 80-acre infill wells to accelerate production. We discovered these new well bores had virgin reservoir pressure, which meant we were actually tapping into new reserves. Subsequently, we have proved up the infill concept down to 20-acre spacing, and we were even able to book reserves based on 10-acre spacing at year-end 2008.

In late 2007, we initiated a pilot program to hydraulically fracture existing well bores. Hydraulic fracturing was a technology with only limited use in the Basin prior to that time. The early results were encouraging, so we expanded the program and fractured 70 wells using a variety of techniques during 2008. On the wells where the fracs have been successful, we've seen average initial production rates many times higher than pre-frac rates. We are still evaluating the results based on the different facie we encounter throughout the Basin and fields as well as the variety of techniques we have used. We have attempted to frac the deeper, tighter, over-pressured Guinda formation, but to date have had mixed results. We continue to believe our hydraulic fracturing can be improved and will unlock additional reserves in the future.

The Sacramento Basin has historically enjoyed a low price differential compared to NYMEX, which significantly enhances the economics of the field. In 2008, the cost of a successful well in the greater Grimes area was around $1.2 million, average IP for these wells was about 550 MCF/d, with reserves of 300 MMCF on the initial completion, with another one to three completions possible in each well adding to reserves.

Given the current pricing environment, we scaled back our 2009 capital plans for the Basin by 50% to approximately $74.0 million. But, with reduced costs, we believe we can drill more than 70 wells and perform 100 workovers/recompletions in 2009. We continue to believe the Sacramento Basin has tremendous potential – in further downspacing, deeper horizons, fracing and expanding the productive footprint of the fields by stepping out from existing wells.





Workover operation in the Greater Grimes area near the Sutter Buttes.

Operations: Southern California

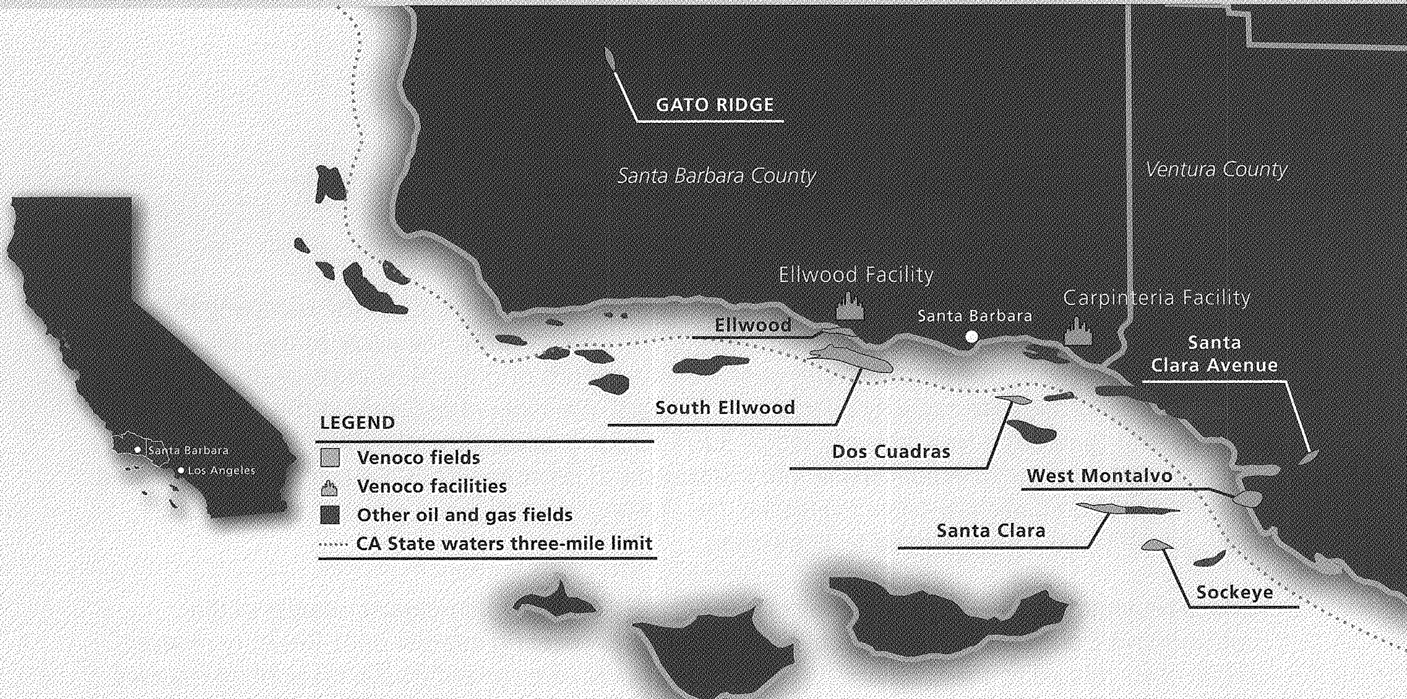
Our oil producing properties in Southern California are the foundation of Venoco's stable production and low decline rates. We operate eight fields, including three very large ones – South Ellwood and Sockeye, which are both offshore, and West Montalvo, which straddles the coastline. We also have a 25% non-op interest in the offshore Dos Cuadras field. Combined, these four fields contain over 3.6 billion barrels of original oil in place.

California continues to be a challenging place to operate compared to the rest of the U.S., but having operated in the state for fifteen years, we believe our experience gives us a strategic advantage. We have operated our two large offshore fields for 12 and 10 years, so in addition to our extensive operational expertise, we also have some of the broadest technical expertise regarding the Monterey Shale, our primary target in Southern California. This unconventional, naturally fractured shale ranges in thickness from 1,000 to 3,500 feet with multiple horizons and fault blocks. This large target provides us with significant development opportunities, and the low recoveries to date provide significant potential to increase future recoveries with new technologies.

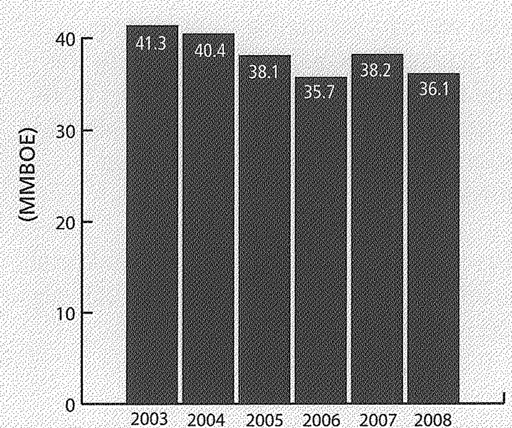
The West Montalvo field has been our most active Southern California asset since we acquired it in May 2007. We spent the balance of 2007 revamping operations and facilities, from lifting systems to fluid handling and well repairs. Our West Montalvo production averaged about 650 BOE/d net in the first quarter of 2008, and with our active recompletion and workover program throughout the year, we saw net production climb to almost 1,150 BOE/d in the fourth quarter. We spud three wells in the second half of 2008 and spud another in 2009, which we believe will contribute to additional production and reserve growth this year. Because the field extends offshore in an area where it is very difficult to obtain 3-D seismic data, the limits of the field's western boundary have never been defined. We have drilled two wells that bottomed in the offshore portion of the field, both of which extended the western boundary of field. In 2009, we plan to drill additional development wells that will bottom in the onshore portion of the field.

We continue to pursue our project to extend the lease boundary of the South Ellwood field. In 2008, we crossed some major milestones for the project as the draft Environmental Impact Report (EIR) was issued and public comments were received. The final EIR is anticipated in 2009. The lease boundary extension project includes replacing the existing barging operation with an onshore, 10-mile pipeline that will connect to an existing All-American Pipeline system to deliver our crude oil to market. We filed our initial application prior to the expiration of a state law that provides for the sharing of the state's royalty with the local jurisdictions. If the project is approved, the County of Santa Barbara will receive 20% of the royalties, which are estimated to be as much as $1 billion. The project does not require any additional infrastructure, as the wells can all be drilled from our existing Platform Holly. An interesting benefit of producing oil from the Monterey formation is a reduction in air and water pollution by significantly reducing the prolific naturally occurring oil and gas seeps located off the coast of Santa Barbara. Since acquiring the field in 1997, Venoco has operated natural seep containment structures, which were originally installed in 1982, that capture hundreds of thousands of cubic feet of greenhouse gases every day.

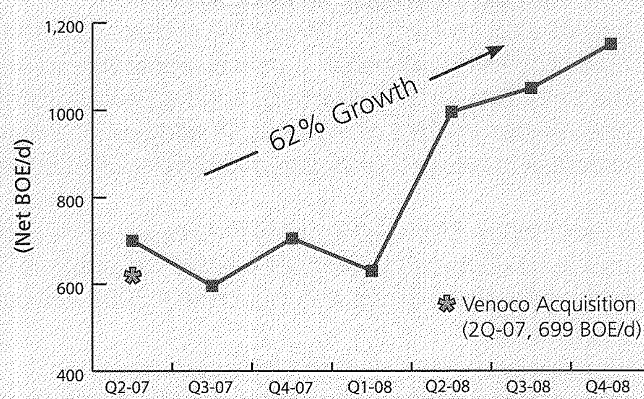
In our Sockeye Field, which we acquired from Chevron in 1999, we have continued to see a favorable response to a waterflood we initiated several years ago. We have expanded the aerial sweep of the flood, upsized our fluid processing capacity and increased the injection rate to advance the flood. Gross oil rates in the latter part of 2008 were around 5,000 barrels per day.



California Offshore Reserve History



West Montalvo Production



We have plans in 2009 to drill a dual-completion well that will produce from the Monterey formation and inject into another formation to enhance the waterflood. We also plan to complete a facilities project which will enable us to sell additional volumes of natural gas from the field.

We have approximately $35.0 million in our 2009 capital budget for Southern California assets, the majority of which will go to drilling the new wells in the West Montalvo field and to the drilling and facilities work at Sockeye.

Venoco's platform Gail, Sockeye Field.

Operations: Texas

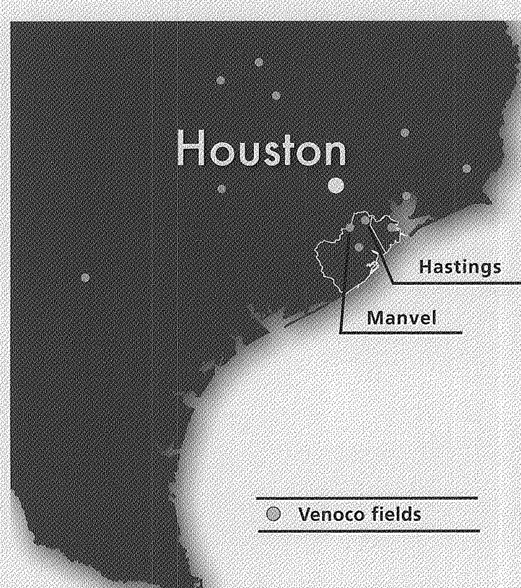
When we acquired TexCal in 2006, our initial focus was on the 'Cal' part of the company that was adjacent to our Sacramento Basin assets. However, we soon realized the value of the 'Tex' assets and the unique Hastings Complex. With over 1 billion barrels of original oil in place, the complex had proven its productive capacity over nearly 70 years. We took a fresh look at this cash-starved property and turned it into a property worth $201 million – approximately $80,000 per daily barrel of production – when we sold it to Denbury Resources in February 2009. Despite having produced nearly 700 million barrels of oil in its lifetime, the Hastings Complex has another life as a CO2 flood, which Denbury has agreed to implement.

Venoco retained the deep rights in the complex and a 2% overriding royalty interest in the producing horizon sold, plus we can back in to a 22.3% working interest once Denbury recovers certain costs related to the CO2 flood of the field. Though we currently have no booked reserves related to the CO2 flood or the back-in, we estimate that net reserves to Venoco could be up to 30 million barrels.

The work we undertook to revitalize Hastings – returning idle wells to production, converting gas-lift wells to electric submersible pumps, converting wells to injection and greatly upsizing the fluid processing capacity – is directly applicable to our nearby Manvel field. Manvel produces from the same Frio sands as Hastings and had about 250 million barrels of original oil in place – about one-quarter the size of Hastings. In addition to the conventional upside in the field, we have expertise in house to evaluate and develop a CO2 flood for Manvel.

In addition to Manvel, we believe there are many other fields in Texas that have both conventional upside by revitalizing operations as well as potential for subsequent CO2 flooding. We are actively looking for these properties and believe 2009 will be a good year to identify these types of acquisitions.

We operate twelve other properties of diverse sizes in Texas and have non-operating interests in two other properties. For 2009, we expect to participate in drilling 2-3 wells in Texas and continue to be focused on lowering operating costs and enhancing production.



Fluid processing facility.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2008

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to
Commission file number 333-123711

VENOCO, INC.

(Exact Name of Registrant as Specified in its Charter)

Delaware (State or other jurisdiction of incorporation or organization)	**77-0323555** (I.R.S. Employer Identification No.)
370 17th Street, Suite 3900 **Denver, Colorado** (Address of principal executive offices)	**80202-1370** (Zip Code)

(303) 626-8300
(Registrant's telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Exchange on Which Registered
Common Stock, par value $0.01 per share	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ☐ No ☒

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐ Accelerated filer ☒ Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the registrant's common stock held by non-affiliates of the registrant on June 30, 2008 was $513.2 million, based on the closing price as reported on the New York Stock Exchange (treating, for this purpose, all executive officers and directors of the registrant, and a charitable foundation associated with the registrant's chief executive officer, as affiliates). There were 51,531,495 shares of common stock outstanding as of February 28, 2009.

DOCUMENTS INCORPORATED BY REFERENCE

Part III is incorporated by reference from the registrant's definitive Proxy Statement for its 2009 Annual Meeting of Stockholders to be filed, pursuant to Regulation 14A, no later than 120 days after the close of the registrant's fiscal year.

VENOCO, INC. 2008 ANNUAL REPORT ON FORM 10-K
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FORWARD-LOOKING STATEMENTS

This report on Form 10-K, including information incorporated herein by reference, contains forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995. The use of any statements containing the words "anticipate," "intend," "believe," "estimate," "project," "expect," "plan," "should," "could" or similar expressions are intended to identify such statements. Forward-looking statements may relate to, among other things:

- our future financial position, including cash flow and anticipated liquidity;
- amounts and nature of future capital expenditures;
- acquisitions and other business opportunities, including those relating to the proposed full-field development project in the South Ellwood field and our interest in the planned enhanced recovery project to be pursued at the Hastings complex;
- our ability to raise capital through debt or equity offerings or borrowings under our revolving credit facility, including lenders' willingness and ability to fund amounts under the revolving credit facility and our ability to comply with covenants set forth in the revolving credit agreement;
- operating costs and other expenses;
- wells to be drilled, reworked or recompleted and the results of those activities;
- oil and natural gas prices and demand;
- exploitation, development and exploration prospects;
- the amount and timing of expenses relating to asset retirement obligations;
- the ability and willingness of counterparties to our commodity derivative contracts to perform their obligations;
- expiration of oil and natural gas leases that are not held by production;
- declines in the values of our natural gas and oil properties that may result in write-downs;
- estimates of proved oil and natural gas reserves, PV-10 and related cash flows;
- reserve potential;
- development and infill drilling potential;
- business strategy;
- future production of oil and natural gas;
- the receipt of governmental permits and approvals relating to our operations, including permits and approvals relating to the proposed full-field development project in the South Ellwood field;
- transportation of the oil and natural gas we produce;
- planned or possible asset sales or dispositions; and
- expansion and growth of our business and operations.

The expectations reflected in such forward-looking statements may prove to be incorrect. Disclosure of important factors that could cause actual results to differ materially from our expectations, or cautionary statements, are included under the heading "Risk Factors" and elsewhere in this report, including, without limitation, in conjunction with the forward-looking statements. All forward-looking statements speak only as of the date made. All subsequent written and oral forward-looking statements attributable to us, or persons acting on our behalf, are expressly qualified in their entirety by the cautionary statements. Except as required by law, we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which it is made or to reflect the occurrence of anticipated or unanticipated events or circumstances.

Factors that could cause actual results to differ materially from our expectations include, among others, such things as:

- changes in oil and natural gas prices, including reductions in prices that would adversely affect our revenues, income, cash flow from operations, liquidity and reserves;
- a continuation of, or further deterioration in, currently adverse conditions in global credit markets and in economic conditions generally;
- risks related to our level of indebtedness;
- our ability to replace oil and natural gas reserves;
- risks arising out of our hedging transactions;
- our inability to access oil and natural gas markets due to operational impediments;
- uninsured or underinsured losses in, or operational problems affecting, our oil and natural gas operations;
- inaccuracy in reserve estimates and expected production rates;
- exploitation, development and exploration results, including from enhanced recovery activities;
- our ability to manage expenses, including expenses associated with asset retirement obligations;
- a lack of available capital and financing;
- the potential unavailability of drilling rigs and other field equipment and services;
- the existence of unanticipated liabilities or problems relating to acquired businesses or properties;
- difficulties involved in the integration of operations we have acquired or may acquire in the future;
- factors affecting the nature and timing of our capital expenditures;
- the impact and costs related to compliance with or changes in laws or regulations governing our oil and natural gas operations;
- environmental liabilities;
- loss of senior management or technical personnel;
- acquisitions and other business opportunities (or the lack thereof) that may be presented to and pursued by us;
- risk factors discussed in this report; and
- other factors, many of which are beyond our control.

GLOSSARY OF TECHNICAL TERMS

3D and 2D seismic	3D seismic data is geophysical data that depicts the subsurface strata in three dimensions. 3D seismic data typically provides a more detailed and accurate interpretation of the subsurface strata than two dimensional, or 2D, seismic data.
Anticline	An arch-shaped fold in rock in which rock layers are upwardly convex.
Bbl	One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbon.
Bcf	One billion cubic feet of natural gas.
Bcfe	One billion cubic feet of natural gas equivalent, using the ratio of one barrel of crude oil, condensate or natural gas liquids to six Mcf of natural gas.
BOE	One stock tank barrel of oil equivalent, using the ratio of six Mcf of natural gas to one barrel of crude oil, condensate or natural gas liquids.
Btu	British thermal unit, the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.
Completion	The installation of permanent equipment for the production of oil or natural gas.
Condensate	Hydrocarbons which are in a gaseous state under reservoir conditions but which become liquid at the surface and may be recovered by conventional separators.
/d	Per day.
Developed acreage	The number of acres which are allocated or assignable to producing wells or wells capable of production.
Development drilling or development wells	Drilling or wells drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.
Dry well	A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion of the well.
Exploitation and development activities	Drilling, facilities and/or production-related activities performed with respect to proved and probable reserves.
Exploration activities	The initial phase of oil and natural gas operations that includes the generation of a prospect and/or play and the drilling of an exploration well.

Exploration well	Means "exploratory well" as defined in Rule 4-10(a)(10) of SEC Regulation S-X and refers to a well drilled to find and produce oil or natural gas reserves in an unproved area, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir. See "Business and Properties— Exploration Activities."
Finding and development costs	Capital costs incurred in the acquisition, exploration, development and revision of proved oil and natural gas reserves divided by proved reserve additions.
Gross acres or gross wells	The total acres or wells, as applicable, in which a working interest is owned.
Infill drilling	Drilling of an additional well or wells at less than existing spacing to more adequately drain a reservoir.
Injection well	A well in which water is injected, the primary objective typically being to maintain reservoir pressure.
MBbl	One thousand barrels.
MBOE	One thousand BOEs.
Mcf	One thousand cubic feet of natural gas. For the purposes of this report, this volume is stated at the legal pressure base of the state or area in which the reserves are located and at 60 degrees Fahrenheit.
Mcfe	One thousand cubic feet of natural gas equivalent, using the ratio of one barrel of crude oil, condensate or natural gas liquids to 6 Mcf of natural gas.
MMcf	One million cubic feet of natural gas. For the purposes of this report, this volume is stated at the legal pressure base of the state or area in which the reserves are located and at 60 degrees Fahrenheit.
MMBbl	One million barrels.
MMBOE	One million BOEs.
MMBtu	One million British thermal units.
Natural gas liquids	Hydrocarbons found in natural gas which may be extracted as liquefied petroleum gas and natural gasoline.
Net acres or net wells	The gross acres or wells, as applicable, multiplied by the working interests owned.
NYMEX	The New York Mercantile Exchange.
Oil	Crude oil, condensate and natural gas liquids.
Pay zone	A geological deposit in which oil and natural gas is found in commercial quantities.

Producing well or productive well	A well that is producing oil or natural gas or that is capable of production in sufficient quantities to justify completion, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities.
Proved developed non-producing reserves	Proved developed reserves that do not qualify as proved developed producing reserves, including reserves that are expected to be recovered from (i) completion intervals that are open at the time of the estimate, but have not started producing, (ii) wells that are shut in because pipeline connections are unavailable or (iii) wells not capable of production for mechanical reasons.
Proved developed reserves	This term means "proved developed oil and gas reserves" as defined in Rule 4-10(a)(3) of SEC Regulation S-X, and refers to reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved developed reserves to production ratio	The ratio of proved developed reserves to total net production for the fourth quarter of the relevant year or other specified period.
Proved developed producing reserves	Reserves that are being recovered through existing wells with existing equipment and operating methods.
Proved reserves or proved oil and natural gas reserves	This term means "proved oil and gas reserves" as defined in Rule 4-10(a)(2) of SEC Regulation S-X and refers to the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.
Proved reserves to production ratio	The ratio of total proved reserves to total net production for the fourth quarter of the relevant year or other specified period.
Proved undeveloped reserves	This term is defined in Rule 4-10(a)(4) of SEC Regulation S-X and refers to reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

PV-10	The PV-10 of reserves is the present value of estimated future revenues to be generated from the production of the reserves net of estimated production and future development costs and future plugging and abandonment costs, using prices and costs as of the date of estimate without future escalation, without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion, amortization and impairment and income taxes, and discounted using an annual discount rate of 10%.
Recompletion	The completion for production of an existing wellbore in a different formation or producing horizon, either deeper or shallower, from that in which the well was previously completed.
Secondary recovery	The second stage of hydrocarbon production during which an external fluid such as water or gas is injected into the reservoir through injection wells located in rock that has fluid communication with production wells. The purpose of secondary recovery is to maintain reservoir pressure and to displace hydrocarbons toward the wellbore.
Shut in	A well suspended from production or injection but not abandoned.
Undeveloped acreage	Acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether the acreage contains proved oil and natural gas reserves.
Waterflood	A method of secondary recovery in which water is injected into the reservoir formation to displace residual oil.
Working interest	The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and to receive a share of production, subject to all royalties, overriding royalties and other burdens, all costs of exploration, development and operations and all risks in connection therewith.
Workover	Remedial operations on a well conducted with the intention of restoring or increasing production from the same zone, including by plugging back, squeeze cementing, reperforating, cleanout and acidizing.

PART I

ITEM 1. AND ITEM 2. Business and Properties

We are an independent energy company primarily engaged in the acquisition, exploration, exploitation and development of oil and natural gas properties. Since our founding in 1992, our core areas of focus have been offshore and onshore California. Our principal properties are located both onshore and offshore Southern California, onshore in California's Sacramento Basin and onshore along the Gulf Coast of Texas, and are characterized by long reserve lives, predictable production profiles and substantial opportunities for further exploitation and development.

We are one of the largest independent oil and natural gas companies in California based on production volumes. According to a reserve report prepared by DeGolyer & MacNaughton, we had proved reserves of approximately 97.5 MMBOE as of December 31, 2008, of which 60% were oil and 54% were proved developed. The PV-10 of our proved reserves as of that date was approximately $616.7 million. Our definition of PV-10, and a reconciliation of a standardized measure of discounted future net cash flows to PV-10, is set forth in "Management's Discussion and Analysis of Financial Condition and Results of Operation—PV-10." Our average net production in the fourth quarter of 2008 was 22,674 BOE/d.

The following table summarizes certain information concerning our production in 2008 and our reserves and inventory of drilling locations as of December 31, 2008. As described in "—Recent Developments," in February 2009 we sold our principal interests in the Hastings complex in Texas for approximately $201.0 million. The "Pro Forma Excluding Hastings" line in the following table reflects our 2008 production and our estimated reserves as of December 31, 2008 as if the Hastings sale had been completed on January 1, 2008.

	2008 Net Production			Proved Reserves			
	Oil (MBbl)	Gas (MMCF)	(MBOE)	Total (MMBOE)	% Oil	PV-10 ($MM)(1)	Drilling Locations(2)
Southern California	2,842	1,063	3,019	50.2	91.9%	$266.2	52
Sacramento Basin	4	20,449	3,412	32.1	0.0%	$243.4	530
Texas (excluding Hastings)	308	1,479	555	7.5	57.9%	$ 80.9	33
Hastings	937	59	947	7.7	99.1%	$ 26.2	—
Total	4,091	23,050	7,933	97.5	59.6%	$616.7	615
Pro Forma Excluding Hastings	3,154	22,991	6,986	89.8	56.3%	$590.5	615

(1) Based on unescalated year-end posted prices of $44.60 per Bbl for oil and natural gas liquids and $5.62 per MMBtu for natural gas, in each case, then adjusted for regional price differentials and similar factors.

(2) Represents total gross drilling locations identified by management as of December 31, 2008. Of the total, 339 locations are classified as proved.

Our Strengths

We believe that the following strengths provide us with significant competitive advantages:

High quality asset base with a long reserve life. Most of our reserves are located in fields that have large volumes of hydrocarbons in place in multiple geologic horizons. One of our primary objectives is to use our engineering expertise to improve recovery rates from these fields and thereby increase our production and reserves. Our offshore Southern California fields and our Texas Gulf Coast fields generally have well-established production histories and exhibit relatively moderate production declines. As of December 31, 2008, our proved reserves to production ratio was 12 years based on production during the fourth quarter of 2008 and pro forma for the Hastings sale. We believe that this relatively stable base of long-lived production is a strong platform to support further growth in our reserves and production.

Significant drilling inventory and growth potential. As of December 31, 2008, we had identified 615 drilling locations on our properties, and we anticipate identifying additional locations on those properties as we pursue our exploitation and development activities. We believe that the continued exploitation and development of our properties will allow us to develop significant additional reserves even if we do not make additional acquisitions. Growth projects that we expect to pursue include a full-field development project, including an extension of the lease area, in our South Ellwood field, a hydraulic fracturing program, new wells targeting the deeper Guinda formation and infill drilling of 20 and 10 acre spacing in the Sacramento Basin and redevelopment of the West Montalvo and Manvel fields.

Strong position in the Sacramento Basin. We have considerable expertise in the exploration, exploitation and development of properties in the Sacramento Basin, where we have operated since 1996 and are currently one of the largest producers. We believe that our experience, expertise and substantial presence in the basin will allow us to take advantage of attractive acquisition, exploration, exploitation and development opportunities there. In addition, we believe that the basin's proximity to northern California natural gas markets, its substantial gathering infrastructure and pipeline capacity and the relatively small historical differential to NYMEX prices received for natural gas produced there contribute to the value of our position.

Extensive knowledge of the Monterey shale formation. A substantial portion of our production consists of offshore production from an unconventional reservoir, the fractured Monterey shale formation in California. Our technical team has extensive offshore experience with the evaluation and exploitation of this reservoir. We believe that there are significant exploration, exploitation and development opportunities relating to the Monterey formation onshore as well, and that our offshore expertise will help us take advantage of those opportunities.

Experienced, proven management and operations team. The members of our management team have an average of over 25 years of experience in the oil and natural gas industry. Prior to founding our company in 1992, our CEO, Timothy Marquez, worked for Unocal for 13 years in both engineering and managerial positions. Our operations team has significant experience in the California and Texas oil and natural gas industry across a broad range of disciplines, including geology, drilling and operations, and regulatory and environmental matters. Our team includes 61 engineers and geoscientists as of December 31, 2008. We believe that our experience and knowledge of the California oil and natural gas industry, including the unconventional Monterey reservoir, are important competitive advantages for us.

High percentage of operated properties. We have operating control of substantially all of our properties, operating approximately 96% of our production in the fourth quarter of 2008. Maintaining control of our properties allows us to use our technical and operational expertise to manage overhead, production and drilling costs and capital expenditures and to control the timing of exploration, exploitation and development activities.

Reputation for environmental, safety and regulatory compliance. We believe that we have established a reputation among regulators and other oil and natural gas companies as having a commitment to safe environmental practices. For example, the state of California has presented us with awards for outstanding lease maintenance at our Beverly Hills and Santa Clara Avenue fields. We believe that our reputation is an important advantage for us when we are competing to acquire properties, particularly those in environmentally sensitive areas, because sellers are often concerned that they could be held responsible for environmental problems caused by the purchaser.

Constructive relationships with local communities. We have devoted substantial effort towards establishing and maintaining good relationships with the communities in which we operate, and have won several awards for our community service and outreach programs. We believe that maintaining strong community ties can, among other things, help to facilitate the process of obtaining the governmental approvals needed to expand our operations.

Our Strategy

We intend to continue to use our competitive strengths to advance our corporate strategy. The following are key elements of that strategy:

Pursue relatively low-risk exploration, exploitation and development projects. We operate properties with substantial volumes of remaining hydrocarbons. We believe that we can develop additional reserves from these properties on a cost-effective basis with relatively limited risk. We expect that our exploration, exploitation and development capital expenditures in 2009 will be approximately $150.0 million.

Make opportunistic acquisitions of underdeveloped properties. We pursue acquisitions that we believe will add reserves and production on a cost-effective basis. Our primary focus is on operated interests in large, mature fields that are located in our core operating regions and have significant production histories, established proved reserves and potential for further exploitation and development. We intend to continue to pursue acquisition opportunities to selectively expand our portfolio of properties.

Continue development of the Sacramento Basin. We intend to continue to pursue an active drilling and acreage acquisition program in the Sacramento Basin. In 2008, our net production in the basin was 3,412 MBOE, up 26% from our net production there in 2007, and up 73% from our net production there in 2006. We believe the basin presents significant exploration, exploitation and development opportunities. As one of the largest operators in the basin, we believe that we are well positioned to identify and exploit these opportunities.

Exploration and exploitation of unconventional reservoirs. We plan to use the expertise we have developed with the fractured Monterey shale formation and other complex, unconventional reservoirs in our acquisition, exploration, exploitation and development of properties with similar characteristics. As of December 31, 2008, we controlled approximately 130,000 net acres with proven, probable and possible Monterey reserves.

Develop CO_2 enhanced recovery projects and expertise. We have a significant interest in the CO_2 enhanced recovery project Denbury Resources, Inc., or Denbury, has agreed to pursue at the Hastings complex. See "—Recent Developments—Hastings Sale." We are applying our experience with that project towards other properties we believe may be suitable candidates for enhanced recovery activities. For example, we believe that our Manvel field, which is geologically similar to the Hastings complex, may provide opportunities for a CO_2 enhanced recovery project. We are in the process of developing the personnel and other resources necessary to fully exploit these opportunities.

Continue to focus on the California market. Historically, we have focused primarily on properties onshore and offshore California. We believe the California market will continue to provide us with attractive growth opportunities. Many properties in California are characterized by significant hydrocarbons in place with multiple pay zones and long reserve lives—characteristics that our technical expertise makes us well-suited to exploit. In addition, competition for the acquisition of properties in California is limited relative to many other markets because of the state's unique operational and regulatory environment. We believe that our technical capabilities, environmental record and experience with California regulatory requirements will allow us to grow in the California market.

Reduce per-unit production expenses. We expect our production expenses to decrease on a per BOE basis for 2009 as a whole as a result of production volume increases at some of our lower-cost Southern California fields and as a result of the sale of our principal interests in the Hastings complex, where our per BOE costs were relatively high. We continue to focus on our operating cost structure in order to improve production and processing efficiencies and reduce operational downtime.

Maintain financial flexibility. We believe that maintaining both financial flexibility and a disciplined capital expenditure program are integral to the successful execution of our business strategy. Our cash flow from operations is supported by the hedges we have in place from 2009 through 2011. For 2009, we have floors covering 101% of our production guidance. Our weighted-average NYMEX floor price for 2009 oil production is $54.06 and our weighted-average NYMEX floor price for 2009 natural gas production is $7.01. Using primarily purchased floors and collars, we maintain a balanced oil and natural gas derivative position intended to limit downside price risk. We will continue to pursue our hedging strategy in order to protect our ability to execute our capital expenditure plan. See "Quantitative and Qualitative Disclosures About Market Risk" for a summary of our derivative/hedging activity.

Recent Developments—Hastings Sale

In February 2009, we completed the sale of our principal interests in the Hastings complex to Denbury for approximately $201.0 million (the "Hastings sale"). As a result of the sale, we repaid all amounts outstanding under our revolving credit facility and $5.5 million of the outstanding principal balance on our second lien term loan facility. See "Management's Discussion and Analysis of Financial Condition and Results of Operation—Liquidity and Capital Resources—Capital Resources and Requirements" for further information concerning the effect of the Hastings sale on our financial position.

Pursuant to the agreement governing the sale, Denbury will commit to a plan to pursue a CO_2 enhanced recovery project at the Hastings properties it acquired. The plan will call for Denbury to make capital expenditures of at least $178.7 million by the end of 2014. As part of the plan, Denbury will be responsible for providing the necessary CO_2. We have retained an overriding royalty interest of 2.0% in production from the properties. We will also have the right to back in to a working interest of approximately 22.3% in the CO_2 project after Denbury recoups certain costs.

We have included unaudited pro forma condensed financial information in relevant financial tables throughout this annual report to present the results of operations giving effect to the Hastings sale. The pro forma adjustments are made based upon available information and assumptions that we believe are reasonable. The unaudited pro forma condensed financial information is presented for illustrative purposes only and is based on the estimates set forth in the accompanying notes. The results may have been different had the transaction occurred at dates assumed in the pro forma presentation.

The unaudited pro forma condensed financial information reflects the following:

- The sale of the properties for total proceeds of $201.0 million;
- The repayment of all amounts outstanding under the revolving credit facility and repayment of $5.5 million of the outstanding principal balance on the second lien term loan with the remaining proceeds held in cash and cash equivalents;
- The unaudited pro forma balance sheet data has been prepared as if the transaction occurred on December 31, 2008 after the ceiling test impairment;
- The unaudited pro forma statement of operations have been prepared as if the sale occurred on January 1, 2008.

We have also included in this annual report certain pro forma operating information, which reflects results giving effect to the Hastings sale as if it had occurred on January 1, 2008.

Description of Properties

Southern California

South Ellwood Field. The South Ellwood field is located in state waters approximately two miles offshore California in the Santa Barbara channel. We conduct our operations in the field from platform Holly and own related onshore processing facilities. We acquired our interest in the field from Mobil Oil Corporation in 1997. Since that time, we have made numerous operational enhancements to the field, including redrills, sidetracks and reworks of existing wells and upgrades at the platform and the onshore treatment facility. We operate the field and have a 100% working interest.

The South Ellwood field is approximately seven miles long and is part of a regional east-west trend of similar geologic structures running along the northern flank of the Santa Barbara channel and extending to the Ventura basin. This trend encompasses several fields that, over their respective lifetimes, are each expected to produce over 100 million barrels of oil, according to the California Division of Oil, Gas, and Geothermal Resources. The Monterey formation is the primary oil reservoir in the field, producing sour oil with a gravity of approximately 21 degrees. As of December 31, 2008, there were 16 producing wells and three injection wells in the field.

The permitting process continues for our full-field development project in the South Ellwood field. We anticipate receiving a final environmental impact report relating to the project in 2009 and for the project approval hearings to begin thereafter. Key components of the project include an extension of the current lease boundary (which would effectively double the size of the existing lease area) and the installation of an onshore oil transport pipeline to replace the existing barge. Development of the lease extension area can be accomplished from the field's existing platform. We have been pursuing the pipeline permitting process and acquiring rights-of-way. Our 2009 capital expenditure budget includes a small amount for continued pipeline permitting and acquisition of rights-of-way.

Our processing and transportation facilities at South Ellwood include a common carrier pipeline, an onshore facility, a pier and a marine terminal. We conduct two-phase separation on the drilling platform and the oil/water emulsion is transported by pipeline to the onshore facility for further separation. The oil is then transported to the marine terminal via the common carrier pipeline. From the marine terminal, the oil is transported by barge. Title to the oil is transferred when the barge completes delivery. At this time, the barge is the only means available to us for delivery of oil produced from the field. The barge is owned and operated by a third party with whom we have a long-term service contract. We sell oil production from the field to the operator of a refinery in Long Beach and San Francisco, California pursuant to a contract that provides for a price based on a fixed differential to the NYMEX price for light sweet crude. Pursuant to the agreement, we expect to have access to an alternate barge to make deliveries of oil production from the field when the barge we currently use is out of service and are currently in the process of obtaining the consents and approvals required prior to our use of the alternate barge. Natural gas produced at the field is transported by common carrier pipeline.

Santa Clara Federal Unit. The Santa Clara Federal Unit is located approximately ten miles offshore in the Santa Barbara channel near Oxnard, California. Our operations in the unit are conducted from two platforms, platform Gail in the Sockeye field and platform Grace in the Santa Clara field. We acquired our interest in the unit and the associated facilities from Chevron in February 1999. Production is transported via pipeline to Los Angeles, California. We operate the unit and have a 100% working interest.

The Sockeye field structure is a northwest/southeast trending anticline bounded to the north and south by fault systems. The field produces from multiple stacked reservoirs ranging from the Monterey, at about 4,000 feet, to the Upper Juncal at approximately 12,000 feet. Other formations include the Upper Topanga, Lower Topanga and Sespe. As of December 31, 2008, there were 24 producing wells and 12 injection wells in the field. The oil produced from the Monterey and Upper Topanga is sour with gravities ranging from 12 to 18 degrees. The Lower Topanga and Sespe horizons produce sweet crude with gravities of 26 to 30 degrees. Chevron shut in production at platform Grace in the Santa Clara field in 1997, and we currently use the platform as a launching and receiving facility for pipeline cleaning devices and as an interconnecting pipeline to transport oil and natural gas produced from platform Gail to our onshore plant.

West Montalvo. We acquired the West Montalvo field in Ventura County, California in May 2007. We operate the field and have a 100% working interest. The field, which includes an offshore portion that is reachable from onshore locations, produces from the Sespe formation. As of December 31, 2008, there were 30 producing wells in the field. Since acquiring the field, our activities have focused on returning idle wells to production, working over and recompleting existing wells, and upgrading well lift systems and processing facilities. Redeveloping the West Montalvo field is a central part of our near term strategy. We believe this field provides us with significant development opportunities, and will look to leverage our experience with the field to identify and acquire other fields in our core operating areas with similar characteristics and potential for redevelopment.

Dos Cuadras Field. The Dos Cuadras field is located in federal waters approximately five miles offshore California in the Santa Barbara channel. We acquired our 25% non-operated working interest in the western two-thirds of the field from Chevron in February 1999. We have working interests ranging from approximately 17.5% to 25% in the associated onshore facility and pipelines. The field is operated by an unaffiliated third party. Production is transported via pipeline to Los Angeles, California. As of December 31, 2008, there were 91 producing wells and 19 injection wells in the field.

Onshore Southern California. Our onshore properties in the Southern California region include the Beverly Hills West field, the Santa Clara Avenue field and the Cat Canyon field. The Beverly Hills West field is located in Beverly Hills, California. All drilling and production operations at the field are conducted from a 0.6 acre surface location adjacent to the campus of Beverly Hills high school. We acquired our interest in the field in 1995. We operate the field and have a 100% working interest. The Santa Clara Avenue field is located in Ventura County, California. We acquired our interest in this field in 1994 and 1996. We operate the field and have working interests ranging from 43% to 100%. The Cat Canyon field, which we acquired in December 2007, is located in Santa Barbara County, California. We operate the field and have a 100% working interest. As of December 31, 2008, there were a total of 47 producing wells in these onshore Southern California fields.

Sacramento Basin

In terms of historical production, the Sacramento Basin is one of California's most prolific onshore natural gas producing areas not associated with oil production. It is approximately 210 miles long and 60 miles wide and contains a variety of different geologic plays. We own 3D seismic data covering over 1,100 square miles in the basin, and 2D seismic data covering approximately 20,000 line miles. We continue to analyze this data to identify additional exploration, exploitation and development opportunities on our properties. We believe this data will also help us assess acquisition opportunities in the basin.

Willows and Greater Grimes Fields. The Willows and Greater Grimes fields are located in Colusa, Glenn and Sutter Counties north of Sacramento, California. Our combined lease position in these fields was approximately 167,000 net acres as of December 31, 2008. We operate substantially all of the fields and have a volume-weighted average working interest of 84% (based on production during the fourth quarter of 2008).

Natural gas production in the Greater Grimes field is from the Forbes, Kione and Guinda formations and production in the Willows field is from the Forbes and Kione formations. Depths range from 2,800 feet in the Willows field to 8,900 feet in the Greater Grimes field. There were 439 producing wells in the fields as of December 31, 2008.

Other Sacramento Basin. We own interests in a number of other fields in Solano, Contra Costa, San Joaquin and Colusa Counties. We operate substantially all of these fields and have a volume-weighted average working interest of 84% (based on production during the fourth quarter of 2008). As of December 31, 2008, there were a total of 43 producing wells in these fields. We believe that the fields will provide us with exploration, exploitation and development opportunities that are similar to those found in the Willows and Greater Grimes fields.

Texas

Hastings Complex. The Hastings complex encompasses approximately 4,850 net or 5,800 gross acres located 30 miles south of Houston in Brazoria County. The complex is comprised of the West Hastings Unit, the East Hastings field and the Hastings field. The complex produces light, sweet crude oil with a gravity of approximately 30 degrees and is characterized by long-life, stable production. The fields in the complex produce from multiple Miocene and Frio reservoirs at depths ranging from 2,000 to 6,100 feet. As of December 31, 2008, there were 149 producing wells in the complex. Average net production from the complex was 2,550 Bbl/d of oil and 88 Mcf/d of natural gas during the fourth quarter of 2008. Our primary focus at the complex during 2008 was on the continuation of our workover and recompletion programs. During the year, we performed 154 projects at the complex including workovers, recompletions and wells returned to production.

In February 2009, we sold our interest in properties producing from the Frio formation in the Hastings complex to Denbury for approximately $201.0 million, subject to certain adjustments, pursuant to an option agreement we entered into with Denbury in November 2006. Substantially all of the current production from the complex is from the Frio formation. The purchase price was in addition to the $50.0 million option payment Denbury previously made to us under the agreement. We retained certain interests in the complex not related to the Frio formation.

Pursuant to the agreement, Denbury will commit to a plan to pursue a CO_2 enhanced recovery project at properties it acquired. The plan will call for Denbury to make capital expenditures of at least $178.7 million by the end of 2014. As part of the plan, Denbury will be responsible for providing the necessary CO_2. We have retained an overriding royalty interest of 2.0% in production from the properties. We will also have the right to back in to a working interest of approximately 22.3% in the CO_2 project after Denbury recoups (i) its operating costs relating to the project and a portion of the purchase price and (ii) 130% of its capital expenditures made on the project. Denbury will either resell the properties to us at a discount or make additional payments to us if recovery operations do not meet certain development milestones by January 2013. The agreement also establishes an area of mutual interest with respect to us and Denbury in specified areas adjacent to the properties. The success of the planned CO_2 enhanced recovery project will be subject to numerous risks and uncertainties, including those relating to the geologic suitability of the properties for such a project and the availability of an economic and reliable supply of CO_2.

Manvel. We acquired the Manvel field in Brazoria County, Texas, and certain related properties, in April 2007. We operate the field and have a 100% working interest. The field produces from the

Frio sands. As of December 31, 2008, there were 46 producing wells in the field. We believe that the field provides us with exploitation and development opportunities, including potential CO_2 enhanced recovery opportunities, that are similar to those in the Hastings complex, which is nearby and geologically similar.

Constitution Field. The Constitution field is located in Jefferson County, Texas. We operate part of the field and have working interests ranging from 25% to 100%. The field produces oil with a gravity of 47.8 degrees and natural gas from the Yegua reservoir at depths ranging from 13,500 feet to 15,300 feet. As of December 31, 2008, there were three producing wells in the field.

South Liberty Field. The South Liberty field is located in Liberty County, Texas. The field produces from the Miocene, Frio, and Yegua formations. Currently all of our production in the field is from the Yegua formation at depths ranging from 7,400 feet to 10,000 feet. We operate the field and have a 100% working interest. As of December 31, 2008, there were seven producing wells in the field.

Other. Our other Texas properties encompass approximately 24,000 net acres in the southern Gulf Coast region. We operate substantially all of our production in these fields and have a volume-weighted average working interest of 82% (based on production during the fourth quarter of 2008). As of December 31, 2008, there were a total of 51 producing wells in these fields.

Exploration Activities

We intend to allocate a portion, typically 10 to 20 percent, of our annual capital expenditure budget to exploration activities. Our exploration portfolio includes numerous prospects across our core operating regions, and occasionally we pursue ventures in other areas that we believe align with our corporate strengths and strategy. We have developed an extensive knowledge of the Monterey shale formation and believe the formation holds significant exploration opportunities. A significant portion of our exploration projects target that formation.

In addition to the exploration activities described above, we also drill a significant number of wells to non-proved locations in the Sacramento Basin. These wells are considered "exploratory wells" as defined in SEC Regulation S-X. See "—Drilling Activity." The majority of the wells in the basin that are "exploratory wells" under SEC Regulation S-X are wells drilled on the border of existing fields in an attempt to test and expand the limits of a producing area. We generally do not distinguish between those wells and development wells from an operating perspective.

Oil and Natural Gas Reserves

The following table sets forth our net proved reserves as of the dates indicated. Our reserve estimates as of December 31, 2006 are based on reserve reports prepared by NSAI and DeGolyer & MacNaughton, and our reserve estimates as of December 31, 2007 and 2008 are based on reserve reports prepared by DeGolyer & MacNaughton. Proved reserves as of each date indicated reflect all acquisitions and dispositions completed as of that date. The reserve estimates were based upon the review by the relevant engineering firm(s) of production histories and other geological, economic, ownership and engineering data. The "Pro Forma 2008" column reflects 2008 reserves as if the

Hastings sale had been completed on December 31, 2008. See "—Recent Developments—Hastings Sale."

Net proved reserves (end of period)	December 31, 2006	2007	2008	Pro Forma 2008
Oil (MBbl)				
Developed	37,497	44,730	34,468	26,847
Undeveloped	12,110	19,446	23,691	23,691
Total	49,607	64,176	58,159	50,538
Natural gas (MMcf)				
Developed	79,796	96,522	107,417	107,025
Undeveloped	150,156	118,083	128,749	128,749
Total	229,952	214,605	236,166	235,774
Total proved reserves (MBOE)	87,932	99,944	97,520	89,834
% Oil	56%	64%	60%	56%
% Proved Developed	58%	61%	54%	50%
Proved Reserves to Production Ratio	13 years	14 years	12 years	12 years

We have not filed any estimates of our total net proved oil or natural gas reserves with any federal authority or agency other than the Securities and Exchange Commission, or SEC, since January 1, 2008.

Production, Prices, Costs and Balance Sheet Information

The following table sets forth certain information regarding our net production volumes, average sales prices realized, certain expenses associated with sales of oil and natural gas for the periods indicated and selected balance sheet information as of December 31, 2008. The "Pro Forma 2008" column reflects production, capital expenditures and related statement of operations information as if the Hastings sale had been completed on January 1, 2008 and condensed balance sheet information as if the Hastings sale had been completed on December 31, 2008 after the ceiling impairment. See "—Recent Developments—Hastings Sale" and note 2 to our consolidated financial statements. We urge you to read this information in conjunction with the information contained in our financial statements and related notes included elsewhere in this report. The information set forth below is not necessarily indicative of future results.

	Years ended December 31,			
	2006(1)	2007	2008	Pro Forma 2008
Production Volume:				
Oil (MBbls)(2)	3,411	3,981	4,091	3,154
Natural gas (MMcf)	14,314	18,895	23,050	22,991
MBOE	5,797	7,130	7,933	6,986
Daily Average Production Volume:				
Oil (Bbls/d)	9,958	10,907	11,178	8,619
Natural gas (Mcf/d)	44,346	51,767	62,978	62,817
BOE/d	17,349	19,535	21,674	19,088
Oil Price per Bbl Produced (in dollars):				
Realized price	$ 55.92	$ 64.06	$ 89.69	$ 86.46
Realized commodity derivative loss and amortization of commodity derivative premiums	(8.38)	(4.35)	(20.71)	(26.85)
Net realized price	$ 47.54	$ 59.71	$ 68.98	$ 59.91
Natural Gas Price per Mcf Produced (in dollars):				
Realized price	$ 6.04	$ 6.61	$ 8.21	$ 8.21
Realized commodity derivative gain (loss) and amortization of commodity derivative premiums	0.36	0.23	0.08	0.08
Net realized price	$ 6.40	$ 6.84	$ 8.29	$ 8.29
Average Sale Price per BOE(3)	$ 44.13	$ 50.24	$ 58.56	$ 52.91
Expense per BOE:				
Lease operating expenses(4)	$ 14.18	$ 15.05	$ 16.86	$ 14.32
Production and property taxes(4)	$ 0.91	$ 1.69	$ 1.98	$ 1.72
Transportation expenses	$ 0.61	$ 0.85	$ 0.75	$ 0.85
Depletion, depreciation and amortization	$ 10.91	$ 13.86	$ 16.95	$ 16.87
General and administrative expense, net(5)	$ 4.88	$ 4.46	$ 5.43	$ 6.17
Interest expense	$ 8.42	$ 8.43	$ 6.81	$ 7.08
Other Financial Data (in thousands):				
Capital Expenditures	$174,613	$ 322,283	$ 318,582	$ 291,621
Balance Sheet Data (end of period) (in thousands):				
Cash and cash equivalents(6)	$ 8,364	$ 9,735	$ 191	$ 58,948
Plant, property and equipment, net(7)	$774,253	$1,131,032	$ 702,734	$ 498,758
Total assets(6),(7)	$893,193	$1,265,485	$ 864,254	$ 719,035
Long-term debt, excluding current portion(6)	$529,616	$ 691,896	$ 797,670	$ 657,118
Stockholders' equity	$190,316	$ 245,602	$(135,167)	$ (135,167)

(1) Includes information for TexCal Energy (LP) LLC ("TexCal") from March 31, 2006, the date of acquisition. Daily average production volumes shown represent (i) second, third and fourth quarter 2006 production from TexCal properties divided by 275 days plus (ii) production from other Venoco properties for the full year 2006 divided by 365 days. Total net production for 2006 divided by 365 days results in average net production of 15,882 BOE/d.

(2) Amounts shown are oil production volumes for offshore properties and sales volumes for onshore properties (differences between onshore production and sales volumes are minimal). Revenue accruals for offshore properties are adjusted for actual sales volumes since offshore oil inventories

can vary significantly from month to month based on the timing of barge deliveries, oil in tank and pipeline inventories, and oil pipeline sales nominations.

(3) Amounts shown are based on oil and natural gas sales, net of inventory changes, realized commodity derivative gains (losses), and amortization of commodity derivative premiums, divided by sales volumes.

(4) Lease operating expenses and property and production taxes are combined to comprise oil and natural gas production expense on the consolidated statements of operations.

(5) Net of amounts capitalized.

(6) Proceeds from the Hastings sale of $201.0 million were initially offset by $1.2 million of revenue suspense balance assumed by Denbury. The remaining net proceeds of $199.8 million were used to repay all amounts outstanding under the revolving credit facility and accrued interest (at December 31, 2008, the balance outstanding under the facility was $135.1 million and accrued interest was $0.5 million) and to repay $5.5 million of the outstanding principal balance on our second lien term loan facility. The balance of the proceeds are reflected in cash and cash equivalents.

(7) Proceeds from the Hastings sale of $201.0 million are reflected as a reduction to the full cost pool along with the removal of the asset retirement obligation of $2.9 million associated with the properties transferred in the Hastings sale.

Drilling Activity

The following table sets forth information with respect to development and exploration wells we completed from January 1, 2006 through December 31, 2008. The number of gross wells is the total number of wells we participated in, regardless of our ownership interest in the wells. Fluid injection wells for waterflood and other enhanced recovery projects are not included as gross or net wells.

	Development Wells Drilled		
	2006	2007	2008
Producing			
Gross	17.0	45.0	24.0
Net	12.4	41.0	22.0
Dry			
Gross	1.0	9.0	4.0
Net	0.7	6.8	3.8

	Exploration Wells Drilled		
	2006	2007	2008
Producing			
Gross	42.0	67.0	69.0
Net	31.5	60.6	59.1
Dry			
Gross	10.0	15.0	19.0
Net	8.2	12.0	17.2

The information above should not be considered indicative of future drilling performance, nor should it be assumed that there is any correlation between the number of productive wells drilled and the amount of oil and natural gas that may ultimately be recovered. Of the gross producing exploration wells drilled in 2008, 68 were drilled in the Sacramento Basin, of which five were allocated to the exploration component of our capital expenditure budget. See "—Exploration Activities."

Oil and Natural Gas Wells

The following table details our working interests in producing wells as of December 31, 2008. A well with multiple completions in the same bore hole is considered one well. Wells are classified as oil or natural gas wells according to the predominant production stream, except that a well with multiple completions is considered an oil well if one or more is an oil completion.

	Gross Producing Wells	Net Producing Wells	Average Working Interest
Oil	436.0	347.6	79.7%
Natural gas	508.0	390.7	76.9%
Total(1)	944.0	738.3	78.2%

(1) Amounts shown include 16 oil wells and ten natural gas wells with multiple completions.

Acreage

The following table summarizes our estimated developed and undeveloped leasehold acreage as of December 31, 2008. We have excluded acreage in which our interest is limited to a royalty or overriding royalty interest.

	Developed		Undeveloped(1)		Total	
Area	Gross	Net	Gross	Net	Gross	Net
Southern California						
South Ellwood	7,682	7,682	0	0	7,682	7,682
Santa Clara Federal Unit	36,000	27,360	0	0	36,000	27,360
Dos Cuadras	5,400	1,350	0	0	5,400	1,350
West Montalvo	540	540	5,110	5,110	5,650	5,650
Paredon(2)	0	0	4,111	4,096	4,111	4,096
Onshore	5,935	4,948	83,989	54,356	89,924	59,304
Total Southern California	55,557	41,880	93,210	63,562	148,767	105,442
Sacramento Basin	121,797	104,752	123,294	103,067	245,091	207,819
Texas (excluding Hastings)	24,254	15,522	20,636	13,362	44,890	28,884
Hastings	4,819	4,553	972	303	5,791	4,856
Other	0	0	56,892	56,773	56,892	56,773
Total	206,427	166,707	295,004	237,067	501,431	403,774

(1) The percentage of undeveloped acreage held under leases due to expire in 2009, 2010 and 2011 unless production commences is approximately 5%, 8% and 6%, respectively.

(2) Paredon is a non-producing prospect and there are no proved reserves associated with the property.

Operating Hazards and Insurance

The oil and natural gas business involves numerous operating risks, such as those described under "Risk Factors—Our business involves significant operating risks that could adversely affect our production and could be expensive to remedy." In accordance with industry practice, we maintain insurance against some, but not all, potential risks and losses. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and other environmental risks are generally not fully insurable. If a significant accident or similar event occurs and is not fully covered by insurance, it would adversely affect us.

Title to Properties

We believe that we have satisfactory title to all of our material assets. Title to our properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry. However, we believe that none of these liens, restrictions, easements, burdens and encumbrances materially detract from the value of our properties or from our interest in those properties or materially interfere with our use of those properties, in each case in the operation of our business as currently conducted. We believe that we have obtained sufficient right-of-way grants and permits from public authorities and private parties for us to operate our business in all material respects as described in this report. As is customary in the oil and natural gas industry, we typically make minimal investigation of title at the time we acquire undeveloped properties. We make title investigations and receive title opinions of local counsel only before we commence drilling operations.

Our credit facilities and the indenture governing our senior notes, which we refer to collectively as our debt agreements, are secured by liens on substantially all of our oil and natural gas properties and other assets. See "Management's Discussion and Analysis of Financial Condition and Results of Operation—Liquidity and Capital Resources—Capital Resources and Requirements."

Marketing and Major Customers

Markets for oil and natural gas are volatile and are subject to wide fluctuations depending on numerous factors beyond our control, including seasonality, economic conditions, foreign imports, political conditions in other energy producing countries, OPEC market actions, and domestic government regulations and policies. All of our production is sold to competing buyers, including large oil refining companies and independent marketers. In the year ended December 31, 2008, approximately 87% of our revenues were generated from sales to four purchasers: ConocoPhillips (32%), Enserco Energy (27%), Teppco Partners (16%), and Tesoro Refining and Marketing Company (12%). Substantially all of our production is sold pursuant to agreements with pricing based on prevailing commodity prices, subject to adjustment for regional differentials and similar factors.

Competition

The oil and natural gas business is highly competitive in the search for and acquisition of additional reserves and in the sale of oil and natural gas. Our competitors principally consist of major and intermediate sized integrated oil and natural gas companies, independent oil and natural gas companies and individual producers and operators. Our competitors include Plains Exploration & Production Company, Berry Petroleum Company and Breitburn Energy Partners L.P. In particular, we compete for property acquisitions and for the equipment and labor required to operate and develop our properties. These competitors may be able to pay more for properties and may be able to define, evaluate, bid for and purchase a greater number of properties than we can. Ultimately, our future success will depend on our ability to develop or acquire additional reserves at costs that allow us to remain competitive.

Offices

We currently lease approximately 52,800 net square feet of office space in Denver, Colorado, where our principal office is located. The lease for the Denver office expires in 2014. We lease an additional 30,000 net square feet of office space in Carpinteria, California from 6267 Carpinteria Avenue, LLC. The lease for the Carpinteria office will expire in 2019. 6267 Carpinteria Avenue, LLC was a wholly owned subsidiary of ours prior to March 2006, when we paid a dividend consisting of 100% of the membership interests in 6267 Carpinteria Avenue, LLC to our then-sole stockholder. The lease has remained in effect following the payment of the dividend. We also lease approximately 28,500 square feet of office space in Houston, Texas, where we maintain a regional office. We believe that our office facilities are adequate for our current needs and that additional office space can be obtained if necessary.

Employees

As of December 31, 2008, we had approximately 401 full-time employees, none of whom were party to collective bargaining arrangements.

Regulatory Environment

Our oil and natural gas exploration, production and transportation activities are subject to extensive regulation at the federal, state and local levels. These regulations relate to, among other things, environmental and land-use matters, conservation, safety, pipeline use, drilling and spacing of wells, well stimulation, transportation, and forced pooling and protection of correlative rights among interest owners. The following is a summary of some key regulations that affect our operations.

Environmental and Land Use Regulation

A wide variety of environmental and land use regulations apply to companies engaged in the production and sale of oil and natural gas. These regulations have been changed frequently in the past and, in general, these changes have imposed more stringent requirements that increase operating costs and/or require capital expenditures to remain in compliance. Failure to comply with these requirements can result in civil and/or criminal penalties and liability for non-compliance, clean-up costs and other environmental damages. It also is possible that unanticipated developments or changes in the law could require us to make environmental expenditures significantly greater than those we currently expect.

California Environmental Quality Act ("CEQA"). CEQA is California legislation that requires consideration of the environmental impacts of proposed actions that may have a significant effect on the environment. CEQA requires the responsible governmental agency to prepare an environmental impact report that is made available for public comment. The responsible agency also is required to consider mitigation measures. The party requesting agency action bears the expense of the report.

We currently are in the CEQA process in connection with, among other things, our requested renewal of the state lease for the marine terminal at the South Ellwood field and our proposed full-field development project at the field. See "Description of Properties—Southern California—South Ellwood field."

We may be required to undergo the CEQA process for other lease renewals and other proposed actions by state and local governmental authorities that meet specified criteria. At a minimum, the CEQA process delays and adds expense to the process of obtaining new leases, permits and lease renewals.

Discharges to Waters. The Federal Water Pollution Control Act of 1972, as amended (the "Clean Water Act"), and comparable state statutes impose restrictions and controls on the discharge of produced waters and other oil and natural gas wastes into regulated waters and wetlands. These controls generally have become more stringent over time, and it is possible that additional restrictions will be imposed in the future. These laws prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and other substances related to the oil and natural gas industry into onshore, coastal and offshore waters without appropriate permits. Violation of the Clean Water Act and similar state regulatory programs can result in civil, criminal and administrative penalties for unauthorized discharges of oil, hazardous substances and other pollutants. They also can impose substantial liability for the costs of removal or remediation associated with discharges of oil or hazardous substances.

The Clean Water Act also regulates stormwater discharges from industrial properties and construction activities, and requires separate permits and implementation of a Stormwater Pollution Prevention Plan ("SWPPP") establishing best management practices, training, and periodic monitoring of covered activities. Certain operations also are required to develop and implement Spill Prevention, Control, and Countermeasure ("SPCC") plans or facility response plans to address potential oil spills. Certain exemptions from some Clean Water Act requirements have been created or broadened pursuant to the Energy Policy Act of 2005.

Oil Spill Regulation. The Oil Pollution Act of 1990, as amended ("OPA"), amends and augments the Clean Water Act as it relates to oil spills. It imposes potentially unlimited liability on responsible parties without regard to fault for the costs of cleanup and other damages resulting from an oil spill in federal waters. Responsible parties include (i) owners and operators of onshore facilities and pipelines and (ii) lessees or permittees of offshore facilities. In addition, OPA requires parties responsible for offshore facilities to provide financial assurance in the amount of $35.0 million, which can be increased to $150.0 million in some circumstances, to cover potential OPA liabilities.

Regulations imposed by the Minerals Management Service ("MMS") also require oil-spill response plans and oil-spill financial assurance from offshore oil and natural gas operations, whether operating in state or federal offshore waters. These regulations were designed to be consistent with OPA and other similar requirements. Under MMS regulations, operators must join a cooperative that makes oil-spill response equipment available to its members. The California Department of Fish and Game's Office of Oil Spill Prevention and Response ("OSPR") has adopted oil-spill prevention regulations that overlap with federal regulations. We have complied with these OPA, MMS and OSPR requirements by adopting an offshore oil spill contingency plan and becoming a member of Clean Seas, LLC, a cooperative entity operated with other offshore operators to prevent and respond to oil spills in the offshore region in which we operate.

Air Emissions. Our operations are subject to local, state and federal regulations governing emissions of air pollutants. Local air-quality districts are responsible for much of the regulation of air-pollutant sources in California. California requires new and modified stationary sources of air pollutants to obtain permits prior to commencing construction. Major sources of air pollutants are subject to more stringent, federally-based permitting requirements. Because of the severity of ozone levels in portions of California, the state has the most severe restrictions on emissions of volatile organic compounds ("VOCs") and nitrogen oxides ("NOX") of any state. Producing wells, natural gas plants and electric generating facilities all generate VOCs and NOX. Some of our producing wells are in counties that are designated as non-attainment for ozone and, therefore, potentially are subject to restrictive emission limitations and permitting requirements. California also operates a stringent program to control hazardous (toxic) air pollutants, and this program could require the installation of additional controls. Administrative enforcement actions for failure to comply strictly with air pollution regulations or permits generally are resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could require us to forego construction, modification or operation of certain air-emission sources. Air emissions from oil and natural gas operations also are regulated by oil and natural gas permitting agencies, including the MMS, the State Lands Commission and other local agencies.

Waste Disposal. We currently own or lease a number of properties that have been used for production of oil and natural gas for many years. Although we believe the prior owners and/or operators of those properties generally utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties we currently own or lease. State and federal laws applicable to oil and natural gas wastes have become more stringent. Under new laws, we could be required to remediate property, including groundwater, containing or impacted by previously disposed wastes (including wastes disposed of or released by prior owners or operators) or to perform remedial well-plugging operations to prevent future, or mitigate existing, contamination.

We may generate wastes, including "solid" wastes and "hazardous" wastes that are subject to the federal Resource Conservation and Recovery Act, as amended ("RCRA") and comparable state statutes, although certain oil and natural gas exploration and production wastes currently are exempt from regulation as hazardous wastes under RCRA. The federal Environmental Protection Agency (the "EPA") has limited the disposal options for certain wastes that are designated as hazardous wastes under RCRA. Furthermore, it is possible that certain wastes generated by our oil and natural gas operations that currently are exempt from regulation as hazardous wastes may in the future be designated as hazardous wastes, and therefore be subject to more rigorous and costly management, disposal and clean-up requirements. State and federal oil and natural gas regulations also provide guidelines for the storage and disposal of solid wastes resulting from the production of oil and natural gas, both onshore and offshore.

Superfund. Under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended, also known as CERCLA or the Superfund law, and similar state laws, responsibility for the entire cost of cleanup of a contaminated site, as well as natural resource damages, can be imposed upon current or former site owners or operators, or upon any party who released one or more designated "hazardous substances" at the site, regardless of the lawfulness of the original activities that led to the contamination. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to public health or the environment and to seek to recover from the potentially responsible parties the costs of such action. Although CERCLA generally exempts petroleum from the definition of hazardous substances, in the course of our operations we may have generated and may generate wastes that fall within CERCLA's definition of hazardous substances. We may also be an owner or operator of facilities at which hazardous substances have been released by previous owners or operators. We may be responsible under CERCLA for all or part of the costs of cleaning up facilities at which such substances have been released and for natural resource damages. We have not, to our knowledge, been identified as a potentially responsible party under CERCLA, nor are we aware of any prior owners or operators of our properties that have been so identified with respect to their ownership or operation of those properties.

Abandonment, Decommissioning and Remediation Requirements. Federal, state and local regulations provide detailed requirements for the abandonment of wells, closure or decommissioning of production and transportation facilities and the environmental restoration of operations sites. MMS regulations, coupled with applicable lease and permit requirements and each property's specific development and production plan, prescribe the requirements for decommissioning our federally leased offshore facilities. The California State Lands Commission ("CSLC"), and the California Department of Conservation, Division of Oil, Gas and Geothermal Resources ("DOGGR") are the principal state agencies responsible for regulating the drilling, operation, maintenance and abandonment of all oil and natural gas wells in the state, whether onshore or offshore. In Texas, the Railroad Commission of Texas regulates these activities. MMS regulations require federal leaseholders to post performance bonds. See "—Potentially Material Costs Associated with Environmental Regulation of Our Oil and Natural Gas Operations—Plugging and Abandonment Costs" for a discussion of our principal obligations relating to the abandonment and decommissioning of our facilities.

California Coastal Act. The California Coastal Act regulates the conservation and development of California's coastal resources. The California Coastal Commission (the "Coastal Commission") works with local governments to make permit decisions for new developments in certain coastal areas and reviews local coastal programs, such as land-use restrictions. The Coastal Commission also works with the OSPR to protect against and respond to coastal oil spills. The Coastal Commission has direct regulatory authority over offshore oil and natural gas development within the state's three mile jurisdiction and has authority, through the Federal Coastal Zone Management Act, over federally permitted projects that affect the state's coastal zone resources. We conduct activities that may be subject to the California Coastal Act and the jurisdiction of the Coastal Commission.

Other Environmental Regulation. Our leases in federal waters on the Outer Continental Shelf are administered by the MMS and require compliance with detailed MMS regulations and orders. Under certain circumstances, the MMS may require any of our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition and operations.

Our offshore leases in state waters or "tidelands" (within three miles of the coastline) are administered by the state of California and require compliance with certain regulations of the CLSC and DOGGR. The CSLC serves as the lessor of our state offshore leases and is charged with overseeing leasing, exploration, development and environmental protection of the state tidelands.

Commencing with the Cunningham Shell Act of 1955, California has enacted several pieces of legislation that withhold state tidelands from oil and natural gas leasing. The Cunningham Shell Act protected an area of tidelands offshore Santa Barbara County that stretches west from Summerland Bay to Coal Oil Point, and included waters offshore the unincorporated area of Montecito, the City of Santa Barbara and the University of California at Santa Barbara. It also protected the state tidelands around the islands of Anacapa, Santa Cruz, Santa Rosa and San Miguel. In 1994, California enacted the California Sanctuary Act which, with three exceptions, prohibits leasing of any state tidelands for oil and natural gas development. Oil and natural gas leases in effect as of January 1, 1995 are unaffected by this legislation until such leases revert back to the state, at which time they will become part of the California Coastal Sanctuary. This legislation does not restrict our existing state offshore leases or our current or planned future operations.

Recent and future environmental regulations, including additional federal and state restrictions on greenhouse gas emissions that may be passed in response to climate change concerns, may increase our operating costs and also reduce the demand for the oil and natural gas we produce. On September 27, 2006, California's governor signed into law the "California Global Warming Solutions Act of 2006" Assembly Bill (AB) 32, which establishes a statewide cap on greenhouse gases ("GHG") that will reduce the state's GHG emissions to 1990 levels by 2020. The California Air Resources Board has been designated as the lead agency to establish and adopt regulations to implement AB 32 by January 1, 2012. We will continue to monitor the establishment of these regulations through industry trade groups and other organizations in which we are a member. Similar regulations may be adopted by other states in which we operate or by the federal government.

Other environmental protection statutes that may impact our operations included the Marine Mammal Protection Act, the Marine Life Protection Act, the Marine Protection, Research, and Sanctuaries Act of 1972, the Endangered Species Act, the Fish and Wildlife Coordination Act, the Fishery Conservation and Management Act, the Migratory Bird Treaty Act and the National Historic Preservation Act.

Potentially Material Costs Associated with Environmental Regulation of Our Oil and Natural Gas Operations

Significant potential costs relating to environmental and land-use regulations associated with our existing properties and operations include those relating to (i) plugging and abandonment of facilities,

(ii) clean-up costs and damages due to spills or other releases and (iii) penalties imposed for spills, releases or non-compliance with applicable laws and regulations. As is customary in the oil and natural gas industry, we typically have contractually assumed, and may assume in the future, obligations relating to plugging and abandonment, clean-up and other environmental costs in connection with our acquisition of operating interests in fields, and these costs can be significant.

Plugging and Abandonment Costs. Our operations, and in particular our offshore platforms and related facilities, are subject to stringent abandonment and closure requirements imposed by the MMS and the state of California. With respect to the Santa Clara Federal Unit, Chevron retained most of the abandonment obligations relating to the platforms and facilities when it sold the fields to us in 1999. We are responsible for abandonment costs relating to the wells and to any expansions or modifications we made following our acquisition of the fields. We also agreed to assume from Chevron all abandonment obligations associated with its 25% interest in the infrastructure (but not the wells) in the Dos Cuadras field. We agreed to assume all of the abandonment costs relating to the operations, including platform Holly, in the South Ellwood field when we purchased it from Mobil Oil Corporation in 1997.

As described in note 5 to our financial statements, we have estimated the present value of our aggregate asset retirement obligations to be $80.6 million as of December 31, 2008. This figure reflects the expected future costs associated with site reclamation, facilities dismantlement and plugging and abandonment of wells. The discount rates used to calculate the present value varied depending on the estimated timing of the obligation, but typically ranged between 4% and 9%. Actual costs may differ from our estimates. Our financial statements do not reflect any liabilities relating to other environmental obligations.

Under a variety of applicable laws and regulations, including CERCLA, RCRA and MMS regulations, we could in some circumstances be held responsible for abandonment and clean-up costs relating to our operations, both onshore and offshore, notwithstanding contractual arrangements that assign responsibility for those costs to other parties.

Clean-up Costs. We currently have two onshore facilities with known environmental contamination. Our onshore facility at the South Ellwood field is known to have hydrocarbon contamination. We currently are required to provide quarterly monitoring reports to the county. Because oil occurs naturally in the area, regulators have not yet determined the applicable cleanup requirements for this facility. We expect that we will be permitted to defer remedial actions at the facility until we cease operations there, and our present intention is to continue using it for the foreseeable future. We currently estimate that the cost of a clean-up of the facility will be between $6.0 million and $11.0 million. This cost is included in the asset retirement obligations shown in our financial statements. For the purpose of calculating the asset retirement obligation, we estimated that the facility will be abandoned in 25 years (as of 2008). The onshore oil and natural gas plant associated with the Santa Clara Federal Unit is also known to have hydrocarbon contamination. Chevron is contractually obligated to remediate the contamination that was present at the time we purchased the property upon the closure of that facility. We will be responsible for the clean-up of any additional contamination. To our knowledge, no such additional contamination has occurred. Accordingly, we currently do not expect to incur any remediation costs in connection with this facility.

Penalties for Non-Compliance. We believe that our operations are in material compliance with all applicable oil and natural gas, safety, environmental and land-use laws and regulations. However, from time to time we receive notices of noncompliance with Clean Air Act and other requirements from relevant regulatory agencies. We received a number of minor notices of violation ("NOVs") from regulatory agencies in 2008. We do not expect to incur significant penalties with respect to any outstanding NOV. See "Legal Proceedings."

Other Regulation

The pipelines we use to gather and transport our oil and natural gas are subject to regulation by the U.S. Department of Transportation ("DOT") under the Hazardous Liquids Pipeline Safety Act of 1979, as amended ("HLPSA"), and the Pipeline Safety Act of 1992, which relate to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Under the Pipeline Safety Act, the Research and Special Programs Administration of DOT is authorized to require certain pipeline modifications as well as operational and maintenance changes. We believe our pipelines are in substantial compliance with HLPSA and the Pipeline Safety Act. Nonetheless, significant expenses could be incurred if new or additional safety requirements are implemented.

The rates, terms and conditions applicable to the interstate transportation of natural gas by pipelines are regulated by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act and the Natural Gas Policy Act. Since 1985, FERC has implemented regulations intended to increase competition within the natural gas industry by making natural gas transportation more accessible to natural gas buyers and sellers on an open-access, non-discriminatory basis.

The rates, terms, and conditions applicable to the interstate transportation of oil by pipelines also are regulated by FERC under the Interstate Commerce Act. FERC has implemented a simplified and generally applicable ratemaking methodology for interstate oil pipelines to fulfill the requirements of Title VIII of the Energy Policy Act of 1992, comprised of an indexing system to establish ceilings on interstate oil pipeline rates. FERC has announced several important transportation related policy statements and rule changes, including a statement of policy and final rule issued February 25, 2000 concerning alternatives to its traditional cost-of-service rate-making methodology to establish the rates interstate pipelines may charge for their services. The final rule revises FERC's pricing policy and current regulatory framework to improve the efficiency of the market and further enhance competition in natural gas markets. With respect to transportation of natural gas on the Outer Continental Shelf, FERC requires, as a part of its regulation under the Outer Continental Shelf Lands Act, that all pipelines provide open and non-discriminatory access to both owner and non-owner shippers.

The safety of our operations primarily is regulated by the MMS, the CSLC, the Coast Guard and the Occupational Safety and Health Administration. We believe our facilities and operations are in substantial compliance with the applicable requirements of those agencies. In the event different or additional safety measures are required in the future, we could incur significant expenses to meet those requirements.

Executive Officers of the Registrant

The following table sets forth certain information with respect to our executive officers as of December 31, 2008.

Name	Age	Position
Timothy Marquez	50	Chairman and Chief Executive Officer
William Schneider	47	President
Timothy A. Ficker	41	Chief Financial Officer
Terry L. Anderson	61	General Counsel and Secretary
Douglas J. Griggs	49	Chief Accounting Officer

Timothy Marquez co-founded Venoco in September 1992 and served as our CEO from our formation until June 2002. He founded Marquez Energy in 2002 and served as its CEO until we acquired it in March 2005. Mr. Marquez returned as our Chairman, CEO and President in June 2004. Mr. Marquez has a B.S. in petroleum engineering from the Colorado School of Mines. Mr. Marquez began his career with Unocal Corporation, where he worked for 13 years managing assets offshore California and in the North Sea and performing other managerial and engineering functions.

William Schneider became our President in January 2005. Prior to joining us, Mr. Schneider was a managing director at BMO Capital Markets (formerly known as Harris Nesbitt), an investment bank, where he focused on mergers and acquisitions in the energy industry. He joined BMO Capital Markets in February 2001. From January 1998 to January 2001, he worked in the Energy Investment Banking division of Donaldson, Lufkin & Jenrette. Mr. Schneider's experience also includes service in Smith Barney's Energy Investment Banking division. Before entering investment banking, Mr. Schneider held a variety of engineering and corporate positions at Unocal for over 12 years. Mr. Schneider holds an M.B.A. in Finance from U.C.L.A. and a B.S. in petroleum engineering from the Colorado School of Mines.

Timothy A. Ficker became our CFO in April 2007. Prior to joining us, Mr. Ficker was Vice President, CFO and Secretary of Infinity Energy Resources, Inc., a NASDAQ-listed energy company, having been appointed to those positions in May 2005. From October 2003 through April 2005, Mr. Ficker served as an audit partner in KPMG LLP's Denver office, and from June 2002 through September 2003, he served as an audit director for KPMG LLP. From September 1989 through June 2002, he worked for Arthur Andersen LLP, including as an audit partner after September 2001, where he served clients primarily in the energy industry. Mr. Ficker is a certified public accountant and received a B.B.A. in accounting from Texas A&M University.

Terry L. Anderson is our General Counsel and Secretary. Mr. Anderson joined us in March 1998 and served as General Counsel until June 2002. From July 2002 to August 2004, Mr. Anderson was in private practice in Santa Barbara, California. He returned in his current capacities in August 2004. Mr. Anderson holds a B.S. in petroleum engineering and a J.D. from the University of Southern California. Mr. Anderson was Vice President and General Counsel of Monterey Resources, Inc., a NYSE-listed company, from August 1996 to January 1998. Prior to that, he was chief transactional attorney for Santa Fe Energy Resources in Houston, Texas. Mr. Anderson is licensed to practice law in Texas and California.

Douglas J. Griggs was appointed as our Chief Accounting Officer in January 2006. Mr. Griggs is a certified public accountant with twenty six years of accounting and financial management experience, including 13 years with Ernst & Young LLP. From January 2003 through December 2005, he was an independent consultant in the areas of finance, accounting and Sarbanes-Oxley compliance. From 1997 to December 2002, he served as CFO for Engineered Data Products, Inc. Mr. Griggs has an accounting degree from the University of Northern Iowa.

Available Information

We maintain a link to investor relations information on our website, *www.venocoinc.com*, where we make available, free of charge, our filings with the SEC, including our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, or Exchange Act, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. We also make available on our website copies of the charters of the audit, compensation and corporate governance/nominating committees of our board of directors, our code of business conduct and ethics and our corporate governance guidelines. Stockholders may request a printed copy of these governance materials or any exhibit to this report by writing to the Corporate Secretary, Venoco, Inc., 6267 Carpinteria Avenue, Carpinteria, CA 93013-1423. You may also read and copy any materials we file with the SEC at the SEC's Public Reference Room, which is located at 100 F Street, NE, Room 1580, Washington, D.C. 20549. Information regarding the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains a website at *www.sec.gov* that contains the documents we file with the SEC. Our website and the information contained on or connected to our website is not incorporated by reference herein and our web address is included as an inactive textual reference only.

ITEM 1A. Risk Factors

Oil and natural gas prices are volatile and change for reasons that are beyond our control. Decreases in the price we receive for our oil and natural gas production adversely affect our business, financial condition, results of operations and liquidity.

Declines in the prices we receive for our oil and natural gas production, such as the severe declines we experienced in the second half of 2008, adversely affect many aspects of our business, including our financial condition, revenues, results of operations, liquidity, rate of growth and the carrying value of our oil and natural gas properties, all of which depend primarily or in part upon those prices. For example, declines in the prices we receive for our oil and natural gas adversely affect our ability to finance capital expenditures, make acquisitions, raise capital and satisfy our financial obligations. In addition, declines in prices reduce the amount of oil and natural gas that we can produce economically and, as a result, adversely effect our quantities of proved reserves. Among other things, a reduction in our reserves can limit the capital available to us, as the maximum amount of available borrowing under the revolving credit facility is, and the availability of other sources of capital likely will be, based to a significant degree on the estimated quantities of those reserves. See "Management's Discussion and Analysis of Financial Condition and Results of Operation—Overview—Trends Affecting Our Results of Operations—Oil and Natural Gas Prices" for a discussion of certain impacts on us of the declines in prices that have occurred since mid-2008.

Oil and natural gas are commodities and their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Prices have historically been volatile and are likely to continue to be volatile in the future. The prices of oil and natural gas are affected by a variety of factors that are beyond our control, including changes in global supply and demand for oil and natural gas, domestic and foreign governmental regulations and taxes, the level of global oil and natural gas exploration activity and inventories, the price, availability and consumer acceptance of alternative fuel sources, the availability of refining capacity, technological advances affecting energy consumption, weather conditions, financial and commercial market uncertainty and worldwide economic conditions.

In addition to factors affecting the price of oil and natural gas generally, the prices we receive for our oil and natural gas production is affected by factors specific to us and to the local markets where the production occurs. Pricing can be influenced by, among other things, local or regional supply and demand factors (such as refinery or pipeline capacity issues, trade restrictions and governmental regulations) and the terms of our sales contracts. For example, the termination in 2006 of the sales arrangement pursuant to which we historically sold oil from the South Ellwood field required us to enter into a new contract with a new purchaser which priced our oil at a significantly greater discount to the NYMEX price.

The prices we receive for our production are also affected by the specific characteristics of the production relative to production sold at benchmark prices. For example, our California oil typically has a lower gravity, and a portion has higher sulfur content, than oil sold at the NYMEX price. Therefore, because our oil requires more complex refining equipment to convert it into high value products, it sells at a discount to the NYMEX price. This discount varies over time and can be affected by factors that do not have the same impact on the price of premium grade light oil. We cannot predict how the discount applicable to our production will change in the future, and it is possible that it will increase. The difficulty involved in predicting the differential also makes it more difficult for us to effectively hedge our production. Substantially all of our hedging arrangements are based on benchmark prices, and therefore do not fully protect us from adverse changes in the differential applicable to our production. The oil we produce from our Texas properties typically sells at a smaller discount to NYMEX than our California oil. Because we sold our largest producing property in Texas in February 2009, the risks associated with the differential are currently greater, relative to our overall production, than they have been in recent years.

Our planned operations will require additional capital that may not be available, especially if current market conditions persist.

Our business is capital intensive, and requires substantial expenditures to maintain currently producing wells, to make the acquisitions and/or conduct the exploration, exploitation and development activities necessary to replace our reserves, to pay expenses and to satisfy our other obligations. Based on current commodities prices, we do not expect to be able to finance our planned capital expenditures in 2009 solely with cash flow from operations. That fact makes us dependent on external financing, including borrowings under our revolving credit facility, to a greater degree than many of our competitors. Our substantial existing indebtedness increases the risk that external financing will not be available to us when needed.

With respect to our revolving credit facility, lenders may not fund borrowings under the facility when we request them to do so. One of the lenders, Lehman Commercial Paper ("LCP"), is no longer funding amounts under the facility as a result of the bankruptcy of its parent company, Lehman Brothers Holding, Inc. Other lenders under the facility, some of which have received government support in connection with the ongoing credit crisis, may face similar issues. Our ability to borrow under the facility may also be limited if we are unable, or run a significant risk of becoming unable, to comply with the financial covenants that we are required to satisfy under the facility. Based on our current capital expenditure budget and current commodities prices, we believe that it will be difficult to maintain compliance with the requirement that we maintain a specified ratio of debt to EBITDA (as defined in the agreement) at the end of 2009 if we borrow a significant portion of amounts available under the facility. In addition, the borrowing base under the facility is subject to redetermination periodically and from time to time in the lenders' discretion. In addition to reducing the capital available to finance our operations, a reduction in the borrowing base could cause us to be required to repay amounts outstanding under the facility in excess of the reduced borrowing base, and the funds necessary to do so may not be available at that time. Sources of external financing other than revolving credit facility borrowings may not be available when needed on acceptable terms or at all, especially if conditions in financial markets do not improve. In addition, if we finance our operations through borrowings under our credit facility or other additional indebtedness, the risks that we now face relating to our current debt level would intensify, and it may be more difficult to satisfy our existing financial obligations.

A reduction in capital spending to more closely match capital spending with expected cash flow will likely result in reduced production and reduced cash flow.

In significant part due to declining oil and natural gas prices, we reduced our 2009 exploration, exploitation and development capital expenditure budget from $400.0 million to $150.0 million in second half of 2008 and January 2009. Based on the new budget, we currently expect our average daily net production in 2009 to be roughly flat relative to 2008, pro forma for the Hastings sale. Expected 2009 production will result in cash flow that is significantly less than the reduced 2009 capital expenditure budget, based on current commodity prices. A further reduction in capital spending to more closely match our expected cash flow would likely result in reduced production and reduced cash flow. In addition, cash flow from operations may be less than we expect due to changes in commodities prices, operational difficulties or other factors. A reduction in cash flow from operations could have a material adverse effect on our financial condition, results of operation, liquidity and ability to replace our reserves.

Our debt level and the covenants in the agreements governing our debt could negatively impact our financial condition, results of operations, business prospects and ability to finance our operations.

As of March 3, 2009, we had total indebtedness under the credit facilities and our 8.75% senior notes due 2011 of approximately $650.1 million, and this indebtedness bore interest at a weighted average rate of 6.0%. Our ability to make required principal and interest payments on our indebtedness and comply with the other terms of our debt agreements will depend to a significant extent on our financial and operating performance, which is subject to prevailing economic conditions, commodity prices and a variety of other factors. If currently adverse economic conditions persist, it will be considerably more difficult for us to comply with the terms of our debt agreements. The breach of any of the terms of our debt agreements could result in a default under the applicable agreement, which would permit the affected lenders or noteholders, as the case may be, to declare all amounts outstanding thereunder to be due and payable, together with accrued and unpaid interest, and to foreclose on substantially all of our assets. A foreclosure could result in a complete loss of our stockholders' investment in our company. Current market conditions may make it more difficult to obtain a waiver from our lenders or noteholders in the event of a breach.

If our cash flow and other capital resources are insufficient to fund our obligations under our debt agreements or we are otherwise unable to comply with those agreements, we could attempt to refinance or repay the debt with the proceeds from an equity offering or from sales of assets. The proceeds of future borrowings, equity financings or asset sales may not be sufficient to refinance or repay the debt, and we may be unable to complete such transactions in a timely manner or at all. In addition, our credit agreements contain provisions that would limit our flexibility in responding to a shortfall in our expected liquidity by selling assets or taking certain other actions. For example, we could be required to use some or all of the proceeds of an asset sale to reduce amounts outstanding under one or both of our credit facilities in some circumstances. See "Management's Discussion and Analysis of Financial Condition and Results of Operation—Liquidity and Capital Resources—Capital Resources and Requirements." We expect to refinance all or a significant amount of our existing indebtedness at or prior to its maturity through the incurrence of additional indebtedness. Our ability to do so will depend on a variety of factors, many of which will be out of our control. Any refinancing that requires the use of cash, including a refinancing of our senior notes that we may pursue in 2009, could require us to curtail planned capital expenditures.

Our level of indebtedness, and the covenants contained in our debt agreements, could have important consequences for our operations, including by:

- making it more difficult for us to satisfy our obligations under our debt agreements and increasing the risk that we may default on our debt obligations;
- requiring us to dedicate a substantial portion of our cash flow from operations and certain types of transactions to required payments on debt, thereby reducing the availability of cash flow for working capital, capital expenditures, acquisition opportunities and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and other activities;
- limiting management's discretion in operating our business;
- limiting our flexibility in planning for, or reacting to, changes in commodity prices, our business or the industry in which we operate;
- impairing our ability to withstand successfully a downturn in commodity prices, our business or the economy generally;
- placing us at a competitive disadvantage against less leveraged competitors; and
- making us vulnerable to increases in interest rates.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or the relevant underlying assumptions will materially affect the quantity and present value of our reserves.

The reserve data included in this report represent estimates only. Estimating quantities of proved oil and natural gas reserves is a complex process. It requires interpretations of available technical data and various estimates, including estimates based upon assumptions relating to economic factors, such as future commodity prices, production costs, severance and excise taxes and availability of capital, estimates of required capital expenditures and workover and remedial costs, and the assumed effect of governmental regulation. The assumptions underlying our estimates of our proved reserves could prove to be inaccurate, and any significant inaccuracy could materially affect, among other things, future estimates of our reserves, the economically recoverable quantities of oil and natural gas attributable to our properties, the classifications of reserves based on risk of recovery and estimates of our future net cash flows.

At December 31, 2008, 46% of our estimated proved reserves were proved undeveloped and 6% were proved developed non-producing. Estimation of proved undeveloped reserves and proved developed non-producing reserves is almost always based on analogy to existing wells as contrasted with the performance data used to estimate producing reserves. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Revenues from estimated proved developed non-producing reserves will not be realized until some time in the future, if at all.

You should not assume that the present values referred to in this report represent the current market value of our estimated oil and natural gas reserves. The timing and success of the production and the expenses related to the development of oil and natural gas properties, each of which is subject to numerous risks and uncertainties, will affect the timing and amount of actual future net cash flows from our proved reserves and their present value. In addition, our PV-10 estimates are based on prices and costs as of the date of the estimates. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Further, the effect of derivative instruments is not reflected in these assumed prices. Also, the use of a 10% discount factor to calculate PV-10 may not necessarily represent the most appropriate discount factor given actual interest rates and risks to which our business or the oil and natural gas industry in general are subject.

Oil and natural gas exploration, exploitation and development activities may not be successful and could result in a complete loss of a significant investment.

Exploration, exploitation and development activities are subject to many risks. For example, new wells we drill may not be productive and we may not recover all or any portion of our investment in such wells. Similarly, previously producing wells that are returned to production after a period of being shut in may not produce at levels that justify the expenditures made to bring the wells back on line. Drilling for oil and natural gas often involves unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient oil or natural gas to return a profit at then realized prices after deducting drilling, operating and other costs. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or natural gas is present or that it can be produced economically. The cost of exploration, exploitation and development activities is subject to numerous uncertainties, and cost factors can adversely affect the economics of a project. Further, our development activities may be curtailed, delayed or canceled as a result of numerous factors, including:

- title problems;
- problems in delivery of our oil and natural gas to market;
- pressure or irregularities in geological formations;

- equipment failures or accidents;
- shortages of, or delays in obtaining, equipment or qualified personnel;
- adverse weather conditions;
- reductions in oil and natural gas prices;
- compliance with environmental and other governmental requirements; and
- costs of, or shortages or delays in the availability of, drilling rigs, equipment and services.

Dry holes and other unsuccessful or uneconomic exploration, exploitation and development activities adversely affect our cash flow, profitability and financial condition, and can adversely affect our reserves.

The marketability of our production is dependent upon gathering systems, transportation facilities and processing facilities that we do not control. For our largest field, we rely on one barge to transport production from the field. When these facilities or systems, including the barge, are unavailable, our operations can be interrupted and our revenues reduced.

The marketability of our oil and natural gas production depends in part upon the availability, proximity and capacity of pipelines, natural gas gathering systems, transportation barges and processing facilities owned by third parties. In general, we do not control these facilities and our access to them may be limited or denied due to circumstances beyond our control. A significant disruption in the availability of these facilities could adversely impact our ability to deliver to market the oil and natural gas we produce and thereby cause a significant interruption in our operations. In some cases, our ability to deliver to market our oil and natural gas is dependent upon coordination among third parties who own transportation and processing facilities we use, and any inability or unwillingness of those parties to coordinate efficiently could also interrupt our operations. These are risks for which we generally do not maintain insurance.

We are at particular risk with respect to oil produced at our South Ellwood field, which is our largest field in terms of proved reserves. Our average net oil production from the field during the fourth quarter of 2008 was 2,440 Bbl/d, or approximately 21% of our aggregate net oil production for the quarter. The oil produced at the field is delivered via a single-hulled barge owned and operated by an unaffiliated third party. This third party is the only company that currently has a permit to deliver oil via barge in the vicinity of the field and, at this time, the barge is the only means available to us for delivery of oil produced from the field. Our loss of the use of the barge, in the absence of a satisfactory alternative delivery arrangement, would have an adverse effect on our financial condition and results of operations. Our ability to use the alternate barge described in "Business and Properties—Description of Properties—Southern California—South Ellwood Field" is subject to receipt of certain permits and approvals, and we cannot assure you that we will obtain those consents and approvals in a timely manner or at all. In addition, our ability to use the alternate barge at any given time will be subject to its other delivery commitments. Accordingly, even after the necessary consents and approvals are obtained, we would not expect to have access to the alternate barge on short notice.

From time to time, the barge is unavailable due to maintenance and repair requirements. It has been out of service, sometimes for several weeks at a time, for scheduled and unscheduled maintenance and repairs on multiple occasions in the past three years. Because we have limited storage capacity for oil produced from the field, we were required to significantly curtail production at the field during the periods in which the barge was unavailable. In addition, the owner of the refinery to which we historically delivered oil production from the field informed us in August 2006 that it was unwilling to accept further deliveries from the barge. If the current purchaser of oil production from the field were to make a similar decision, we would have to find a new purchaser and/or enter into an alternative delivery arrangement for the production. Any new delivery or sales arrangement would require time to implement and could require us to accept lower prices for our production and/or incur higher transportation costs. In addition, if we are unable, for any sustained period, to implement an acceptable delivery or sales arrangement, we will be required to shut in or curtail production from the field. Any such shut in or curtailment, or an inability to obtain favorable terms for delivery of the oil produced from the field, would adversely affect our financial condition and results of operations. We would be similarly affected if any of the other transportation, gathering and processing facilities we use became unavailable or unable to provide services.

Our hedging arrangements involve credit risk and may limit future revenues from price increases, result in financial losses or reduce our income.

To reduce our exposure to fluctuations in the prices of oil and natural gas, we enter into hedging arrangements with respect to a substantial portion of our oil and natural gas production. See "Quantitative and Qualitative Disclosures About Market Risk" for a summary of our hedging activity. Hedging arrangements expose us to risk of financial loss in some circumstances, including when:

- production is less than expected;
- a counterparty to a hedging contract fails to perform under the contract; or
- there is a change in the expected differential between the underlying price in the hedging contract and the actual prices received.

Based on current commodities prices, we expect a substantial percentage of our cash flow during 2009 to result from payments made to us by our hedge counterparties. We previously maintained some hedge positions with Lehman Brothers Commodity Services, Inc., which we terminated in connection with the bankruptcy of Lehman Brothers Holdings Inc. If other hedge counterparties, some of which have received governmental support in connection with the ongoing credit crisis, are unable to make payments to us under our hedging arrangements, our results of operation, financial condition and liquidity would be adversely affected.

In addition, the uncertainties associated with our hedging programs are greater than those of many of our competitors because the price of the heavy oil that we produce in California is subject to risks that are in addition to the price risk associated with premium grade light oil. Also, our working capital could be impacted if we enter into derivative arrangements that require cash collateral and commodity prices subsequently change in a manner adverse to us. The obligation to post cash or other collateral could, if imposed, adversely affect our liquidity.

Moreover, we have experienced, and may continue to experience, substantial realized and unrealized losses relating to our hedging arrangements. Realized commodity derivative gains or losses represent the difference between the strike prices set forth in hedging contracts settled during the relevant period and the ultimate settlement prices. We incur a realized commodity derivative loss when a contract is settled at a price above the strike price. Losses of this type reflect the limit our hedging arrangements impose on the benefits we would otherwise have received from an increase in the price of oil or natural gas during the period. Unrealized commodity derivative gains and losses represent the change in the fair value of our open derivative contracts from period to period. We incur an unrealized commodity derivative loss when the futures price used to estimate the fair value of a contract at the end of the period rises. Increases in oil prices have caused us to incur substantial realized and unrealized commodity derivative losses in some recent periods, and we may experience similar or greater losses of these types in future periods. We may experience more volatility in our commodity derivative gains and losses than many of our competitors because we discontinued the use of hedge accounting in 2007 and because we hedge a larger percentage of our production than some of our competitors. As discussed in "Management's Discussion and Analysis of Results of Operation and

Financial Condition—Liquidity and Capital Resources—Capital Resources and Requirements," our second lien term loan agreement requires us to hedge a significant percentage of our anticipated production.

We are subject to complex laws and regulations, including environmental laws and regulations, that can adversely affect the cost, manner and feasibility of doing business and limit our growth.

Our operations and facilities are subject to extensive federal, state and local laws and regulations relating to exploration for, and the exploitation, development, production and transportation of, oil and natural gas, as well as environmental and safety matters. We cannot be certain that existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws or regulations, will not harm our business, results of operations and financial condition. Laws and regulations applicable to us include those relating to:

- land use restrictions, which are particularly strict along the coast of southern California where many of our operations are located;
- drilling bonds and other financial responsibility requirements;
- spacing of wells;
- emissions into the air (including emissions from ships in the Santa Barbara channel);
- unitization and pooling of properties;
- habitat and endangered species protection, reclamation and remediation;
- the containment and disposal of hazardous substances, oil field waste and other waste materials;
- the use of underground storage tanks;
- transportation and drilling permits;
- the use of underground injection wells, which affects the disposal of water from our wells;
- safety precautions;
- the prevention of oil spills;
- the closure of production facilities;
- operational reporting; and
- taxation and royalties.

Under these laws and regulations, we could be liable for:

- personal injuries;
- property and natural resource damages;
- releases or discharges of hazardous materials;
- well reclamation costs;
- oil spill clean-up costs;
- other remediation and clean-up costs;
- plugging and abandonment costs, which may be particularly high in the case of offshore facilities;
- governmental sanctions, such as fines and penalties; and

- other environmental damages.

Any noncompliance with these laws and regulations could subject us to material administrative, civil or criminal penalties or other liabilities. We are a defendant in a series of lawsuits alleging, among other things, that air, soil and water contamination from the oil and natural gas facility at our Beverly Hills field caused the plaintiffs to develop cancer or other diseases or to sustain related injuries. See "Legal Proceedings—Beverly Hills Litigation." If resolved adversely to us, these suits could have a material adverse effect on our financial condition. In addition, compliance with applicable laws and regulations could require us to delay, curtail or terminate existing or planned operations.

Some environmental laws and regulations impose strict liability. Strict liability means that in some situations we could be exposed to liability for clean-up costs and other damages as a result of conduct that was lawful at the time it occurred or for the conduct of prior operators of properties we have acquired or other third parties. In addition, we may be required to make large and unanticipated capital expenditures to comply with applicable laws and regulations, for example by installing and maintaining pollution control devices. Similarly, our plugging and abandonment obligations will be substantial and may be more than our estimates. Compliance costs are relatively high for us because many of our properties are located offshore California and in other environmentally sensitive areas and because California environmental laws and regulations are generally very strict. It is not possible for us to estimate reliably the amount and timing of all future expenditures related to environmental matters, but they will be material. Environmental risks are generally not fully insurable.

In addition, our operations could be adversely affected by environmental and other laws and regulations that require us to obtain permits before commencing drilling or other activities. For example, as discussed in "Business and Properties—Southern California," we are pursuing a full-field development project in the South Ellwood field that includes a proposed extension of the area covered by our lease. We will be required to obtain numerous consents and approvals from governmental agencies prior to commencing work on the project, including from the U.S. Coast Guard, the California State Lands Commission, the California Coastal Commission, the California Division of Oil, Gas, and Geothermal Resources, the Santa Barbara County Air Pollution Control District, Santa Barbara County and the City of Goleta. We may not be able to obtain these consents and approvals as quickly as we expect or at all. In addition, the necessary consents and approvals may be granted subject to conditions which impose delays on the project, increase its costs or reduce its benefits to us. Other projects we pursue will typically be subject to similar risks. These risks are high for us relative to many of our competitors because oil and natural gas projects are frequently the source of considerable political controversy in California, and political opposition may make it more difficult for us to obtain consents and approvals for our projects. A recent attempt by another energy company to obtain an offshore lease in Southern California was rejected by the California State Lands Commission.

We could also be adversely affected by existing or future tax laws and regulations. For example, proposals have been made to amend federal and/or California law to impose "windfall profits," severance or other taxes on oil and natural gas companies. If any of these proposals become law, our costs would increase, possibly materially. Significant financial difficulties currently facing the State of California may increase the likelihood that one or more of these proposals will become law.

Our business involves significant operating risks that could adversely affect our production and could be expensive to remedy.

Our operations are subject to all the risks normally incident to the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells, including:

- well blowouts;
- cratering and explosions;
- pipe failures and ruptures;

- pipeline accidents and failures;
- casing collapses;
- fires;
- mechanical and operational problems that affect production;
- formations with abnormal pressures;
- uncontrollable flows of oil, natural gas, brine or well fluids; and
- releases of contaminants into the environment.

Our offshore operations are further subject to a variety of operating risks specific to the marine environment, including a dependence on a limited number of gas and water injection wells and electrical transmission lines. Moreover, because we operate in California, we are also susceptible to risks posed by natural disasters such as earthquakes, mudslides, fires and floods.

In addition to lost production and increased costs, these hazards could cause serious injuries, fatalities, contamination or property damage for which we could be held responsible. The potential consequences of these hazards are particularly severe for us because a significant portion of our operations are conducted offshore and in other environmentally sensitive areas, including areas with significant residential populations. We do not maintain insurance in amounts that cover all of the losses to which we may be subject, and the insurance we have may not continue to be available on acceptable terms. The occurrence of an uninsured or underinsured loss could result in significant costs that could have a material adverse effect on our financial condition and liquidity. In addition, maintenance activities undertaken to reduce operational risks can be costly and can require exploration, exploitation and development operations to be curtailed while those activities are being completed.

A failure to complete successful acquisitions would limit our growth.

An important component of our strategy is to acquire additional oil and natural gas properties, or businesses that own or operate such properties, when attractive opportunities arise. Our focus on the California market reduces the pool of suitable acquisition opportunities. If we do identify an appropriate acquisition candidate, we may be unable to negotiate mutually acceptable terms with the seller, finance the acquisition or obtain the necessary regulatory approvals. Our substantial level of indebtedness will further limit our ability to make future acquisitions, particularly if difficult conditions in the credit markets persist. If we are unable to complete suitable acquisitions, it will be more difficult to replace our reserves, and an inability to replace our reserves would have a material adverse effect on our financial condition and results of operations.

Acquisitions involve a number of risks, including the risk that we will discover unanticipated liabilities or other problems associated with the acquired business or property.

In assessing potential acquisitions, we typically rely to a significant extent on information provided by the seller. We independently review only a portion of that information. In addition, our review of the business or property to be acquired will not be comprehensive enough to uncover all existing or potential problems that could affect us as a result of the acquisition. Accordingly, it is possible that we will discover problems with an acquired business or property that we did not anticipate at the time we completed the transaction. These problems may be material and could include, among other things, unexpected environmental problems, title defects or other liabilities. Often, we acquire properties on an "as-is" basis, and have limited or no remedies against the seller with respect to these types of problems.

The success of any acquisition we complete will depend on a variety of factors, including our ability to accurately assess the reserves associated with the acquired properties, future oil and natural gas prices and operating costs, potential environmental and other liabilities and other factors. These assessments are necessarily inexact. As a result, we may not recover the purchase price of a property from the sale of production from the property or recognize an acceptable return from such sales. In addition, we may face greater risks to the extent we acquire properties in areas outside of California and the Gulf Coast of Texas, because we may be less familiar with operating, regulatory and other issues specific to those areas.

Our ability to achieve the benefits we expect from an acquisition will also depend on our ability to efficiently integrate the acquired operations with ours. Our management may be required to dedicate significant time and effort to the integration process, which could divert its attention from other business concerns. The challenges involved in the integration process may include retaining key employees and maintaining key employee morale, addressing differences in business cultures, processes and systems and developing internal expertise regarding the acquired properties.

Competition in the oil and natural gas industry is intense and may adversely affect our results of operations.

We operate in a competitive environment for acquiring properties, marketing oil and natural gas, integrating new technologies and employing skilled personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be willing and able to pay more for oil and natural gas properties than our financial resources permit, and may be able to define, evaluate, bid for and purchase a greater number of properties. Our competitors may also enjoy technological advantages over us and may be able to implement new technologies more rapidly than we can. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. We may not be able to compete successfully in the future with respect to acquiring prospective reserves, developing reserves, marketing our production, attracting and retaining qualified personnel, implementing new technologies and raising additional capital.

Our operations are subject to a variety of contractual, regulatory and other constraints that can limit our production and increase our operating costs and thereby adversely affect our results of operations.

We are subject to a variety of contractual, regulatory and other operating constraints that limit the manner in which we conduct our business. These constraints affect, among other things, the permissible uses of our facilities, the availability of pipeline capacity to transport our production and the manner in which we produce oil and natural gas. These constraints can change to our detriment without our consent. For example, effective January 2003, the terms of the sales gas transportation contract relating to the South Ellwood field were revised to reduce the permitted amount of carbon dioxide in the natural gas we transport from the field and to make the method of measuring carbon dioxide levels more stringent. To comply with these new requirements, we shut in some wells with a high natural gas-to-oil ratio, and this reduced our natural gas sales from the field. Similar events may occur in the future. These events, many of which are beyond our control, could have a material adverse effect on our results of operations and financial condition and could reduce estimates of our proved reserves.

The loss of our CEO or other key personnel could adversely affect our business.

We believe our continued success depends in part on the collective abilities and efforts of Timothy Marquez, our CEO, and other key personnel, including the executive officers listed in "Business and Properties—Executive Officers of the Registrant." We do not maintain key man life insurance policies. The loss of the services of Mr. Marquez or other key management personnel could have a material adverse effect on our results of operations. Additionally, if we are unable to find, hire and retain needed key personnel in the future, our results of operations could be materially and adversely affected.

Shortages of qualified operational personnel or field equipment and services could affect our ability to execute our plans on a timely basis, increase our costs and adversely affect our results of operations.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. From time to time, there have also been shortages of drilling rigs and other field equipment, as demand for rigs and equipment has increased with the number of wells being drilled. These factors can also result in significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate increased demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. We have experienced some difficulty in obtaining drilling rigs, experienced crews and related services in the past year and may continue to experience these difficulties in the future. In part, these difficulties arise from the fact that the California market is not as attractive for oil field workers and equipment operators as mid-continent and Gulf Coast areas where drilling activities are more widespread. In addition, the cost of drilling rigs and related services has increased significantly over the past several years. If shortages persist or prices continue to increase, our profit margin, cash flow and operating results could be adversely affected and our ability to conduct our operations in accordance with current plans and budgets could be restricted.

Because we cannot control activities on properties we do not operate, we cannot control the timing of those projects. If we are unable to fund required capital expenditures with respect to non-operated properties, our interests in those properties may be reduced or forfeited.

Other companies operated approximately 4% of our production in the fourth quarter of 2008. Our ability to exercise influence over operations for these properties and their associated costs is limited. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence operations and associated costs could prevent the realization of our targeted returns on capital with respect to exploration, exploitation, development or acquisition activities. The success and timing of exploration, exploitation and development activities on properties operated by others depend upon a number of factors that may be outside our control, including:

- the timing and amount of capital expenditures;
- the operator's expertise and financial resources;
- approval of other participants in drilling wells; and
- selection of technology.

Where we are not the majority owner or operator of a particular oil and natural gas project, we may have no control over the timing or amount of capital expenditures associated with the project. If we are not willing and able to fund required capital expenditures relating to a project when required by the majority owner or operator, our interests in the project may be reduced or forfeited. Also, if the majority owner or operator becomes insolvent, we may be liable for plugging and abandonment and other liabilities in excess of our proportionate interest in the property.

Changes in the financial condition of any of our large oil and natural gas purchasers could make it difficult to collect amounts due from those purchasers.

For the year ended December 31, 2008, approximately 87% of our oil and natural gas revenues were generated from sales to four purchasers: ConocoPhillips, Enserco Energy, Teppco Partners, and Tesoro Refining and Marketing Company. A material adverse change in the financial condition of any of our largest purchasers could adversely impact our future revenues and our ability to collect current accounts receivable from such purchasers.

We were required to write down the carrying value of our properties as of December 31, 2008 and may be required to do so again in the future.

We use the full cost method of accounting for oil and natural gas exploitation, development and exploration activities. Under full cost accounting rules, we perform a "ceiling test." This test is an impairment test and generally establishes a maximum, or "ceiling," of the book value of our oil and natural gas properties that is equal to the expected after-tax present value of the future net cash flows from proved reserves, calculated using prevailing prices on the last day of the relevant period. If the net book value of our properties (reduced by any related net deferred income tax liability) exceeds the ceiling, we write down the book value of the properties. At December 31, 2008, our net capitalized costs exceeded the ceiling by $641 million, net of income tax effects, and we recorded an impairment of our oil and gas properties in that amount. We could recognize further impairments in the future. To the extent our finding and development costs increase, we will become more susceptible to ceiling test write downs in low price environments.

We are controlled by Timothy Marquez, who is able to determine the outcome of matters submitted to a vote of our stockholders. This limits the ability of other stockholders to influence our management and policies.

Timothy Marquez, our Chairman and CEO, beneficially owned approximately 60% of our outstanding common stock as of February 19, 2009. Through this ownership, Mr. Marquez is able to control the composition of our board of directors and direct our management and policies. Accordingly, Mr. Marquez has the direct or indirect power to:

- elect all of our directors and thereby control our policies and operations;
- amend our bylaws and some provisions of our certificate of incorporation;
- appoint our management;
- approve future issuances of our common stock or other securities;
- approve the payments of dividends, if any, on our common stock;
- approve the incurrence of debt by us; and
- agree to or prevent mergers, consolidations, sales of all or substantially all our assets or other extraordinary transactions.

Mr. Marquez's significant ownership interest could adversely affect investors' perceptions of our corporate governance. In addition, Mr. Marquez may have an interest in pursuing acquisitions, divestitures and other transactions that involve risks to us and you. For example, Mr. Marquez could cause us to make acquisitions that increase our indebtedness or to sell revenue generating assets. Mr. Marquez may from time to time acquire and hold interests in businesses that compete directly or indirectly with us. Also, we have engaged, and may continue to engage, in related party transactions involving Mr. Marquez. For example, we purchased certain real property interests from an affiliate of Mr. Marquez for $5.3 million in December 2008.

Some of our directors have relationships with other companies in the oil and natural gas industry that could result in conflicts of interest.

Some of our directors serve as directors and/or officers of other companies engaged in the oil and natural gas industry and may have other relationships with such companies. For example, Mac McFarland provides consulting services to various energy-related companies from time to time, Joel Reed is the lead principal of a firm that provides investment banking services to such companies from time to time and Rick Walker provides executive search services to such companies from time to time. To the extent those companies are involved in ventures in which we may participate, or compete for acquisitions or financial resources with us, the relevant director will face a conflict of interest. In the event such a conflict arises, the relevant director will be required to disclose the nature and extent of the conflict and abstain from voting for or against any action of the board that is or could be affected by the conflict.

The market price of our common stock could be adversely affected by sales of substantial amounts of our common stock in the public markets or the issuance of additional shares of common stock in future acquisitions.

Sales of a substantial number of shares of our common stock in the public market, or the perception that these sales may occur, could cause the market price of our common stock to decline. In addition, the sale of these shares in the public market, or the possibility of such sales, could impair our ability to raise capital through the sale of additional common or preferred stock. As of February 19, 2009, Timothy Marquez beneficially owned approximately 60% of our common stock, primarily through the Marquez Trust. As of December 31, 2008, we had granted options to purchase an aggregate of approximately 3.5 million shares of our common stock and 851,545 shares of restricted stock to certain of our directors and employees. The Marquez Trust and these other holders, subject to compliance with applicable securities laws, are permitted to sell shares they own or acquire upon the exercise of options in the public market. Sales of a substantial number of shares of our common stock by those holders could cause our stock price to fall.

In addition, in the future, we may issue shares of our common stock in connection with acquisitions of assets or businesses. If we use our shares for this purpose, the issuances could have a dilutive effect on the market value of shares of our common stock, depending on market conditions at the time of an acquisition, the price we pay, the value of the business or assets acquired, our success in exploiting the properties or integrating the businesses we acquire and other factors.

Our certificate of incorporation and bylaws and Delaware law contain provisions that may prevent, discourage or frustrate attempts to replace or remove our current management by our stockholders, even if such replacement or removal may be in our stockholders' best interests.

Our certificate of incorporation and bylaws and Delaware law contain provisions that could enable our management, including Mr. Marquez, to resist a takeover attempt (even if Mr. Marquez ceases to beneficially own a controlling block of our common shares). These provisions:

- restrict various types of business combinations with significant stockholders (other than the Marquez Trust, Mr. Marquez and his wife);
- provide for a classified board of directors;
- limit the right of stockholders to remove directors or change the size of the board of directors;
- limit the right of stockholders to fill vacancies on the board of directors;
- limit the right of stockholders to act by written consent or call a special meeting of stockholders;
- require a higher percentage of stockholders than would otherwise be required to amend, alter, change or repeal certain provisions of our certificate of incorporation; and
- authorize the issuance of preferred stock with any voting rights, dividend rights, conversion privileges, redemption rights and liquidation rights and other rights, preferences, privileges, powers, qualifications, limitations or restrictions as may be specified by our board of directors.

These provisions could:

- discourage, delay or prevent a change in the control of our company or a change in our management, even if the change would be in the best interests of our stockholders;
- adversely affect the voting power of holders of common stock; and

- limit the price that investors might be willing to pay in the future for shares of our common stock.

ITEM 1B. Unresolved Staff Comments

None.

ITEM 3. Legal Proceedings

In the ordinary course of our business we are named from time to time as a defendant in various legal proceedings. We maintain liability insurance and believe that our coverage is reasonable in view of the legal risks to which our business ordinarily is subject.

Beverly Hills Litigation

Between June 2003 and April 2005, six lawsuits were filed against us and certain other energy companies in Los Angeles County Superior Court by persons who attended Beverly Hills High School or who were or are citizens of Beverly Hills/Century City or visitors to that area during the time period running from the 1930s to date. There are approximately 1,000 plaintiffs (including plaintiffs in two related lawsuits in which we have not been named) who claimed to be suffering from various forms of cancer or other illnesses, fear they may suffer from such maladies in the future, or are related to persons who have suffered from cancer or other illnesses. Plaintiffs alleged that exposure to substances in the air, soil and water that originated from either oil-field or other operations in the area were the cause of the cancers and other maladies. We have owned an oil and natural gas facility adjacent to the school since 1995. For the majority of the plaintiffs, their alleged exposures occurred before we acquired the facility. All cases were consolidated before one judge. Twelve "representative" plaintiffs were selected to have their cases tried first, while all of the other plaintiffs' cases were stayed. In November 2006, the judge entered summary judgment in favor of all defendants in the test cases, including us. The judge dismissed all claims by the test case plaintiffs on the ground that they offered no evidence of medical causation between the alleged emissions and the plaintiffs' alleged injuries. Plaintiffs appealed the ruling. A decision on the appeal is expected in 2009. We vigorously defended the actions, and will continue to do so until they are resolved. Certain defendants have made claims for indemnity for events occurring prior to 1995, which we are disputing. We cannot predict the cost of these indemnity claims at the present time.

One of our insurers currently is paying for the defense of these lawsuits under a reservation of its rights. Three other insurers that provided insurance coverage to us (the "Declining Insurers") took the position that they were not required to provide coverage for losses arising out of, or to defend against, the lawsuits because of a pollution exclusion contained in their policies. In February 2006, we filed a declaratory relief action against the Declining Insurers in Santa Barbara County Superior Court seeking a determination that those insurers have a duty to defend us in the lawsuits. Two of the three Declining Insurers settled with us. The third Declining Insurer disputed our position and in November 2007 the Santa Barbara Court granted that insurer's motion for summary judgment, in part on the basis that the pollution exclusion provision in the policy did not require that insurer to provide a defense for us. We have appealed the Santa Barbara Court's ruling. We have no reason to believe that the insurer currently providing defense of these actions will cease providing such defense. If it does, and we are unsuccessful in enforcing its rights in any subsequent litigation, we may be required to bear the costs of the defense, and those costs may be material. If it ultimately is determined that the pollution exclusion or another exclusion contained in one or more of our policies applies, we will not have the protection of those policies with respect to any damages or settlement costs ultimately incurred in the lawsuits.

In accordance with SFAS No. 5, *Accounting for Contingencies*, we have not accrued for a loss contingency relating to the Beverly Hills litigation because we believe that, although unfavorable outcomes in the proceedings may be reasonably possible, we do not consider them to be probable or reasonably estimable. If one or more of these matters are resolved in a manner adverse to us, and if insurance coverage is determined not to be applicable, their impact on our results of operations, financial position and/or liquidity could be material.

State Lands Commission Royalty Audit

We pay royalties to the state of California pursuant to certain oil and natural gas leases relating to the South Ellwood field. We have been informed by the California State Lands Commission (the "SLC") that the SLC is in the process of auditing our royalty payment calculations on those leases. The SLC has not completed its audit, nor has it presented us with any audit conclusions. We do not currently expect that the audit adjustments, if any, will be material.

ITEM 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of stockholders during the fourth quarter of the fiscal year covered by this report.

PART II

ITEM 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Price Range of Common Stock and Number of Holders

Our common stock is listed on the New York Stock Exchange under the symbol "VQ".

The following table sets forth the high and the low sale prices per share of our common stock for the periods indicated. The closing price of the common stock on March 2, 2008 was $2.89.

	2007		2008	
Period	**High**	**Low**	**High**	**Low**
1st Quarter	$17.90	$13.86	$19.86	$11.50
2nd Quarter	$21.02	$17.31	$23.99	$11.90
3rd Quarter	$19.64	$13.40	$23.96	$12.33
4th Quarter	$23.71	$16.93	$12.59	$ 2.07

As of February 28, 2009, there were 346 record holders, and approximately 2,573 beneficial owners, of our common stock.

Unregistered Sales of Equity Securities

Not applicable.

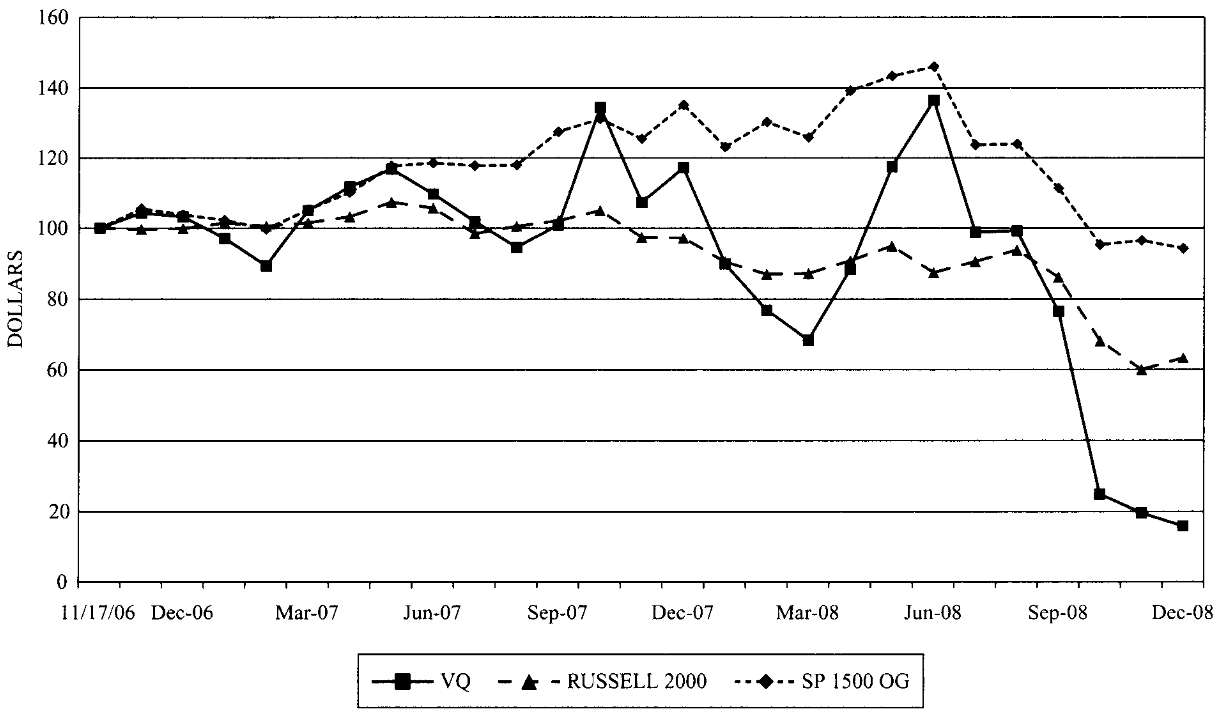
Dividend Policy

We have not declared any cash dividends on our common stock during the two most recent fiscal years and have no plans to do so in the foreseeable future. The ability of our board of directors to declare any dividend is subject to limits imposed the terms of our debt agreements, which currently prohibit us from paying dividends on our common stock. See "Management's Discussion and Analysis of Financial Condition and Results of Operation—Liquidity and Capital Resources—Capital Resources and Requirements." Our ability to pay dividends is also subject to limits imposed by Delaware law. In determining whether to declare dividends, the board will consider the limits imposed by our debt agreements, our financial condition, results of operations, working capital requirements, future prospects and other factors it considers relevant.

Comparison of Cumulative Return

The following graph compares the cumulative return on a $100 investment in our common stock from November 17, 2006, the date the common stock trading began on the New York Stock Exchange, through December 31, 2008, to that of the cumulative return on a $100 investment in the Russell 2000 Index and the S&P 1500 Oil and Gas Consumable Fuels Index for the same period. In calculating the cumulative return, reinvestment of dividends, if any, is assumed. The indices are included for comparative purpose only. This graph is not "soliciting material," is not deemed filed with the SEC and is not to be incorporated by reference in any of our filings under the Securities Act of 1933 or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language in any such filing.

COMPARISON OF CUMULATIVE TOTAL RETURN AMONG VENOCO, INC., THE RUSSELL 2000 INDEX, AND THE S&P 1500 OIL AND GAS CONSUMABLE FUELS INDEX



ITEM 6. Selected Financial Data

The table below contains selected consolidated financial data. The statement of operations, cash flow, balance sheet and other financial data for each year has been derived from our consolidated financial statements. You should read this information together with "Management's Discussion and Analysis of Financial Condition and Results of Operation" and our consolidated financial statements and the related notes included elsewhere in this report. Amounts are in thousands, except per share data. Pro forma information reflects the effect of the Hastings sale as if it had been completed on January 1, 2008 for statement of operations data and capital expenditures. The pro forma condensed balance sheet data is presented as if the sale had been completed on December 31, 2008, after the ceiling impairment. See "Business and Properties—Recent Developments—Hastings Sale."

	Years ended December 31,					
	2004(3)(4)	2005	2006	2007	2008	Pro Forma 2008
Statement of Operations Data:						
Oil and natural gas revenues(5)	$137,819	$191,772	$ 268,822	$ 373,155	$ 555,917	$ 461,186
Other revenues(1),(5)	5,457	4,456	5,470	3,355	3,603	3,509
Total revenues	143,276	196,228	274,292	376,510	559,520	464,695
Oil and natural gas production(5)	49,567	54,038	87,505	119,321	149,504	112,115
Transportation expense	2,915	2,596	3,533	6,061	5,958	5,958
Depletion, depreciation and amortization(6)	16,489	21,680	63,259	98,814	134,483	117,834
Impairment of oil and natural gas properties(6)	—	—	—	—	641,000	458,000
Accretion of asset retirement obligations(7)	1,482	1,752	2,542	3,914	4,203	3,990
General and administrative expenses, net of capitalized amounts	11,272	16,007	28,317	31,770	43,101	43,101
Total expenses	81,725	96,073	185,156	259,880	978,249	740,998
Income (loss) from operations	61,551	100,155	89,136	116,630	(418,729)	(276,303)
Interest expense, net(8)	2,269	13,673	48,795	60,115	54,049	49,488
Amortization of deferred loan costs	3,050	1,755	3,776	4,197	3,344	3,344
Interest rate derivative losses (gains), net	—	—	590	17,177	20,567	20,567
Loss on extinguishment of debt	—	—	—	12,063	—	—
Commodity derivative losses (gains), net	16,543	58,275	(3,626)	142,650	(116,757)	(116,757)
Total financing costs and other	21,862	73,703	49,535	236,202	(38,797)	(43,358)
Income (loss) before minority interest	39,689	26,452	39,601	(119,572)	(379,932)	(232,945)
Income tax provision (benefit)(9)	16,088	10,300	15,650	(46,200)	11,200	11,200
Minority interest in Marquez Energy	95	42	—	—	—	—
Net income (loss)	23,506	16,110	23,951	(73,372)	(391,132)	(244,145)
Preferred stock dividends	(7,134)	—	—	—	—	—
Excess of carrying value over repurchase price of preferred stock(2)	29,904	—	—	—	—	—
Net income (loss) applicable to common equity	$ 46,276	$ 16,110	$ 23,951	$ (73,372)	$(391,132)	$(244,145)
Earnings per common share:						
Basic	$ 1.33	$ 0.49	$ 0.71	$ (1.58)	$ (7.75)	$ (4.84)
Diluted:	$ 0.48	$ 0.49	$ 0.69	$ (1.58)	$ (7.75)	$ (4.84)
Cash Flow Data:						
Cash provided by (used in):						
Operating activities	$ 43,309	$ 39,931	$ 89,090	$ 160,863	$ 212,379	N/A
Investing activities	(27,990)	(58,695)	(595,204)	(433,363)	(332,861)	N/A
Financing activities	30,979	(26,562)	505,089	273,871	110,938	N/A
Other Financial Data:						
Capital expenditures	$ 16,442	$ 79,470	$ 174,613	$ 322,283	$ 318,582	$ 291,621
Balance Sheet Data (end of period):						
Cash and cash equivalents(10)	$ 54,715	$ 9,389	$ 8,364	9,735	191	58,948
Plant, property and equipment, net(11)	198,563	233,776	774,253	1,131,032	702,734	498,758
Total assets(10)(11)	298,882	302,558	893,193	1,265,485	864,254	719,035
Long-term debt, excluding current portion(10)	163,542	178,943	529,616	691,896	797,670	657,118
Stockholders' equity	48,439(4)	4,334	190,316	245,602	(135,167)	(135,167)

(1) Other revenues primarily include amounts received from purchasers of our oil production to reimburse us for transportation and barge expenses.

(2) Amount comprises the excess of the carrying value over the repurchase price of our mandatorily redeemable convertible preferred stock plus accrued and unpaid dividends net of unamortized issuance costs.

(3) We acquired Marquez Energy, a Colorado limited liability company majority owned and controlled by our CEO, Timothy Marquez, in March 2005. The purchase price for the membership interests in Marquez Energy was $16.8 million (including a $2.0 million deposit paid in 2004). Because Marquez Energy was a company under common control with us since July 12, 2004, our financial statements and production information for all of 2005 and for the third and fourth quarters of 2004 include Marquez Energy. For the same reason, the acquisition was accounted for in a manner similar to a pooling of interests whereby the historical results of Marquez Energy have been combined with our financial results since July 1, 2004.

(4) Mr. Marquez's percentage beneficial ownership in our common stock increased from approximately 94% to 100% on December 22, 2004, the date we effected a merger with a corporation the sole stockholder of which was the Marquez Trust. Accordingly, Mr. Marquez's basis in our assets has been "pushed-down" as of the date of the merger, meaning that our post-transaction financial statements reflect Mr. Marquez's basis in our assets (the successor basis) rather than our historical basis. The aggregate purchase price has been allocated to a portion of the underlying assets and liabilities based upon their respective fair values at the date of the merger, with the values of certain long-lived assets reduced on a pro rata basis for the excess of Mr. Marquez's portion of the fair value of acquired net assets over the purchase price of the shares acquired. Due to the *de minimis* impact on our results of operations for the nine-day period ended December 31, 2004, the successor basis of accounting has been applied to our financial statements as of December 31, 2004, with the consolidated statements of operations, comprehensive income (loss), and cash flows for the fiscal year ended 2004 being presented on a historical, or "predecessor" basis.

(5) The pro forma information reflects the removal of all Hastings related revenues and production expenses for the year ended December 31, 2008.

(6) The pro forma information reflects the effect on depletion expense and the ceiling test impairment related to the removal of Hastings related production, reserves, capital expenditures and the allocation of the proceeds to the full cost pool.

(7) The pro forma information reflects the removal of the asset retirement obligation accretion expense related to Hastings.

(8) The pro forma information reflects the effect on interest expense assuming full repayment of the outstanding balance on our revolving credit facility and repayment of $5.5 million of the outstanding principal balance on our second lien term loan.

(9) The pro forma income tax balance is unchanged due to the valuation allowance recorded at December 31, 2008.

(10) Proceeds from the Hastings sale of $201.0 million were initially offset by $1.2 million of revenue suspense balance assumed by Denbury. The remaining net proceeds of $199.8 million were used to repay all amounts outstanding under the revolving credit facility and accrued interest (at December 31, 2008, the balance outstanding under the facility was $135.1 million and accrued interest was $0.5 million) and to repay $5.5 million of the outstanding principal balance on our second lien term loan facility. The remaining proceeds are reflected in cash and cash equivalents.

(11) The pro forma information reflects proceeds from the Hastings sale of $201.0 million allocated to the full cost pool along with the removal of the asset retirement obligation of $2.9 million associated with the properties sold in the Hastings sale.

ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operation

The following discussion and analysis should be read in conjunction with our financial statements and related notes and the other information appearing in this report.

Overview

We are an independent energy company primarily engaged in the acquisition, exploration, exploitation and development of oil and natural gas properties. Our strategy is to grow through exploration, exploitation and development projects we believe to be relatively low risk and through selective acquisitions of underdeveloped properties. Pursuit of this strategy has led to increases in our oil and natural gas production over the past three years. Our average net production increased from 17,349 BOE/d in 2006 (calculated as described in footnote 1 to the table included in "—Results of Operations") to 19,535 BOE/d in 2007 and to 21,674 BOE/d in 2008. Our proved reserves were 87.9 MMBOE at December 31, 2006, 99.9 MMBOE at December 31, 2007 and 97.5 MMBOE at December 31, 2008.

In the execution of our strategy, our management is principally focused on developing additional reserves of oil and natural gas and on maximizing production levels through exploration, exploitation and development activities on a cost-effective basis and in a manner consistent with preserving adequate liquidity and financial flexibility.

Capital Expenditures

We have developed an active capital expenditure program to take advantage of our extensive inventory of drilling prospects and other projects. Our exploration, exploitation and development capital expenditures, including amounts accrued and unpaid at December 31, 2008, were $301.8 million in 2008, down from $310.1 million in 2007, and we expect that they will be approximately $150.0 million in 2009. We expect to spend approximately 49% of the amount budgeted for 2009 on projects in the Sacramento Basin, 23% in the Southern California region, 3% in Texas, 12% for exploration projects in a variety of areas, and the balance for capitalized G&A. We have entered into hedging arrangements to secure floors on 101% of our forecast 2009 production. The price floors are intended to ensure a minimum revenue stream to sustain an active capital expenditure program and satisfy our other obligations. The aggregate levels of capital expenditures for 2009, and the allocation of those expenditures, are dependent on a variety of factors, including the availability of capital resources to fund the expenditures and changes in our business assessments as to where our capital can be most profitably employed. Accordingly, the actual levels of capital expenditures and the allocation of those expenditures may vary materially from our estimates. The following summarizes certain significant aspects of our capital spending program in 2008 and 2009:

Southern California—Exploitation and Development

In Southern California, we drilled four new wells in 2008, including one at platform Grace that was spud in 2007 and plugged during the first quarter of 2008. The remaining three wells were all in the West Montalvo field. The first, a successful onshore development well, was spud in September and completed in November. The second, also a successful onshore well, was spud in October and was completed and brought on to production in January 2009. The third well is an offshore well drilled from an onshore surface location. This well was spud in December 2008 and is expected to be completed and placed on production in the first half of March 2009. We have projects ongoing to increase our gas handling capacity at West Montalvo and we do not expect these wells to produce at full capacity until this work is completed later in March. We also performed 19 workovers and recompletions in Southern California during 2008. This work included six workovers and eight wells returned to production at the West Montalvo field, four workovers at the Sockeye field, and one workover at the South Ellwood field. In 2009, we plan to drill two additional wells in the West Montalvo field and one new well at the Sockeye field. We also plan to conduct wellwork as part of waterflood optimizations at the Sockeye and Beverly Hills West fields.

In the Sockeye field, we continue to implement our waterflood program from platform Gail and are working on the evaluation and design of a possible expansion of the program. We are also continuing to evaluate a possible expansion of our horizontal and multi-lateral well drilling activities to the Monterey formation in the field.

In the South Ellwood field, the permitting process continues for our full-field development project in the South Ellwood field. We anticipate receiving a final environmental impact report relating to the project in 2009 and for the project approval hearings to begin thereafter. Key components of the project include an extension of the current lease boundary (which would effectively double the size of the existing lease area) and the installation of an onshore oil transport pipeline to replace the existing barge. Development of the lease extension area can be accomplished from the field's existing platform. We have been pursuing the pipeline permitting process and acquiring rights-of-way. Our 2009 capital expenditure budget includes a small amount for continued work towards pipeline permitting and acquisition of rights-of-way.

Sacramento Basin—Exploitation and Development

In the Sacramento Basin, we continue to pursue our infill drilling program in the greater Grimes and Willows fields. We drilled 112 wells in the basin in 2008 (81% of which were productive) and performed 144 workovers and recompletions. We operated during the majority of 2008 with five drilling rigs in the basin. For a short period of time at the end of 2008 and beginning of 2009 we operated with six drilling rigs. As of February 2009, we have three drilling rigs and seven workover/completion rigs working in the basin. We expect to drill over 70 new wells and perform more than 100 workovers and recompletions there in 2009. As of December 31, 2008, we had identified 530 drilling locations in the basin, and we anticipate identifying additional locations as we pursue exploitation and development opportunities there.

We continue to test and evaluate potential downspacing opportunities in the basin as well as new methods of improving productivity and reducing drilling costs. Of the 112 wells drilled in the basin during 2008, 45 were drilled on 40-acre spacing, 53 were drilled on 20-acre spacing, and 14 were drilled on 10-acre spacing. We also initiated a hydraulic fracturing program during 2008 to targets in the Forbes and deeper formations of the basin. We fractured 70 wells during 2008. We have been encouraged by the results and continue to analyze those results in order to optimize future fracture simulations in the basin. As of December 31, 2008, our acreage position in the basin had grown to approximately 208,000 net acres (245,000 gross).

Texas—Exploitation and Development

In Texas, our primary focus in 2008 was the redevelopment of the Hastings complex in preparation for the sale of our principal interests in the complex to Denbury. Other Texas activity included the drilling of three new wells. One of these wells was a development well in the Manvel field that was spud in December 2008. We drilled across a fault and plan to use the well for a sidetrack at a later date. The second well was a successful exploration gas well drilled in the South Liberty field. The third well, also an exploration well, was spud in August. The well was unsuccessful and we plan to plug and abandon it in the first quarter of 2009. We also performed 170 workovers and recompletions in Texas during 2008, of which 154 were completed at the Hastings complex and 12 were completed in the Manvel field. In 2009, we plan to drill three wells and perform approximately seven workovers and recompletions in our Texas fields.

Acquisitions and Divestitures

West Montalvo and Manvel Acquisitions. We acquired the West Montalvo field in Ventura County, California in May 2007 for approximately $61.3 million. We acquired the Manvel field in Brazoria County, Texas, and certain other fields in Texas, in April 2007 for $44.5 million.

TexCal Transaction. We acquired TexCal Energy (LP) LLC on March 31, 2006 for $456.8 million in cash. In order to finance the purchase price for the acquisition and related transaction costs of approximately $14.4 million, we borrowed approximately $119.5 million under our revolving credit facility and $350.0 million under our second lien term loan facility.

Hastings Sale. In February 2009, we completed the sale of our principal interests in the Hastings complex to Denbury for approximately $201.0 million. As a result of the sale, we repaid all amounts outstanding under our revolving credit facility and $5.5 million of the outstanding principal balance on our second lien term loan facility.

Other. We have an active acreage acquisition program and we regularly engage in acquisitions (and, to a lesser extent, dispositions) of oil and natural gas properties, primarily in and around our existing core areas of operations, including several transactions in each of 2006, 2007 and 2008.

Trends Affecting our Results of Operations

Oil and Natural Gas Prices. Historically, prices received for our oil and natural gas production have been volatile and unpredictable, and that volatility is expected to continue. Changes in the market prices for oil and natural gas directly impact many aspects of our business, including our financial condition, revenues, results of operations, liquidity, rate of growth, the carrying value of our oil and natural gas properties and borrowing capacity under credit facilities, all of which depend primarily or in part upon those prices. For example, as a result of lower commodity prices at December 31, 2008, we were required to record a full cost ceiling impairment of our oil and gas properties in the fourth quarter. Continued low prices in early 2009 contributed significantly to a reduction in the borrowing base under our revolving credit facility. In addition, as a result of declines in commodity prices, as well as the deterioration in the overall economy, we significantly reduced our capital expenditures planned for 2009 as compared to our actual capital expenditures incurred in 2008. In order to reduce the variability of the prices we receive for our production and provide a minimum revenue stream, we employ a hedging strategy. As of March 3, 2009, we had hedge contract floors covering approximately 101% of our 2009 production guidance, in excess of 90% of our anticipated 2010 production and in excess of 60% of our anticipated 2011 production. All of our derivatives counterparties are commercial banks that are parties to our credit facilities. See "Quantitative and Qualitative Disclosures About Market Risk—Commodity Derivative Transactions" for further details concerning our hedging activities.

Expected Production. We expect that the execution of our capital expenditure program in 2009 will result in average daily production volumes in 2009 that are consistent with 2008 volumes, pro forma for the Hastings sale. We expect our Southern California properties, which produced 3.0 MMBOE during 2008 (of which 94% was oil), to exhibit modest production growth as compared to 2008. In particular, we expect the drilling and workover/recompletion programs we began at the West Montalvo field in 2007 to result in production increases there in 2009. In the Sacramento Basin, we intend to continue our multi-year drilling program and plan to drill more than 70 new wells and perform over 100 workovers and recompletions. As a result of reducing the number of rigs active in the basin from five to three, we expect average daily production in the basin to decline over the course of 2009 but expect full year average net production in 2009 to be relatively flat relative to average 2008 net production from the basin. At the Manvel field, which we acquired in April 2007, we are continuing a redevelopment program by upgrading our fluid handling and injection capacity and plan to drill two new wells and perform approximately five workovers and recompletions. Our expectations with respect to future production rates are subject to a number of uncertainties, including those associated with third party services, oil and natural gas prices, events resulting in unexpected downtime, permitting issues, drilling success rates, pipeline capacity, changes in our capital expenditure budget and other factors, including those referenced in "Risk Factors."

Production Expenses. Production expenses consist of lease operating expenses ("LOE") and production and property taxes. LOE per BOE increased from $15.05 per BOE in 2007 to $16.86 per BOE in 2008. The 2008 LOE reflects an increase in electrical usage and rates in Texas, non-recurring maintenance costs at Sockeye and twelve full months of expense at Manvel and West Montalvo (acquired in April 2007 and May 2007, respectively). We expect our production expenses to decrease on a BOE basis for 2009 as a whole, primarily due to the sale of the relatively high cost Hastings properties in the first quarter of 2009. Production and property taxes decreased as a percentage of revenue from 3.2% in 2007 to 2.8% in 2008, primarily due to increased revenues in 2008 as a result of historically high commodity prices in the first half of the year. We expect production/property taxes to increase as a percentage of revenue in 2009 due to lower expected commodity prices in 2009. Our expectations with respect to future expenses are subject to numerous risks and uncertainties, including those described and referenced in the preceding paragraph.

General and Administrative Expenses. General and administrative expenses were $4.79 per BOE in 2008, excluding charges under SFAS 123R of $0.30 per BOE and non-recurring charges of $0.34 per BOE relating to the termination of a planned master limited partnership ("MLP") offering. This represented an increase from per BOE G&A costs of $4.04 (excluding SFAS 123R charges of $0.42) in 2007. The change resulted from an overall increase in G&A costs in the 2008 period due to increased headcount and related infrastructure. Excluding SFAS 123R charges, we expect our 2009 G&A costs to be similar to our full year 2008 costs on a per BOE basis. As with production expenses, our expectations with respect to G&A costs are subject to numerous risks and uncertainties.

Unrealized Derivative Gains and Losses. Rising oil prices led to substantial unrealized commodity derivative losses in 2007 and the first half of 2008, while sharp declines in both oil and gas prices in the second half of 2008 resulted in unrealized commodity derivative gains in 2008. These unrealized gains and losses resulted from mark-to-market valuations of derivative positions that are not accounted for as cash flow hedges and are reflected as unrealized commodity derivative gains or losses in our income statement. Payments actually due to or from counterparties in the future on these derivatives will typically be offset by corresponding changes in prices ultimately received from the sale of our production. We may incur significant gains or losses of this type in 2009 and in subsequent years. As described in the notes to the consolidated financial statements included in this report, we discontinued hedge accounting as of April 1, 2007. This may increase volatility in gains and losses of this type in subsequent periods. We may also have significant unrealized interest rate derivative gains and losses in subsequent periods due to changes in market interest rates.

Results of Operations

The following table reflects the components of our oil and natural gas production and sales prices, and our operating revenues, costs and expenses, for the periods indicated. See "Business and

Properties—Production, Prices, Costs and Balance Sheet Information" for information presented on a pro forma basis reflecting the Hastings sale.

	Years ended December 31,		
	2006(1)	2007	2008
Production Volume:			
Oil (MBbls)(2)	3,411	3,981	4,091
Natural gas (MMcf)	14,314	18,895	23,050
MBOE	5,797	7,130	7,933
Daily Average Production Volume:			
Oil (Bbls/d)	9,958	10,907	11,178
Natural gas (Mcf/d)	44,346	51,767	62,978
BOE/d	17,349	19,535	21,674
Oil Price per Bbl Produced (in dollars):			
Realized price	$55.92	$64.06	$89.69
Realized commodity derivative gain (loss) and amortization of commodity derivative premiums	(8.38)	(4.35)	(20.71)
Net realized price	$47.54	$59.71	$68.98
Natural Gas Price per Mcf Produced (in dollars):			
Realized price	$ 6.04	$ 6.61	$ 8.21
Realized commodity derivative gain (loss) and amortization of commodity derivative premiums	0.36	0.23	0.08
Net realized price	$ 6.40	$ 6.84	$ 8.29
Average Sale Price per BOE(3)	$44.13	$50.24	$58.56
Expense per BOE:			
Lease operating expenses(4)	$14.18	$15.05	$16.86
Production and property taxes(4)	$ 0.91	$ 1.69	$ 1.98
Transportation expenses	$ 0.61	$ 0.85	$ 0.75
Depletion, depreciation and amortization	$10.91	$13.86	$16.95
General and administrative expense, net(5)	$ 4.88	$ 4.46	$ 5.43
Interest expense	$ 8.42	$ 8.43	$ 6.81

(1) Includes information for TexCal from March 31, 2006, the date of acquisition. Daily average production volumes shown represent (i) second, third and fourth quarter 2006 production from TexCal properties divided by 275 days plus (ii) production from other Venoco properties for the full year 2006 divided by 365 days. Total net production for 2006 divided by 365 days results in average net production of 15,882 BOE/d.

(2) Amounts shown are oil production volumes for offshore properties and sales volumes for onshore properties (differences between onshore production and sales volumes are minimal). Revenue accruals are adjusted for actual sales volumes since offshore oil inventories can vary significantly from month to month based on the timing of barge deliveries, oil in tanks and pipeline inventories, and oil pipeline sales nominations.

(3) Amounts shown are based on oil and natural gas sales, net of inventory changes, realized commodity derivative gains (losses), and amortization of commodity derivative premiums, divided by sales volumes.

(4) Lease operating expenses and property and production taxes are combined to comprise oil and natural gas production expense on the consolidated statements of operations.

(5) Net of amounts capitalized.

Comparison of Year Ended December 31, 2008 to Year Ended December 31, 2007

Oil and Natural Gas Sales. Oil and natural gas sales increased $182.7 million (49%) to $555.9 million in 2008 from $373.2 million in 2007. The increase was primarily due to a 11% increase in production and a 17% increase in average sales prices as described below.

Oil sales increased by $116.8 million in 2008 (47%) to $366.6 million compared to $249.8 million in 2007. Oil production rose 3%, with production of 4,091 MBbl in 2008 compared to 3,981 MBbl in 2007. The production increase was attributable primarily to a full year of production from the Manvel field, which was acquired in April 2007, and the West Montalvo field, which was acquired in May 2007, and to our workover program in the Hastings complex, offset by the natural decline of production. Our average realized price for oil increased $25.63 (40%) to $89.69 per Bbl for the period.

Natural gas sales increased $66.0 million in 2008 (54%) to $189.3 million compared to $123.3 million in 2007. Natural gas production increased 22%, with production of 23,050 MMcf compared to 18,895 MMcf in 2007. The increase was due primarily to drilling and recompletion activities in the Sacramento Basin. Our average realized price for natural gas increased $1.60 (24%) to $8.21 per Mcf for the period.

Other Revenues. Other revenue was relatively constant at $3.6 million in 2008 compared to $3.4 million in 2007.

Production Expenses. Production expenses, which consist of lease operating expenses ("LOE") and production/property taxes, increased $30.2 million (25%) to $149.5 million in 2008 from $119.3 million in 2007. The increase was due to (i) a significant increase in electricity usage and rates in Texas in 2008, (ii) non-recurring maintenance costs incurred at Sockeye in 2008, (iii) the effect of twelve full months of expense related to the Manvel and West Montalvo acquisitions, which occurred in April and May 2007, respectively, and (iv) an increase in secured and supplemental property taxes related to our California properties. On a per unit basis, LOE increased to $16.86 per BOE in 2008 from $15.05 per BOE in 2007.

Transportation Expenses. Transportation expenses remained relatively flat at $6.0 million in 2008 compared to $6.1 million in 2007. On a per BOE basis, transportation expenses decreased $0.10 per BOE, from $0.85 per BOE in 2007 to $0.75 per BOE in 2008.

Depletion, Depreciation and Amortization (DD&A). DD&A expense increased $35.7 million (36%) to $134.5 million in 2008 from $98.8 million in 2007. DD&A expense per BOE rose $3.09, from $13.86 per BOE in 2007 to $16.95 per BOE in 2008. The increase was primarily due to a higher depletion expense resulting from increases in oil and natural gas property costs resulting from our capital expenditure program.

Impairment. During the fourth quarter of 2008, we recorded an impairment charge to the net book value of oil and gas properties of $641 million as the result of the required full cost ceiling test. The impairment was caused principally by lower year-end oil and natural gas prices.

Accretion of Abandonment Liability. Accretion expense increased $0.3 million (7%) to $4.2 million in 2008 from $3.9 million in 2007. The increase was due to accretion from the properties acquired in the Manvel and West Montalvo acquisitions and from new wells drilled and completed in 2007 and 2008.

General and Administrative (G&A). G&A expense, net of amounts capitalized, increased $11.3 million (36%) to $43.1 million in 2008 from $31.8 million in 2007. The increase was a result of $2.7 million of costs that were expensed in the second quarter of 2008 related to the cancellation of the planned MLP offering, and an increase in our professional staff and related infrastructure. Non-cash share-based compensation expense included in G&A was $3.0 million in 2007 and $2.4 million in 2008.

The increase was primarily due to the increase in our professional staff. Excluding the effect of the non-cash SFAS 123R charges and the non-recurring MLP charges, G&A increased $0.75 per BOE from $4.04 per BOE in 2007 to $4.79 per BOE in 2008.

Interest Expense, Net. Interest expense, net of interest income, decreased $6.1 million (10%) from $60.1 million in 2007 to $54.0 million in 2008, primarily as a result of a decrease in interest rates during 2008, partially offset by an increase in average debt outstanding in 2008.

Amortization of Deferred Loan Costs. Amortization of deferred loan costs decreased $0.9 million (20%), from $4.2 million in 2007 to $3.3 million in 2008. The decrease was primarily due to the write-off of deferred loan costs in connection with the refinancing of our term loan facility in 2007, as well as the amendment to the revolving credit facility in May 2008 which extended the maturity date of the facility.

Interest Rate Derivative Losses (Gains), Net. Changes in the fair value of our interest rate swap derivative instruments resulted in unrealized losses of $10.3 million in 2008 and $17.3 million in 2007. The change between years is the result of an increase in the notional amount of debt covered by the interest rate swap and a more significant decrease in expected future interest rates in 2007 than in 2008. We realized an interest rate swap loss of $10.2 million in 2008 compared to a realized gain of $0.1 million in 2007.

Loss on the Extinguishment of Debt. We incurred a loss on extinguishment of debt of $12.1 million in the second quarter of 2007 when we prepaid the prior second lien term loan facility and replaced it with the new term loan facility. We paid a premium of $3.5 million and wrote off related deferred loan costs of $8.6 million in connection with the prepayment.

Commodity Derivative Losses (Gains), Net. The following table sets forth the components of commodity derivative (gains) losses, net in our consolidated statements of operations for the years indicated (in thousands):

	Years Ended December 31,	
	2007	2008
Realized commodity derivative (gains) losses	$ 13,041	$ 61,446
Unrealized commodity derivative (gains) losses	122,779	(184,459)
Amortization of commodity derivative premiums	6,830	6,256
Total	$142,650	$(116,757)

Realized commodity derivative gains or losses represent the difference between the strike prices in the contracts settled during the period and the ultimate settlement prices. The realized commodity derivative losses in 2007 and 2008 reflect the settlement of contracts at prices above the relevant strike prices. Unrealized commodity derivative (gains) losses represent the change in the fair value of our open derivative contracts from period to period. The change in unrealized commodity derivative (gains) losses reflects an increase in the notional volumes under derivative contracts outstanding in 2008 and a decrease in the futures prices used to estimate the fair value of those contracts at the end of the period. Derivative premiums are amortized over the term of the underlying derivative contracts.

Income Tax Expense. We provided a valuation allowance against our net deferred tax assets of $156.9 million as of December 31, 2008, since we cannot conclude that is more likely than not that the net deferred tax assets will be realized. The valuation allowance resulted in income tax expense of $11.2 million in 2008, even though we incurred a loss before taxes. In 2007, the loss before taxes resulted in an income tax benefit of $46.2 million.

Net Income (Loss). Our net loss for 2008 was $391.1 million compared to net loss of $73.4 million in 2007. The change between periods is the result of the items discussed above.

Comparison of Year Ended December 31, 2007 to Year Ended December 31, 2006

Oil and Natural Gas Sales. Oil and natural gas sales increased $104.3 million (39%) to $373.1 million in 2007 from $268.8 million in 2006. The increase was primarily due to a 23% increase in production and a 14% increase in average sales prices as described below.

Oil sales increased by $65.3 million in 2007 (35%) to $249.8 million compared to $184.5 million in 2006. Oil production rose 17%, with production of 3,981 MBbl in 2007 compared to 3,411 MBbl in 2006. The production increase was attributable primarily to the acquisition of the TexCal properties in March 2006, the Manvel field in April 2007 and the West Montalvo field in May 2007, and to our workover program in the Hastings complex. Our average realized price for oil increased $8.14 (15%) to $64.06 per Bbl for the period.

Natural gas sales increased $39.0 million in 2007 (46%) to $123.3 million compared to $84.3 million in 2006. Natural gas production increased 32%, with production of 18,895 MMcf compared to 14,314 MMcf in 2006. The increase was due primarily to drilling and recompletion activities in the Sacramento Basin and production attributable to the March 2006 TexCal acquisition, offset by decreases in natural gas production at the South Ellwood field and the Santa Clara Federal Unit. Our average realized price for natural gas increased $0.57 (9%) to $6.61 per Mcf for the period.

Other Revenues. Other revenue decreased 39%, from $5.5 million in 2006 to $3.4 million in 2007. The change was primarily due to lower transportation income received from purchasers of oil production from the South Ellwood field.

Production Expenses. Production expenses, which consist of lease operating expenses ("LOE") and production and property taxes, increased $31.8 million (36%) to $119.3 million in 2007 from $87.5 million in 2006. The increase was primarily due to production expenses attributable to the TexCal, Manvel and West Montalvo acquisitions and an increase in the number of producing wells at other Venoco properties. On a per unit basis, LOE increased to $15.05 per BOE in 2007 compared to $14.18 per BOE in 2006.

Transportation Expenses. Transportation expenses increased 72%, from $3.5 million in 2006 to $6.1 million in 2007. This was primarily attributable to increased transportation costs for barge deliveries. On a per BOE basis, transportation expenses increased $0.24 per BOE, from $0.61 per BOE in 2006 to $0.85 per BOE in 2007.

Depletion, Depreciation and Amortization (DD&A). DD&A expense increased $35.5 million (56%) to $98.8 million in 2007 from $63.3 million in 2006. DD&A expense per BOE rose $2.95, from $10.91 per BOE in 2006 to $13.86 per BOE in 2007. The increase was primarily due to a higher depletion expense resulting from the increase in the oil and natural gas property cost as a result of the TexCal, Manvel and West Montalvo acquisitions and the increase in oil and natural gas property costs during the year resulting from our capital expenditure program.

Accretion of Abandonment Liability. Accretion expense increased $1.4 million (54%) to $3.9 million in 2007 from $2.5 million in 2006. The increase was due to accretion from the properties acquired in the TexCal, Manvel and West Montalvo acquisitions and from new wells drilled and completed in the second half of 2006 and in 2007.

General and Administrative (G&A). G&A expense, net of amounts capitalized, increased $3.5 million (12%) to $31.8 million in 2007 from $28.3 million in 2006. The increase resulted primarily from increases in our professional staff and related infrastructure costs and non-recurring charges of $1.3 million for the settlement of employment contracts in 2007. Non-cash share-based compensation expense included in G&A was $2.8 million in 2006 and $3.0 million in 2007. The increase was primarily due to the increase in our professional staff. Excluding the effect of the non-cash SFAS 123R charges, G&A decreased $0.37 per BOE from $4.41 per BOE in 2006 to $4.04 per BOE in 2007.

Interest Expense, Net. Interest expense, net of interest income, increased $11.3 million (23%) from $48.8 million in 2006 to $60.1 million in 2007. The increase was primarily due to an increase in average debt outstanding in 2007.

Amortization of Deferred Loan Costs. Amortization of deferred loan costs increased $0.4 million, from $3.8 million in 2006 to $4.2 million in 2007, because the 2007 total reflects a full year of amortization of loan costs related to our second lien term loan facility compared to nine months of amortization in 2006 (the debt was initially incurred on March 31, 2006).

Interest Rate Derivative Losses (Gains), Net. Changes in the fair value of our interest rate swap derivative instruments resulted in unrealized losses of $0.5 million in 2006 and $17.3 million in 2007. The change between years is the result of an increase in the notional amount of debt covered by the interest rate swap and a decrease in estimated interest rates used to determine the fair value of the derivative instruments. Realized interest rate swap gains were $0.1 million in 2007 compared to losses of $0.1 million in 2006.

Loss on Extinguishment of Debt. We incurred a loss on extinguishment of debt of $12.1 million in the second quarter of 2007 when we prepaid the prior second lien term loan facility and replaced it with the new term loan facility. We paid a premium of $3.5 million and wrote off related deferred loan costs of $8.6 million in connection with the prepayment of the prior term loan facility.

Commodity Derivative Losses (Gains), Net. The following table sets forth the components of commodity derivative losses, net in our consolidated statements of operations for the years indicated (in thousands):

	Years Ended December 31,	
	2006	2007
Realized commodity derivative (gains) losses	$ 15,263	$ 13,041
Unrealized commodity derivative (gains) losses	(21,079)	122,779
Amortization of commodity derivative premiums	2,190	6,830
Total	$ (3,626)	$142,650

Realized commodity derivative gains or losses represent the difference between the strike prices in the contracts settled during the period and the ultimate settlement prices. The realized commodity derivative losses in 2006 and 2007 reflect the settlement of contracts at prices above the relevant strike prices. Unrealized commodity derivative (gains) losses represent the change in the fair value of our open derivative contracts from period to period. The change in unrealized commodity derivative (gains) losses reflects an increase in the notional volumes under derivative contracts outstanding in 2007 and an increase in the futures prices used to estimate the fair value of those contracts at the end of the period. Derivative premiums are amortized over the term of the underlying derivative contracts. The increase in amortization of derivative premiums in 2007 reflects additional premiums paid in connection with the additional contracts outstanding in 2007.

Income Tax Expense. The loss before taxes in 2007 resulted in an income tax benefit of $46.2 million compared to income tax expense of $15.7 million in 2006.

Net Income (Loss). Our net loss for 2007 was $73.4 million compared to net income of $24.0 million in 2006. The change between periods is the result of the items discussed above.

Liquidity and Capital Resources

Our primary sources of liquidity are cash generated from our operations and amounts available under our revolving credit facility.

Cash Flows

	Years ended December 31,		
	2006	2007	2008
	(in thousands)		
Cash provided by (used in) operating activities . . .	$ 89,090	$ 160,863	212,379
Cash provided by (used in) investing activities . . .	(595,204)	(433,363)	(332,861)
Cash provided by (used in) financing activities . . .	505,089	273,871	110,938

Net cash provided by operating activities was $212.4 million in 2008, up from $160.9 million in 2007 and $89.0 million in 2006. Cash flows from operating activities were favorably impacted in 2007 and 2008 by increases in commodity prices and production from properties acquired in 2007 and our development program.

Net cash used in investing activities was $332.9 million in 2008 compared to $433.4 million in 2007 and $595.2 million in 2006. The primary investing activities in 2008 were $311.2 million in expenditures for oil and gas properties and $14.3 million for acquisitions. The primary investing activities in 2007 include $316.9 million in expenditures for oil and gas properties and $121.8 million paid to acquire the West Montalvo and Manvel fields and other properties. The primary investing activities in 2006 include $447.5 million paid in cash to acquire TexCal (net of TexCal cash) and $185.2 million in expenditures for oil and gas properties.

Net cash provided by financing activities was $110.9 million in 2008 compared to $273.9 million in 2007 and $505.1 million in 2006. The primary financing activities in 2008 were $93.1 million in net borrowings under the revolving credit facility to fund capital expenditures and working capital needs. The primary financing activities in 2007 were $151.1 million in net borrowings under the second lien term loan facility to fund capital expenditures and working capital needs and $11.4 million in net borrowings under the revolving credit facility. Net proceeds from an additional offering of common stock completed in July 2007 were $116.0 million, of which $95.0 million was used to pay down amounts outstanding under our revolving credit facility; the remainder was used to fund our capital expenditure program. Proceeds from long-term debt in 2006 included $350.0 million borrowed under the prior term loan facility and $119.5 million in net borrowings under the revolving credit facility, which amounts were primarily used to fund the acquisition of TexCal and $14.4 million in loan costs. Net proceeds from our initial public offering of common stock in November 2006 were $157.5 million, of which $156.5 million and $1.1 million were used to reduce amounts outstanding under the revolving credit facility and the second lien term loan facility, respectively. Other net borrowings in 2006 under the revolving credit facility of $47.5 million were used to fund capital expenditures and working capital needs.

Capital Resources and Requirements

We plan to make substantial capital expenditures in the future for the acquisition, exploration, exploitation and development of oil and natural gas properties. We expect that our exploration, exploitation and development capital expenditures, which were $301.8 million in 2008, will be approximately $150.0 million in 2009. We intend to finance these capital expenditures through a combination of cash flow from operations and cash on hand of approximately $37 million at March 2, 2009. We expect to supplement our capital budget with additional amounts borrowed under our revolving credit facility, in particular to satisfy short-term working capital needs, but do not currently expect to have a significant amount drawn on our revolving credit facility by the end of 2009. Uncertainties relating to our capital resources and requirements in 2009 include the possibility that one or more of the counterparties to our hedging arrangements fails to perform under the contracts and the possibility that we will pursue one or more significant acquisitions that would require additional debt or equity financing.

Amended Revolving Credit Facility. We entered into a second amended and restated agreement governing our revolving credit facility in March 2006, and have entered into several subsequent amendments to the agreement. In May 2008 we amended the facility to, among other things, extend its maturity to March 2011. The agreement contains customary representations, warranties, events of default, indemnities and covenants, including covenants that restrict our ability to incur indebtedness and require us to maintain specified ratios of current assets to current liabilities and debt to EBITDA. The minimum ratio of current assets to current liabilities (as those terms are defined in the agreement) is one to one; the maximum ratio of debt to EBITDA (as defined in the agreement) is four to one. The revolving credit facility has a total capacity of $300.0 million, but is limited by a borrowing base currently established at $125.0 million. The borrowing base is subject to redetermination in April and November of each year, and may be redetermined at other times at our request or at the request of the lenders. The agreement requires us to reduce amounts outstanding under the facility with the proceeds of certain transactions or events, including sales of assets, in certain circumstances. The revolving credit facility is secured by a first priority lien on substantially all of our assets.

Loans under the revolving credit facility designated as "Base Rate Loans" bear interest at a floating rate equal to (i) the greater of Bank of Montreal's announced base rate and the overnight federal funds rate plus 0.50% plus (ii) an applicable margin ranging from zero to 0.75%, based upon utilization. Loans designated as "LIBO Rate Loans" under the revolving credit facility bear interest at (i) LIBOR plus (ii) an applicable margin ranging from 1.50% to 2.25%, based upon utilization. A commitment fee ranging from 0.375% to 0.5% per annum is payable with respect to unused borrowing availability under the facility.

In anticipation of the Hastings sale, in January 2009 we requested a borrowing base redetermination. Consequently, effective with the sale, the borrowing base under the revolving credit facility was reduced from $200.0 million to $125.0 million. Lending commitments under the facility have been allocated at various percentages to a syndicate of twelve banks. Certain of the institutions included in the syndicate have received support from governmental agencies in connection with recent events in the credit markets. In addition, 4.75% of the $125.0 million borrowing base has been allocated to Lehman Commercial Paper ("LCP"), a wholly-owned subsidiary of Lehman Brothers Holding, Inc., which filed for bankruptcy protection in September 2008. LCP is no longer funding its portion of our borrowing requests made under the facility. Our effective borrowing base is $119.1 million, excluding $5.9 million related to LCP. A failure of any other member of the syndicate to fund under the facility, or a reduction in the borrowing base, would adversely affect our liquidity. As a result of the Hastings sale in February 2009, we repaid the outstanding balance of the facility in full. Subsequently, we borrowed approximately $5.6 million solely to maintain a balance of variable rate debt equivalent to the notional amount of our interest rate swap. See "Quantitative and Qualitative Disclosures About Market Risk." While we do not expect to be in violation of any of our debt covenants during 2009, we believe that it will be important to monitor the requirement that we maintain a specified ratio of debt to EBITDA (as defined in the agreement governing the revolving credit facility), in particular if commodity prices do not increase and we pursue our current capital expenditure plan. We do not currently expect to borrow any additional amounts under the facility until the third quarter of 2009. If we believe at that time that borrowing under the facility will give rise to a significant possibility of a covenant default, we may take a variety of actions, including but not limited to reducing our capital expenditure budget so as to reduce or eliminate the need to borrow under the facility.

Second Lien Term Loan. We entered into a $500.0 million senior secured second lien term loan agreement in May 2007. The term loan agreement contains customary representations, warranties, events of default and indemnities and certain customary operational covenants, including covenants that restrict our ability to incur additional indebtedness. The agreement requires us to maintain derivative contracts covering at least 70% of our projected oil and natural gas production attributable to proved developed producing reserves through May 8, 2010, and at least 50% of such production on an annual basis until the maturity date of the term loan. We cannot, however, enter into derivative contracts (other than certain put contracts) covering more than 80% of such projected oil and gas production in any month. The agreement also prohibits us from paying dividends on our common stock. The agreement will require us to make offers to prepay amounts outstanding under the second lien term loan facility with the proceeds of certain transactions or events, including sales of assets, in certain circumstances. Amounts prepaid under the facility may not be reborrowed. The term loan facility is secured by a second priority lien on substantially all of our assets. We repaid $5.5 million of principal under the facility in February 2009 after the Hastings sale.

Loans under the term loan facility designated as "Base Rate Loans" bear interest at a floating rate equal to (i) the greater of the overnight federal funds rate plus 0.50% and the administrative agent's announced base rate, plus (ii) 3.00%. Loans designated as "LIBO Rate Loans" bear interest at LIBOR plus 4.00%. We have entered into interest rate swaps pursuant to which amounts borrowed under the term loan agreement will effectively bear interest at a fixed rate of approximately 9.3% until June 2010. See "Quantitative and Qualitative Disclosures About Market Risk—Interest Rate Derivative Transactions."

Senior Notes. We issued $150.0 million of our senior notes in December 2004. The notes bear interest at 8.75% per year and will mature on December 15, 2011. We may redeem the notes at a redemption price initially equal to 104.375% of the principal amount and declining to 100% of the principal amount by December 15, 2010. Upon the occurrence of a change of control of our company, each holder of the notes may require us to repurchase all or a portion of its notes for cash at a price equal to 101% of the aggregate principal amount of those notes, plus any accrued and unpaid interest. The indenture governing the notes also contains operational covenants that, among other things, limit our ability to make investments, incur additional indebtedness or create liens on our assets. The notes are secured with the second lien term loan on an equal and ratable basis.

Principal on our second lien term loan facility is payable on May 8, 2014. However, if the senior notes are not refinanced in full prior to September 20, 2011, principal on the second lien term loan facility will be payable on that date. In order to preserve the later maturity date for the second lien term loan, we expect to pursue a refinancing of the senior notes. We are currently considering different refinancing options and will likely seek to exercise one of those refinancing options during 2009 if we believe market conditions are appropriate. If currently adverse conditions in the credit markets persist or worsen, it may be more difficult, or impossible, to refinance the senior notes.

Because we must dedicate a substantial portion of our cash flow from operations to the payment of amounts due under our debt agreements, that portion of our cash flow is not available for other purposes. Our ability to make scheduled interest payments on our indebtedness and pursue our capital expenditure plan will depend to a significant extent on our financial and operating performance, which is subject to prevailing economic conditions, commodity prices and a variety of other factors. If our cash flow and other capital resources are insufficient to fund our debt service obligations and our capital expenditure budget, we may be forced to reduce or delay scheduled capital projects, sell material assets or operations and/or seek additional capital. Needed capital may not be available on acceptable terms or at all. Our ability to raise funds through the incurrence of additional indebtedness and certain other means is limited by covenants in our debt agreements. In addition, pursuant to mandatory prepayment provisions in our credit facilities, our ability to respond to a shortfall in our expected liquidity by selling assets or incurring additional indebtedness would be limited by provisions in the facilities that require us to use some or all of the proceeds of such transactions to reduce amounts outstanding under one or both of the facilities in some circumstances. If we are unable to obtain funds when needed and on acceptable terms, we may not be able to complete acquisitions that may be favorable to us, meet our debt obligations or finance the capital expenditures necessary to replace our reserves.

Commitments and Contingencies

As of December 31, 2008, the aggregate amounts of contractually obligated payment commitments for the next five years were as follows (in thousands):

	Less than One Year	1 to 3 Years	3 to 5 Years	After 5 years	Total(1)
Long-term debt	$ 2,598	$797,670	—	—	$800,268
Interest on senior notes	13,125	25,639	—	—	38,764
Rental of office space	2,455	4,741	$4,660	$7,957	19,813
Total	$18,178	$828,050	$4,660	$7,957	$858,845

(1) Total contractually obligated payment commitments do not include the anticipated settlement of derivative contracts, obligations to taxing authorities or amounts relating to our asset retirement obligations, which include plugging and abandonment obligations, due to the uncertainty surrounding the ultimate settlement amounts and timing of these obligations. Our total asset retirement obligations were $80.6 million at December 31, 2008.

(2) Amounts related to interest expense on our revolving credit facility and second lien term loan facility are not included in the table above because the interest rates on those debt instruments are variable. During the years ended December 31, 2006, 2007 and 2008, we incurred interest expense on those debt instruments of $35.4 million, $50.0 million and $40.3 million, respectively.

Off-Balance Sheet Arrangements

At December 31, 2008, we had no existing off-balance sheet arrangements, as defined under SEC rules, that have or are reasonably likely to have a material current or future effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon financial statements that have been prepared in accordance with accounting principles generally accepted in the United States, or GAAP. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. We have identified certain accounting policies as being of particular importance to the presentation of our financial position and results of operations and which require the application of significant judgment by our management. We analyze our estimates, including those related to oil and natural gas revenues, oil and natural gas properties, fair value of derivative instruments, income taxes and contingencies and litigation, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies and estimates affect our more significant judgments and estimates used in the preparation of our financial statements.

Reserve Estimates

Our estimates of oil and natural gas reserves are, by necessity, projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as in the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and natural gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulation by governmental agencies and assumptions governing future oil and natural gas prices, future operating costs, severance, ad valorem and excise taxes, development costs and workover and remedial costs, all of which may vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on the likelihood of recovery and estimates of the future net cash flows expected from them may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value and the rate of depletion of the oil and natural gas properties. For example, oil and natural gas price changes affect the estimated economic lives of oil and natural gas properties and therefore cause reserve revisions. Our December 31, 2008 estimate of net proved oil and natural gas reserves totaled 97.5 MBOE. Had oil and natural gas prices been 10% lower as of the date of the estimate, our total oil and natural gas reserves would have been approximately 3.4% lower. In addition, our proved reserves are concentrated in a relatively small number of wells. At December 31, 2008, 16% of our proved reserves were concentrated in our 20 largest wells. As a result, any changes in proved reserves attributable to such individual wells could have a significant effect on our total reserves. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material.

Oil and Natural Gas Properties, Depletion and Full Cost Ceiling Test

We follow the full cost method of accounting for oil and natural gas properties. Under this method, all productive and nonproductive costs incurred in connection with the acquisition of, exploration for and exploitation and development of oil and natural gas reserves are capitalized. Such capitalized costs include costs associated with lease acquisition, geological and geophysical work, delay rentals, drilling, completing and equipping oil and natural gas wells, and salaries, benefits and other internal salary related costs directly attributable to these activities. Proceeds from the disposition of oil and natural gas properties are generally accounted for as a reduction in capitalized costs, with no gain or loss recognized. Depletion of the capitalized costs of oil and natural gas properties, including estimated future development and capitalized asset retirement costs, is provided for using the equivalent unit-of-production method based upon estimates of proved oil and natural gas reserves. The capitalized costs are amortized over the life of the reserves associated with the assets, with the amortization being expensed as depletion in the period that the reserves are produced. This depletion expense is calculated by dividing the period's production volumes by the estimated volume of reserves associated with the investment and multiplying the calculated percentage by the sum of the capitalized investment and estimated future development costs associated with the investment. Changes in our reserve estimates will therefore result in changes in our depletion expense per unit. For example, a 10% reduction in our estimated reserves as of December 31, 2008 would have resulted in an increase of approximately $1.98 per BOE in our depletion expense rate during 2008. Costs associated with production and general corporate activities are expensed in the period incurred. Interest costs related to unproved properties and properties under development are also capitalized to oil and natural gas properties. Unproved property costs not subject to amortization consist primarily of leasehold and seismic costs related to unproved areas. Costs are transferred into the amortization base on an ongoing basis as the properties are evaluated and proved reserves established or impairment determined. We will continue to evaluate these properties and costs will be transferred into the amortization base as undeveloped areas are tested. Unproved oil and natural gas properties are not amortized, but are assessed, at least annually, for impairment either individually or on an aggregated basis to determine whether we are still actively pursuing the project and whether the project has been proven, either to have economic quantities of reserves or that economic quantities of reserves do not exist.

Capitalized costs of oil and natural gas properties, excluding costs associated with unproved properties, may not exceed the present value of estimated future net revenues from proved reserves, discounted at 10%. Application of the ceiling test generally requires pricing future revenue at the unescalated prices in effect as of the last day of the relevant quarter and requires a write down for accounting purposes if the ceiling is exceeded. At December 31, 2008, our net capitalized costs exceeded the ceiling by $641 million, net of income tax effects, and we recorded a write down of our oil and natural gas properties in that amount. We may be required to recognize additional impairments of oil and gas properties in future periods if market prices of oil and natural gas continue to decline.

Asset Retirement Obligations

Effective January 1, 2003, we adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* ("SFAS 143"). SFAS 143 provides that, if the fair value for asset retirement obligations can be reasonably estimated, the liability should be recognized in the period when it is incurred. Oil and natural gas producing companies incur this liability upon acquiring or drilling a well. Under the method prescribed by SFAS No. 143, the retirement obligation is recorded as a liability at its estimated present value at the asset's inception, with the offsetting charge to property cost. Periodic accretion of discount of the estimated liability is recorded in the income statement. Prior to adoption of SFAS No. 143, we accrued for future abandonment costs of wells and related facilities through our depletion calculation in accordance with Regulation S-X Rule 4-10 and industry practice. This method resulted in recognition of the obligation over the life of the property on a unit-of-production basis, with the estimated obligation netted in property cost as part of the accumulated depreciation, depletion and amortization balance.

Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our properties at the end of their productive lives, in accordance with applicable laws. We have determined our asset retirement obligation by calculating the present value of estimated cash flows related to each liability. The discount rates used to calculate the present value varied depending on the estimated timing of the relevant obligation, but typically ranged between 4% and 9%. We periodically review the estimate of costs to plug, abandon and remediate our properties at the end of their productive lives. This includes a review of both the estimated costs and the expected timing to incur such costs. We believe most of these costs can be estimated with reasonable certainty based upon existing laws and regulatory requirements and based upon wells and facilities currently in place. Any changes in regulatory requirements, which changes cannot be predicted with reasonable certainty, could result in material changes in such costs. Changes in reserve estimates and the economic life of oil and natural gas properties could affect the timing of such costs and accordingly the present value of such costs.

Income Tax Expense

Income taxes reflect the tax effects of transactions reported in the financial statements and consist of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income tax assets and liabilities represent the future tax return consequences of those differences, which will either be taxable or deductible when assets are recovered or settled. Deferred income taxes are also recognized for tax credits that are available to offset future income taxes. Deferred income taxes are measured by applying current tax rates to the differences between financial statement and income tax reporting. We have recognized a valuation allowance against our net deferred taxes because we cannot conclude that it is more likely than not that the net deferred tax assets will be realized as a result of estimates of our future operating income based on current oil and natural gas commodity pricing. In assessing the realization of deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. We consider the scheduled reversal of deferred tax liabilities, available taxes in carryback periods, projected future taxable income and tax planning strategies in making this assessment. We will continue to evaluate whether the valuation allowance is needed in future reporting periods.

Derivative Instruments

Under SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended, we reflect the fair market value of our derivative instruments on our balance sheet. Our estimates of fair value are determined by obtaining independent market quotes, as well as utilizing a Black-Scholes option valuation model that is based upon underlying forward price curve data, a risk-free interest rate and estimated volatility factors. Changes in commodity prices will result in substantially similar changes in the fair value of our commodity swap agreements, and in substantially similar changes in the fair value of our commodity collars to the extent the changes are outside the floor or cap of our collars.

Recent Accounting Pronouncements

In March 2008, the FASB issued Statement No. 161, *Disclosure about Derivative Instruments and Hedging Activities—an amendment to FASB Statement No. 133* ("SFAS 161"). SFAS 161 expands interim and annual disclosures about derivative and hedging activities that are intended to better convey the purpose of derivative use and the risks managed. SFAS 161 is effective for fiscal years and interim periods beginning after November 15, 2008. The adoption of SFAS 161 is not expected to have an impact on our consolidated financial statements, other than additional disclosures.

In June 2008, the FASB issued FASB Staff Position No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* ("FSP 03-6-1"). FSP 03-6-1 addresses whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the earnings allocation in computing earnings per share (EPS) under the two-class method described in FASB Statement No. 128, *Earnings per Share*. The FSP concludes that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents are participating securities and shall be included in the computation of EPS pursuant to the two-class method. The statement is effective for fiscal years beginning after December 15, 2008, and interim periods within those years. All prior-period EPS data presented is to be adjusted retrospectively to conform to the provisions of this FSP. Our restricted stock awards contain dividend rights. We are currently assessing the impact of adoption of the FSP on our earnings per share calculations.

In December 2007, the FASB issued Statement No. 141R, *Business Combinations* ("SFAS 141R"). SFAS 141R establishes principles and requirements for how the acquirer of a business recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree. The statement also provides guidance for recognizing and measuring the goodwill acquired in business combinations and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. The statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. SFAS 141R may have an impact on our consolidated financial statements when effective, but the nature and magnitude of the specific effects will depend upon the nature, terms and size of the acquisitions we consummate after the effective date.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* ("SFAS 157"), which defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. This pronouncement applies to other standards that require or permit fair value measurements. Accordingly, this statement does not require any new fair value measurements. The provisions of SFAS 157 are effective January 1, 2008. The FASB has also issued Staff Position FAS 157-2 (FSP No. 157-2), which delays the effective date of SFAS 157 for nonfinancial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until fiscal years beginning after November 15, 2008. We adopted SFAS 157 as of January 1, 2008 for all financial and nonfinancial assets and liabilities recognized or disclosed at fair value on a recurring basis. We elected to defer the application thereof to nonfinancial assets and liabilities in accordance with FSP No. 157-2.

In December 2008, the SEC published revised rules regarding oil and gas reserves reporting requirements. The objective of the rules are to provide readers of financial statements with more meaningful and comprehensive understanding of oil and gas reserves. Key elements of the revised rules include a change in the pricing used to estimate reserves at period end, optional disclosure of probable and possible reserves, allowance of the use of new technologies in the determination of reserves and additional disclosure requirements. The rules also revise the prices used for reserves in determining depletion and the full cost ceiling test from a period end price to a 12-month average price. The revised rules are effective for registration statements filed on or after January 1, 2010 and for annual reports for fiscal years ending on or after December 31, 2009. Early adoption is not allowed. We are currently assessing the impact that the adoption of the revised rules will have on our operating results, financial position, cash flows, oil and gas reserves and disclosures.

PV-10

The pre-tax present value of future net cash flows, or PV-10, is a non-GAAP measure because it excludes income tax effects. Management believes that pre-tax cash flow amounts are useful for evaluative purposes since future income taxes, which are affected by a company's unique tax position and strategies, can make after-tax amounts less comparable. We derive PV-10 based on the present value of estimated future revenues to be generated from the production of proved reserves, net of estimated production and future development costs and future plugging and abandonment costs, using prices and costs as of the date of estimate without future escalation, without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion, amortization and impairment and income taxes, and discounted using an annual discount rate of 10%. The following table reconciles the standardized measure of future net cash flows to PV-10 as of the dates shown (in thousands):

	December 31,		
	2006(1)	2007(2)	2008(3)
Standardized measure of discounted future net cash flows	$ 819,302	$1,655,641	$610,096
Add: Present value of future income tax discounted at 10%	301,774	703,674	6,585
PV-10	$1,121,076	$2,359,315	$616,681

(1) Based on unescalated year-end posted prices of (i) $57.75 per Bbl for oil and natural gas liquids, and adjusted for quality, transportation fees and regional price differentials and (ii) $5.64 per MMBtu for natural gas, and adjusted for energy content, transportation fees and regional price differentials.

(2) Based on unescalated year-end posted prices of $95.97 per Bbl for oil and natural gas liquids and $7.48 per MMBtu for natural gas, and adjusted, in each case, as described in note (1) above.

(3) Based on unescalated year-end posted prices of $44.60 per Bbl for oil and natural gas liquids and $5.62 per MMBtu for natural gas, and adjusted, in each case, as described in note (1) above.

ITEM 7A. Quantitative and Qualitative Disclosures About Market Risk

This section provides information about derivative financial instruments we use to manage commodity price volatility. Due to the historical volatility of crude oil and natural gas prices, we have implemented a hedging strategy aimed at reducing the variability of the prices we receive for our production and providing a minimum revenue stream. Currently, we purchase puts and enter into other derivative transactions such as collars and fixed price swaps in order to hedge our exposure to changes in commodity prices. All contracts are settled with cash and do not require the delivery of a physical quantity to satisfy settlement. While this hedging strategy may result in us having lower revenues than we would have if we were unhedged in times of higher oil and natural gas prices, management believes that the stabilization of prices and protection afforded us by providing a revenue floor on a portion of our production is beneficial.

This section also provides information about derivative financial instruments we use to manage interest rate risk. See "—Interest Rate Derivative Transactions."

Commodity Derivative Transactions

Oil. As of December 31, 2008, we had entered into option, swap and collar agreements to receive average minimum and maximum NYMEX West Texas Intermediate prices as summarized below. Location and quality differentials attributable to our properties are not reflected in those prices. The agreements provide for monthly settlement based on the differential between the agreement price and the actual NYMEX crude oil price.

	Minimum		Maximum	
	Bbls/d	Weighted Avg. Prices	Bbls/d	Weighted Avg. Prices
Crude oil derivatives at December 31, 2008 for production:				
January 1–December 31, 2009	8,983	$54.06	6,983	$ 74.38
January 1–December 31, 2010	8,000	56.22	6,150	72.88
January 1–December 31, 2011	7,000	50.00	7,000	141.64

Natural Gas. As of December 31, 2008, we had entered into option, swap and collar agreements to receive average minimum and maximum NYMEX or PG&E Citygate prices as follows:

	Minimum		Maximum	
	MMBtu/d	Weighted Avg. Prices	MMBtu/d	Weighted Avg. Prices
Natural gas derivatives at December 31, 2008 for production:				
January 1–December 31, 2009	67,125	$6.92	23,125	$11.42
January 1–December 31, 2010	58,900	6.41	17,900	11.05
January 1–December 31, 2011	26,000	6.71	12,000	13.53

Portfolio of Derivative Transactions

Our portfolio of commodity derivative transactions as of December 31, 2008 is summarized below:

Oil

Type of Contract	Counterparty	Basis	Quantity (Bbl/d)	Strike Price ($/Bbl)	Term
Collar	Bank of Montreal	NYMEX	2,170	$50.00/$75.00	Jan 1–Jun 30, 09
Collar	Bank of Montreal	NYMEX	50	$60.00/$82.75	Jan 1–Jun 30, 09
Collar	Bank of Montreal	NYMEX	3,000	$55.00/$77.00	Jan 1–Dec 31, 09
Swap	Fortis Bank	NYMEX	2,000	$67.22	Jan 1–Dec 31, 09
Collar	Bank of Montreal	NYMEX	1,000	$56.00/$79.25	Jul 1–Dec 31, 09
Collar	Bank of Montreal	NYMEX	750	$60.00/$82.75	Jul 1–Dec 31, 09
Put	Bank of Montreal	NYMEX	2,000	$40.00	Jan 1–Dec 31, 09
Collar	Bank of Oklahoma	NYMEX	3,500	$60.00/$73.00	Jan 1–Dec 31, 10
Swap	Fortis Bank	NYMEX	1,000	$66.75	Jan 1–Dec 31, 10
Collar	Fortis Bank	NYMEX	1,000	$60.00/$72.80	Jan 1–Dec 31, 10
Collar	Bank of Montreal	NYMEX	650	$60.00/$81.75	Jan 1–Dec 31, 10
Put	Scotia Bank	NYMEX	1,850	$40.00	Jan 1–Dec 31, 10
Collar	Key Bank	NYMEX	2,000	$50.00/$141.00	Jan 1–Dec 31, 11
Collar	Key Bank	NYMEX	2,000	$50.00/$144.75	Jan 1–Dec 31, 11
Collar	Credit Suisse	NYMEX	3,000	$50.00/$140.00	Jan 1–Dec 31, 11

Natural Gas

Type of Contract	Counterparty	Basis	Quantity (MMBtu/d)	Strike Price ($/MMBtu)	Term
Collar	Credit Suisse	NYMEX	1,250	$7.75/$13.05	Jan 1–Jun 30, 09
Swap	Credit Suisse	NYMEX	1,250	$ 8.72	Jan 1–Jun 30, 09
Basis Swap	Bank of Montreal	PG&E Citygate	6,000	$ 0.10	Jan 1–Dec 31, 09
Basis Swap	Bank of Montreal	PG&E Citygate	7,500	$ 0.11	Jan 1–Dec 31, 09
Collar	Bank of Montreal	NYMEX	1,125	$8.00/$12.00	Jan 1–Dec 31, 09
Collar	Bank of Montreal	NYMEX	4,000	$ 7.30/$9.85	Jan 1–Dec 31, 09
Collar	Bank of Montreal	NYMEX	7,000	$7.50/$12.75	Jan 1–Dec 31, 09
Collar	Credit Suisse	NYMEX	8,500	$7.50/$11.15	Jan 1–Dec 31, 09
Put	Credit Suisse	NYMEX	10,000	$ 8.50	Jan 1–Dec 31, 09
Put	Credit Suisse	NYMEX	34,000	$ 6.00	Jan 1–Dec 31, 09
Basis Swap	Credit Suisse	PG&E Citygate	19,625	$ 0.00	Jan 1–Dec 31, 09
Swap	Credit Suisse	NYMEX	1,250	$ 8.00	Jul 1–Dec 31, 09
Collar	Credit Suisse	NYMEX	1,250	$7.25/$11.30	Jul 1–Dec 31, 09
Collar	Bank of Montreal	NYMEX	1,000	$ 7.00/$9.10	Jan 1–Dec 31, 10
Collar	Bank of Montreal	NYMEX	900	$7.50/$12.20	Jan 1–Dec 31, 10
Put	Bank of Montreal	NYMEX	41,000	$ 6.00	Jan 1–Dec 31, 10
Collar	Bank of Oklahoma	NYMEX	10,000	$7.00/$10.35	Jan 1–Dec 31, 10
Basis Swap	Bank of Oklahoma	PG&E Citygate	10,000	$ 0.22	Jan 1–Dec 31, 10
Collar	Credit Suisse	NYMEX	6,000	$7.50/$11.95	Jan 1–Dec 31, 10
Basis Swap	Credit Suisse	PG&E Citygate	7,900	$ 0.05	Jan 1–Dec 31, 10
Collar	Credit Suisse	NYMEX	12,000	$7.50/$13.50	Jan 1–Dec 31, 11
Basis Swap	Credit Suisse	PG&E Citygate	12,000	$ 0.03	Jan 1–Dec 31, 11
Put	Key Bank	NYMEX	14,000	$ 6.00	Jan 1–Dec 31, 11

In January 2009, we entered into two transactions whereby we unwound natural gas puts covering 6,000 MMBtu per day for the period from February 2009 through December 2009 and entered into natural gas puts covering 10,000 MMBtu per day for the period from January 2011 through December 2011. The average production and minimum prices from the contracts are summarized below:

	Minimum	
	MMBtu/Day	Avg. Prices
Natural gas derivatives for production:		
February 1–December 31, 2009	(6,000)	$6.00
January 1–December 31, 2011	10,000	$6.02

We enter into derivative contracts, primarily collars, swaps and option contracts, to hedge future crude oil and natural gas production in order to mitigate the risk of market price fluctuations. Most of our derivative contracts relate to changes in the market price relative to the applicable benchmark price; basis swap contracts relate to changes in the applicable differential. The objective of our hedging activities and the use of derivative financial instruments is to achieve more predictable cash flows. Our hedging activities mitigate our exposure to price declines and allow us more flexibility to continue to execute our capital plan even if prices decline. Our collar and swap contracts, however, prevent us from receiving the full advantage of increases in oil or natural gas prices above the maximum fixed amount specified in the hedge agreement. Also, if production is less than the amount we have hedged and the price of oil or natural gas exceeds a fixed price in a hedge contract, we will be required to make payments against which there are no offsetting sales of production. This could impact our ability to fund future capital expenditures. In addition, we have incurred, and may incur in the future, substantial unrealized commodity derivative losses in connection with our hedging activities, although we do not expect such losses to have a material effect on our ability to fund expected capital expenditures. Finally, the use of derivatives involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. Lehman Brothers Commodity Services, Inc. ("LBCS") was a counterparty to several derivative contracts with us entered into between August 2006 and May 2008. In September 2008, Lehman Brothers Holdings Inc. ("LBH"), credit support provider for LBCS, filed for bankruptcy. The bankruptcy filing of LBH constituted an event of default under the ISDA Master Agreement. Accordingly, we notified LBCS that we were terminating each of the outstanding transactions, effective immediately. Subsequent to our notification of termination, LBCS filed for bankruptcy protection. Similar issues could affect other hedge counterparties in the future.

Because a large portion of our commodity derivatives do not qualify for hedge accounting and to increase clarity in our financial statements, we elected to discontinue hedge accounting effective April 1, 2007. Consequently, from that date forward, we have recognized mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income for those commodity derivatives that qualify as cash flow hedges.

All derivative instruments are recorded on the balance sheet at fair value. Fair value is generally determined based on the difference between the fixed contract price and the underlying market price at the determination date. Changes in the fair value of derivatives are recorded in commodity derivative gains (losses) on the consolidated statement of operations.

Interest Rate Derivative Transactions

We are subject to interest rate risk with respect to amounts borrowed under our credit facilities because those amounts bear interest at variable rates. As of March 3, 2009, there was approximately $500.1 million outstanding under those facilities. We have entered into an interest rate swap transaction to limit our exposure to changes in interest rates with respect to our second lien term loan facility to lock in our interest cost on $500.0 million of borrowings through June 2010. As a result, amounts borrowed up to $500.0 million will effectively bear interest at a fixed rate of approximately 9.3% until June 2010. Accordingly, we expect to be subject to interest rate risk until that time only with respect to amounts borrowed in excess of $500.0 million. A 1.0% increase in interest rates on unhedged variable rate borrowings of $135.1 million at December 31, 2008 would result in additional annualized interest expense of $1.4 million. As of December 31, 2008, the fair value of our interest rate derivatives was a liability of $28.1 million.

See notes to our consolidated financial statements for a discussion of our long-term debt as of December 31, 2008.

ITEM 8. Financial Statements and Supplementary Data

See "Index to Financial Statements" on page F-1 of this report.

ITEM 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

ITEM 9A. Controls and Procedures

Attached as exhibits to this report are certifications of our CEO and CFO required pursuant to Rule 13a-14 under the Exchange Act. This section includes information concerning the controls and procedures evaluation referred to in the certifications. Included in this report is the report of Ernst & Young LLP, our independent registered public accounting firm, regarding its audit of our internal control over financial reporting. This section should be read in conjunction with the certifications and the Ernst & Young LLP report for a more complete understanding of the topics presented.

Evaluation of Disclosure Controls and Procedures. We conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) as of December 31, 2008. This evaluation was conducted under the supervision and with the participation of management, including our CEO and CFO. Based on this evaluation, our CEO and CFO have concluded that, subject to the limitations noted in this section, as of December 31, 2008, our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the rules and forms of the SEC. We also concluded that our disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed in the reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our CEO and CFO, to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control over Financial Reporting. Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of assets of the company, (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Under the supervision and with the participation of our management, including our CEO and CFO, we assessed our internal control over financial reporting as of December 31, 2008, the end of our fiscal year. This assessment was based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our assessment, management has concluded that our internal control over financial reporting was effective as of December 31, 2008.

The effectiveness of our internal control over financial reporting as of December 31, 2008 has been audited by Ernst & Young LLP, our independent registered public accounting firm, as stated in their report which is included herein.

Changes in Internal Control over Financial Reporting. There have been no changes in our internal control over financial reporting during the fourth quarter of 2008 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Inherent Limitations on Effectiveness of Controls. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

ITEM 9B. Other Information

None.

PART III

ITEM 10. Directors, Executive Officers and Corporate Governance

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2009 annual stockholders' meeting and is incorporated by reference in this report. Certain information concerning our executive officers is set forth in "Business and Properties— Executive Officers of the Registrant."

ITEM 11. Executive Compensation

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2009 annual stockholders' meeting and is incorporated by reference in this report.

ITEM 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2009 annual stockholders' meeting and is incorporated by reference in this report.

ITEM 13. Certain Relationships and Related Transactions, and Director Independence

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2009 annual stockholders' meeting and is incorporated by reference in this report.

ITEM 14. Principal Accounting Fees and Services

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2009 annual stockholders' meeting and is incorporated by reference in this report.

ITEM 15. Exhibits and Financial Statement Schedules

Financial Statements and Financial Statement Schedules

See "Index to Consolidated Financial Statements" on page F-1.

Exhibits

Exhibit Number	Exhibit
3.1	Restated Certificate of Incorporation of Venoco, Inc. (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on November 17, 2005).
3.2	Amended and Restated Bylaws of Venoco, Inc. (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K of Venoco, Inc. filed on September 5, 2008).
4.2	Indenture, dated as of December 20, 2004, by and among Venoco, Inc., the Guarantors party thereto and U.S. Bank National Association, as Trustee, and supplemental indenture dated as of December 14, 2007 (incorporated by reference to Exhibit 4.2 to the Annual Report on Form 10-K of Venoco, Inc. filed on March 17, 2008).
4.2.1	Second Supplemental Indenture, dated as of October 16, 2008, to the Indenture, dated as of December 20, 2004, by and among Venoco, Inc., the Guarantors party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.2.1 to the Current Report on Form 8-K of Venoco, Inc. filed on October 21, 2008).
10.1	Second Amended and Restated Credit Agreement, dated as of March 30, 2006, by and among Venoco, Inc. and Bank of Montreal, as Administrative Agent and Lead Syndication Agent, Harris Nesbitt Corp., as Lead Arranger, Credit Suisse Securities (USA) LLC and Lehman Brothers Inc., as Co-Arrangers, and Credit Suisse, Cayman Islands Branch and Lehman Commercial Paper Inc., as Co-Syndication Agents and Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to the Annual Report on Form 10-K of Venoco, Inc. filed on April 5, 2006).
10.1.1	First Amendment to the Second Amended and Restated Credit Agreement, dated as of May 2, 2006, by and among Venoco, Inc., the Guarantors identified therein, the Lenders party thereto, Bank of Montreal, as Administrative Agent, Credit Suisse, Cayman Islands Branch and Lehman Commercial Paper Inc., as Co-Syndication Agents, and Fortis Capital Corp., as Documentation Agent (incorporated by reference to Exhibit 10.1.1 to Pre-Effective Amendment No. 2 to the Registration Statement on Form S-1 of Venoco, Inc. filed on June 12, 2006).
10.1.2	Second Amendment to the Second Amended and Restated Credit Agreement, dated as of October 25, 2006, by and among Venoco, Inc., the Guarantors identified therein, the Lenders party thereto, Bank of Montreal, as Administrative Agent, Credit Suisse, Cayman Islands Branch and Lehman Commercial Paper Inc., as Co-Syndication Agents, and Fortis Capital Corp., as Documentation Agent (incorporated by reference to Exhibit 10.1.2 to Pre-Effective Amendment No. 5 to the Registration Statement on Form S-1 of Venoco, Inc. filed on October 30, 2006).

Exhibit Number	Exhibit
10.1.3	Third Amendment to the Second Amended and Restated Credit Agreement, dated as of November 29, 2006, by and among Venoco, Inc., the Guarantors identified therein, the Lenders party thereto, Bank of Montreal, as Administrative Agent, Credit Suisse, Cayman Islands Branch and Lehman Commercial Paper Inc., as Co-Syndication Agents, and Fortis Capital Corp., as Documentation Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on December 1, 2006).
10.1.4	Fourth Amendment to the Second Amended and Restated Credit Agreement, dated as of March 1, 2007, by and among Venoco, Inc., the Guarantors identified therein, the Lenders party thereto, Bank of Montreal, as Administrative Agent, Credit Suisse, Cayman Islands Branch and Lehman Commercial Paper Inc., as Co-Syndication Agents, and Fortis Capital Corp., as Documentation Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on March 7, 2007).
10.1.5	Fifth Amendment to the Second Amended and Restated Credit Agreement, dated as of May 7, 2007, by and among Venoco, Inc., the Guarantors identified therein, the Lenders party thereto, Bank of Montreal, as Administrative Agent, Credit Suisse, Cayman Islands Branch and Lehman Commercial Paper Inc., as Co-Syndication Agents, and Fortis Capital Corp., as Documentation Agent (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Venoco, Inc. filed on May 11, 2007).
10.1.6	Sixth Amendment to the Second Amended and Restated Credit Agreement, dated as of May 9, 2008, by and among Venoco, Inc., the Guarantors identified therein, the Lenders party thereto, Bank of Montreal, as Administrative Agent, Credit Suisse, Cayman Islands Branch and Lehman Commercial Paper Inc., as Co-Syndication Agents, and Fortis Capital Corp., as Documentation Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on May 12, 2008).
10.2	Term Loan Agreement, dated as of May 7, 2007, by and among Venoco, Inc., the Guarantors identified therein, the Lenders party thereto, Credit Suisse, Cayman Islands Branch, as Administrative Agent, UBS Securities LLC, as Syndication Agent, Credit Suisse Securities (USA) LLC and UBS Securities LLC, as Joint Lead Arrangers, Lehman Commercial Paper Inc. and Bank of Montreal, as Co-Documentation Agents, and Lehman Brothers Inc. and BMO Capital Markets Corp., as Co-Arrangers, and First Amendment to Term Loan Agreement, dated as of November 7, 2007 (incorporated by reference to Exhibit 10.2 to the Annual Report on Form 10-K of Venoco, Inc. filed on March 17, 2008).
10.3	Collateral Trust Agreement, dated as of March 30, 2006, by and between Venoco, Inc. and Credit Suisse, Cayman Islands Branch, as Administrative Agent and Collateral Trustee (incorporated by reference to Exhibit 10.3 to the Annual Report on Form 10-K of Venoco, Inc. filed on April 5, 2006).
10.4	Option Agreement, dated as of November 1, 2006, by and between TexCal Energy South Texas, L.P. and Denbury Onshore, LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on November 9, 2006).
10.4.1	First Amendment to Option Agreement, by and between TexCal Energy South Texas, L.P. and Denbury Onshore, LLC, dated as of August 29, 2008 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on September 2, 2008).
10.5	Contract of Affreightment, dated as of March 13, 1998, by and between Public Service Marine Inc. and Venoco, LLC (incorporated by reference to Exhibit 10.4 to the Registration Statement on Form S-4 of Venoco, Inc. filed on March 31, 2005).

Exhibit Number	Exhibit
10.5.1	First Amendment to Contract of Affreightment, by and between Public Service Marine Inc. and Venoco, Inc. (incorporated by reference to Exhibit 10.5 to Pre-Effective Amendment No. 1 to the Registration Statement on Form S-4 of Venoco, Inc. filed on April 20, 2005).
10.6	Venoco, Inc. 2008 Employee Stock Purchase Plan, dated as of November 18, 2008, as amended as of December 31, 2008.
10.7	Venoco, Inc. 2000 Stock Incentive Plan (incorporated by reference to Exhibit 10.12 to the Registration Statement on Form S-4 of Venoco, Inc. filed on March 31, 2005).
10.7.1	Amendment No. 1 to the Venoco, Inc. 2000 Stock Incentive Plan, dated as of November 17, 2008 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Venoco, Inc. filed on November 20, 2008).
10.7.2	Form of Non-Qualified Stock Option Agreement for Non-Employee Directors Pursuant to the 2000 Stock Incentive Plan (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on November 17, 2005).
10.7.3	Form of Non-Qualified Stock Option Agreement for Non-Executive Officer Employees Pursuant to the 2000 Stock Incentive Plan (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on November 17, 2005).
10.7.4	Form of Amendment to Nonqualified Stock Option Agreement Pursuant to the 2000 Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on June 12, 2006).
10.7.5	Form of Bonus Payment Agreement Relating to the 2000 Stock Incentive Plan (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Venoco, Inc. filed on June 12, 2006).
10.8	Venoco, Inc. Amended and Restated 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on May 12, 2006).
10.8.1	Amendment No. 1 to the Venoco, Inc. Amended and Restated 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on May 15, 2007).
10.8.2	Amendment No. 2 to the Venoco, Inc. Amended and Restated 2005 Stock Incentive Plan, dated as of November 17, 2008 (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Venoco, Inc. filed on November 20, 2008).
10.8.3	Form of Non-Qualified Stock Option Agreement Pursuant to the 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.2 the Current Report on Form 8-K of Venoco, Inc. filed on May 12, 2006).
10.8.4	Form of Notice of Stock Award Pursuant to the Venoco, Inc. Amended and Restated 2005 Stock Incentive Plan and Stock Award Agreement, as amended.
10.8.5	Venoco, Inc. 2007 Long-Term Incentive Program (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on May 15, 2007).
10.9	Venoco, Inc. 2007 Senior Executive Bonus Plan, as amended (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on May 12, 2008).
10.10	Employment Agreement, dated as of May 4, 2005, by and between Venoco, Inc. and Timothy Marquez (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on May 16, 2005).

Exhibit Number	Exhibit
10.11.1	Employment Agreement, dated as of January 25, 2005, by and between Venoco, Inc. and William Schneider (incorporated by reference to Exhibit 10.11 to the Registration Statement on Form S-4 of Venoco, Inc. filed on March 31, 2005).
10.11.2	Non-Qualified Stock Option Agreement, dated as of May 4, 2005, by and between Venoco, Inc. and William Schneider (incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on May 16, 2005).
10.12	Employment Agreement, dated as of March 19, 2007, by and between Venoco, Inc. and Timothy A. Ficker (incorporated by reference to Exhibit 10.14 to the Annual Report on Form 10-K of Venoco, Inc. filed on April 2, 2007).
10.13.1	Employment Agreement, dated as of May 4, 2005, by and between Venoco, Inc. and Terry Anderson (incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on May 16, 2005).
10.13.2	Non-Qualified Stock Option Agreement, dated as of May 4, 2005, by and between Venoco, Inc. and Terry Anderson (incorporated by reference to Exhibit 10.10 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on May 16, 2005).
10.14.1	Employment Agreement, dated as of August 15, 2005, by and between Venoco, Inc. and Mark DePuy (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on November 17, 2005).
10.14.2	Non-Qualified Stock Option Agreement, dated as of August 15, 2005, by and between Venoco, Inc. and Mark DePuy (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on November 17, 2005).
10.14.3	Resignation and Release Agreement, dated as of October 20, 2008, by and between Mark DePuy and Venoco, Inc. (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on November 6, 2008).
10.14.4	Independent Contractor Agreement, dated as of November 4, 2008, by and between Mark DePuy and Venoco, Inc. (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on November 6, 2008).
10.15	Form of Amendment to Employment Agreement (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on July 12, 2006).
10.16	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on October 31, 2005).
10.17	Registration Rights Agreement, dated as of August 25, 2006, by and between Venoco, Inc. and the Marquez Trust (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on August 31, 2006).
10.17.1	Amendment to Registration Rights Agreement and Joinder, dated as of May 23, 2007, by and among Venoco, Inc., the Marquez Trust and the Marquez Foundation (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on May 25, 2007).
10.18	Indemnity and Guaranty Agreement, dated as of March 22, 2006, by the Marquez Trust in favor of Venoco, Inc. (incorporated by reference to Exhibit 10.29 to the Annual Report on Form 10-K of Venoco, Inc. filed on April 5, 2006).

Exhibit Number	Exhibit
10.19	Assignment and Subordination of Master Lease and Consent of Master Tenant, dated as of December 9, 2004, by and among 6267 Carpinteria Avenue, LLC, Venoco, Inc. and German American Capital Corporation (incorporated by reference to Exhibit 10.30 to the Annual Report on Form 10-K of Venoco, Inc. filed on April 5, 2006).
10.20.1	Ground Lease, dated as of August 29, 2006, by and between Venoco, Inc. and Carpinteria Bluffs, LLC (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Venoco, Inc. filed on August 31, 2006).
10.20.2	Development Agreement, dated as of August 29, 2006, by and between Venoco, Inc. and Carpinteria Bluffs, LLC (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Venoco, Inc. filed on August 31, 2006).
10.20.3	Dividend Distribution Agreement, dated as of August 29, 2006, by and among Venoco, Inc., the Marquez Trust and Carpinteria Bluffs, LLC (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K of Venoco, Inc. filed on August 31, 2006).
10.20.4	Purchase Agreement, dated as of December 23, 2008, by and between Carpinteria Bluffs, LLC and Venoco, Inc. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on December 29, 2008).
10.20.5	Letter Agreement, dated as of December 9, 2008, by and between the Marquez Trust and Venoco, Inc. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on December 10, 2008).
21.1	Subsidiaries of the Registrant
23.1	Consent of Ernst & Young LLP.
23.2	Consent of Deloitte & Touche LLP.
23.3	Consent of Netherland, Sewell & Associates, Inc.
23.4	Consent of DeGolyer & MacNaughton.
31.1	Certification of the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	Certification of the Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

VENOCO, INC.

By: /s/ TIMOTHY M. MARQUEZ
Name: Timothy M. Marquez
Title: *Chairman and Chief Executive Officer*
Date: March 4, 2009

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ TIMOTHY M. MARQUEZ Timothy M. Marquez	Chairman and Chief Executive Officer (Principal Executive Officer)	March 4, 2009
/s/ TIMOTHY A. FICKER Timothy A. Ficker	Chief Financial Officer (Principal Financial Officer)	March 4, 2009
/s/ DOUGLAS J. GRIGGS Douglas J. Griggs	Chief Accounting Officer (Principal Accounting Officer)	March 4, 2009
/s/ DONNA L. LUCAS Donna L. Lucas	Director	March 4, 2009
/s/ J. C. MCFARLAND J. C. McFarland	Director	March 4, 2009
/s/ JOEL L. REED Joel L. Reed	Director	March 4, 2009
/s/ M. W. SCOGGINS M. W. Scoggins	Director	March 4, 2009
/s/ MARK A. SNELL Mark A. Snell	Director	March 4, 2009
/s/ RICHARD S. WALKER Richard S. Walker	Director	March 4, 2009

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Venoco, Inc.
Denver, Colorado

We have audited the accompanying consolidated balance sheet of Venoco, Inc. and subsidiaries (the "Company") as of December 31, 2008, and the related consolidated statements of operations, comprehensive income (loss), changes in stockholders' equity, and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Venoco Inc. and subsidiaries at December 31, 2008, and the consolidated results of their operations and their cash flows for the year then ended, in conformity with U.S. generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2008, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 3, 2009 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Denver, Colorado
March 3, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Venoco, Inc.
Denver, Colorado

We have audited the accompanying consolidated balance sheet of Venoco, Inc. and subsidiaries (the "Company") as of December 31, 2007, and the related consolidated statements of operations, comprehensive income (loss), changes in stockholders' equity, and cash flows for each of the two years in the period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Venoco Inc. and subsidiaries as of December 31, 2007, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
March 14, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Venoco, Inc.
Denver, Colorado

We have audited Venoco, Inc.'s (the "Company") internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The Company's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have material effect on the financial statements.

Because of the inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of the effectiveness to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the COSO criteria.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of the Company as of December 31, 2008, and the related consolidated statements of operations, comprehensive income (loss), changes in stockholders' equity, and cash flows for the year then ended and our report dated March 3, 2009 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Denver, Colorado
March 3, 2009

VENOCO, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In thousands, except shares amounts)

	December 31, 2007	December 31, 2008
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 9,735	$ 191
Accounts receivable, net of allowance for doubtful accounts of $850 and $750 at December 31, 2007 and 2008, respectively	55,597	41,306
Inventories	10,377	12,361
Prepaid expenses and other current assets	4,391	4,314
Income tax receivable	6,725	546
Deferred income taxes	21,967	—
Commodity derivatives	7,780	57,247
Total current assets	116,572	115,965
PROPERTY, PLANT AND EQUIPMENT, AT COST:		
Oil and natural gas properties (full cost method, of which $12,034 and $30,228 for unproved properties were excluded from amortization at December 31, 2007 and 2008, respectively)	1,331,531	1,671,799
Drilling equipment	14,460	14,460
Other property and equipment	17,208	22,932
Total property, plant and equipment	1,363,199	1,709,191
Accumulated depletion, depreciation and amortization	(232,167)	(1,006,457)
Net property, plant and equipment	1,131,032	702,734
OTHER ASSETS:		
Commodity derivatives	3,768	35,314
Deferred loan costs	9,699	7,458
Other	4,414	2,783
Total other assets	17,881	45,555
TOTAL ASSETS	$1,265,485	$ 864,254
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable and accrued liabilities	$ 82,094	$ 75,400
Undistributed revenue payable	11,298	8,277
Interest payable	6,839	5,325
Current maturities of long-term debt	3,449	2,598
Commodity and interest derivatives	68,756	21,284
Total current liabilities	172,436	112,884
LONG-TERM DEBT	691,896	797,670
DEFERRED INCOME TAXES	16,607	—
COMMODITY AND INTEREST DERIVATIVES	87,224	9,363
ASSET RETIREMENT OBLIGATIONS	51,720	79,504
Total liabilities	1,019,883	999,421
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' EQUITY:		
Common stock, $.01 par value (200,000,000 shares authorized; 50,593,403 and 51,548,990 shares issued and outstanding at December 31, 2007 and 2008, respectively)	506	515
Additional paid-in capital	309,887	319,336
Retained earnings (accumulated deficit)	(62,462)	(453,594)
Accumulated other comprehensive loss	(2,329)	(1,424)
Total stockholders' equity	245,602	(135,167)
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$1,265,485	$ 864,254

See notes to consolidated financial statements.

VENOCO, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share amounts)

	Years Ended December 31,		
	2006	2007	2008
REVENUES:			
Oil and natural gas sales	$268,822	$ 373,155	$ 555,917
Other	5,470	3,355	3,603
Total revenues	274,292	376,510	559,520
EXPENSES:			
Oil and natural gas production	87,505	119,321	149,504
Transportation	3,533	6,061	5,958
Depletion, depreciation and amortization	63,259	98,814	134,483
Impairment of oil and natural gas properties	—	—	641,000
Accretion of asset retirement obligations	2,542	3,914	4,203
General and administrative, net of amounts capitalized	28,317	31,770	43,101
Total expenses	185,156	259,880	978,249
Income (loss) from operations	89,136	116,630	(418,729)
FINANCING COSTS AND OTHER:			
Interest expense, net	48,795	60,115	54,049
Amortization of deferred loan costs	3,776	4,197	3,344
Interest rate derivative losses (gains), net	590	17,177	20,567
Loss on extinguishment of debt	—	12,063	—
Commodity derivative losses (gains), net	(3,626)	142,650	(116,757)
Total financing costs and other	49,535	236,202	(38,797)
Income (loss) before income taxes	39,601	(119,572)	(379,932)
INCOME TAXES:			
Current	610	1,100	6,300
Deferred	15,040	(47,300)	4,900
Income tax provision (benefit)	15,650	(46,200)	11,200
Net income (loss)	$ 23,951	$ (73,372)	$(391,132)
Earnings per common share:			
Basic	$ 0.71	$ (1.58)	$ (7.75)
Diluted	$ 0.69	$ (1.58)	$ (7.75)
Weighted average common shares outstanding:			
Basic	33,795	46,372	50,486
Diluted	34,860	46,372	50,486

See notes to consolidated financial statements.

VENOCO, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(In thousands)

	Years Ended December 31,		
	2006	**2007**	**2008**
Net income (loss)	$23,951	$(73,372)	$(391,132)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF INCOME TAX:			
Hedging activities:			
Reclassification adjustments for settled contracts(1)	3,602	2,877	905
Changes in fair value of outstanding hedging positions(2)	7,116	(2,740)	—
Other comprehensive income (loss)	10,718	137	905
Comprehensive income (loss)	$34,669	$(73,235)	$(390,227)

(1) Net of income tax expense (benefit) of $2,389, $1,840 and $532 for the years ended December 31, 2006, 2007 and 2008, respectively.

(2) Net of income tax expense (benefit) of $4,720, $(1,722) and $0 for the years ended December 31, 2006, 2007 and 2008, respectively.

See notes to consolidated financial statements.

VENOCO, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY
(In thousands)

	Common Stock		Additional Paid-in Capital	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss)	Total
	Shares	Amount				
BALANCE AT DECEMBER 31, 2005	32,693	$327	$ 20,976	$ (3,785)	$(13,184)	$ 4,334
Comprehensive income:						
Reclassification adjustment for settled contracts, net of tax	—	—	—	—	3,602	3,602
Change in value of derivatives, net of tax	—	—	—	—	7,116	7,116
Issuance of stock, net of underwriters' discounts	10,090	101	160,292	—	—	160,393
Stock issuance costs	—	—	(2,874)	—	—	(2,874)
Distributions to shareholder	—	—	—	(9,256)	—	(9,256)
Share-based payments	—	—	3,050	—	—	3,050
Net income (loss)	—	—	—	23,951	—	23,951
BALANCE AT DECEMBER 31, 2006	42,783	428	181,444	10,910	(2,466)	190,316
Comprehensive income:						
Reclassification adjustment for settled contracts, net of tax	—	—	—	—	2,877	2,877
Change in value of derivatives, net of tax	—	—	—	—	(2,740)	(2,740)
Issuance of stock, net of underwriters' discounts	6,565	65	116,530	—	—	116,595
Stock issuance costs	—	—	(561)	—	—	(561)
Issuance of stock for acquisition of oil and gas properties	171	2	3,028	—	—	3,030
Issuance of stock for cash upon exercise of options	703	7	4,770	—	—	4,777
Issuance of restricted shares	371	4	(4)	—	—	—
Share-based payments	—	—	4,680	—	—	4,680
Net income (loss)	—	—	—	(73,372)	—	(73,372)
BALANCE AT DECEMBER 31, 2007	50,593	$506	$309,887	$ (62,462)	$ (2,329)	$ 245,602
Comprehensive income:						
Reclassification adjustment for settled contracts, net of tax	—	—	—	—	905	905
Issuance of stock for cash upon exercise of options	451	5	2,951	—	—	2,956
Issuance of restricted shares, net of cancellations	516	5	(5)	—	—	—
Restricted stock used for tax withholding	(11)	(1)	(156)	—	—	(157)
Share-based payments	—	—	5,710	—	—	5,710
Disgorgement of stock sale profits	—	—	949	—	—	949
Net income (loss)	—	—	—	(391,132)	—	(391,132)
BALANCE AT DECEMBER 31, 2008	51,549	$515	$319,336	$(453,594)	$ (1,424)	$(135,167)

See notes to consolidated financial statements.

VENOCO, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Years Ended December 31,		
	2006	2007	2008
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 23,951	$ (73,372)	$(391,132)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization	63,259	98,814	134,483
Impairment of oil and natural gas properties	—	—	641,000
Accretion of asset retirement obligations	2,542	3,914	4,203
Deferred income taxes (benefit)	15,040	(47,300)	4,900
Share-based compensation	3,050	4,680	3,064
Amortization of deferred loan costs	3,776	4,197	3,344
Loss on extinguishment of debt	—	12,063	—
Amortization of bond discounts and other non-cash interest	1,124	700	519
Unrealized interest rate swap derivative losses	494	17,312	10,336
Unrealized commodity derivative (gains) losses and amortization of premiums and other comprehensive loss	(12,898)	134,325	(176,768)
Other	(177)	—	—
Changes in operating assets and liabilities:			
Accounts receivable	3,534	(10,055)	14,291
Inventories	(1,458)	(7,166)	(1,984)
Prepaid expenses and other current assets	(955)	2,606	(63)
Income tax receivable	(2,092)	1,373	6,179
Other assets	272	(2,551)	1,558
Accounts payable and accrued liabilities	(4,795)	29,632	3,695
Undistributed revenue payable	1,865	(4,298)	(3,021)
Net premiums paid on derivative contracts	(7,442)	(4,011)	(42,225)
Net cash provided by (used in) operating activities	89,090	160,863	212,379
CASH FLOWS FROM INVESTING ACTIVITIES:			
Expenditures for oil and natural gas properties	(165,748)	(316,894)	(311,173)
Acquisitions of oil and natural gas properties	(19,461)	(121,822)	(14,279)
Expenditures for drilling equipment	(5,666)	(847)	—
Expenditures for other property and equipment	(3,199)	(4,542)	(7,409)
Proceeds from sale of oil and natural gas properties	46,389	10,742	—
Acquisition of TexCal Energy, net of cash acquired	(447,519)	—	—
Net cash provided by (used in) investing activities	(595,204)	(433,363)	(332,861)

VENOCO, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)
(In thousands)

	Years Ended December 31, 2006	2007	2008
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from long-term debt	569,529	777,421	260,052
Principal payments on long-term debt	(210,101)	(619,729)	(169,892)
Payments for deferred loan costs	(15,335)	(4,923)	(963)
Premium to retire debt	—	(3,489)	—
Proceeds from derivative premium financing	3,903	3,780	17,993
Proceeds from issuance of common stock	160,393	116,595	—
Stock issuance costs	(2,874)	(561)	(5)
Proceeds from exercise of stock options	—	4,777	2,961
Proceeds from disgorgement of stock sale profits	—	—	949
Restricted stock used for tax withholding	—	—	(157)
Dividend paid to shareholder	(426)	—	—
Net cash provided by (used in) financing activities	505,089	273,871	110,938
Net (decrease) increase in cash and cash equivalents	(1,025)	1,371	(9,544)
Cash and cash equivalents, beginning of period	9,389	8,364	9,735
Cash and cash equivalents, end of period	$ 8,364	$ 9,735	$ 191
Supplemental Disclosure of Cash Flow Information—			
Cash paid for interest	$ 44,540	$ 58,650	$ 55,350
Cash paid (received) for income taxes	$ 2,701	$ (273)	$ 124
Supplemental Disclosure of Noncash Activities—			
Accrued capital expenditures at period end	$ 39,515	$ 42,680	$ 30,203
(Decrease) increase in accrued capital expenditures	$ 19,420	$ 3,165	(12,477)
Distributions of land and building	$ 18,399	$ —	$ —
Distribution of building note payable	$ 9,857	$ —	$ —
Common stock issued for the acquisition of oil and natural gas properties	$ —	$ 3,030	$ —

See notes to consolidated financial statements.

VENOCO, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2006, 2007, AND 2008

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of Operations Venoco, Inc. (the "Company"), a Delaware corporation, is engaged in the acquisition, exploration, exploitation and development of oil and natural gas properties with a focus on properties offshore and onshore California and the Gulf Coast of Texas.

Principles of Consolidation The consolidated financial statements include the accounts of the Company and its subsidiaries, all of which are wholly owned. All intercompany balances and transactions have been eliminated in consolidation.

Use of Estimates The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Items subject to such estimates and assumptions include (1) oil and gas reserves; (2) cash flow estimates used in impairment tests of long-lived assets; (3) depreciation, depletion and amortization; (4) asset retirement obligations; (5) assigning fair value and allocating purchase price in connection with business combinations; (6) accrued revenue and related receivables; (7) valuation of commodity and interest derivative instruments; (8) accrued liabilities; (9) valuation of share-based payments and (10) income taxes. Although management believes these estimates are reasonable, actual results could differ from these estimates.

Business Segment Information The Company has evaluated how it is organized and managed and has identified only one operating segment, which is the exploration and production of crude oil, natural gas and natural gas liquids. The Company considers its gathering, processing and marketing functions as ancillary to its oil and gas producing activities. All of the Company's operations and assets are located in the United States, and all of its revenues are attributable to United States customers.

Concentration of Credit Risk The Company's accounts receivable result from (i) oil and natural gas sales to major oil and intrastate gas pipeline companies and (ii) billings to joint working interest partners in properties operated by the Company. The Company's trade and accrued production receivables are dispersed among various customers and purchasers and most of the Company's significant purchasers are large companies with solid credit ratings. If customers are considered a credit risk, letters of credit are the primary security obtained to support the extension of credit. For most joint working interest partners, the Company may have the right of offset against related oil and natural gas revenues. The Company recorded an allowance for doubtful accounts as of December 31, 2007 and 2008 of $0.9 million and $0.8 million, respectively, for customer and joint working interest partner accounts. As of December 31, 2008, 22%, 16%, 7% and 6% of the total accounts receivable balance was receivable from the Company's four major customers.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

The following table provides the percentage of revenue derived from oil and natural gas sales to the Company's top four customers (the customers in each year are not necessarily the same from year to year):

	Years Ended December 31,		
	2006	2007	2008
Customer A	31%	30%	32%
Customer B	20%	29%	27%
Customer C	13%	17%	16%
Customer D	12%	12%	12%

Revenue Recognition and Gas Imbalances Revenues from the sale of natural gas and crude oil are recognized when the product is delivered at a fixed or determinable price, title has transferred, collectability is reasonably assured and evidenced by a contract. This generally occurs when a barge completes delivery, oil or natural gas has been delivered to a refinery or a pipeline, or has otherwise been transferred to a customer's facilities or possession. Oil revenues are generally recognized based on actual volumes of completed deliveries where title has transferred. Title to oil sold is typically transferred at the wellhead, except in the case of the South Ellwood field, where title is transferred when the barge that transports production from the field completes delivery.

The Company uses the entitlement method of accounting for natural gas revenues. Under this method, revenues are recognized based on actual production of natural gas. The Company incurs production gas volume imbalances in the ordinary course of business. Net deliveries in excess of entitled amounts are recorded as liabilities, while net under-deliveries are reflected as assets. Imbalances are reduced either by subsequent recoupment of over- and under-deliveries or by cash settlement, as required by applicable contracts. The Company's production imbalances were not material at December 31, 2007 and 2008.

Other revenues primarily include pipeline revenues and amounts received from purchasers of oil production to reimburse the Company for transportation and barge expenses. Transportation expense, net of pipeline tariff, is reflected separately in the consolidated statement of operations.

Cash and Cash Equivalents Cash and cash equivalents consist of cash and liquid investments with an original maturity of three months or less.

Inventories Included in inventories are oil field materials and supplies, stated at the lower of cost or market, cost being determined by the first-in, first-out method.

Crude Oil Inventories Crude oil inventories are carried at the lower of current market value or cost (generally determined under the first-in, first-out method). Inventory costs include expenditures and other charges incurred in bringing the inventory to its existing condition and location.

Oil and Natural Gas Properties The Company's oil and natural gas producing activities are accounted for using the full cost method of accounting. Accordingly, the Company capitalizes all costs incurred in connection with the acquisition of oil and natural gas properties and with the exploration for and development of oil and natural gas reserves. Proceeds from the disposition of oil and natural

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

gas properties are accounted for as adjustments to the full cost pool, with no gain or loss recognized unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves.

Depletion of the capitalized costs of oil and natural gas properties, including estimated future development and abandonment costs, is provided for using the equivalent unit-of-production method based upon estimates of proved oil and natural gas reserves. Depletion expense for the years ended December 31, 2006, 2007, and 2008 was $61.0 million, $94.7 million, and $129.4 million, respectively ($10.52, $13.29, and $16.31, respectively, per equivalent barrel of oil).

Unproved property costs not subject to amortization consist primarily of leasehold costs related to unproved areas. Costs are transferred into the amortization base on an ongoing basis as the properties are evaluated and proved reserves are established or impairment is determined. Costs of dry holes are transferred to the amortization base immediately upon determination that the well is unsuccessful. The Company will continue to evaluate these properties and costs which will be transferred into the amortization base as the undeveloped areas are tested. The Company did not transfer any unproved costs to the amortization base as a result of impairment in 2006 or 2007 and transferred $2.4 million into the amortization base in 2008 due to impairment. No interest costs were capitalized in 2006, 2007 or 2008 because the Company did not have any unusually significant investments in unproved properties that qualify for interest capitalization.

In accordance with the full cost method of accounting, the net capitalized costs of oil and natural gas properties are subject to a ceiling based upon the related estimated future net revenues, discounted at 10 percent, net of tax considerations, plus the lower of cost or estimated fair value of unproved properties. The ceiling test is calculated using oil and natural gas prices in effect as of the balance sheet date. Due to lower oil and natural gas prices at December 31, 2008, the Company's net capitalized costs exceeded the ceiling by $641.0 million, net of income tax effects, and the Company recorded an impairment of oil and natural gas properties in the same amount. The Company may be required to recognize additional impairments of oil and natural gas properties in future periods if market prices of oil and natural gas continue to decline.

General and Administrative Expenses Under the full cost method of accounting, the Company capitalizes a portion of general and administrative expenses that are directly identified with acquisition, exploration and development activities. These capitalized costs include salaries, employee benefits, costs of consulting services and other specifically identifiable costs and do not include costs related to production operations, general corporate overhead or similar activities. The Company capitalized general and administrative costs of $4.4 million, $11.8 million, and $18.8 million directly related to its acquisition, exploration and development activities during 2006, 2007 and 2008, respectively.

Drilling Equipment and Other Property and Equipment Drilling equipment and other property and equipment, which includes buildings, leasehold improvements, office and other equipment, are stated at cost. Depreciation and amortization are calculated using the straight-line method over the estimated useful lives of the related assets, ranging from 3 to 25 years. Depreciation and amortization expense for the years ended December 31, 2006, 2007 and 2008 was $2.3 million, $4.1 million and $5.1 million, respectively.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Derivative Financial Instruments The Company enters into derivative contracts, primarily collars, swaps and option contracts, to hedge future crude oil and natural gas production in order to mitigate the risk of market price fluctuations. Under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, all derivative instruments are recorded on the balance sheet at fair value. All of the Company's derivative counterparties are commercial banks that are parties to its credit facilities.

If the derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings as a component of financing costs and other. If the derivative qualifies for cash flow hedge accounting, the gain or loss on the derivative is deferred in Accumulated Other Comprehensive Income (Loss) ("OCI"), a component of Stockholders' Equity, to the extent the hedge is effective. Gains and losses are reclassified from OCI to the income statement as a component of revenues in the period the hedged production occurs.

Because a large portion of the Company's commodity derivatives do not qualify for hedge accounting, the Company elected to discontinue hedge accounting prospectively for its commodity derivatives beginning April 1, 2007. Consequently, from that date forward, the Company has recognized mark-to-market gains and losses in earnings currently, rather than deferring such amounts in OCI for those commodity derivatives that qualify as cash flow hedges.

The Company has also entered into interest rate swap contracts to mitigate the risk of interest rate fluctuations on $500 million of borrowings under its variable rate credit facilities. The Company does not designate the interest rate swap contacts as hedges.

Deferred Loan Costs Deferred loan costs, included in Other Assets, are amortized over the estimated lives of the related obligations or, in certain circumstances, accelerated if the obligation is refinanced, using the straight line method, which approximates the effective interest method.

Income Taxes Deferred income tax assets and liabilities are recognized for the future income tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective income tax bases. Deferred income tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred income tax assets and liabilities of a change in income tax rates is recognized in income in the period that includes the enactment date. The measurement of deferred income tax assets is reduced, if necessary, by a valuation allowance if management believes that it is more likely than not that some portion or all of the net deferred tax assets will not be fully realized on future income tax returns. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, available taxes in carryback periods, projected future taxable income and tax planning strategies in making this assessment.

In June 2006, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 48 ("FIN 48"), *Accounting for Uncertainties in Income Taxes*, an interpretation of FASB Statement No. 109, *Accounting for Income Taxes.* This interpretation addresses how tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN 48, the Company may recognize the tax benefit from an uncertain tax position only if it is more likely than

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties on income taxes and accounting in interim periods and requires increased disclosures.

The Company adopted the provisions of FIN 48 on January 1, 2007, and has analyzed filing positions in all of the federal and state jurisdictions where it is required to file income tax returns, as well as all open tax years in these jurisdictions. As a result of the implementation of FIN 48 on January 1, 2007, the Company recognized a $3.8 million reduction in prepaid income taxes for unrecognized tax benefits which was offset by a corresponding reduction to deferred income tax liabilities. There was no cumulative adjustment made to the opening balance of retained earnings at January 1, 2007.

The Company's policy is to recognize interest and/or penalties related to uncertain tax positions in income tax expense. The Company did not recognize any interest or penalties upon the adoption of FIN 48 on January 1, 2007, or during the years ended December 31, 2007 or December 31, 2008.

Environmental The Company is subject to extensive federal, state and local environmental laws and regulations. These laws and regulations, which regularly change, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment and/or remediation is probable and the costs can be reasonably estimated. Such liabilities are generally recorded at their undiscounted amounts unless the amount and timing of payments is fixed or reliably determinable. The Company believes that it is in material compliance with existing laws and regulations.

Earnings Per Share Statement of Financial Accounting Standards No. 128, *Earnings Per Share*, requires presentation of "basic" and "diluted" earnings per share. Basic earnings per common share of stock is calculated by dividing net income (loss) by the weighted average number of common shares outstanding during each period. The weighted average number of common shares outstanding used to calculate basic net income (loss) per share excludes the effect of non-vested restricted shares subject to future vesting. As those restricted shares vest, they will be included in the shares outstanding used to calculate basic earnings per common share (although all restricted shares are issued and outstanding upon grant). Diluted earnings per common share of stock is calculated by dividing net income by the weighted average number of common shares outstanding and other dilutive securities. The Company's dilutive securities include non-qualified stock option awards and non-vested restricted shares with only service conditions. Non-vested restricted shares with service and market conditions are excluded from basic and dilutive earnings per common share calculations until they vest.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

The treasury stock method is used to measure the dilutive impact of stock options. The following table details the weighted average dilutive and anti-dilutive securities related to stock options for the periods presented (in thousands, except share and per share amounts):

	Years ended December 31,		
	2006	2007	2008
Dilutive	3,952,569	—	—
Anti-dilutive	318,169	4,501,894	3,852,468

The following table sets forth the calculation of basic and diluted earnings per share (in thousands except per share amounts):

	Years ended December 31,		
	2006	2007	2008
Net income (loss)	$23,951	$(73,372)	$(391,132)
Adjustments to net income for dilution	—	—	—
Net income (loss) adjusted for the effect of dilution	$23,951	$(73,372)	$(391,132)
Basic weighted average common shares outstanding	33,795	46,372	50,486
Add: dilutive effect of stock options and non-vested restricted shares	1,065	—	—
Diluted weighted average common shares outstanding	34,860	46,372	50,486
Basic earnings per common share	$ 0.71	$ (1.58)	$ (7.75)
Diluted earnings per common share	$ 0.69	$ (1.58)	$ (7.75)

Stock-Based Compensation The Company accounts for stock-based compensation in accordance with Statement of Financial Accounting Standards ("SFAS") No. 123 (Revised), *Share-Based Payment* ("SFAS 123R") using the modified prospective method. Under this method, compensation cost is recorded for all unvested stock options beginning in the period of adoption and prior period financial statements are not restated. Under the fair value recognition provisions of SFAS 123R, stock-based compensation is measured at the grant date based on the value of the awards and the value is recognized on a straight-line basis over the requisite service period (usually the vesting period). SFAS 123R requires the recognition of the equity component of deferred compensation as additional paid-in capital. SFAS 123R also requires the Company to estimate forfeitures in calculating the cost related to stock-based compensation as opposed to recognizing these forfeitures and the corresponding reduction in expense as they occur.

Reclassifications The Company made certain reclassifications to prior period consolidated statements of operations to be consistent with the current presentation. The consolidated statements of operations were modified to separately disclose interest rate derivative losses. In addition, commodity derivative (gains) losses were reclassified from revenues to financing costs and other in the consolidated statements of operations so as not to distort revenue trends with significant non-designated future

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

economic hedging. These reclassifications had no impact on the Company's financial position, income (loss) before taxes or cash flows from operating, investing or financing activities.

Recent Accounting Pronouncements

In March 2008, the FASB issued Statement No. 161, *Disclosure about Derivative Instruments and Hedging Activities—an amendment to FASB Statement No. 133* ("SFAS 161"). SFAS 161 expands interim and annual disclosures about derivative and hedging activities that are intended to better convey the purpose of derivative use and the risks managed. SFAS 161 is effective for fiscal years and interim periods beginning after November 15, 2008. The adoption of SFAS 161 is not expected to have an impact on the Company's consolidated financial statements, other than additional disclosures.

In June 2008, the FASB issued FASB Staff Position No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* ("FSP 03-6-1"). FSP 03-6-1 addresses whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the earnings allocation in computing earnings per share (EPS) under the two-class method described in FASB Statement No. 128, *Earnings per Share*. The FSP concludes that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents are participating securities and shall be included in the computation of EPS pursuant to the two-class method. The statement is effective for fiscal years beginning after December 15, 2008, and interim periods within those years. All prior-period EPS data presented is to be adjusted retrospectively to conform to the provisions of this FSP. The Company's restricted stock awards contain certain dividend rights. The Company is currently assessing the impact of adoption of the FSP on the Company's earnings per share calculations.

In December 2007, the FASB issued Statement No. 141R, *Business Combinations* ("SFAS 141R"). SFAS 141R establishes principles and requirements for how the acquirer of a business recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree. The statement also provides guidance for recognizing and measuring the goodwill acquired in business combinations and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. The statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. SFAS 141R may have an impact on the Company's consolidated financial statements when effective, but the nature and magnitude of the specific effects will depend upon the nature, terms and size of the acquisitions the Company consummates after the effective date.

In December 2008, the SEC published revised rules regarding oil and gas reserves reporting requirements. The objective of the rules are to provide readers of financial statements with more meaningful and comprehensive understanding of oil and gas reserves. Key elements of the revised rules include a change in the pricing used to estimate reserves at period end, optional disclosure of probable and possible reserves, allowance of the use of new technologies in the determination of reserves and additional disclosure requirements. The rules also revise the prices used for reserves in determining depletion and the full cost ceiling test from a period end price to a 12-month average price. The revised rules are effective for registration statements filed on or after January 1, 2010 and for annual reports for fiscal years ending on or after December 31, 2009. Early adoption is not allowed. The

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Company is currently assessing the impact that the adoption of the revised rules will have on its operating results, financial position, cash flows, oil and natural gas reserves and disclosures.

Fair Value Measurements—In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements ("SFAS 157"), which defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. This pronouncement applies to other standards that require or permit fair value. Accordingly, this statement does not require any new fair value measurements. The provisions of SFAS 157 are effective January 1, 2008. The FASB has also issued Staff Position FAS 157-2 (FSP No. 157-2), which delays the effective date of SFAS 157 for nonfinancial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until fiscal years beginning after November 15, 2008. The Company adopted SFAS 157 as of January 1, 2008 for all financial and nonfinancial assets and liabilities recognized or disclosed at fair value on a recurring basis. The Company elected to defer the application thereof to nonfinancial assets and liabilities in accordance with FSP No. 157-2. Non-recurring nonfinancial assets and nonfinancial liabilities for which the Company has not applied the provisions of SFAS 157 include those measured at fair value in impairment testing for unproved properties, asset retirement obligations initially measured at fair value, and those initially measured at fair value in a business combination.

As defined in SFAS 157, fair value is the price that would be received in the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. The Company classifies fair value balances based on the observability of those inputs. SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement).

The three levels of the fair value hierarchy defined by SFAS 157 are as follows:

Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives and listed equities.

Level 2—Pricing inputs are other than quoted prices in active markets included in level 1, but are either directly or indirectly observable as of the reported date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for interest rates and commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category generally include non-exchange-traded derivatives such as commodity swaps, interest rate swaps, options and collars.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Level 3—Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Instruments in this category generally include non-exchange-traded derivatives such as commodity swaps, options and collars that are valued similar to the industry-standard models described above, however, these derivatives are classified in Level 3 because of inputs that may not be observable.

As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The following table sets forth by level within the fair value hierarchy the Company's financial assets and liabilities that were accounted for at fair value as of December 31, 2008 (in thousands).

	Level 1	Level 2	Level 3	Fair Value as of December 31, 2008
Assets (Liabilities):				
Commodity derivatives	$—	$ 92,561	$—	$ 92,561
Commodity derivatives	—	(2,467)	—	(2,467)
Interest rate swaps	—	(28,180)	—	(28,180)

The fair value of the interest rate swaps are valued using Level 2 fair value methodologies. The Company is able to value the assets and liabilities based on observable market data for similar instruments. This observable data includes the forward curve for interest rates based on quoted market prices.

In the first quarter of 2008, commodity derivative instruments were classified as a Level 3 measurement because the Company was unable to document certain observable factors. In the second quarter of 2008, the commodity derivatives previously classified as a Level 3 measurement were transferred to a Level 2 measurement classification due to additional documentation obtained by the Company to support such a classification. The table below presents a reconciliation for the liabilities

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

measured at fair value on a recurring basis using significant unobservable inputs (Level 3) during the year ended December 31, 2008 (in thousands).

	Year ended December 31, 2008
Beginning Balance	$(126,625)
Realized and Unrealized Losses(1)	(56,373)
Purchases, issuances and settlements	8,510
Transfers in and out of Level 3	174,488
Balance as of December 31, 2008	$ —
Change in unrealized (gains) losses included in earnings relating to Level 3 derivatives still held as of December 31, 2008	$ —

(1) Realized and unrealized losses are included in commodity derivative (gains) losses, net in the consolidated statement of operations.

Fair Value of Financial Instruments The Company's financial instruments consist primarily of cash and cash equivalents, accounts receivable and payable, derivatives (discussed above) and long-term debt. The carrying values of cash equivalents and accounts receivable and payable are representative of their fair values due to their short-term maturities. As a result of the sale of the Hastings complex in February 2009, the Company repaid the outstanding balance of its revolving credit facility. Therefore, the revolving credit facility is stated at its approximate fair value at December 31, 2008, due to its short term nature. The fair value of the second lien term loan, the 8.75% senior notes and financed derivative premiums were derived from available market data and valuation methodologies. This disclosure is presented in accordance with SFAS No. 107, "Disclosures about Fair Value of Financial Instruments" and does not impact our financial position, results of operations or cash flows.

	December 31, 2007		December 31, 2008	
Long Term Debt (in thousands)	**Carrying Value**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
Revolving credit agreement	$ 42,000	$ 42,000	$135,052	$ 135,052
Second lien term loan	500,000	500,000	500,000	315,000
8.75% senior notes	149,453	147,938	149,590	67,500
Financed derivative premiums	3,892	3,862	15,626	15,159

2. ACQUISITIONS AND SALES OF PROPERTIES

West Montalvo and Manvel Acquisitions. The Company acquired the West Montalvo field in Ventura County, California in May 2007 for approximately $61.3 million. The Company acquired the Manvel field in Brazoria County, Texas, and certain other fields in Texas, in April 2007 for $44.5 million.

TexCal Energy Acquisition. On March 31, 2006, the Company acquired 100% of the members' interest in TexCal Energy (LP) LLC (the "TexCal Acquisition"), an independent exploration and

2. ACQUISITIONS AND SALES OF PROPERTIES (Continued)

production company with properties in Texas and California, for approximately $456.8 million in cash and related financing costs of $14.4 million. TexCal's operations are located entirely onshore and are concentrated in the Gulf Coast region of Texas and in the Sacramento Basin in California. The Company financed the acquisition through loans advanced under a second amendment and restatement of its existing revolving credit facility and a senior secured second lien term loan facility. The purchase price was allocated to assets and liabilities, adjusted for tax effects, based on their estimated fair values at the date of acquisition. The acquisition was accounted for using the purchase method of accounting and has been included in the Company's consolidated financial statements as of the date of the acquisition.

The cash consideration paid for the TexCal Acquisition was allocated as follows (in thousands):

	Purchase Price Allocation
Current assets	$ 25,834
Oil and natural gas properties	461,907
Other non-current assets	1,018
Current liabilities	(22,411)
Long-term asset retirement obligations	(9,538)
Cash consideration	$456,810

The following unaudited pro forma condensed consolidated operating results for the years ended December 31, 2006 and 2007 give effect to the TexCal Acquisition (for the three months ended March 31, 2006 only) and the West Montalvo and Manvel acquisitions as if they had been completed as of January 1, 2006. The pro forma amounts shown below are not necessarily indicative of the operating results that would have occurred if the transactions had occurred on such date. The pro forma adjustments made are based on certain assumptions that the Company believes are reasonable based on currently available information (in thousands, except per share amounts) (unaudited).

	Years Ended December 31,	
	2006	2007
	Pro Forma	Pro Forma
Total revenues	$338,925	$243,205
Net income (loss)	$ 37,467	$(71,315)
Basic earnings per common share	$ 1.11	$ (1.54)
Diluted earnings per common share	$ 1.07	$ (1.54)

Grayson County Acquisition. In September 2008, the Company acquired working interests in approximately 11,000 undeveloped acres located in Grayson County, Texas for approximately $5.9 million from an entity (the "Seller") affiliated with a former member of the Company's board of directors. Under the purchase and sale agreement, the Company agreed to drill two horizontal test wells on the acreage by March 2010. The Seller has the option to participate on a 12.5% working interest basis in any wells the Company drills beyond the two test wells. The Company is required to

2. ACQUISITIONS AND SALES OF PROPERTIES (Continued)

carry the Seller's costs on wells drilled subsequent to the test wells until the Company has incurred costs of approximately \$5.7 million, net to the Seller's 12.5% working interest. If the Company has not incurred such costs by September 2011, it will be required to pay Seller the difference between \$5.7 million and amounts actually incurred, or reassign its interest in the then undeveloped acreage to Seller.

The board member resigned from the Company's board of directors on August 29, 2008, prior to the execution of a definitive agreement relating to the acquisition.

Hastings Complex Sale. In February 2009, the Company closed the sale of its principal interests in the Hastings complex ("Hastings Sale") to a subsidiary of Denbury Resources Inc. ("Denbury") for approximately \$201.0 million, subject to certain post-closing adjustments. The Company used the proceeds from the sale to repay the full balance of the revolving credit facility of \$187.1 million and related interest of \$0.5 million. In addition, the Company paid \$5.5 million toward the principal balance on the second lien term loan.

As a result of the sale, Denbury has committed to a development plan related to a CO_2 enhanced recovery project that will require it to make minimum capital expenditures in the amount of \$178.7 million by the end of 2014. As part of the plan, Denbury will be responsible for providing the necessary CO_2. The Company retains an overriding royalty interest of 2.0% in the production from the properties. In addition, the Company has the right to back in to a working interest of approximately 22.3% in the CO_2 project after Denbury recoups certain costs.

3. LONG-TERM DEBT

As of the dates indicated, the Company's long-term debt consisted of the following (in thousands):

	December 31,	
	2007	2008
Revolving credit agreement due March 2011	\$ 42,000	\$135,052
Second lien term loan due September 2011	500,000	500,000
8.75% senior notes due December 2011	149,453	149,590
Financed derivative premiums due through 2011	3,892	15,626
Total long-term debt	695,345	800,268
Less: current portion of long-term debt	3,449	2,598
Long-term debt, net of current portion	\$691,896	\$797,670

Revolving credit facility. The Company has a \$300.0 million revolving credit facility with a syndicate of banks ("revolving credit facility"). In May 2008, the revolving credit facility was amended to, among other things, extend the maturity date to March 30, 2011 and increase the borrowing base from \$140.0 million to \$200.0 million. The revolving credit facility is secured by a first priority lien on substantially all of the Company's oil and natural gas properties and other assets, including the equity interests in all of the Company's subsidiaries, and was unconditionally guaranteed by each of the Company's operating subsidiaries other than Ellwood Pipeline, Inc. The collateral also secures the Company's obligations to hedging counterparties that are also lenders, or affiliates of lenders, under

3. LONG-TERM DEBT (Continued)

the revolving credit agreement. Loans designated as Base Rate Loans under the revolving credit facility bear interest at a floating rate equal to (i) the greater of a market base rate and the overnight federal funds rate plus 0.50% plus (ii) an applicable margin ranging from zero to 0.75%, based upon utilization. Loans designated as LIBO Rate Loans under the revolving credit facility bear interest at (i) LIBOR plus (ii) an applicable margin ranging from 1.50% to 2.25%, based upon utilization. A commitment fee ranging from 0.375% to 0.5% per annum is payable with respect to unused borrowing availability under the facility. The agreement governing the facility contains customary representations, warranties, events of default, indemnities and covenants, including operational covenants that restrict the Company's ability to incur indebtedness and financial covenants that require the Company to maintain specified ratios of current assets to current liabilities and debt to EBITDA. The borrowing base is subject to redetermination in April and November of each year. In connection with the Hastings sale, the borrowing base was re-determined in February 2009, resulting in a reduction of the borrowing base from $200.0 million to $125.0 million. As of March 3, 2009, the Company had effective available borrowing capacity of $112.6 million (net of the outstanding balance of $5.6 million, $0.9 million in outstanding letters of credit and $5.9 million attributable to Lehman Commercial Paper—see below) under the revolving credit facility.

The borrowing base under the Company's revolving credit facility is currently $125.0 million and has been allocated at various percentages to a syndicate of 12 banks. Certain of the institutions included in the syndicate have received support from governmental agencies in connection with recent events in the credit markets. In addition, 4.75% of the $125.0 million borrowing base has been allocated to Lehman Commercial Paper ("LCP"), a wholly-owned subsidiary of Lehman Brothers Holding, Inc., which filed for bankruptcy protection in September 2008. LCP is no longer funding its portion of the Company's borrowing requests made under the facility. As of March 3, 2009, the Company had a balance of $5.6 million on the revolving credit facility. The Company's effective borrowing base is $119.1 million, excluding $5.9 million related to LCP.

Second lien term loan facility. The Company originally entered into a $350.0 million senior secured second lien term facility in connection with the TexCal Acquisition. In May 2007, the Company prepaid and replaced this facility with a $500.0 million second lien term loan facility. In connection with the settlement of the prior facility, the Company paid a prepayment premium of $3.5 million and wrote off related deferred loan costs of $8.6 million. Those amounts are reflected as a loss on extinguishment of debt on the consolidated statement of operations. Loans made under the $500.0 million facility are designated, at the Company's option, as either "Base Rate Loans" or "LIBO Rate Loans." Loans designated as Base Rate Loans bear interest at a floating rate equal to (i) the greater of the overnight federal funds rate plus 0.50% and a market base rate, plus (ii) 3.00%. Loans designated as LIBO Rate Loans bear interest at LIBOR plus 4.00%.

The term loan agreement contains customary representations, warranties, events of default and indemnities and certain customary covenants, including covenants that restrict the Company's ability to incur additional indebtedness. The facility is secured by second priority liens on substantially all of the Company's oil and natural gas properties and other assets, including the equity interests in all of its subsidiaries, and is unconditionally guaranteed by each of the Company's subsidiaries other than Ellwood Pipeline, Inc. Principal on the facility is payable on May 8, 2014. However, if the senior notes

3. LONG-TERM DEBT (Continued)

(see below) are still outstanding on September 20, 2011, principal on the term loan facility will be payable on that date.

The Company may from time to time make optional prepayments of amounts borrowed under the facility if no amounts are outstanding under the revolving credit facility. Optional prepayments made prior to May 7, 2009 are subject to a prepayment premium of 1%. After that date, no premium will be payable with respect to any optional prepayment. Amounts prepaid under the facility may not be reborrowed. As a result of the Hastings sale in February 2009, the Company was required to repay $5.5 million of the outstanding principal balance on the second lien term loan.

Senior notes. In December 2004, the Company issued $150.0 million in 8.75% senior notes (the "senior notes") due December 2011. Interest on the senior notes is due each June 15 and December 15. The senior notes are senior obligations and contain covenants that, among other things, limit the Company's ability to make investments, incur additional debt, issue preferred stock, pay dividends, repurchase its stock, create liens or sell assets. The senior notes were issued as unsecured obligations, but are currently secured equally and ratably with the Company's second lien term loan facility.

The Company was in compliance with all debt covenants at December 31, 2008.

Financed Derivative Premiums. The Company has entered into derivative contracts that contain provisions for the deferral of the payment or receipt of premiums until the period of production for which the derivative contract relates. Both the derivative and the net liability for the payment of premiums were recorded at their fair values at the inception of the derivative contracts.

Scheduled annual maturities of long-term debt were as follows at December 31, 2008 (in thousands):

Year Ending December 31 (in thousands):	
2009	$ 2,598
2010	10,541
2011	787,129
2012	—
2013	—
2014 and after	—
	$800,268

4. HEDGING AND DERIVATIVE FINANCIAL INSTRUMENTS

The Company utilizes swap and collar agreements and option contracts to hedge the effect of price changes on a portion of its future oil and natural gas production. The objective of the Company's hedging activities and the use of derivative financial instruments is to achieve more predictable cash flows. While the use of these derivative instruments limits the downside risk of adverse price movements, they also limit future revenues from favorable price movements. The use of derivatives also involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. Lehman Brothers Commodity Services, Inc. ("LBCS") was a counterparty to several derivative contracts with the Company entered into between August 2006 and May 2008. In September 2008, Lehman Brothers Holdings Inc. ("LBH"), credit support provider for LBCS, filed for bankruptcy. The bankruptcy filing of LBH constituted an event of default under the ISDA Master Agreement. Accordingly, the Company notified LBCS that the Company was terminating each of the outstanding transactions, effective immediately. Subsequent to the Company's notification of termination, LBCS filed for bankruptcy protection. Similar issues could affect other hedge counterparties in the future.

The components of commodity derivative losses (gains) in the consolidated statements of operations are as follows (in thousands):

	Years ended December 31,		
	2006	2007	2008
Realized commodity derivative losses (gains)	$ 15,263	$ 13,041	$ 61,446
Amortization of commodity derivative premiums	2,190	6,830	6,256
Unrealized commodity derivative losses (gains):			
Change in fair value of derivatives that do not qualify for hedge accounting	(25,040)	122,892	(184,459)
Ineffective portion of derivatives qualifying for hedge accounting	3,961	(113)	—
Total unrealized commodity derivative losses (gains)	(21,079)	122,779	(184,459)
Commodity derivative losses (gains), net	$ (3,626)	$142,650	$(116,757)

Because a large portion of the Company's commodity derivatives do not qualify for hedge accounting and to increase clarity in its financial statements, the Company elected to discontinue hedge accounting prospectively for its commodity derivatives beginning April 1, 2007. Consequently, from that date forward, the Company has recognized mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (loss) for those commodity derivatives that qualify as cash flow hedges. The net mark-to-market loss on outstanding derivatives on the date the Company discontinued hedge accounting included in accumulated other comprehensive loss of $8.3 million ($5.1 million after tax) is being amortized into future earnings as the original hedged transactions affect earnings. This change in reporting has no impact on the Company's reported cash flows, although future results of operations are affected by mark-to-market gains and losses which fluctuate with volatile oil and natural gas prices. The Company amortized accumulated other comprehensive loss into oil and natural gas sales of $4.7 million and $1.4 million during the years ended December 31, 2007 and 2008, respectively.

As of December 31, 2008, the remaining unrealized derivative fair value loss of $2.3 million ($1.4 million after tax) million for derivative contracts previously designated as cash flow hedges is recorded in accumulated other comprehensive loss. The Company will amortize the remaining net

4. HEDGING AND DERIVATIVE FINANCIAL INSTRUMENTS (Continued)

unrealized derivative losses out of accumulated other comprehensive loss into earnings during the next twelve months.

Crude Oil Agreements. As of December 31, 2008, the Company had entered into option, swap and collar agreements to receive average minimum and maximum New York Mercantile Exchange (NYMEX) West Texas Intermediate (WTI) prices as summarized below. Location and quality differentials attributable to the Company's properties are not included in the following prices. The agreements provide for monthly settlement based on the differential between the agreement price and the actual NYMEX crude oil price.

	Minimum		Maximum	
	Barrels/day	Avg. Prices	Barrels/day	Avg. Prices
Crude oil derivatives at December 31, 2008 for production:				
January 1–December 31, 2009	8,983	$54.06	6,983	$ 74.38
January 1–December 31, 2010	8,000	$56.22	6,150	$ 72.88
January 1–December 31, 2011	7,000	$50.00	7,000	$141.64

Natural Gas Agreements. As of December 31, 2008, the Company had entered into option, swap and collar agreements to receive average minimum and maximum PG&E Citygate prices as follows:

	Minimum		Maximum	
	MMBtu/Day	Avg. Prices	MMBtu/Day	Avg. Prices
Natural gas derivatives at December 31, 2008 for production:				
January 1–December 31, 2009	67,125	$6.92	23,125	$11.42
January 1–December 31, 2010	58,900	$6.41	17,900	$11.05
January 1–December 31, 2011	26,000	$6.71	12,000	$13.53

In January 2009, the Company entered into two transactions whereby it unwound existing natural gas puts covering 6,000 MMBtu per day for the period from February 2009 through December 2009 and entered into natural gas puts covering 10,000 MMBtu per day for the period from January 2011 through December 2011. The average production and minimum prices from the contracts are summarized below:

	Minimum	
	MMBtu/Day	Avg. Prices
Natural gas derivatives for production:		
February 1–December 31, 2009	(6,000)	$6.00
January 1–December 31, 2011	10,000	$6.02

Interest Rate Swap. The Company entered into an interest rate swap transaction during 2006 to lock in its interest cost on $200.0 million of borrowings under its second lien term loan facility through May 2008. In June 2007, the Company entered into an additional interest rate swap relating to borrowings under the second lien term loan. The swap fixes the interest rate on $500.0 million of borrowings through June 2010. The Company pays a fixed interest rate of 5.32% and receives a floating

4. HEDGING AND DERIVATIVE FINANCIAL INSTRUMENTS (Continued)

interest rate based on the three-month LIBO rate, with settlements made quarterly. As a result of these transactions, amounts borrowed under the second lien term loan facility will effectively bear interest at a fixed rate of approximately 9.3% until June 2010 (including the 4.0% margin payable on borrowed amounts). The Company has not designated either interest rate swap as a hedge. The fair value liability of the interest rate swaps of $17.8 million at December 31, 2007 and $28.1 million at December 31, 2008 has been recorded in commodity and interest derivatives in the consolidated balance sheets.

The components of interest rate derivative losses in the consolidated statements of operations are as follows (in thousands):

	Years ended December 31,		
	2006	2007	2008
Realized interest rate derivative losses (gains)	$ 96	$ (135)	$10,231
Unrealized interest rate derivative losses (gains)	494	17,312	10,336
Interest rate derivative losses (gains), net	$590	$17,177	$20,567

The estimated fair values of derivatives included in the consolidated balance sheets at December 31, 2007 and December 31, 2008 are summarized below. The net fair value of the Company's derivatives increased by $206.3 million from a net liability of $144.4 million at December 31, 2007 to a net asset of $61.9 million at December 31, 2008 due to lower futures prices for crude oil and natural gas, which are used in the calculation of the fair value of commodity derivatives, and lower estimated futures interest rates, which are used in the calculation of the fair value of interest derivatives. The Company does not offset asset and liability positions with the same counterparties within the financial statements, rather, all contracts are presented at their gross estimated fair value. As of the dates indicated, the Company's derivative assets and liabilities consisted of the following (in thousands):

	December 31, 2007	December 31, 2008
Derivative assets:		
Oil derivative contracts	$ 3,341	$ 35,630
Gas derivative contracts	8,207	56,931
Derivative liabilities:		
Oil derivative contracts	(134,505)	(1,672)
Gas derivative contracts	(3,668)	(832)
Interest rate derivative contracts	(17,807)	(28,143)
Net derivative asset (liability)	$(144,432)	$ 61,914

5. ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations primarily represent the estimated present value of the amounts expected to be incurred to plug, abandon and remediate producing and shut-in properties (including removal of certain onshore and offshore facilities) at the end of their productive lives in accordance with applicable state and federal laws. The Company determines asset retirement

5. ASSET RETIREMENT OBLIGATIONS (Continued)

obligations by calculating the present value of estimated cash flows related to plugging and abandonment liabilities. The asset retirement liability is accreted to its present value each period and the capitalized asset retirement cost is depleted as a component of the full cost pool using the units-of-production method.

The following table summarizes the activities for the Company's asset retirement obligations for the years ended December 31, 2007 and 2008 (in thousands):

	2007	2008
Asset retirement obligations at beginning of period	$42,049	$52,220
Revisions of estimated liabilities	(502)	20,838
Liabilities incurred	6,880	3,795
Liabilities settled	(121)	(478)
Accretion expense	3,914	4,204
Asset retirement obligations at end of period	52,220	80,579
Less: current asset retirement obligations (classified with accounts payable and accrued liabilities)	(500)	(1,075)
Long-term asset retirement obligations	$51,720	$79,504

Discount rates used to calculate the present value vary depending on the estimated timing of the obligation, but typically range between 4% and 9%. The 2007 and 2008 revisions primarily relate to updated estimates for expected cash outflows and changes in the timing of obligations based on reserve evaluations. In 2007, the Company incurred $3.8 million in new liabilities related to acquisitions.

6. INCOME TAXES

The Company accounts for income taxes under SFAS No. 109, *Accounting for Income Taxes*. SFAS 109 is an asset and liability approach that requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been recognized in the Company's consolidated financial statements or tax returns.

The Company's income tax provision (benefit) is composed of the following (in thousands):

	Years ended December 31,		
	2006	2007	2008
Current:			
Federal	$ 580	$ 1,200	$ 2,700
State	30	(100)	3,600
	610	1,100	6,300
Deferred:			
Federal	13,640	(43,465)	4,500
State	1,400	(3,835)	400
	15,040	(47,300)	4,900
Total income tax provision (benefit)	$15,650	$(46,200)	$11,200

6. INCOME TAXES (Continued)

A reconciliation of the income tax provision (benefit) computed by applying the federal statutory rate of 35% to the Company's income tax provision (benefit) is as follows (in thousands):

	2006	2007	2008
Income tax expense (benefit) at federal statutory rate	$13,860	$(41,850)	$(132,976)
State income taxes	1,424	(3,693)	(12,837)
Other	366	(657)	68
Valuation allowance	—	—	156,945
	$15,650	$(46,200)	$ 11,200

The components of deferred tax assets and (liabilities) are as follows (in thousands):

	December 31,	
	2007	2008
Deferred income tax assets:		
Bad debts	$ 149	$ 112
Accrued liabilities	1,543	1,300
Unrealized commodity derivative losses	53,395	—
Unrealized interest rate swap losses	6,782	10,801
Share-based compensation	938	1,648
Net operating losses	48,967	26,394
State tax benefit	—	1,912
Alternative minimum tax credits	—	3,549
Charitable contributions	730	736
Oil and gas properties	—	129,411
Valuation allowance	—	(156,945)
	112,504	18,918
Deferred income tax liabilities:		
Oil and natural gas properties	(105,733)	—
Unrealized commodity derivative gains	—	(17,543)
Prepaid expenses	(1,398)	(1,375)
Other	(13)	—
	(107,144)	(18,918)
Net deferred income tax assets (liabilities)	5,360	—
Net current deferred tax asset	21,967	—
Noncurrent deferred tax liability	$ (16,607)	$ —

The Company has net operating loss carryovers as of December 31, 2008 of $79.7 million for federal income tax purposes and $67.1 million for financial reporting purposes. The difference of $12.6 million relates to tax deductions for compensation expense for financial reporting purposes for which the benefit will not be recognized until the related deductions reduce taxes payable. The net operating loss carryovers may be carried back two years and forward twenty years from the year the net operating loss was generated. The net operating losses may be used to offset taxable income through

6. INCOME TAXES (Continued)

2027. The Company provided a valuation allowance against its net deferred tax assets of $156.9 million as of December 31, 2008, since it cannot conclude that it is more likely than not that the net deferred tax assets will be fully realized on future income tax returns. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, available taxes in carryback periods, projected future taxable income and tax planning strategies in making this assessment. The Company will continue to evaluate whether the valuation allowance is needed in future reporting periods.

The Company's federal income tax returns for the 2003 and 2004 tax years have been examined by the U.S. Internal Revenue Service ("IRS"). In both the 2003 and 2004 examinations, the IRS proposed adjustments that relate to the amount of cost depletion deducted and the capitalization of certain lease operating expenses as depreciable property rather than as deductible expenses in the year incurred. In the 2004 examination, the IRS proposed additional adjustments related to the capitalization of intangible drilling costs as depreciable property rather than as deductible expenses in the year incurred. Further, the IRS proposed adjustments for certain legal fees deducted. The Company disagreed with a majority of the IRS proposed adjustments. In December 2008, the Company received from the IRS Appeals Office a Schedule of Proposed Adjustments agreed to in the Appeals Conference held in November 2008. In February 2009, the Company received from the IRS Appeals Office a letter and forms to close both examination years. In summary, the IRS Appeals Office has agreed with the Company with respect to all adjustments protested by the Company in the 2003 and 2004 formal protests. As a result, the net increase in federal income tax settled with the IRS Appeals Office for both the 2003 and 2004 tax years is $0.9 million.

The California Department of Revenue has also notified the Company that it intends to examine the Company's 2003 and 2004 California tax returns. The Company does not expect the state examinations to begin until the current federal examinations are finalized.

The Company adopted the provisions of FIN 48 on January 1, 2007, and has analyzed filing positions in all of the federal and state jurisdictions where it is required to file income tax returns, as well as all open tax years in these jurisdictions. As of December 31, 2008, the Company reduced the balance of unrecognized tax benefits due to the settlement with the IRS related to the 2003 and 2004 examinations. The settlement with the IRS related primarily to timing differences and did not have a material impact on the Company's effective tax rate. The remaining balance of uncertain tax positions relates to the pending examination of the 2003 and 2004 California tax returns. These uncertain tax positions relate primarily to timing differences and management does not believe any such uncertain tax positions will materially impact the Company's effective tax rate in future periods. The Company anticipates that none of the uncertain tax positions will be recognized within the next twelve months.

6. INCOME TAXES (Continued)

A rollforward of changes in the Company's unrecognized tax benefits is shown below (in thousands).

	Years ended December 31,	
	2007	2008
Balance at beginning of period	$ 3,800	$ 2,400
Additions based on tax positions related to the current year	500	—
Additions for tax positions of prior years	—	—
Reductions for tax positions of prior years	(1,900)	(1,300)
Settlements	—	(900)
Balance at end of period	$ 2,400	$ 200

The Company is subject to taxation in federal and various state jurisdictions. The Company's tax years for 2003 and forward are subject to examination by state tax authorities. The Company has been notified by the IRS that the Company's 2005 federal income tax return will be examined.

The Company's policy is to recognize interest and/or penalties related to uncertain tax positions in income tax expense. The Company did not recognize any interest or penalties during the years ended December 31, 2007 and 2008.

7. CAPITAL STOCK AND TRANSACTIONS WITH SHAREHOLDER

All of the Company's outstanding common stock was controlled by the Company's CEO from December 2004 until August 2006, when the Company's then sole stockholder, a trust affiliated with the CEO, donated shares of stock to two charitable institutions. The Company issued and sold 10,090,800 shares of its common stock in the fourth quarter of 2006 in an initial public offering and received net proceeds of $160.4 million. In July 2007, the Company completed an additional public offering of common stock in which it issued and sold 6,565,000 shares of stock and received net proceeds of $116.0 million. The majority of the net proceeds from the offerings were used to repay the outstanding balance under the Company's revolving credit facility.

The Company has 58.8 million shares of common stock issued or reserved for issuance at December 31, 2008. At December 31, 2008, the Company has 51.5 million common shares issued and outstanding, of which 0.9 million shares are restricted stock granted under the Company's 2005 stock incentive plan. At December 31, 2008, the Company had approximately 3.5 million options outstanding and 3.5 million shares available to be issued pursuant to awards under its stock incentive plans, including the 2008 Employee Stock Purchase Plan.

On March 22, 2006, the Company paid a dividend consisting of 100% of its membership interest in 6267 Carpinteria to its then sole stockholder, a trust controlled by the Company's CEO. 6267 Carpinteria owns the office building and related land used by the Company in Carpinteria, California. At the date of the dividend, 6267 Carpinteria had net assets of $4.7 million, including $0.4 million in cash and land and building with a net book value of $13.4 million, and a note payable of $9.9 million. The Company makes lease payments to 6267 Carpinteria under a lease for the office building entered

7. CAPITAL STOCK AND TRANSACTIONS WITH SHAREHOLDER (Continued)

into prior to the dividend. The lease provides for minimum lease payments of approximately $1.1 million per year through 2019.

Venoco operates a property located in Carpinteria, California as a transit point for several of the Company's offshore oil and gas producing properties in the Santa Barbara Channel (the "Bluffs Property"). During the third quarter of 2006, the Company declared and paid a dividend on its common stock of 51 acres of real property at the Bluffs Property and entered into certain agreements with its then-sole stockholder and an affiliate of the stockholder, including a ground lease and a development agreement relating to the property. Under the ground lease, which had a 20-year term, the Company leased the property for use in its oil and gas operations for rent of $1 per year. The stockholder's affiliate had the right to require the Company to consolidate its operations at a future date from an approximate 14 acre footprint to 2 acres (the "consolidation"). If consolidation had been requested, the Company estimated that it would have incurred approximately $10 million in capital cost to acquire and install new equipment to effect the consolidation. After completion of the consolidation, the Company would have had the ability to enter into a new ground lease for $1 per year for up to 99 years (effectively the remaining productive life of the related offshore oil and gas producing properties). Independent third party appraisals were obtained which valued the unencumbered value of the land in excess of the Company's historical cost of $10.3 million. In addition, the fair value of the property was appraised at $5.0 million after taking into account the encumbrance for the ground lease and the time value of money for the consolidation. Therefore, the Company recorded a dividend of $5.0 million for the appraised value of the interest conveyed and a retained leasehold interest of $5.3 million which was to be amortized over the expected life of the ground lease of 20 years.

In December 2008, the Company repurchased the Bluffs Property from the affiliate of the stockholder for $5.3 million. The Company intends to continue its oil and gas operations on the property and also plans to pursue a drilling project from the property. An independent third party appraisal was obtained which valued the unencumbered land in excess of the purchase price. As a result of the transaction, the ground lease and the consolidation requirement were both cancelled and the remaining unamortized leasehold interest of $4.7 million was recorded to land.

In December 2008, the Company entered into an agreement with an affiliate of the Chief Executive Officer, pursuant to which the affiliate paid to the Company $0.9 million which equaled the amount of profits the affiliate was deemed to have realized under Section 16(b) of the Securities and Exchange Act of 1934, as amended, with respect to transactions involving the Company's common stock.

8. SHARE-BASED PAYMENTS

The Company has granted options to directors, certain employees and officers of the Company other than its CEO. As of December 31, 2008, there are a total of 3,504,263 options outstanding with a weighted average exercise price of $9.16 ($6.00 to $20.00). The options vest over a four year period, with 20% vesting on the grant date and 20% vesting on each subsequent anniversary of the grant date. The options typically have a maximum life of 10 years. The options will generally vest upon a change in control of the Company. The agreements with employee option holders generally provide that all of the holder's options will vest if the Company terminates the holder's employment, unless the termination is

8. SHARE-BASED PAYMENTS (Continued)

for specified types of misconduct. The agreements with director option holders provide that any unvested options will terminate when the director's service to the Company ceases.

In November 2008, the Company's Board of Directors approved the 2008 Employee Stock Purchase Plan (the "ESPP") and the plan will be submitted to the Company's shareholders for approval at the Company's 2009 annual shareholders' meeting. In connection with the approval of the ESPP, the Board authorized 1.5 million shares of common stock to be issued under the ESPP. Participation in the ESPP is open to all employees who meet limited qualifications. Under the terms of the ESPP, employees will be able to purchase Company stock at a 5% discount as determined by the fair market value of the Company's stock on the last trading day of each purchase period. Employees are limited to $25,000 of common stock purchased in any calendar year. The ESPP is non-compensatory, as defined by SFAS 123R. The ESPP became effective February 1, 2009.

As of December 31, 2008, there were a total of 851,545 shares of restricted stock outstanding under the Company's 2005 stock incentive plan, including 365,773 shares to its CEO. The restricted shares generally vest over a four year service period. The grant date fair value of restricted stock subject to service conditions only is determined by the closing stock price, as published by the New York Stock Exchange, on the day prior to the date of grant. The vesting of 482,851 of the shares is also subject to market conditions based on the Company's total shareholder return in comparison to peer group companies for each calendar year. The weighted-average fair value of the restricted shares subject to market conditions was derived using a Monte Carlo technique and the fair value of awards granted was estimated to be $13.53 per share and $10.43 per share in 2007 and 2008, respectively. As of December 31, 2008, none of the shares subject to market conditions have vested.

In accordance with SFAS 123R, the Company recognized total share-based compensation costs as follows (in thousands):

	Years Ended December 31,		
	2006	2007	2008
General and administrative expense	$2,750	$ 4,380	$ 5,030
Oil and natural gas production expense	300	300	680
Total share-based compensation costs	3,050	4,680	5,710
Less: share-based compensation costs capitalized	—	(1,402)	(2,646)
Share-based compensation expensed	$3,050	$ 3,278	$ 3,064

As of December 31, 2008, there was $2.0 million of total unrecognized compensation cost related to stock options which is expected to be amortized over a weighted-average period of 1.9 years and $7.1 million of total unrecognized compensation cost related to restricted stock which is expected to be amortized over a weighted-average period of 2.9 years.

8. SHARE-BASED PAYMENTS (Continued)

The following summarizes the Company's stock option activity for the years ended December 31, 2006, 2007 and 2008:

	Years Ended December 31,						
	2006		2007		2008		
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Aggregate Intrinsic Value of Options(1)
							(in thousands)
Outstanding, start of period	4,013,663	$ 7.04	4,740,663	$ 8.55	4,159,463	$ 9.19	
Granted	727,000	$16.85	265,000	$16.93	—	—	
Exercised	—	—	(702,690)	$ 6.80	(450,460)	$ 6.59	
Cancelled	—	—	(143,510)	$13.85	(204,740)	$15.50	
Outstanding, end of period	4,740,663	$ 8.55	4,159,463	$ 9.19	3,504,263	$ 9.16	$ 0
Exercisable, end of period	1,750,865	$ 7.86	2,296,318	$ 8.62	2,683,110	$ 8.77	$ 0
Weighted average grant-date fair value of options granted during the period		$ 6.45		$ 7.54		—	—

(1) The intrinsic value of a stock option is the amount by which the market value exceeds the exercise price.

Additional information related to options outstanding at December 31, 2008 is as follows:

	Options Outstanding			Options Exercisable		
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life	Weighted-Average Exercise Prices	Number Exercisable	Weighted Average Remaining Contractual Life	Weighted Average Exercise Prices
$6.00–$7.33	2,008,950	6.0	$ 6.13	1,603,410	5.9	$ 6.13
$8.00–$8.68	424,613	5.7	$ 8.34	337,920	5.6	$ 8.36
$10.67–$14.97	444,750	5.8	$12.22	347,750	5.2	$11.81
$15.00–$20.00	625,950	6.8	$17.26	394,030	6.1	$17.18
	3,504,263			2,683,110		

The aggregate intrinsic value of options exercised in 2007 and 2008 was $8.4 million and $7.1 million, respectively. There were no options exercised prior to 2007.

8. SHARE-BASED PAYMENTS (Continued)

The following summarizes the Company's unvested stock option award activity for the year ended December 31, 2008.

Non-vested stock options	Shares	Weighted-Average Grant-Date Fair Value
Non-vested at January 1, 2008	1,863,145	$3.97
Granted	—	—
Vested	(928,292)	$3.40
Forfeited	(113,700)	$5.29
Non-vested at December 31, 2008	821,153	$4.42

The fair value of each option is estimated on the grant date using the Black-Scholes option valuation model. Option valuation models require the input of highly subjective assumptions, including the expected volatility of the price of the underlying stock. The Company's stock options have characteristics significantly different from those of traded options, and because changes in the subjective input assumptions can materially affect the fair value estimate, it is management's opinion that the valuations afforded by the existing models are different from the value that the options would realize if traded in the market.

The following assumptions were used during 2006 and 2007 to compute the weighted average fair market value of options granted during the periods presented. No options were granted in 2008.

	Years Ended December 31	
	2006	2007
Expected option life	6 years	6 years
Risk free interest rates	4.3%–4.8%	4.3%–5.1%
Estimated volatility	40%	37%
Dividend yield	0.0%	0.0%

The expected life of the options is based, in part, on historical exercise patterns of the holders of options with similar terms with consideration given to how historical patterns may differ from future exercise patterns based on current or expected market conditions and employee turnover. For both periods presented above, the Company calculated the expected life of all options granted using the "simplified" method set forth in Staff Accounting Bulletin 107 (average of vesting period and the term of the option) due to the limited exercise history of options that have been granted. The risk free interest rate was based on the U.S. Treasury yield curve in effect at the time of grant. The expected volatility was based on the historical volatility of other public companies with characteristics similar to the Company for the previous six years.

8. SHARE-BASED PAYMENTS (Continued)

The following summarizes the Company's unvested restricted stock award activity for the years ended December 31, 2007 and 2008.

	Year Ended December 31,			
	2007		2008	
Non-vested restricted stock	Shares	Weighted-Average Grant-Date Fair Value	Shares	Weighted-Average Grant-Date Fair Value
Non-vested, start of period	—	—	370,785	$14.32
Granted	371,785	$14.24	553,693	$11.74
Vested	(1,000)	$15.34	(36,891)	$15.52
Forfeited	—	—	(36,042)	$13.37
Non-vested, end of period	370,785	$14.24	851,545	$12.65

9. COMMITMENTS

Leases—The Company has entered into lease agreements for office space and an office building. As of December 31, 2008, future minimum lease payments under operating leases that have initial or remaining non-cancelable terms in excess of one year are $2.4 million in 2009, $2.4 million in 2010, $2.3 million in 2011, $2.3 million in 2012, $2.4 million in 2013 and S8.0 million thereafter. Net rent expense incurred for office space and the office building was $1.8 million, $2.7 million and $3.4 million in 2006, 2007 and 2008, respectively.

10. LITIGATION

Beverly Hills Litigation

Between June 2003 and April 2005, six lawsuits were filed against the Company and certain other energy companies in Los Angeles County Superior Court by persons who attended Beverly Hills High School or who were or are citizens of Beverly Hills/Century City or visitors to that area during the time period running from the 1930s to date. There are approximately 1,000 plaintiffs (including plaintiffs in two related lawsuits in which the Company has not been named) who claimed to be suffering from various forms of cancer or other illnesses, fear they may suffer from such maladies in the future, or are related to persons who have suffered from cancer or other illnesses. Plaintiffs alleged that exposure to substances in the air, soil and water that originated from either oil-field or other operations in the area were the cause of the cancers and other maladies. The Company has owned an oil and natural gas facility adjacent to the school since 1995. For the majority of the plaintiffs, their alleged exposures occurred before the Company acquired the facility. All cases were consolidated before one judge. Twelve "representative" plaintiffs were selected to have their cases tried first, while all of the other plaintiffs' cases were stayed. In November 2006, the judge entered summary judgment in favor of all defendants in the test cases, including the Company. The judge dismissed all claims by the test case plaintiffs on the ground that they offered no evidence of medical causation between the alleged emissions and the plaintiffs' alleged injuries. Plaintiffs appealed the ruling. A decision on the appeal is expected in 2009. The Company vigorously defended the actions, and will continue to do so until they

10. LITIGATION (Continued)

are resolved. Certain defendants have made claims for indemnity for events occurring prior to 1995, which the Company is disputing. The Company cannot predict the cost of these indemnity claims at the present time.

One of the Company's insurers currently is paying for the defense of these lawsuits under a reservation of its rights. Three other insurers that provided insurance coverage to the Company (the "Declining Insurers") took the position that they were not required to provide coverage for losses arising out of, or to defend against, the lawsuits because of a pollution exclusion contained in their policies. In February 2006, the Company filed a declaratory relief action against the Declining Insurers in Santa Barbara County Superior Court seeking a determination that those insurers have a duty to defend the Company in the lawsuits. Two of the three Declining Insurers settled with the Company. The third Declining Insurer disputed the Company's position and in November 2007 the Santa Barbara Court granted that insurer's motion for summary judgment, in part on the basis that the pollution exclusion provision in the policy did not require that insurer to provide a defense for the Company. The Company has appealed the Santa Barbara Court's ruling. The Company has no reason to believe that the insurer currently providing defense of these actions will cease providing such defense. If it does, and the Company is unsuccessful in enforcing its rights in any subsequent litigation, the Company may be required to bear the costs of the defense, and those costs may be material. If it ultimately is determined that the pollution exclusion or another exclusion contained in one or more of the Company's policies applies, it will not have the protection of those policies with respect to any damages or settlement costs ultimately incurred in the lawsuits.

In accordance with SFAS No. 5, *Accounting for Contingencies*, the Company has not accrued for a loss contingency relating to the Beverly Hills litigation because the Company believes that, although unfavorable outcomes in the proceedings may be reasonably possible, the Company does not consider them to be probable or reasonably estimable. If one or more of these matters are resolved in a manner adverse to the Company, and if insurance coverage is determined not to be applicable, their impact on the Company's results of operations, financial position and/or liquidity could be material.

State Lands Commission Royalty Audit

The Company pays royalties to the state of California pursuant to certain oil and natural gas leases relating to the South Ellwood field. The Company has been informed by the California State Lands Commission (the "SLC") that the SLC is in the process of auditing the Company's royalty payment calculations on those leases. The SLC has not completed its audit, nor has it presented the Company with any audit conclusions. The Company does not currently expect that the audit adjustments, if any, will be material.

Other

In addition, the Company is subject from time to time to other claims and legal actions that arise in the ordinary course of business. The Company believes that the ultimate liability, if any, with respect to these other claims and legal actions will not have a material adverse effect on its consolidated financial position, results of operations or liquidity.

11. QUARTERLY FINANCIAL DATA (UNAUDITED)

The following is a summary of the unaudited financial data for each quarter for the years ended December 31, 2007 and 2008 (in thousands, except per share data):

	Three Months Ended			
	March 31, 2007	June 30, 2007	September 30, 2007	December 31, 2007
Year Ended December 31, 2007:				
Revenues	$ 74,241	$90,682	$96,695	$114,892
Income (loss) from operations	16,110	31,691	33,269	35,560
Net income (loss)	(10,365)	(3,123)	481	(60,365)
Basic earnings per common share	$ (0.24)	$ (0.07)	$ 0.01	$ (1.21)
Diluted earnings per common share	$ (0.24)	$ (0.07)	$ 0.01	$ (1.21)

	Three Months Ended			
	March 31, 2008	June 30, 2008	September 30, 2008	December 31, 2008
Year Ended December 31, 2008:				
Revenues	$137,450	$ 168,047	$159,153	$ 94,870
Income (loss) from operations	62,839	90,464	70,870	(642,902)
Net income (loss)	(25,456)	(172,569)	220,937	(414,044)
Basic earnings per common share	$ (0.51)	$ (3.43)	$ 4.36	$ (8.17)
Diluted earnings per common share	$ (0.51)	$ (3.43)	$ 4.23	$ (8.17)

During the quarter ended December 31, 2008, the Company recognized an impairment of $641.0 million as a result of the ceiling test performed pursuant to the full cost method of accounting for oil and natural gas properties.

12. SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (UNAUDITED)

The following information concerning the Company's natural gas and oil operations has been provided pursuant to SFAS No. 69, *Disclosures about Oil and Gas Producing Activities*. At December 31, 2008, the Company's oil and natural gas producing activities were conducted onshore within the continental United States and offshore in federal and state waters off the coast of California. The evaluations of oil and natural gas reserves for certain properties at December 31, 2006 were prepared by Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton, independent petroleum reserve engineers. The evaluations of the oil and natural gas reserves at December 31, 2007 and 2008 were prepared by DeGolyer and MacNaughton, independent petroleum reserve engineers.

12. SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (UNAUDITED) (Continued)

Capitalized Costs of Oil and Natural Gas Properties

	As of December 31,		
	2006	2007	2008
		(in thousands)	
Unevaluated properties(1)	$ 4,850	$ 12,034	$ 30,228
Properties subject to amortization	876,720	1,319,496	1,641,571
Total capitalized costs	881,570	1,331,530	1,671,799
Accumulated depreciation, depletion and amortization	(127,207)	(221,953)	(351,334)
Impairment	—	—	(641,000)
Net capitalized costs	$ 754,363	$1,109,577	$ 679,465

(1) Unevaluated costs represent amounts the Company excludes from the amortization base until proved reserves are established or impairment is determined. The Company estimates that the remaining costs will be evaluated within three years.

Capitalized Costs Incurred

Costs incurred for oil and natural gas exploration, development and acquisition are summarized below. Costs incurred during the years ended December 31, 2006, 2007 and 2008 include capitalized general and administrative costs related to acquisition, exploration and development of natural gas and oil properties of $4.4 million, $11.8 million and $18.8 million, respectively. Costs incurred also include asset retirement costs of $16.8 million, $6.3 million and $24.2 million during the years ended December 31, 2006, 2007 and 2008, respectively.

	Years ended December 31,		
	2006	2007	2008
		(in thousands)	
Property acquisition and leasehold costs:			
Unevaluated property	$ 2,238	$ 4,985	$ 20,561
Proved property	479,112	134,890	23,035
Exploration costs	26,180	99,822	117,905
Development costs	163,005	210,264	178,767
Total costs incurred	$670,535	$449,961	$340,268

12. SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (UNAUDITED) (Continued)

Estimated Net Quantities of Natural Gas and Oil Reserves

The following table sets forth the Company's net proved reserves, including changes, and proved developed reserves (all within the United States) at the end of each of the three years in the periods ended December 31, 2006, 2007 and 2008.

	Crude Oil, Liquids and Condensate (MBbls)			Natural Gas (MMcf)		
	2006(1)	2007(2)	2008(3)	2006(1)	2007(2)	2008(3)
Beginning of the year reserves	35,300	49,607	64,176	74,053	229,952	214,605
Revisions of previous estimates	2,580	9,759	(5,202)	10,766	(28,201)	(4,880)
Extensions, discoveries and improved recovery(4)	935	4	3,177	54,061	13,359	47,223
Purchases of reserves in place	14,484	8,787	99	105,570	18,390	2,268
Production	(3,411)	(3,981)	(4,091)	(14,314)	(18,895)	(23,050)
Sales of reserves in place	(281)	—	—	(184)	—	—
End of year reserves	49,607	64,176	58,159	229,952	214,605	236,166
Proved developed reserves:						
Beginning of year	24,154	37,497	44,730	53,390	79,796	96,522
End of year	37,497	44,730	34,468	79,796	96,522	107,418

(1) Based on unescalated year-end posted prices of (i) $57.75 per Bbl for oil and natural gas liquids, and adjusted for quality, transportation fees and regional price differentials and (ii) $5.64 per MMBtu for natural gas, and adjusted for energy content, transportation fees and regional price differentials.

(2) Based on unescalated year-end posted prices of $95.97 per Bbl for oil and natural gas liquids and $7.48 per MMBtu for natural gas, and adjusted, in each case, as described in note (1) above.

(3) Based on unescalated year-end posted prices of $44.60 per Bbl for oil and natural gas liquids and $5.62 per MMBtu for natural gas, and adjusted, in each case, as described in note (1) above.

(4) Extensions for the years ended December 31, 2006, 2007 and 2008 include 2,668 MMcf, 1,939 MMcf, and 4,962 MMcf, respectively, resulting from the Company's infill program in the Sacramento Basin.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves

The following summarizes the policies used in the preparation of the accompanying oil and natural gas reserve disclosures, standardized measures of discounted future net cash flows from proved oil and natural gas reserves and the reconciliations of standardized measures from year to year. The information disclosed, as prescribed by Statement of Financial Accounting Standards No. 69, is an attempt to present the information in a manner comparable with industry peers.

The information is based on estimates of proved reserves attributable to the Company's interest in oil and natural gas properties as of December 31 of the years presented. These estimates were

12. SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (UNAUDITED) (Continued)

prepared by independent petroleum reserve engineers. Proved reserves are estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

(1) Estimates are made of quantities of proved reserves and future periods during which they are expected to be produced based on year-end economic conditions.

(2) The estimated future cash flows are compiled by applying year-end prices of crude oil and natural gas relating to the Company's proved reserves to the year-end quantities of those reserves.

(3) The future cash flows are reduced by estimated production costs, costs to develop and produce the proved reserves and abandonment costs, all based on year-end economic conditions.

(4) Future income tax expenses are based on year-end statutory tax rates giving effect to the remaining tax basis in the oil and natural gas properties, other deductions, credits and allowances relating to the Company's proved oil and natural gas reserves.

(5) Future net cash flows are discounted to present value by applying a discount rate of 10%.

The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair value of the Company's oil and natural gas reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves is as follows and does not include cash flows associated with hedges outstanding at each of the respective reporting dates.

	As of December 31,		
	2006	2007	2008
		(in thousands)	
Future cash inflows	$ 3,783,163	$ 7,027,334	$ 3,387,228
Future production costs	(1,485,192)	(2,155,902)	(1,652,888)
Future development costs	(441,846)	(562,852)	(636,285)
Future income taxes	(465,412)	(1,275,076)	(10,576)
Future net cash flows	1,390,713	3,033,504	1,087,479
10% annual discount for estimated timing of cash flows	(571,411)	(1,377,863)	(477,383)
Standardized measure of discounted future net cash flows	$ 819,302	$ 1,655,641	$ 610,096

12. SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (UNAUDITED) (Continued)

The following table summarizes changes in the standardized measure of discounted future net cash flows.

	Years ended December 31,		
	2006	2007	2008
		(in thousands)	
Beginning of the year	$ 565,385	$ 819,302	$1,655,641
Changes in prices and production costs	(325,398)	1,145,648	(1,599,448)
Revisions of previous quantity estimates	59,631	179,148	(60,099)
Changes in future development costs	(201,200)	(132,166)	(92,391)
Development costs incurred during the period	113,791	58,393	56,328
Extensions, discoveries and improved recovery, net of related costs	135,578	49,055	110,378
Sales of oil and natural gas, net of production costs	(187,458)	(252,796)	(400,456)
Accretion of discount	89,383	112,108	238,875
Net change in income taxes	26,672	(401,902)	697,089
Sale of reserves in place	(5,071)	—	—
Purchases of reserves in place	551,774	168,210	4,766
Production timing and other	(3,785)	(89,359)	(587)
End of year	$ 819,302	$1,655,641	$ 610,096

13. GUARANTOR FINANCIAL INFORMATION

All subsidiaries of the Company other than Ellwood Pipeline Inc. ("Guarantors") have fully and unconditionally guaranteed, on a joint and several basis, the Company's obligations under the senior notes. Ellwood Pipeline, Inc. is not a Guarantor (the "Non-Guarantor Subsidiary"). The condensed consolidating financial information for prior periods has been revised to reflect the guarantor and non-guarantor status of the Company's subsidiaries as of December 31, 2008. All Guarantors are 100% owned by the Company. Presented below are the Company's condensed consolidating balance sheets, statements of operations and statements of cash flows as required by Rule 3-10 of Regulation S-X of the Securities Exchange Act of 1934.

CONDENSED CONSOLIDATING BALANCE SHEETS
AT DECEMBER 31, 2007
(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ 8,762	$ 973	$ —	$ —	$ 9,735
Accounts receivable	38,020	17,512	65	—	55,597
Inventories	5,217	5,160	—	—	10,377
Prepaid expenses and other current assets	4,391	—	—	—	4,391
Income taxes receivable	6,725	—	—	—	6,725
Deferred income taxes	21,967	—	—	—	21,967
Commodity derivatives	7,780	—	—	—	7,780
TOTAL CURRENT ASSETS	92,862	23,645	65	—	116,572
PROPERTY, PLANT & EQUIPMENT, NET	755,487	374,246	1,299	—	1,131,032
COMMODITY DERIVATIVES	3,768	—	—	—	3,768
INVESTMENTS IN AFFILIATES	431,083	—	—	(431,083)	—
OTHER	13,296	817	—	—	14,113
TOTAL ASSETS	$1,296,496	$398,708	$ 1,364	$(431,083)	$1,265,485
LIABILITIES AND STOCKHOLDERS' EQUITY					
CURRENT LIABILITIES:					
Accounts payable and accrued liabilities	$ 75,524	$ 6,570	$ —	$ —	$ 82,094
Undistributed revenue payable	11,298	—	—	—	11,298
Interest payable	6,839	—	—	—	6,839
Current maturities of long-term debt	3,449	—	—	—	3,449
Commodity and interest derivatives	68,756	—	—	—	68,756
TOTAL CURRENT LIABILITIES:	165,866	6,570	—	—	172,436
LONG-TERM DEBT	691,896	—	—	—	691,896
DEFERRED INCOME TAXES	16,607	—	—	—	16,607
COMMODITY AND INTEREST DERIVATIVES	87,224	—	—	—	87,224
ASSET RETIREMENT OBLIGATIONS	40,587	10,317	816	—	51,720
INTERCOMPANY PAYABLES (RECEIVABLES)	48,714	(11,705)	(37,009)	—	—
TOTAL LIABILITIES	1,050,894	5,182	(36,193)	—	1,019,883
TOTAL STOCKHOLDERS' EQUITY	245,602	393,526	37,557	(431,083)	245,602
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$1,296,496	$398,708	$ 1,364	$(431,083)	$1,265,485

CONDENSED CONSOLIDATING BALANCE SHEETS
AT DECEMBER 31, 2008
(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ 190	$ 1	$ —	$ —	$ 191
Accounts receivable	33,654	7,652	—	—	41,306
Inventories	5,544	6,817	—	—	12,361
Prepaid expenses and other current assets	4,314	—	—	—	4,314
Income taxes receivable	546	—	—	—	546
Commodity derivatives	57,247	—	—	—	57,247
TOTAL CURRENT ASSETS	101,495	14,470	—	—	115,965
PROPERTY, PLANT & EQUIPMENT, NET	580,317	121,353	1,064	—	702,734
COMMODITY DERIVATIVES	35,314	—	—	—	35,314
INVESTMENTS IN AFFILIATES	498,670	—	—	(498,670)	—
OTHER	9,546	695	—	—	10,241
TOTAL ASSETS	$1,225,342	$ 136,518	$ 1,064	$(498,670)	$ 864,254
LIABILITIES AND STOCKHOLDERS' EQUITY					
CURRENT LIABILITIES:					
Accounts payable and accrued liabilities	$ 67,832	$ 7,568	$ —	$ —	$ 75,400
Undistributed revenue payable	8,277	—	—	—	8,277
Interest payable	5,325	—	—	—	5,325
Current maturities of long-term debt	2,598	—	—	—	2,598
Commodity and interest derivatives	21,284	—	—	—	21,284
TOTAL CURRENT LIABILITIES:	105,316	7,568	—	—	112,884
LONG-TERM DEBT	797,670	—	—	—	797,670
COMMODITY AND INTEREST DERIVATIVES	9,363	—	—	—	9,363
ASSET RETIREMENT OBLIGATIONS	68,678	10,107	719	—	79,504
INTERCOMPANY PAYABLES (RECEIVABLES)	379,482	(336,243)	(43,239)	—	—
TOTAL LIABILITIES	1,360,509	(318,568)	(42,520)	—	999,421
TOTAL STOCKHOLDERS' EQUITY	(135,167)	455,086	43,584	(498,670)	(135,167)
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$1,225,342	$ 136,518	$ 1,064	$(498,670)	$ 864,254

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
YEAR ENDED DECEMBER 31, 2006
(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
REVENUES:					
Oil and natural gas sales	$215,300	$53,522	$ —	$ —	$268,822
Other	4,717	52	5,227	(4,526)	5,470
Total revenues	220,017	53,574	5,227	(4,526)	274,292
EXPENSES:					
Oil and natural gas production	58,545	26,910	2,050	—	87,505
Transportation expense	7,204	250	—	(3,921)	3,533
Depletion, depreciation and amortization	53,633	9,483	143	—	63,259
Accretion of asset retirement obligations	2,090	429	23	—	2,542
General and administrative, net of amounts capitalized	27,219	1,389	314	(605)	28,317
Total expenses	148,691	38,461	2,530	(4,526)	185,156
Income from operations	71,326	15,113	2,697	—	89,136
FINANCING COSTS AND OTHER:					
Interest expense, net	51,160	(336)	(2,029)	—	48,795
Amortization of deferred loan costs	3,776	—	—	—	3,776
Interest rate derivative losses, net	590	—	—	—	590
Commodity derivative losses (gains), net	(3,626)	—	—	—	(3,626)
Total financing costs and other	51,900	(336)	(2,029)	—	49,535
Equity in subsidiary income	12,199	—	—	(12,199)	—
Income (loss) before income taxes	31,625	15,449	4,726	(12,199)	39,601
Income tax provision (benefit)	7,674	6,108	1,868	—	15,650
Net income (loss)	$ 23,951	$ 9,341	$ 2,858	$(12,199)	$ 23,951

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

YEAR ENDED DECEMBER 31, 2007

(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
REVENUES:					
Oil and natural gas sales	$ 277,680	$95,475	$ —	$ —	$ 373,155
Other	2,823	54	5,193	(4,715)	3,355
Total revenues	280,503	95,529	5,193	(4,715)	376,510
EXPENSES:					
Oil and natural gas production	73,737	43,840	1,744	—	119,321
Transportation expense	10,491	5	—	(4,435)	6,061
Depletion, depreciation and amortization	78,112	20,622	80	—	98,814
Accretion of asset retirement obligations	3,334	547	33	—	3,914
General and administrative, net of amounts capitalized	29,425	2,344	281	(280)	31,770
Total expenses	195,099	67,358	2,138	(4,715)	259,880
Income from operations	85,404	28,171	3,055	—	116,630
FINANCING COSTS AND OTHER:					
Interest expense, net	62,876	(56)	(2,705)	—	60,115
Amortization of deferred loan costs	4,197	—	—	—	4,197
Interest rate derivative losses, net	17,177	—	—	—	17,177
Loss on extinguishment of debt	12,063	—	—	—	12,063
Commodity derivative losses (gains), net	142,650	—	—	—	142,650
Total financing costs and other	238,963	(56)	(2,705)	—	236,202
Equity in subsidiary income	20,854	—	—	(20,854)	—
Income (loss) before income taxes	(132,705)	28,227	5,760	(20,854)	(119,572)
Income tax provision (benefit)	(59,333)	10,907	2,226	—	(46,200)
Net income (loss)	$ (73,372)	$17,320	$ 3,534	$(20,854)	$ (73,372)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

YEAR ENDED DECEMBER 31, 2008

(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
REVENUES:					
Oil and natural gas sales	$ 412,493	$143,424	$ —	$ —	$ 555,917
Other	3,121	30	5,451	(4,999)	3,603
Total revenues	415,614	143,454	5,451	(4,999)	559,520
EXPENSES:					
Oil and natural gas production	94,110	53,228	2,166	—	149,504
Transportation expense	10,637	24	—	(4,703)	5,958
Depletion, depreciation and amortization	109,846	24,545	92	—	134,483
Impairment of oil and natural gas properties	641,000	—	—	—	641,000
Accretion of asset retirement obligations	3,334	806	63	—	4,203
General and administrative, net of amounts capitalized	39,793	3,308	296	(296)	43,101
Total expenses	898,720	81,911	2,617	(4,999)	978,249
Income from operations	(483,106)	61,543	2,834	—	(418,729)
FINANCING COSTS AND OTHER:					
Interest expense, net	57,260	(18)	(3,193)	—	54,049
Amortization of deferred loan costs	3,344	—	—	—	3,344
Interest rate derivative losses, net	20,567	—	—	—	20,567
Commodity derivative losses (gains), net	(116,757)	—	—	—	(116,757)
Total financing costs and other	(35,586)	(18)	(3,193)	—	(38,797)
Equity in subsidiary income	41,904	—	—	(41,904)	—
Income (loss) before income taxes	(405,616)	61,561	6,027	(41,904)	(379,932)
Income tax provision (benefit)	(14,484)	23,393	2,291	—	11,200
Net income (loss)	$(391,132)	$ 38,168	$ 3,736	$(41,904)	$(391,132)

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2006
(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$ 106,804	$(16,164)	$(1,550)	$—	$ 89,090
CASH FLOWS FROM INVESTING ACTIVITIES:					
Expenditures for oil and natural gas properties	(151,974)	(13,774)	—	—	(165,748)
Acqusitions of oil and natural gas properties	(19,461)	—	—	—	(19,461)
Expenditures for property and equipment and other	(8,734)	(131)	—	—	(8,865)
Proceeds from sale of oil and natural gas properties	8,564	37,825	—	—	46,389
Acquisition of Texcal Energy, net of cash acquired	(456,810)	9,291	—	—	(447,519)
Net cash provided by (used in) investing activities	(628,415)	33,211	—	—	(595,204)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Net proceeds from (repayments of) intercompany borrowings	7,436	(8,689)	1,253	—	—
Proceeds from long-term debt	569,529	—	—	—	569,529
Principal payments on long-term debt	(210,068)	—	(33)	—	(210,101)
Payments for deferred loan costs	(15,335)	—	—	—	(15,335)
Premium to retire debt	—	—	—	—	—
Proceeds from derivative premium financing	3,903	—	—	—	3,903
Proceeds from issuance of common stock	160,393	—	—	—	160,393
Stock issuance costs	(2,874)	—	—	—	(2,874)
Dividend paid to shareholder	(426)	—	—	—	(426)
Net cash provided by (used in) financing activities	512,558	(8,689)	1,220	—	505,089
Net increase (decrease) in cash and cash equivalents	(9,053)	8,358	(330)	—	(1,025)
Cash and cash equivalents, beginning of period	9,041	—	348	—	9,389
Cash and cash equivalents, end of period	$ (12)	$ 8,358	$ 18	$—	$ 8,364

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2007
(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$ 121,086	$ 36,126	$ 3,651	$—	$ 160,863
CASH FLOWS FROM INVESTING ACTIVITIES:					
Expenditures for oil and natrual gas properties	(212,717)	(104,073)	(104)	—	(316,894)
Acqusitions of oil and natural gas properties	(72,512)	(49,310)	—	—	(121,822)
Expenditures for property and equipment and other	(5,182)	(207)	—	—	(5,389)
Proceeds from sale of oil and natural gas properties	829	9,913	—	—	10,742
Acquisition of Texcal Energy, net of cash acquired	—	—	—	—	—
Net cash provided by (used in) investing activities	(289,582)	(143,677)	(104)	—	(433,363)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Net proceeds from (repayments of) intercompany borrowings	(96,601)	100,166	(3,565)	—	—
Proceeds from long-term debt	777,421	—	—	—	777,421
Principal payments on long-term debt	(619,729)	—	—	—	(619,729)
Payments for deferred loan costs	(4,923)	—	—	—	(4,923)
Premium to retire debt	(3,489)	—	—	—	(3,489)
Proceeds from derivative premium financing	3,780	—	—	—	3,780
Proceeds from issuance of common stock	116,595	—	—	—	116,595
Stock issuance costs	(561)	—	—	—	(561)
Proceeds from exercise of stock options	4,777	—	—	—	4,777
Excess income tax benefits from share-based compensation	—	—	—	—	—
Dividend paid to shareholder	—	—	—	—	—
Net cash provided by (used in) financing activities	177,270	100,166	(3,565)	—	273,871
Net increase (decrease) in cash and cash equivalents	8,774	(7,385)	(18)	—	1,371
Cash and cash equivalents, beginning of period	(12)	8,358	18	—	8,364
Cash and cash equivalents, end of period	$ 8,762	$ 973	$ —	$—	$ 9,735

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2008
(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$ 109,898	$ 96,235	$ 6,246	$—	$ 212,379
CASH FLOWS FROM INVESTING ACTIVITIES:					
Expenditures for oil and natrual gas properties	(271,254)	(39,901)	(18)	—	(311,173)
Acqusitions of oil and natural gas properties	(11,857)	(2,422)	—	—	(14,279)
Expenditures for property and equipment and other	(7,228)	(181)	—	—	(7,409)
Net cash provided by (used in) investing activities	(290,339)	(42,504)	(18)	—	(332,861)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Net proceeds from (repayments of) intercompany borrowings	60,931	(54,703)	(6,228)	—	—
Proceeds from long-term debt	260,052	—	—	—	260,052
Principal payments on long-term debt	(169,892)	—	—	—	(169,892)
Payments for deferred loan costs	(963)	—	—	—	(963)
Premium to retire debt	—	—	—	—	—
Proceeds from derivative premium financing	17,993	—	—	—	17,993
Proceeds from issuance of common stock	—	—	—	—	—
Stock issuance costs	(5)	—	—	—	(5)
Proceeds from exercise of stock options	2,961	—	—	—	2,961
Proceeds from disgorgement of stock sale profits	949	—	—	—	949
Restricted stock used for tax withholding	(157)	—	—	—	(157)
Net cash provided by (used in) financing activities	171,869	(54,703)	(6,228)	—	110,938
Net increase (decrease) in cash and cash equivalents	(8,572)	(972)	—	—	(9,544)
Cash and cash equivalents, beginning of period	8,762	973	—	—	9,735
Cash and cash equivalents, end of period	$ 190	$ 1	$ —	$—	$ 191

DIRECTORS AND OFFICERS

Timothy Marquez
Chairman and Chief Executive Officer

William Schneider
President

Timothy A. Ficker
Chief Financial Officer

Terry L. Anderson
General Counsel and Secretary

Douglas Griggs
Chief Accounting Officer

Ed O'Donnell
Senior Vice President, Southern California Operations

Terry Sherban
Vice President, Acquisitions

Kevin Morrato
Vice President, Sacramento Basin Operations

Michael D. Wracher
Vice President, Exploration

Michael G. Edwards
Vice President, Investor Relations

Joel L. Reed, Lead Director
Principal – Relational Advisors

Donna Lucas, Director
CEO/President – Lucas Public Affairs

J.C. "Mac" McFarland, Director
Principal – McFarland Advisors, Inc.

Dr. M.W. Scoggins, Director
President – Colorado School of Mines

Mark Snell, Director
CFO – Sempra Energy

Richard S. Walker, Director
Executive VP & Managing Director – DHR International

CORPORATE OFFICES

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(713) 533-4000

STOCK INFORMATION

Exchange:	NYSE
Ticker:	VQ
CUSIP:	92275P307

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Ernst & Young LLP
Denver, Colorado

LEGAL COUNSEL

Davis Graham & Stubbs LLP
Denver, Colorado

INDEPENDENT RESERVOIR ENGINEERS

DeGolyer and MacNaughton
Dallas, Texas

TRANSFER AGENT

Contact for information regarding changes of address, registration of shares, transfers or lost certificates, or for information about stockholder accounts:

Computershare Trust Company, Inc.
Post Office Box 1596
Denver, Colorado 80201
(303) 262-0600

FORM 10-K

We will provide, without charge, a copy of our Annual Report on Form 10-K for 2008 (including financial statements and schedules but excluding exhibits) to any stockholder who requests one. Requests should be directed to Venoco, Inc., Attention Secretary, 6267 Carpinteria Avenue, Suite 100, Carpinteria, California 93013. Copies of the 10-K and all exhibits thereto may also be obtained from our website.

CODE OF BUSINESS CONDUCT AND ETHICS

The Venoco, Inc. Code of Business Conduct and Ethics is available on our website or a copy may be obtained by writing to the company.

ANNUAL MEETING

The annual meeting of stockholders of Venoco, Inc. will be held at the Sheraton Denver Hotel, 1550 Court Place, Denver, Colorado on May 20, 2009, at 7:30 a.m.

CEO CERTIFICATION

The annual CEO Certification required by Section 303A.12(a) of the New York Stock Exchange Listed Company Manual was provided to the New York Stock Exchange on May 28, 2008.

VQ
LISTED
NYSE

VENOCO, INC.

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